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BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER TO ESTABLISH INTERMEDIATE LOW-CARBON ENERGY PORTFOLIO STANDARDS	Docket No. 20000-___-EA-22 Record No. ________

INITIAL APPLICATION

Pursuant to Wyo. Stat. §§ 37-18-101 and -102 and the Wyoming Public Service Commission ("Commission") Administrative Rules Chapter 1, Sections 3 and 4 "Authority and Definitions"; Chapter 3, Section 38 "Low-Carbon Energy Portfolio Standards", Rocky Mountain Power, a division of PacifiCorp (the "Company"), submits this application ("Application") to satisfy Commission Rule Chapter 3, Section 38(a) ("Section 38(a)") requiring the Company to file an initial application by March 31, 2022 to establish intermediate standards and requirements. The Company is also filing a separate application requesting specific ratemaking treatment pursuant to Wyo. Stat. § 37-18-102(c)(iii) and Section 38(a)(v).

The Company requests approval of the Application by September 1, 2022. In support of the Application, the Company represents as follows:

1. Rocky Mountain Power, an unincorporated division of PacifiCorp, is a public utility operating in the state of Wyoming and is subject to the jurisdiction of the Commission with

regard to its public utility operations, retail rates, service, and accounting practices in Wyoming. PacifiCorp provides retail electricity service as "Rocky Mountain Power" in the states of Wyoming, Utah, and Idaho and as "Pacific Power" in the states of Oregon, Washington, and California.

2. Rocky Mountain Power's principal place of business in Wyoming is 2840 East Yellowstone Highway, Casper, Wyoming, 82609.

3. Formal correspondence and requests for additional information regarding this matter should be addressed to:

By email (preferred): datarequest@pacificorp.com

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Informal inquiries related to this Application may be directed to Stacy Splittstoesser, Wyoming Regulatory Affairs Manager, at (307) 632-2677.

I. BACKGROUND

4. In 2020, the state of Wyoming enacted new statutes requiring the Commission to establish low-carbon electricity generation portfolio standards for public utilities to maximize the

use of carbon capture, utilization, and storage ("CCUS") technology. House Enrolled Act 0079 or House Bill 200 ("HB 200") created Wyo. Stat. §§ 37-18-101 and -102, which became effective on July 1, 2020.

5. HB 200, among other requirements not specifically stated here, authorizes the Commission to allow for and grant reasonable rate recovery to public utilities for the costs of any CCUS technology used to achieve the portfolio standards set by the Commission. *See* Wyo. Stat. § 37-18-102(c)(i). HB 200 also states that the Commission shall authorize a public utility to implement a rate recovery mechanism for prudently incurred incremental costs to comply with the reliable and dispatchable low-carbon standard. Wyo. Stat.§ 37-18-102(c)(iii). The rate recovery mechanism may be established before the utility has incurred incremental costs related to compliance with HB 200.

6. After conducting an administrative rulemaking process, the Commission issued revisions to Chapters 1 and 3 of its rules relating to HB 200. Specifically, Chapter 1, Sections 3 and 4, and Chapter 3, Sections 21 and 38 were revised to implement HB 200. These rules became effective on January 3, 2022. In this Application, Wyo. Stat. §§ 37-18-101 -102 and the Commission rules relating to this statute are referred to generally as the "HB 200 Requirements."

7. Section 38(a) requires each public utility to file an initial application to establish intermediate standards and requirements by March 31, 2022. Each public utility's initial application must include analyses of CCUS technology on certain coal-fired generation units in Wyoming.

II. REQUIREMENTS OF COMMISSION RULE CHAPTER 3 SECTION 38(a) LOW-CARBON ENERGY PORTFOLIO STANDARDS

8. Section 38(a)(i) requires the Company to conduct "[a]n analysis of carbon capture, utilization and storage suitability of a utility's Coal Fired Electric Generation Facilities, owned in whole or in part with another utility or utilities subject to the provisions of Wyo. Stat. § 37-18-102(a)." Per Section 38(a)(i)(A)-(F), the Company analyzed the suitability of each of the Company's Wyoming coal fired electric generation facility for CCUS, including, but not limited to:

- Space requirements and other technical considerations that would support or limit implementation of any given CCUS technology for each unit.
- Proximity to known storage/sequestration locations, carbon dioxide ("CO_2") transport pipelines, and oil fields potentially suitable for enhanced oil recovery ("EOR") or any other possible uses of captured CO_2.
- Relevant environmental and natural resource factors, including potentially applicable pollution control requirements, water availability, and a preliminary identification of all necessary permits with an estimated timeline for obtaining each permit.
- Estimate of generation that would qualify as dispatchable and reliable low-carbon electricity if CCUS technology was installed.
- CCUS impact on current operations.
- Historical and forecasted generation for the past five calendar years, and projected generation for the current year and the next two subsequent years (i.e., 2017 to 2024).

9. The Company also provides other information required by Section 38(a)(ii)-(vi), including, but not limited to:

- A description of public and private entities who submitted CCUS information and proposals to the Company.
- A description of potential offsets or revenue streams for CCUS.
- Results from the economic analysis included in the Company's 2021 Integrated Resource Plan ("IRP"), and other similar economic analyses.

- A description of the rate recovery mechanism the Company proposes relating to the costs incurred to comply with HB 200 Requirements. The Company's request for approval of this mechanism is being filed in a separate application.

- The Company's plan to conduct request for proposal ("RFP") processes for Jim Bridger Units 3 and/or 4 and Dave Johnston Unit 4 that will complete the additional technical analysis for CCUS implementation.

10. PacifiCorp contracted with Kiewit Engineering Group, Inc. ("Kiewit"), an independent third-party engineering firm, to conduct a suitability analysis, per Section 38(a)(i)(A)-(C), including analyzing space and other technical considerations, proximity considerations, and environmental factors, as well as Section 38(a)(vi)(B)-(C), to identify costs and timelines for further technical analyses. Kiewit's analysis is included in Confidential Exhibit 1.1 to this Application.

