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May 6, 2022

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: *Investigation by the Department of Public Utilities into the role of local gas distribution companies as the Commonwealth achieves its target 2050 climate goals,* D.P.U. 20-80

Dear Secretary Marini:

By Hearing Officer Memorandum, dated March 24, 2022, in the above referenced docket, the Department of Public Utilities ("Department") invited shareholder comment on the local gas distribution companies ("LDCs") March 18, 2022, filings. The Office of the Attorney General appreciates the opportunity to offer comments and recommendations for the Department's consideration. In addition, enclosed is a Certificate of Service.

The AGO provides the following:

1. *The Office of the Attorney General's Initial Stakeholder Comments on Consultants' Technical Analysis of Decarbonization Pathways Report*, which provides the AGO's initial comments on the developed pathways set forth in the Independent Consultant Technical Analysis of Decarbonization Pathways and the assumptions underlying the analysis.

2. *Regulating Uncertainty, The Office of the Attorney General's Recommendations to Guide the Commonwealth's Gas Transition to a Net-Zero Future*, which advances the AGO's regulatory recommendations to support the equitable and safe transition to net-zero greenhouse gas emissions by 2050.

When opening this investigation, the Department correctly identified that revision of the regulatory framework – not determination of specific investments or technologies – would be the intended purpose. Toward this end, the AGO's recommendations advance a broad and thorough discussion of regulatory policy which should precede any authorization of specific investments or regulatory approval of untested and/or unreasonably costly technologies. The AGO appreciates the Department's Investigation and the work it has done to date. The sooner the Department acts to adjust the gas utility regulatory framework, the greater the opportunity to control costs for ratepayers, enhance equity, and meet the Commonwealth's decarbonization goals.

Respectfully submitted,

/s/ Rebecca L. Tepper
Rebecca L. Tepper
Chief, Energy and Environment Bureau

Along with Assistant Attorneys General,
Jo Ann Bodemer
Donald Boecke
Jessica Freedman
Clare Harmon

Enclosures
cc: Sarah Smegal, Hearing Officer
D.P.U. 20-80 Service List

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

INVESTIGATION BY THE DEPARTMENT OF PUBLIC UTILITIES INTO THE ROLE OF GAS LOCAL DISTRIBUTION COMPANIES AS THE COMMONWEALTH ACHIEVES ITS TARGET 2050 CLIMATE GOALS	**)**	**D.P.U. 20-80**

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing documents upon all parties of record in this proceeding in accordance with the requirements of 220 C.M.R. 1.05(1) (Department's Rules of Practice and Procedure). Dated at Boston this 6th day of May, 2022.

/s/ Rebecca L. Tepper
Rebecca L. Tepper
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REGULATING UNCERTAINTY

**THE OFFICE OF THE ATTORNEY GENERAL'S
REGULATORY RECOMMENDATIONS TO GUIDE THE COMMONWEALTH'S
GAS TRANSITION TO A NET-ZERO FUTURE.**

MAURA HEALEY
ATTORNEY GENERAL

By: Rebecca L. Tepper
Chief, Energy and Environment Bureau

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MAY 6, 2022

TABLE OF CONTENTS

I. INTRODUCTION

More than half of Massachusetts residents depend on natural gas ("gas")[1] to heat their homes.[2] Massachusetts homes and businesses receive gas primarily from monopoly utility companies that own and operate networks of distribution pipelines regulated by the Department of Public Utilities ("Department" or "DPU"). Today—with considerations of climate change and equity at the forefront, and with electric technologies offering competitive alternatives to fossil fuels—the Office of the Attorney General ("AGO") submits its recommendations for how the Department should regulate gas utilities to ensure a safe, equitable, reliable, and net-zero-emissions future for the Commonwealth.