11. Kiewit performed a technical evaluation of CCUS technologies that could be suitable for application to PacifiCorp's Wyoming coal-fired generation facilities. Technologies were screened for a technology readiness level ("TRL") that would facilitate the required project development timeline and other HB 200 Requirements. Kiewit's analysis included a review of information received through PacifiCorp's 2021 request for expressions of interest ("REOI") process. The REOI was issued to identify and engage with interested parties to explore the feasibility and design of CCUS facilities to remove CO_2 from PacifiCorp's coal-fired generation resources and utilize and/or sequester the removed CO_2.[1] Kiewit's analysis includes a determination of the extent to which the REOI proposals comply with the technical specifications and its professional opinion regarding the technical feasibility of the proposals received.

12. In conjunction with Kiewit's analysis, the Company analyzed the suitability of each PacifiCorp Wyoming coal-fired electric generation facility for CCUS under Section 38(a)(i). The

[1] https://www.pacificorp.com/suppliers/rfps/CCUS-REOI.html

Company has determined that Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 are potentially suitable candidates for CCUS. These identified units: 1) have less expected capital costs that would be incurred for CCUS equipment installation (on a dollar per kilowatt basis); 2) do not have federal closure commitments; and 3) each unit individually would be able to meet a 20 percent threshold if fully allocated to serve Wyoming customers. Among other factors, Dave Johnston Unit 4 is fully owned by PacifiCorp, and has less future environmental regulation compliance issues at this time. Jim Bridger Units 3 and 4 are located in close proximity to CO_2 pipelines, sequestration fields, and oil fields suitable for EOR.

A. Section 38(a)(i) CCUS Suitability Analysis

13. Kiewit considered the following CCUS technologies in the evaluation: 1) amine liquid solvent; 2) oxy-combustion; 3) flameless pressurized oxy-combustion; 4) membrane; 5) cryogenic; and 6) solid sorbent. Kiewit recommends the amine liquid solvent-based technology as the most suitable and determined that the TRL and experience at scale for the other technologies it evaluated are not mature enough to pursue implementation at this time due to the associated scale-up risks.[2]

<u>Suitability of Company Coal Fired Generation Facilities for CCUS, Including Space Requirements and Other Technical Considerations</u>[3]

14. Conceptual site layouts were developed by scaling plot area requirements using data from past projects of similar scale, complexity, and where comparable construction projects were completed. The space required to install CCUS equipment varies depending on the type of technology used. Each plant was evaluated to determine how much space was available for CCUS equipment, balance of plant ("BOP") equipment, and fabrication and equipment laydown areas.

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[2] *See,* Table 1 and Section 3 in Confidential Exhibit 1.1.
[3] Commission Rules Chapter 3, Section 38(a)(i)(A).

Each unit was ranked based on available space and proximity to the units, limitations presented by property boundaries and wetlands, foreseeable complications for construction and implementation of CCUS, and transportation and ease of equipment deliveries.[4] Naughton Units 1 and 2 ranked the most favorable for space requirements as PacifiCorp owns land east of the plant suitable for CCUS and BOP equipment. Dave Johnston Units 1-4 also ranked favorable in available space as PacifiCorp owns ample land near the facility. The Jim Bridger and Wyodak facilities do not rank favorably in space availability as either CCUS equipment and/or BOP equipment may extend past the property lines at those facilities and would require PacifiCorp to lease or purchase additional land to accommodate spacing needs. The facilities are also hindered by other obstacles, such as close proximity to designated wetlands, reclaimed coal combustion residual ("CCR") landfills or impoundments, or power lines that would require relocation.[5]

15. The expected condition of each plant was evaluated based on major retrofits that have been completed along with the age of the units and planned retirement dates. Plants that have been retrofitted with flue gas desulfurization ("FGD"), selective catalytic reduction ("SCR"), or other environmental compliance technology rank more favorably than units with no major retrofits. As a result, Jim Bridger Units 3 and 4 and Wyodak are ranked the most favorable and Dave Johnston Units 1 and 2 and Naughton Units 1 and 2 are ranked least favorable.

<u>Proximity to Known Sequestration Locations, Carbon Dioxide Transport Pipelines, and Oil Fields Potentially Suitable for Enhanced Oil Recovery</u>[6]

16. Coal facility proximity to storage or EOR usage opportunities plays a key role in the overall feasibility of a carbon capture project. Kiewit analyzed the proximity to existing infrastructure including pipelines and utility corridors and the geologic and permitting potential

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[4] Appendix C of Confidential Exhibit 1.1 includes the conceptual site layouts for each plant.
[5] *See,* Sections 5-8 of Confidential Exhibit 1.1 for specific plant and unit evaluations.
[6] Commission Rules Chapter 3, Section 38(a)(i)(B).

near the site for an injection well to be operational. Kiewit determined that the Jim Bridger and Wyodak facilities are the most favorable locations from this perspective, while Dave Johnston and Naughton are less favorable.

17. The overall pipeline infrastructure is documented and displayed through the ArcGIS – geospatial data and mapping program – online datasets from the Wyoming State Geological Survey and the Enhanced Oil Recovery Institute ("EORI") map datasets. The geospatial data is produced through the Wyoming Geological Survey, EORI, and the University of Wyoming. Confidential Exhibit 1.1 includes storage potential and current lateral and trunk CO_2 pipelines in Wyoming, along with the Wyoming Pipeline Corridor Initiative ("WPCI") that established corridors on public lands dedicated for future use of pipelines associated with CCUS, EOR, and delivery of associated petroleum products.[7] Table 10 in Confidential Exhibit 1.1 summarizes PacifiCorp's Wyoming coal facilities proximity to active CO_2 pipelines, EOR fields, WPCI, and indicates whether the facilities are within favorable geologic storage areas and have access to Wyoming's CarbonSAFE[8] project and the Rock Springs Uplift.

18. Jim Bridger and Wyodak appear the most favorable from these perspectives. Jim Bridger has close access to the Rock Springs Uplift, which has the potential to store 25 billion metric tons ("tonnes" or "MT"), is close to both an active pipeline and a WPCI, and has potential for EOR revenue sources enroute to the active pipeline. Wyodak is also relatively close to active pipelines, a WPCI, is located approximately three miles away from CarbonSAFE, and is within a mile of a potential EOR revenue source.

[7] *See*, Section 4.8, Figures 2-3 in Confidential Exhibit 1.1.
[8] The CarbonSAFE project is a Class VI well, currently in the permitting process, which has the potential to store 50 million tonnes.