In 2021, *An Act Creating a Next Generation Roadmap for Massachusetts Climate Policy*[3] (the "Climate Act") established a statutory mandate for the Commonwealth to achieve net-zero greenhouse gas ("GHG") emissions by the year 2050 and at least a 50 percent reduction in GHG emissions by 2030. The building sector—the heating and cooling of residential, commercial, and industrial buildings—will be required to achieve at least a 33 percent reduction in its GHG emissions by 2030.[4]

At the same time, the U.S. gas industry is undergoing a period of significant change.[5] Increased exports of natural gas from North America to meet global demand, competitive heating

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[1] Similar to other fossil fuels, "natural gas" is derived from extraction of resource deposits either through wells, or more recently, from fracking (forcing water, chemicals, and sand down a well under high pressure).

[2] U.S. Census Bureau, Massachusetts, *House Heating Fuel, Table B25040, 2019 ACS 1-Year Estimates Detailed Tables and Energy Information Administration* (retrieved on September 9, 2021), *available at* https://www.eia.gov/state/print.php?sid=MA.

[3] *An Act Creating a Next Generation Roadmap for Massachusetts Climate Policy*, *available at*: https://malegislature.gov/Laws/SessionLaws/Acts/2021/Chapter8 (directing, among other things, implementation of sector-specific interim emissions sublimits in support of the 2050 net-zero emissions limit, including sector-specific GHG emissions sublimits for residential heating, and for natural gas distribution and service).

[4] *See* Executive Office of Energy and Environmental Affairs ("EEA"), *Clean Energy and Climate Plan Presentation* (April 14, 2022) at 5, 10, 14, *available at* https://www.mass.gov/doc/2025-2030-cecp-public-hearings-presentationenglish/.

[5] McKinsey & Company, *The Future of Natural Gas in North America* (January 6, 2020), *available at* https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/the-future-of-natural-gas-in-north-america.

alternatives, greater urgency to address methane emissions, and indoor air pollution awareness are increasing pressure on gas Local Distribution Companies ("LDCs") pricing and sales.[6]

In Massachusetts, these large-scale pressures and the State's nation-leading laws requiring significant GHG reductions will result in a decline in the volume of natural gas sales over the coming decades. Indeed, the Commonwealth's 2050 Climate Roadmap Report issued by the EEA in December 2020 forecasts a decline in volumetric gas sales across all modeled scenarios.[7]

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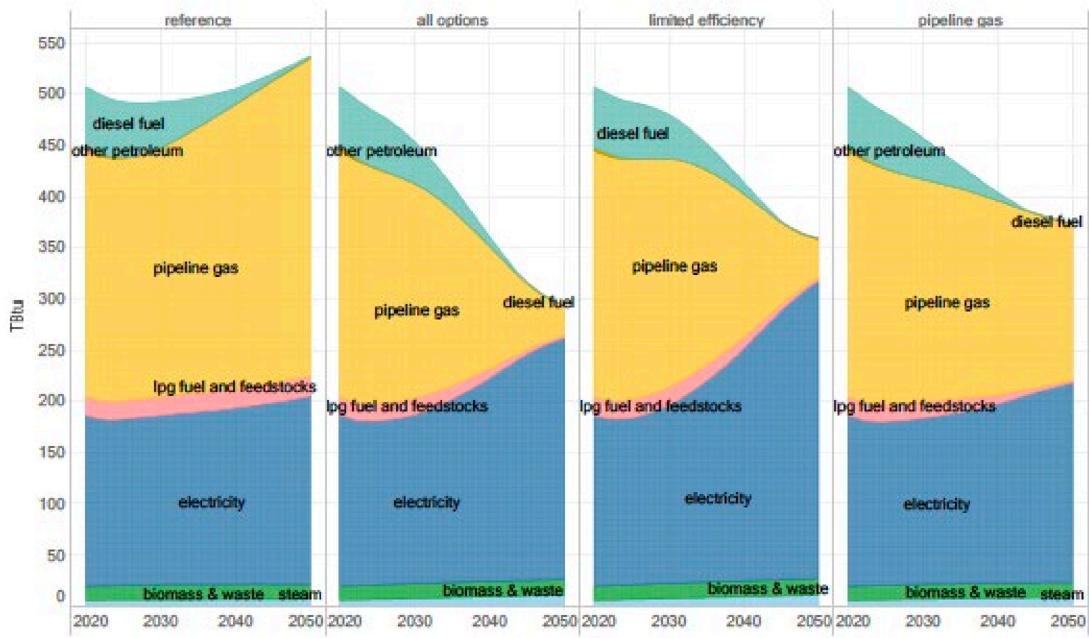
[6] United States Energy Information Administration ("EIA"), *Natural Gas Exports and Re-Exports by Country*, *available at* https://www.eia.gov/dnav/ng/ng_move_expc_s1_a.htm (for U.S. exports of liquefied natural gas ("LNG")); Massachusetts Clean Energy Center ("MassCEC"), *Your Guide to Air Source Heat Pumps*, *available at* https://goclean.masscec.com/wp-content/uploads/2021/01/MassCEC_ASHP_GUIDE.pdf; MassCEC, *Your Guide to Ground Source Heat Pumps*, available at https://goclean.masscec.com/wp-content/uploads/2021/01/MassCEC_GSHP_GUIDE.pdf (for electric end-use technologies); Alvarez et al., *Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain*, in *Science* (June 2018), at 186–188, *available at* https://www.science.org/doi/10.1126/science.aar7204?url_ver=Z39.88-2003&rfr_id=ori:rid:crossref.org&rfr_dat=cr_pub%20%200pubmed; United States National Oceanic and Atmospheric Agency, *Methane Emissions Report*, *available at* https://www.noaa.gov/news-release/increase-in-atmospheric-methane-set-another-record-during-2021; International Energy Agency, *Methane Tracker 2022*, *available at* https://www.iea.org/reports/global-methane-tracker-2022 (for methane emissions); Zhang et al., *Measurement of Ultrafine Particles and Other Air Pollutants Emitted by Cooking Activities*, in *International Journal of Environmental Research and Public Health* (April 2010) at 1744–1759 (for indoor air pollution from combustion of natural gas).

[7] *See* EEA, *Energy Pathways to Deep Decarbonization: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study* (December 2020) ("EEA Roadmap Report"), at 45, Figure 12; *see also id.,* at 83 (modeling a doubling of gas rates due to reduced throughput and the higher cost of decarbonized gas, while average electricity rates stay more or less constant).



The LDCs' Independent Consultant Report[8] confirms this forecast of a long-term decline in gas volumetric consumption across a range of scenarios. According to the Independent Consultant Report, "[m]ost notable in the final energy demand across scenarios is the increased reliance on electricity and the reduction in fossil fuels over time."[9] A wide range of stakeholders agree with the EEA assessment of the logical consequence: the number of gas customers and the volume of gas sales will decline over the coming decades.[10]

The prospect of a declining volume of gas sales presents risk and uncertainty for LDCs and gas customers. LDCs seek to apportion their fixed costs over the greatest number of customers and to sell the largest volume of gas in order to lower the unit cost, or rate, of gas.[11] A decline in gas sales would lead to an increase in the rate of gas, making it more expensive for customers and

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[8] Independent Consultant Report, Technical Analysis of Decarbonization Pathways (March 18, 2022) (the "Independent Consultant Report").

[9] *Id.,* at 47, 50, Figure 15.

[10] *See e.g.*, Acadia Center, *Considerations for LDC and Consultant Use of 2050 Roadmap and 2030 Clean Energy Climate Plan* (May 21, 2021), at 2, *available at* https://acadiacenter.org/resource/considerations-for-ldc-and-consultant-use-of-2050-roadmap-and-2030-clean-energy-climate-plan-in-d-p-u-docket-20-80/.

[11] *See* John Wolfram and Catalyst Consulting, LLC, *Straight Fixed Variable Rate Design* (2013), *available at* http://www.catalystcllc.com/wp/wp-content/uploads/2016/02/StraightFixedVariableRateDesign.pdf.

further encouraging some customers to seek alternatives. The gas regulatory framework[12] that has developed over the last several decades has relied upon a steady and continuous growth of the gas system. Declining gas sales precipitates the need for a new regulatory framework better designed to manage and allocate the risks of a changing gas system, protect the ratepayers who are least able to pay higher heating costs, and better guide the billions of dollars invested toward achieving a decarbonized future.