19. Dave Johnston is limited by its location. It is 30 miles from a WPCI corridor and 50 miles from the nearest active pipeline. There are existing utility corridors that may be beneficial to supporting a future pipeline closer to the plant, but those corridors do not currently create benefit for this evaluation. Surrounding federal lands could increase permitting challenges and increased costs if the existing utility corridors cannot be used. Dave Johnston is, however, near an EOR site that may be a feasible revenue source while still within a favorable geologic storage basin.

20. Naughton is restricted by both its location and the local geologic basin's history. The plant has existing utility corridors that could theoretically be utilized, but it is 23 miles from a WPCI corridor and 38 miles from an active CO_2 pipeline with railroad, topographic changes, river, and major highways crossings, which would increase estimated permitting process timelines and costs. Additionally, there are no EOR opportunities located near Naughton, making it the least feasible regarding carbon storage, use, and infrastructure due to the higher associated costs.

Relevant Environmental Factors, Including Potentially Applicable Pollution Control Requirements, Water Availability, and a Preliminary Identification of all Necessary Permits with an Estimated Timeline for Obtaining Each Permit[9]

21. Kiewit determined that to implement amine-based CCUS, all units would require BOP equipment and a majority of units would require additional pollution control equipment. Jim Bridger Units 3 and 4 did not require additional pollution control equipment. Kiewit also determined that the Jim Bridger units have the best water availability, with potential limitations at Wyodak, Naughton, and Dave Johnston. All units required similar permitting on a similar time frame.[10]

[9] Commission Rules Chapter 3, Section 38(a)(i)(C).
[10] *See,* Sections 5-8 of Confidential Exhibit 1.1 for specific plant and unit evaluations.

Pollution Control Requirements

22. Kiewit determined potentially applicable pollution control requirements based on an amine-based carbon capture system. Amine technology requires the flue gas to be treated for impurities, such as excess nitrogen oxides ("NOx"), sulfur oxides, and particulate matter, before entering the carbon capture system. When sulfur dioxide ("SO_2") is present in the flue gas, it reacts with amine forming heat stable salts ("HSS") which can lead to system salt build-up and solvent degradation. Excess nitrogen dioxide ("NO_2") can also generate HSS when it reacts with the amine solvent. Both SO_2 and NO_2 are present in coal flue gas. These constituents will degrade CO_2 capture capacity and will increase amine consumption over time. While the amine solvent system can operate with these pollutants present, doing so would increase costs and decrease system efficiency. Therefore, it is recommended SO_2 and NO_2 be scrubbed from the flue gas stream before entering the carbon capture system. Kiewit recommended that SO_2 levels should be less than 10 parts per million and NOx levels should be kept as low as possible. The degree to which each coal facility may require reduction of these pollutants requires unit-specific analysis.

23. High efficiency coal-fired units with currently installed wet FGD and SCR are considered the best candidates to implement the amine carbon capture technology followed by wet FGD/no SCR, dry FGD/no SCR, and lastly, no FGD/no SCR. Wet FGD is considered better than dry FGD for amine carbon capture due to higher efficiencies of SO_2 removal and lower flue gas exit temperature. This would reduce the size for the amine carbon capture systems direct contact cooler and additional scrubbing/scrubber. Conversely, retrofits are not attractive for older units with lower efficiencies, nor smaller units. PacifiCorp's Wyoming coal units were evaluated to determine what air quality control ("AQC") system equipment is installed at each facility and what additional equipment may be required at each facility to support application of the amine carbon

capture technology. Table 8 in Confidential Exhibit 1.1 summarizes the current AQC equipment for the units, and AQC and BOP equipment needed for an amine-based carbon capture system.

24. All units would need additional BOP equipment, including water treatment systems, cooling systems, and in some cases, booster ID fans. All units would also require some AQC system technology, except for Jim Bridger Units 3 and 4.

Water Availability

25. Amine carbon capture technology increases a coal unit's water usage by approximately 35-40 percent. Water sources for each facility and allowable storage were reviewed along with plant average and maximum annual consumption. Water consumption requirements to add carbon capture were evaluated against the plant's primary water rights to determine if adequate capacity is available for CCUS.

26. Jim Bridger was found to be the most favorable based on water availability and Wyodak ranked the lowest due to the current air-cooling setup. Dave Johnston would likely be found more favorable once Unit 3 is decommissioned in 2027 when its annual water consumption could potentially be reallocated for carbon capture equipment cooling. Naughton is considered less feasible than other plants unless significant amounts of water could be diverted from the Viva Naughton Reservoir.[11]

Necessary Permits and Timeline

27. Due to the similarities between the four facilities, permitting timelines would be consistent regardless of the unit chosen. The state of Wyoming has primacy for and administers the Clean Air Act and the Clean Water Act throughout much of the state. Each plant would likely need an Industrial Siting Permit, a State Construction Air Permit for modifications to a major air

[11] *See,* Sections 5-8 of Confidential Exhibit 1.1 for specific plant and unit evaluations.

pollution source, and a Floodplain Construction Permit. Each of these permits have long application preparation and review timelines. The total lead time, if concurrent, would take approximately 15 months. In addition to the construction permits needed to make these modifications, the plant would likely need revisions to the facility's Title V Permit and/or the National Pollutant Discharge Elimination System permit for stormwater discharges. This would likely take more than 12 months, depending on the Wyoming Department of Environmental Quality requirements for support materials and modeling needs. The preparation of those permitting support materials could also increase the overall permit revision timeline. Each plant would also need to consider potential waste disposal locations for any hazardous waste material produced by the amine carbon capture system and local solid waste management permit requirements. Other new permits or modifications to current permits may be required depending on the specifics of the retrofit project.[12]

<u>Estimate of Amount of Annual Electricity Generated in Megawatt-Hours that Would Qualify as Dispatchable and Reliable Low-Carbon Electricity with CCUS Installation</u>[13]

28. As shown in Confidential Exhibit 1.2 to the Application, the annual generation that would qualify as dispatchable and reliable low-carbon electricity if CCUS were installed and the corresponding generation portfolio percent were calculated for two scenarios assuming a full-scale carbon capture unit was installed.[14,15] Scenario 1 assumes PacifiCorp owns and operates the carbon capture system; therefore, the carbon capture units' auxiliary load is taken into account when