Risk and its proper allocation between utility shareholders and ratepayers are at the center of most modern regulatory policy.[13] Exposure to some amount of risk, and reward, can act as an important incentive for utilities to expertly manage the planning and operation of complex networks. The challenge that regulators, ratepayers, and gas utilities face today is reaching agreement on the allocation of existing and new risks that arise as the gas industry changes, in part due to decarbonization and in part due to competition from electric end-use technologies. In this proceeding, the Department should take on that challenge by designing a long-term regulatory framework that appropriately allocates the business planning risk of this new period to guide the gas industry over the coming decades. The Department need not, and indeed should not, select a technology pathway for the future, much less pre-authorize utility costs based on specific pathways.

In 2020, the Office of the Attorney General petitioned to initiate this proceeding as a broad investigation into the "business planning and financial implications" for the gas utility in an increasingly electrified future.[14] In its Order opening this Investigation,[15] the Department affirmed that the goal would be to "develop a regulatory and policy roadmap to guide the evolution of the gas distribution industry, while providing ratepayer protection and helping the Commonwealth achieve its goal of net-zero GHG emissions energy."[16] The Department correctly identified that

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[12] For purposes of this discussion, the AGO defines the "gas regulatory framework" as the existing framework established pursuant to applicable law and policy, and by Department orders and regulations pursuant to its authority to regulate the operation of gas utilities in the Commonwealth.

[13] Janice A. Beecher and Steven G. Kihm, *Risk Principles for Public Utility Regulators*, Michigan State University Press (2016); Binz et al., *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know* (2012), *available at* http://www.rbinz.com/Binz%20Sedano%20Ceres%20Risk%20Aware%20Regulation.pdf.

[14] *See* Petition of the Office of the Attorney General (June 4, 2020) (noting that "policymakers and stakeholders are presently discussing and examining various electric-dependent pathways to achieve the 2050 climate requirements, there has been little public discussion of the resulting business planning and financial implications of building electrification and related initiatives that will need to be implemented with sufficient lead time to comply with 2050 emissions reduction mandates").

[15] *See* Appendix A *infra*, providing a procedural summary of D.P.U. 20-80.

[16] Order Opening Investigation (October 29, 2020), at 5.

the regulatory framework—not specific investments or technologies—would be the subject of this Investigation. Toward this end, the AGO offers its recommendations to advance a broad and thorough discussion of regulatory policy—a discussion that should precede any authorization of specific investments or regulatory approval of untested and/or costly technologies. The AGO appreciates the Department's Investigation and the work that it has done to date. The sooner that the Department acts to adjust the gas utility regulatory framework, the greater the opportunity to control costs for ratepayers, enhance equity, and meet the Commonwealth's decarbonization goals.

The following discussion sets forth the AGO's recommendations to better align the regulatory framework for gas utilities with the achievement of the Commonwealth's climate goals and equity priorities. This discussion proceeds as follows: Section II describes the existing gas regulatory model and its shortcomings; Section III details the uncertainties and risks that the gas utilities, regulators, and ratepayers face in an era of decarbonization; Section IV proposes principles to guide regulators as they manage the clean energy transition; and Section V provides specific recommendations for changes to the regulatory framework.

II. THE CURRENT REGULATORY FRAMEWORK

A. The Current Regulatory Framework is Premised on Growth and Customer Acquisition

The primary objective of the current regulatory framework, as established in State law, Department regulations, and a myriad of Department orders, is to maintain safe, affordable, and reliable natural gas service.[17] To achieve this objective, current gas regulatory policy has relied upon and explicitly encouraged continuous growth in the volume of gas sales and the number of gas customers to fund the capital investment and operating expenses necessary to safely maintain the gas system.[18] Over the last few decades, this growth-focused approach has succeeded: the number of residential gas customers in Massachusetts has increased from 1.08 million in 1987 to

[17] *See generally* G.L., c. 164, *et seq*.