[12] *Ibid.*
[13] Commission Rules, Chapter 3, Section 38(a)(i)(D).
[14] Full-scale carbon capture means the carbon capture unit is capable of processing all the flue gas produced by the generating unit at the current net dependable capacity.
[15] Wyo. Stat. §§ 37-18-101 defines *dispatchable* as "a source of electricity that is available for use on demand and that can be dispatched upon request of a power grid operator or that can have its power output adjusted, according to the market needs." The assumption, at the time this initial Application was prepared, was that for CCUS to be economically viable a generating unit would have to run at full capacity except during planned and forced outages (equating to approximately an 85 percent capacity factor). Under this assumption, a generating unit retrofitted with CCUS would not meet Wyoming's definition of being *dispatchable* because the units would not be able to dispatch during the 15 percent planned/forced outage times.

estimating annual generation. Scenario 2 assumes a third-party owns and operates the carbon capture unit; therefore, PacifiCorp's annual generation is not impacted by the auxiliary load of the carbon capture unit. Calculations are based on PacifiCorp's Wyoming retail sales from 2021 and an assumption that the unit is 100 percent allocated to Wyoming through the inter-jurisdictional cost and benefit allocation methodology. Other relevant assumptions include: a total carbon capture net auxiliary load of 25 percent;[16] a capture rate of 90 percent; and operation of the generating units at an 85 percent capacity factor, which has been identified by numerous carbon capture companies as necessary for more favorable economics. The results are summarized in *Table 1* below.

Table 1. Estimated Low-Carbon Generation Portfolio Percent[17]

		Scenario 1		Scenario 2	
Facility	**Unit**	**Annual Net Generation (MWh)**	**Estimated Generation Portfolio (%)**	**Annual Net Generation (MWh)**	**Estimated Generation Portfolio (%)**
Dave Johnston	1	552,866	6.5%	737,154	8.6%
Dave Johnston	2	591,957	6.9%	789,276	9.2%
Dave Johnston	3	1,228,590	14.4%	1,638,120	19.2%
Dave Johnston	4	1,842,885	21.6%	2,457,180	28.8%
Jim Bridger	1	1,977,012	23.1%	2,636,016	30.9%
Jim Bridger	2	2,006,797	23.5%	2,675,730	31.3%
Jim Bridger	3	1,947,226	22.8%	2,596,302	30.4%
Jim Bridger	4	1,958,396	22.9%	2,611,195	30.6%
Naughton	1	871,182	10.2%	1,161,576	13.6%
Naughton	2	1,122,485	13.1%	1,496,646	17.5%
Wyodak	1	1,496,646	17.5%	1,995,528	23.4%

*Capacity factor – 85%; carbon capture net auxiliary load – 25% (only applies to Scenario 1).

[16] Confidential Exhibit 1.1, page 27.

[17] Under the currently approved interjurisdictional cost allocation methodology, the 2020 Protocol, generation costs are allocated to the states based on a system generation factor, which for Wyoming, is approximately 15 percent. Because CCUS was not selected in the 2021 IRP as a resource for the preferred portfolio, this analysis assumes that Wyoming would be allocated the full costs and benefits of a Wyoming coal unit with CCUS to comply with the state specific policy. *See,* Docket No. 20000-572-EA-19 (Record No. 15400).

29. Under Scenario 1 (PacifiCorp-owned) Dave Johnston Unit 4 and the Jim Bridger Units 3 and 4 would presumably meet a 20 percent minimum portfolio standard contemplated by Section 38(a)(vi)(D) as well as the 650 pound per megawatt-hour ("lb/MWh") requirement in Wyo. Stat. § 37-18-101(a)(iii).[18] Under Scenario 2 (third-party owned) Dave Johnston Unit 4, the Jim Bridger units, and Wyodak would, presumably, meet a 20 percent minimum portfolio standard as well as the 650 lb/MWh requirement.

Description of the Estimated Operational Impact of CCUS on Each Unit[19]

30. CCUS developers, as well as Kiewit, indicated that the electricity load and steam derate would equate to approximately 25 percent of the net dependable capacity. The auxiliary load will only impact Scenario 1. Additionally, it is assumed the units would be base-load (annual capacity factor of 85 percent) and may therefore not always be dispatched economically.

Historical and Projected Generation for Each Unit[20]

31. Historical and projected generation for each PacifiCorp Wyoming coal unit is included in Confidential Exhibit 1.3 to this Application for years 2017 to 2024.

B. Company Analysis of Suitability of Each Unit for CCUS

32. Based on the information and analysis from Kiewit described above, along with its own analysis, the Company analyzed the suitability of each PacifiCorp Wyoming coal-fired electric generation facility for CCUS as per Section 38(a)(i).**Error! Reference source not found.** Table 2 below identifies which units are the most suitable for CCUS and will be considered further. The Company has determined that Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 are suitable candidates for further CCUS consideration.

[18] Portfolio percent estimated from Wyoming weather-normalized retail sales in 2021.
[19] Commission Rules, Chapter 3, Section 38(a)(i)(E).
[20] *Id.* at Chapter 3, Section 38(a)(i)(F).

Table 2. Wyoming coal units identified for further CCUS consideration.

Facility	Unit	Further Consideration?
Dave Johnston	1	No
Dave Johnston	2	No
Dave Johnston	3	No
Dave Johnston	4	Yes
Jim Bridger	1	No
Jim Bridger	2	No
Jim Bridger	3	Yes
Jim Bridger	4	Yes
Naughton	1	No
Naughton	2	No
Wyodak	1	No

Dave Johnston Units 1 and 2

33. Dave Johnston Units 1 and 2 are not considered to be suitable candidates for CCUS. They are the oldest units evaluated and would require the most additional emissions control equipment (i.e., both SCR and FGD), resulting in higher capital costs. Additionally, under revisions to the federal Effluent Limitations Guidelines and Standards ("ELGs") for the Steam Electric Power Generating Point Source Category for regulation of wastewater discharges from power plants, PacifiCorp has submitted a Notice of Planned Participation to the Wyoming Department of Environmental Quality, Water Quality Division. The Notice of Planned Participation certifies that Units 1 and 2 will cease combusting coal prior to December 31, 2028. Specifically, the ELGs dictate bottom ash impoundments that discharge to waters of the United States are no longer acceptable as "Best Available Technology." The ELG rule allows such discharges to continue until 2028 for certain generating units conditioned on submission of a letter certifying that the units will permanently cease burning coal by December 31, 2028.[21] PacifiCorp

[21] *See* 40 C.F.R. § 423.19(f). As required under the ELG rule, PacifiCorp submitted a certification to the Wyoming Division of Water Quality that the Unit 1 and 2 boilers will cease combusting coal by December 31, 2028.

will continue to evaluate ELG compliance options for the units in accordance with applicable water discharge permits.

34. PacifiCorp also received a front-end engineering design ("FEED") study from a third-party CCUS technology developer for an oxy-combustion retrofit on Dave Johnston Unit 2. Kiewit thoroughly evaluated the possibility of the retrofit and performed a strength weaknesses opportunity threats analysis of the study and concluded that the proposed oxy-combustion technology at Dave Johnston Unit 2 is not feasible at this time. Furthermore, the capital cost estimates, on a dollar per kilowatt basis, derived from the submitted FEED study exceed the costs estimated in the 2021 IRP for amine-based post combustion, which was not selected as a least-cost resource. PacifiCorp is evaluating the FEED study further through IRP modeling, however based on current reviews and analysis, the oxy-combustion proposal is not technically or economically viable for Dave Johnston Unit 2 at this time.

<u>Dave Johnston Unit 3</u>

35. Dave Johnston Unit 3 has an enforceable federal commitment to permanently cease operation by the end of 2027. The Environmental Protection Agency's ("EPA") January 30, 2014 Regional Haze Federal Implementation Plan ("FIP") provided PacifiCorp two alternative paths to comply with the NOx emission limit requirements of the FIP. The first path required PacifiCorp to meet a 0.07 lb/MMBtu[22] emission limit (with an assumed installation of SCR) within five years of final action with no requirement for shut down. The second compliance path required Dave Johnston Unit 3 to permanently cease operation by December 31, 2027 if the SCR requirement was not met by March 4, 2019. Considering the cost of SCR, PacifiCorp opted for the second

[22] MMBtu = one million British thermal units.

compliance path and did not install SCR. The 2027 retirement requirement for Dave Johnston Unit 3 makes the installation of carbon capture infeasible.

Dave Johnston Unit 4

36. The Company has identified Dave Johnston Unit 4 as a potentially suitable candidate for further analysis of carbon capture for the following reasons:

- Ranks favorably on expected plant condition as compared with the older units.
- The unit does not have an SCR but does have a dry FGD installed, which should lower the capital cost for a CCUS system.
- It is expected to meet preliminary low-carbon standard targets, i.e., the 20 percent minimum portfolio standard, assuming 100 percent of the cost and output is assigned to Wyoming.[23]
- There are no complications with co-ownership, as would be the case with Wyodak and the Jim Bridger units.
- It would not require ongoing operation of wastewater impoundments to treat CCR as would be the case at Jim Bridger Units 3 and 4 as well as Naughton Units 1 and 2.
- There are no federal closure or cease-coal commitments at this time.

Jim Bridger Units 1 and 2

37. Jim Bridger Units 1 and 2 are scheduled to be converted to natural gas in 2024 based on the Company's 2021 IRP analysis, which indicated that a portfolio without these units being converted to natural gas would result in higher costs to customers.[24] The natural gas conversion of these units is also enforceable under a consent decree entered into by the state of

[23] Commission Rule Chapter 3, Section 38(c)(i)(C) ("In no case shall a portfolio standard be set at less than twenty percent (20% of retail Wyoming sales for an identified calendar year unless the utility establishes by clear and convincing evidence that a minimum twenty percent (20%) standard is not economically or technically feasible."). Portfolio standard based on 2021 PacifiCorp Wyoming retail sales and operating Dave Johnston Unit 4 at an 85 percent capacity factor.

[24] PacifiCorp's 2021 IRP, Chapter 9 – Modeling and Portfolio Selection Results, pages 269-270.

Wyoming and the Company.[25] Jim Bridger Units 1 and 2, once converted, would not meet HB 200 Requirements because they will be gas-fired units.

Jim Bridger Units 3 and 4

38. The Company has identified Jim Bridger Units 3 and 4 as potentially suitable candidates for further analysis of carbon capture for the following reasons:

- It would meet the 20 percent minimum portfolio standard, assuming 100 percent of the cost and output is assigned to Wyoming.
- SCR and wet FGD systems are already installed, which should significantly lower the capital cost for a CCUS system.
- There are no federal closure commitments at this time.
- It is in relatively close proximity to CO_2 pipelines, sequestration fields and oil fields suitable for EOR.

39. Jim Bridger Units 3 and 4 may have an additional impediment to CCUS implementation because the Jim Bridger power plant is jointly owned with Idaho Power, which does not serve any customers located in Wyoming and is not subject to the Commission's jurisdiction. Additionally, Idaho Power's 2021 IRP indicates their intent to exit Units 3 and 4 in 2025 and 2028, respectively.

40. Commission Rule Chapter 3, Section 38(d) specifically exempts the Company from having to analyze the units at the Jim Bridger power plant because they are partly owned by Idaho Power, which is not subject to the Wyoming Public Service Commission's jurisdiction. However, the study provided by Kiewit and the Company's subsequent analysis indicate that Units 3 and 4 could be suitable for CCUS, and the Company has determined that these units should continue to be evaluated further.

[25] Wyoming Consent Decree, Docket No. 2022-CV-200-333 (February 14, 2022).