[18] *See e.g.*, St. 2014, c. 149, § 3 (authorizing Department review and approval of gas utility programs that increase the availability and affordability of gas service to customers); *NSTAR Gas Company d/b/a Eversource Energy*, D.P.U.16-79, at 10 (noting same); American Gas Association, *Ratemaking for Energy Pipelines* (2011) at 4, *available at* https://www.phmsa.dot.gov/sites/phmsa.dot.gov/file/docs/Ratemaking%20for%20Energy%20Pipelines%20071111.pdf (providing a general overview of gas utility ratemaking). Also *Bay State Gas Company,* D.P.U. 09-30, at 94 (2009).

1.86 million in 2020[19] and the volume of gas delivered for residential heating has increased by over 35 percent from 1990 to 2020.[20]

Three complementary regulatory priorities have led regulators and legislators to adopt a framework that encourages gas system expansion.[21] First, the addition of new customers economically benefitted existing gas customers by allowing the fixed costs of the gas distribution system to be apportioned over an increasing customer base. Second, the environmental benefits due to lower CO_2 emissions of gas resulting from the conversion of oil and propane heating customers.[22] The conversion of oil customers to natural gas helped Massachusetts to reduce the volume of fuel oil used to heat buildings by over 50 percent from 1990 to 2020, resulting in a reduction of GHG emissions from the building thermal sector.[23] Third, the regulatory imperative to improve safety led to accelerated investment in system improvements through the Gas System Enhancement Program ("GSEP").[24] Motivated by these policy priorities, the regulatory framework—the gas planning process, revenue decoupling methodology, and cost-of-service regulation—consistently incentivized the gas distribution system's expanse, volume, and customer base.

B. <u>A Model Based on Growth is No Longer Appropriate or Realistic</u>

The policy priorities of the regulatory and legislative framework that supported gas expansion are no longer supported by a realistic assessment of industry conditions. First, the growing congestion of regional gas pipeline capacity has changed the economics of adding new

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[19] EIA, *State Energy Data System*, (data retrieved on September 21, 2021) *available at*: https://www.eia.gov/dnav/ng/hist/na1501_sma_8a.htm.

[20] EIA, *State Energy Data System*, (data retrieved on September 21, 2021), *available at*: https://www.eia.gov/dnav/ng/hist/n3010ma2a.htm.

[21] The Legislature's passage of the 2021 Climate Act expresses a policy that prioritizes GHG reductions and is in direct conflict with its earlier policy prioritizing gas system expansion (St. 2014, c. 149, § 3, *supra*). The Climate Act represents the current Commonwealth policy and should serve as the Department's primary guide when taking regulatory action. *See* discussion, *infra* at 46.

[22] *See* Alvarez et al., *Assessment of methane emissions from the U.S. oil and gas supply chain*, *available at* https://www.science.org/doi/10.1126/science.aar7204.

[23] EIA, *State Energy Data System* (data retrieved on September 21, 2021), *available at*: https://www.mass.gov/info-details/ghg-emissions-and-mitigation-policies#greenhouse-gas-emissions-trends-.

[24] In 2014, the Massachusetts Legislature passed *An Act Relative to Natural Gas Leaks*, Acts of 2014, Chapter 149 ("2014 GSEP Act"). The legislation permitted local gas distribution companies to submit to the Department annual plans to repair or replace aged natural gas infrastructure in the interest of public safety and to reduce lost and unaccounted for gas. The Act is codified at G.L. c. 164, §§ 144–145.

customers and gas load and challenges the core assumption that increasing the volume of gas consumption and the number of gas customers will lower the cost of gas services for all customers.[25] Second, continued investment in gas system infrastructure and customer acquisition is inconsistent with current State climate laws.[26] Finally, increased awareness regarding the risk to health and safety from both the combustion of fossil fuels within buildings[27] and methane emissions from pipeline leaks have raised questions about the environmental and health impacts of gas use versus other heating options.[28] Indeed, the scientific community has identified that the combustion of gas within homes contributes to dangerous indoor air quality and that methane emission leaks in gas appliances and pipelines represent a significant source of GHG emissions.[29]