<u>Naughton Units 1 and 2</u>

41. Naughton Units 1 and 2 are not considered feasible. The Naughton facility operates ash-disposal impoundments and is subject to the federal CCR rule which was promulgated under the Resource Conservation and Recovery Act and the Clean Water Act.[26] Some CCR impoundments at the Naughton plant are considered 'unlined' according to specifications in the CCR rule. The rule required the facility to (1) cease receipt of waste and initiate closure of unlined CCR impoundments by April 11, 2021; (2) apply for an extended timeline to continue impoundment operation until new, lined impoundments could be built; or (3) demonstrate the need to continue operations of the unlined impoundments due to a lack of alternative capacity, and commit to cease coal-fired operations *and* complete final closure of unlined CCR impoundments no later than October 17, 2028. The Company determined the first two options were either infeasible or cost-prohibitive and subsequently submitted an alternative closure demonstration under the third option to the EPA in November 2020. The demonstration included a commitment to cease coal-fired operation at Naughton Units 1 and 2 by the end of 2025 to allow PacifiCorp to complete final closure of the impacted impoundments by 2028.

42. Additionally, these units rank among the oldest units in the fleet with initial operation years of 1963 and 1968, respectively. Both units have been retrofitted with a wet FGD, but neither unit has an SCR. These units rank the lowest for proximity to sequestration, oil fields, and existing pipelines, and their water availability ranking is lower than other plants.

<u>Wyodak Unit 1</u>

43. Wyodak is not considered feasible. This unit has a dry FGD and fabric filter but does not have an SCR. Wyodak is one of the newest units in the fleet with an operation year of

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[26] 40 C.F.R. Part 257.

1978, which means that expected ongoing operating conditions of Wyodak rank better than Naughton and Dave Johnston due to its age and major retrofits performed. However, the unit ranks at the lower end for available space. The designated wetlands located east of the plant could pose complications with construction areas. This unit ranks high for proximity to sequestration, oil fields, and existing pipelines. However, Wyodak ranks the lowest for water availability, and the increased water needed for the carbon capture system would greatly exceed the current allowed and available consumption limits.

C. Section38(a)(ii) Entities that Have Submitted CCUS Information

44. As required, the Company is providing details for the entities which submitted information to PacifiCorp pertaining to interest in carbon capture under the Company's 2021 REOI process:

- Battelle
- Black & Veatch
- Dastur Energy
- Devon Energy
- Elysian Ventures
- Enchant Energy
- Energy Development Partners
- Frontier Carbon Solutions
- Glenrock Energy
- Glenrock Energy and Kanata America
- ION Clean Energy
- Jupiter Oxygen
- Linde Engineering
- Membrane Technology & Research
- NET Power (with McDermott)
- Starwood Energy Group and North Shore Energy
- Sustainable Energy Solutions, a Chart Company
- Worley
- Wyoming New Power, Black Diamond

D. Section38(a)(iii) Potential Offsets or Revenue Streams for CCUS Projects

Tax Credit Availability[27]

45. 26 U.S.C. § 45Q provides a tax credit for carbon oxide sequestration under section 45Q to incentivize carbon capture and sequestration ("CCS") investments. The tax credit is computed per tonne of qualified carbon oxide captured and sequestered. Carbon oxide can either be permanently disposed of in secure geological storage or the carbon oxide can be utilized – typically as a tertiary injectant in EOR. Currently, the tax credit amount is $35/tonne for utilization and $50/tonne for storage.[28] There is no limit on the amount of tax credits for CCS, but to be eligible for the tax credit, a minimum of 500,000 tonnes of carbon oxide must be captured annually.[29] The tax credit is available for 12 years from the date the carbon capture equipment is originally placed into service.[30]

CO_2 Sale Revenue[31]

46. Revenue from CO_2 sales is a potential opportunity to offset CCUS capital and operating expenses. However, relying on revenue from CO_2 sales for EOR adds risks to the economic viability of a CCUS project, particularly given the statutory limitation on incremental cost recovery in HB 200. The price of CO_2 used in EOR is directly tied to the demand for oil and

[27] Commission Rule Chapter 3, Section 38(a)(iii)(A).
[28] The tax credit reaches $35/tonne and $50/tonne in 2026. "Section 45Q(b)(1)(A)(i)(II) and (ii)(II) provides that the applicable dollar amount for activities under section 45Q(d)(4) for any taxable year beginning in a calendar year (1) after 2016 and before 2027, is an amount equal to the dollar amount established by linear interpolation between $12.83 and $35 for each calendar year during such period, and (2) after 2026, is an amount equal to the product of $35 and the inflation adjustment factor for such calendar year determined under section 43(b)(3)(B) for such calendar year, determined by substituting ''2025'' for ''1990.'' Section 45Q(b)(1)(B) provides that the applicable dollar amount determined under section 45Q." 86 Fed Reg 4729. Section 45Q allows for those "who physically or contractually ensure the capture and disposal of qualified carbon oxide, use of qualified carbon oxide as a tertiary injectant in a qualified enhanced oil or natural gas recovery project, or utilization of qualified carbon oxide in a manner that qualifies for the credit."
[29] 26 U.S.C. § 45Q(d)(2)(B). For an electric generating facility, a minimum of 500,000 tonnes of qualified carbon oxide must be captured per year to receive the 45Q tax credit. Construction of the qualified facility must begin before January 1, 2026.
[30] 26 U.S.C. § 45Q(a)(4)(A).
[31] Commission Rule Chapter 3, Section 38(a)(iii)(B).

therefore the price of oil. The price of oil has seen considerable volatility. Between March 3, 2017 and March 3, 2022 the price of West Texas Intermediate ("WTI") crude oil had a range of $156.24, varying between $(36.98) on April 20, 2020, and $119.26 on March 3, 2022, as shown in Figure 1.

Figure 1. Crude Oil Prices: WTI - Cushing, Oklahoma, Dollars per Barrel, Daily, Not Seasonally Adjusted[32]

Availability of Grants[33]

47. At the time of this application submittal, there are currently no available federal or state CCUS grant or funding opportunities for CCUS systems on coal plants. It is possible that federal grant funding will become available in the future through the Department of Energy ("DOE"). The DOE issued a request for information ("RFI") for the Deployment and Demonstration Opportunities for Carbon Reduction and Removal Technologies (DE-FOA-

[32] U.S. Energy Information Administration, Crude Oil Prices: West Texas Intermediate (WTI) - Cushing, Oklahoma [DCOILWTICO], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/DCOILWTICO, March 15, 2022.
[33] Commission Rule Chapter 3, Section 38(a)(iii)(C).