The projected decline in customers also calls into question the wisdom of rapidly escalating distribution system investment under GSEPs. GSEP costs continue to trend upward, with more expensive GSEP projects yet to be completed.[30] Eversource's projected gas distribution system capital spending doubled from 2019 to 2022 and is expected to remain at that higher level for 2022

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[25] *See* Black and Veatch, *Natural Gas Infrastructure and Electric Generation* (2012) prepared for New England States Committee on Electricity, at 10.

[26] *See generally e.g.*, EEA Roadmap Report (modeling decreasing gas demand and increasing electrification in preferred "all-options" pathway).

[27] Brett Singer, *Kitchen Ventilation Solutions to Indoor Air Pollution Hazards from Cooking*, *available at* https://www.arb.ca.gov/research/seminars/singer2/singer2.htm. (providing data from the California Air Resources Board suggesting that roughly 55–70 percent of homes that cook with gas exceed the ambient air standard for nitrous oxide).

[28] *See* Sargent et al., *Majority of US Urban Natural Gas Emissions Unaccounted for in Inventories* (November 2, 2021) PNAS 118(44) e2105804118, *available at,* https://doi.org/10.1073/pnas.2105804118

[29] Logue et al., *Pollutant Exposures from Natural Gas Cooking Burners: A Simulation-Based Assessment for Southern California* (2014), Environmental Health Perspectives Volume 122 at 43–50; Rocky Mountain Institute, *Health Effects from Gas Stove Pollution Report* (2019), *available at* https://rmi.org/insight/gas-stoves-pollution-health/; Lebel et al., *Methane and NO_x Emissions from Natural Gas Stoves, Cooktops, and Ovens in Residential Homes* (2022), Environmental Science & Technology, *available at* https://doi.org/10.1021/acs.est.1c04707. For methane emissions *see:* Alvarez et al. *Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain*, in *Science* (June 2018) at 186–188, *available at* https://www.science.org/doi/10.1126/science.aar7204?url_ver=Z39.88-2003&rfr_id=ori:rid:crossref.org&rfr_dat=cr_pub%20%200pubmed; Weller et al., *A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems* (2020) Environmental Science & Technology, 54(14), at 8958–8967, *available at* https://doi.org/10.1021/acs.est.0c00437.

[30] *See* Dorey Seavey Ph.D., *GSEP at the Six-Year Mark: A Review of the Massachusetts Gas System Enhancement Program* (2021) ("*GSEP at the Six-Year Mark*") at 32–37 (providing increasing GSEP costs and discussing drivers of increasing unit costs).

through 2026.[31] In 2019, Eversource reported $453 million in gas distribution capital costs.[32] For years 2022 through 2026, however, Eversource estimates distribution capital cost at $921 million in 2022 increasing to $938 million in 2026—a rough doubling in capital cost in an approximately five-year period, with GSEP representing a major portion of these capital costs.[33] Similarly, National Grid has committed to invest at least $10.5 billion in its U.S. gas distribution operations,[34] with at least $2.4 billion estimated for additional Massachusetts GSEP investment through 2026.[35]

C. **The Projected Decline in Gas Consumption Requires a Shift in the Regulation and Operations of Gas Utilities**

The projected decline in gas consumption necessary to meet the Commonwealth's climate objectives will negatively impact customers absent a thoughtful, planned transition. In general, as gas volume declines, the distribution service rates that remaining customers must pay to fund the gas utility's revenue requirement will increase. This increase, in turn, may well increase the cost of gas heating relative to alternatives, leading more customers to migrate off of gas service, and further reducing gas consumption. This cycle of increasing costs spurring increased migration has the potential to create a "death spiral," with customer sales declining faster than costs, leading to increasing unit costs and further declines in customer bases and declining revenues.[36]