0002660 / 000001) in December 2021, with responses due February 1, 2022. DOE indicated they will "help demonstrate carbon management and clean energy technologies and prove them out at pilot- to commercial-scale in partnership with industry and communities" with allocations allowed under the Infrastructure Investment and Jobs Act of 2021. As shown in Exhibit 1.4, Berkshire Hathaway Energy submitted a letter in support of DOE's RFI.

E. Section 38(a)(iv) Economic Analysis from 2021 IRP

48. CCUS was not selected as a least-cost resource in the Company's 2021 IRP preferred portfolio. PacifiCorp recognizes that the economic analyses is driven by a wide range of assumptions specific to the cost and commercial structure of CCUS opportunities. Consequently, the Company has established an action plan to proceed with a multiple request for proposal ("RFP") processes that will help identify costs and commercial structures and allow the Company to update this analysis.

49. PacifiCorp modeled eight of its 11 Wyoming coal plants in the 2021 IRP. The three units that were not directly modeled have representative equivalent units that were modeled and used as surrogates. For example, Dave Johnston Unit 1 was not directly modeled but Dave Johnston Unit 2 was modeled. These units are of similar size and need the same/similar additional control equipment for NO_X and SO_2 control; therefore, the capital and operating costs will be similar. The 2021 IRP assumed a revenue stream for CO_2 sales for EOR and 45Q tax credits ($35/tonne). The generating units were assumed to operate at an 85 percent capacity factor, with a 90 percent capture rate, and begin operation in 2026 and operate for 20 years. Assumptions and costs used to model carbon capture in the 2021 IRP can be found in Tables 7.1 and 7.2.[34] Costs are

[34] PacifiCorp's 2021 IRP, Chapter 7 – Resource Options, pages 169-185.

on a post-retrofit basis, assuming an amine-based carbon capture system owned and operated by PacifiCorp. All costs are in 2020 dollars.

50. To evaluate the cost to comply with HB 200, the Company ran a variant of the P02-MM[35] portfolio that forced a CCUS retrofit in 2026 on Dave Johnston Unit 4 (scenario P02g-CCUS).[36] Changes in proxy resources and system costs driven by the CCUS retrofit can be isolated by comparing this variant to the P02-MM portfolio.

51. Through 2040, the present value revenue requirement differential ("PVRR(d)") shows that the portfolio with CCUS installed on Dave Johnston Unit 4 is $271 million higher cost than the P02-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio with the Dave Johnston Unit 4 CCUS retrofit is $235 million higher cost than the P02-MM portfolio. On a short-term study ("ST") PVRR basis, capital cost assumptions for the CCUS retrofit at Dave Johnston Unit 4 would need to decrease by approximately 33 percent to achieve break-even economics in the MM price-policy scenario—initial capital would need to drop from $1.14 billion to $761 million. Alternatively, the EOR revenue stream assumed in this analysis (from a credit-worthy counterparty) would need to increase by approximately 84 percent to achieve break-even economics under the MM price-policy scenario.

52. The portfolio that includes the CCUS retrofit at Dave Johnston Unit 4 is higher cost than the P02-MM portfolio across each of the price-policy scenarios. This trend holds true for both the ST PVRR and the risk-adjusted PVRR results. Both portfolios, as measured by energy not served, are very reliable among all price-policy scenarios. Emissions are slightly lower when CCUS is installed on Dave Johnston Unit 4 (approximately one percent relative to the P02-MM

[35] MM – medium gas, medium CO_2 price policy scenario.
[36] PacifiCorp's 2021 IRP, Chapter 9 – Modeling and Portfolio Selection Results, pages 284-286.

portfolio). The magnitude of the increased cost in the portfolio that includes a CCUS retrofit on Dave Johnston Unit 4, which would be situs-assigned to Wyoming customers, is expected to exceed the cost containment language set forth in HB 200, and for this reason, it is not included in the preferred portfolio.

53. Since the completion of the 2021 IRP, the Company performed additional modeling on Jim Bridger Units 3 and 4 based on updated information, including information PacifiCorp received through the 2021 REOI process. The Company updated the assumptions in the model to reflect that the Company would own and operate the carbon capture system for 12 years, would receive 45Q tax credits for storage, and pay a third-party to off-take the CO_2. Through 2040, the PVRR(d) shows that the portfolio with CCUS installed on Jim Bridger Units 3 and 4 is $410 million higher cost than the P02-MM portfolio. On a risk-adjusted basis, the portfolio with the Jim Bridger Units 3 and 4 CCUS retrofit is $384 million higher cost than the P02-MM portfolio. On a ST PVRR basis, capital cost assumptions for the CCUS retrofit at Jim Bridger Units 3 and 4 would need to decrease by approximately 43 percent to achieve break-even economics in the MM price-policy scenario—initial capital would need to drop from $1.25 billion to $713 million. Alternatively, the off-take fee assumed in this analysis would need to decrease by approximately 130 percent to achieve break-even economics under the MM price-policy scenario. The results of this analysis are shown in Confidential Exhibit 1.7.

F. Section 38(a)(v) Description of Proposed Rate Recovery Mechanism

Annual Collection from Wyoming Customer's Electric Bill[37]

54. The Company estimates the annual collection from Wyoming customer's total electric bill, allowable under HB 200's two percent recovery limitation, would be approximately

[37] Commission Rule Chapter 3, Section 38(a)(v)(A).

$13.1 million per year. As shown in Exhibit 1.5, the two percent recovery equates to a capital project estimated at a $100 million dollar project with a 20- to 30-year life. For one full-scale carbon capture system, the capital costs are estimated to range from approximately $400 million to $1 billion. Exhibit 1.5 also includes the first-year revenue requirement associated with various levels of capital investment and various depreciable lives, assuming the Company's current authorized return on equity of 9.5 percent.

55. To account for costs of conducting the technical analysis, developing and administering the RFP, and if feasible, completing a CCUS project, the Company proposes a surcharge on customer bills of 0.5 percent before taxes. The surcharge is proposed to be implemented in a new tariff Schedule 198 Carbon Capture Storage and Utilization, which has been filed in a separate application.

56. The 0.5 percent surcharge will collect approximately $3.1 million in revenue from Wyoming customers on an annual basis and will be applicable to all customers served by the Company in the state of Wyoming.