Without new regulatory strategies and protections, remaining gas customers will bear the burden of higher gas costs. Low- and moderate-income ("LMI") customers, least able to afford upfront payments for clean technology heating conversions, may remain stranded in a high-cost gas system. Landlords and building owners choose the fuel for many LMI customers, with very limited tenant choice.[37] In this situation, the gas system could inadvertently become a regressive

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[31] *See* Eversource Energy, *Year End 2021 Results, 2021 Year-End Investor Call* (February 17, 2022) at slides 18 and 28, *available at* https://static.seekingalpha.com/uploads/sa_presentations/454/79454/original.pdf.

[32] *Id.,* at slide 19.

[33] *Id.*; *see also GSEP at the Six-Year Mark,* at 45–47 (providing projections for GSEP total costs).

[34] National Grid 2020/21 Full Year Results Statement, at 14. "In our US businesses, we expect investment of around £17 billion over the next five years. Over half of this will be safety related projects in our gas networks." Available at: https://www.nationalgrid.com/document/141786/download

[35] *Boston Gas Company d/b/a National Grid*, D.P.U. 21-GSEP-03, Exh. NG-AS-2, at 43.

[36] De la Rue de Can et al., *Design of incentive programs for accelerating penetration of energy-efficient appliances* (September 2014), Energy Policy, Vol. 72, at 56–66.

[37] *See e.g.*, *Residential Nonparticipant Market Characterization and Barriers Study* (2020), prepared for the Massachusetts electric and gas program administrators (providing study results showing low participation by renters in energy efficiency programs and identifying barriers to

trap of relatively high-cost energy and higher health risk for economically at-risk customers. A thoughtful, planned transition will address these concerns and also consider ways to limit stranded costs, maintain the safety of remaining, aging infrastructure, and minimize negative impacts on the gas utility workforce.

The gas utility faces a changing business environment that requires the Department to reexamine regulatory principles to ensure that outcomes align with the State's emissions reduction requirements and that any continued gas service remains safe, equitable, affordable, and reliable.

III. THE UNCERTAINTIES AND RISKS FACING THE GAS UTILITIES, REGULATORS AND RATEPAYERS

While we know that gas consumption will decrease, exactly how that will happen is uncertain. Both the Department and the gas utilities will be operating within the context of the State's broad emissions reduction plan, and they should ensure that their actions are consistent with effectuating that plan. The Department will need to formulate a new regulatory framework uncertain of future gas and electricity pricing, and the extent of market competition from technologies like heat pumps. Rather than attempt to predict the future, the Department should recognize the uncertainty that exists and regulate to reduce the attendant risks. Some of these uncertainties are discussed below.

A. The Uncertainty of Natural Gas Prices

Recent structural changes to the U.S. gas industry and the integration of the U.S. market with global demand have increased commodity price risk for U.S. customers.[38] In the last five years, the North American gas industry has expanded LNG exports from North America.[39] Prior to 2016, the U.S. gas industry existed largely in isolation: gas exports were limited to approximately 6,000 mcf per month.[40] In 2016, however, new LNG export facilities began operating and U.S. gas exports jumped to approximately 125,000 mcf per month by 2017, and over