57. The Company is proposing to implement a balancing account mechanism that will track actual costs incurred against revenues collected. The Company would file an application on an annual basis that will report costs that the Company proposes to be offset by the surcharge revenues, and the current revenue balance in the mechanism. The Company will request a change in the surcharge if costs are exceeding revenues to comply with HB 200 Requirements. This proposal will allow the Company additional time to determine if the CCUS plan is economically feasible and, if necessary, increase the surcharge gradually in the future up to the two percent cap allowed in Wyo. Stat. § 37-18-102(c)(iii). The Company has included a description of the rate recovery mechanism along with the proposed surcharge and tariff sheets in a separate application.

Proposal for a Higher Rate of Return on Equity[38]

58. The Company is not currently proposing a higher rate of return on equity for a CCUS project. Once the Company has conducted its RFP processes, as described further below, a higher rate of return on equity may be proposed in the Company's final plan that is required to be filed no later than March 31, 2023.[39]

G. Plan to Complete CCUS Technical Analysis

Identification of Suitable CCUS Locations[40]

59. The Company (with Kiewit) has conducted a technical analysis, described in the previous paragraphs. Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 were identified as technically feasible units for further analysis.

Timeline and Description of Technical Analysis[41]

60. The Company intends to conduct two RFPs using the results of the Kiewit study as a starting point. Specifically, the Company will issue two concurrent RFPs to engineer, procure, and construct a CCUS system, one at Dave Johnston Unit 4 and one at Jim Bridger Units 3 and/or 4. Each bidder in the RFP process will be required to perform the level of technical analysis needed to submit a proposal that is within the risk tolerance of the organization submitting the proposal. This process will result in lower costs than if the Company conducted the technical analysis, can be competitively bid and is anticipated to meet the schedule required by the Commission's Rules.[42] The RFP process plans are consistent with the Company's typical RFP process.

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[38] Commission Rule Chapter 3, Section 38(a)(v)(B).

[39] Based on the Company's proposed process outlined in this Application, an extension to the March 31, 2023 deadline may be necessary to complete and file the final plan analysis as required in the Commission's Rules, Chapter 3, Section 38(c).

[40] Commission Rule Chapter 3, Section 38(a)(vi)(A).

[41] *Id.* at Chapter 3, Section 38(a)(vi)(B).

[42] If the Company were to conduct pre-FEED and FEED studies for the selected units, it is estimated to cost $16.2 to $38.4 million and take approximately 1 to 2 years to complete.

61. The process for the RFPs is estimated to be completed in 9 to 23 months at an estimated cost of $1 to $2 million. For bidders to submit a lump sum turn-key bid, they will need to conduct detailed engineering design and analysis (i.e., additional technical analysis).

62. The RFP processes will be executed in phases. The phases and timeline are described in Table 4, below.

Table 4. Construction RFP Timeline Description

Phase	Key Activities	Timeframe
Construction RFP Development and Issue	Hire an owner's engineer; prepare procurement plan, commercial terms and conditions, bidding instructions, and technical specifications; compile and coordinate documents to form a complete RFP; identify and send RFP to potential bidders.	4-14 weeks
Preparation and Submittal of Proposals	Bidders submit participation statement; Company holds pre-bid conference and site visit; Company responds to bidder questions; bidders prepare and submit proposals.	12-52 weeks
Evaluation of Proposals and Identification of Bidder Short List	Evaluation of commercial terms and conditions exceptions, technical exceptions, financial capability, and schedules and milestones; perform economic analysis; resolve questions concerning bids; identify bidder short list.	4-16 weeks
Negotiation with Bidders for Signed Contract	If bids are economically viable, then: select successful bidder based on resolution of any final questions, additional economic analysis, and the result of negotiated terms and conditions of final contract; obtain corporate and regulatory approval; sign contract.	2-12 weeks
Total		9-23 months

Incremental Costs of Technical Analysis[43]

63. Having bidders perform the technical analysis necessary to prepare their bids should limit incremental costs to customers. The Company estimates that it will incur $1 to $2 million in administering the RFPs and evaluating the bidder responses. The Company proposes to

[43] Commission Rule Chapter 3, Section 38(a)(vi)(C).

recover these costs through the 0.5 percent surcharge described above, which has been submitted as a separate application.

Estimate of Generation at twenty, forty, sixty, and eighty percent portfolio standard[44]

64. Dave Johnston Unit 4 or Jim Bridger Units 3 or 4 could all presumably meet a minimum 20 percent portfolio standard if the unit is situs-assigned to Wyoming. No single unit with a full-scale carbon capture system could meet a 40 to 80 percent portfolio standard.

65. It is possible to achieve the 40, 60, and 80 percent portfolio standards in select years if more than one carbon capture system were installed. Exhibit 1.6 displays the projected incremental costs associated with 20, 40, 60, and 80 percent portfolio standards based on actual and forecasted Wyoming retail sales from 2021 to 2030.

2021 Actual Retail Sales and Forecast Retail Sales for 2021-2030[45]

66. The Company's actual retail sales for 2021 and forecasted retail sales for 2021-2030 are included in Exhibit 1.6 to this Application.

Estimate of the Highest Economically Feasible Portfolio Standard[46]

67. The economic feasibility of the portfolio standard will be determined by the results of the RFPs, as described above. Based on preliminary estimates included in Exhibit 1.6, there is not a portfolio standard that is economically feasible at this time. However, the Company is actively exploring possibilities and will consider all viable bids submitted in the RFPs.

III. CONCLUSION

Rocky Mountain Power has provided the required information for this initial Application as required by the Commission's rules. The Company has determined that Dave Johnston Unit 4

[44] Commission Rule Chapter 3, Section 38(a)(vi)(D).
[45] Commission Rule Chapter 3, Section 38(a)(vi)(D)(I-II).
[46] Commission Rule Chapter 3, Section 38(a)(vi)(E).

and Jim Bridger Units 3 and 4 are potentially suitable candidates for CCUS and will be further analyzed under the Company's process proposed in this initial Application. The Application, exhibits and supporting analyses developing the low-carbon portfolio standards are prudent and in the public interest and the Company respectfully requests the Commission approve the Application no later than September 1, 2022.

Submitted this 31st day of March, 2022.

ROCKY MOUNTAIN POWER

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