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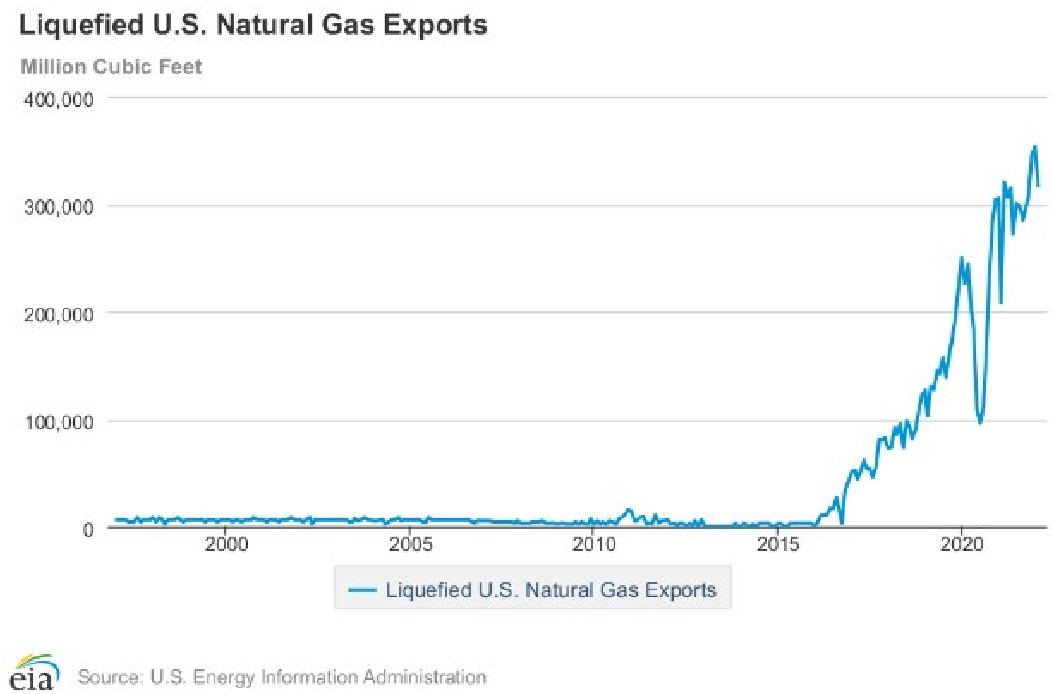
participation), *available at* https://ma-eeac.org/wp-content/uploads/MA19R04-A-NP-Nonpart-MarketBarriersStudy_Final.pdf.

[38] The Implied Volatility ("IV") of natural gas futures hit an all-time high in the winter of 2021–2022 with a 122 percent IV while the price of natural gas futures more than doubled. *See* Reuters, *US NatGas Volatility Jumps as Prices Soar Worldwide* (October 7, 2021), *available at* https://www.reuters.com/business/energy/us-natgas-volatility-jumps-record-prices-soar-worldwide-2021-10-06/.

[39] *See* Federal Energy Regulatory Commission ("FERC"), *North American LNG Export Terminals – Existing, Approved not Yet Built, and Proposed* (December 20, 2021) ("North American LNG"), available at https://cms.ferc.gov/media/north-american-lng-export-terminals-existing-approved-not-yet-built-and-proposed-3.

[40] *See* EIA, *LNG Export Report*, *available at* https://www.eia.gov/dnav/ng/hist/n9133us2m.htm.

300,000 mcf per month by 2021.[41] LNG exports in 2021 represented a 50 percent increase over 2020 levels and now account for over twelve percent of U.S. annual gas production.[42] If all currently proposed facilities were to enter operation, LNG export capacity would increase by another 200 percent and consume over one-third of U.S. gas production.[43]



This new integration of U.S. gas production with global gas demand contributes to commodity cost risk for gas consumers in North America and the LDCs that serve them.[44] With expanded LNG export capacity, gas customers in the Commonwealth are newly subject to international market pressures. International events, such as the phase-out of nuclear facilities in Germany and Japan, the industrialization of Asian economies, or a war in Ukraine and longer-term European desire to reduce dependence on Russian gas supplies, now pose a risk that the price of

[41] *See id.*

[42] EIA, *Natural Gas Monthly* (March 28, 2022), *available at* https://www.eia.gov/todayinenergy/detail.php?id=51818.

[43] *See* North American LNG, *available at* https://cms.ferc.gov/media/north-american-lng-export-terminals-existing-approved-not-yet-built-and-proposed-3.

[44] In April 2020, the U.S. Department of Energy ("DOE") expanded the eligibility of 30-year LNG export licenses to countries that do not have a free trade agreement with the United States. This change dramatically expands the potential commercial partners for LNG exports, including, for the first time, China, and other Asian countries, adding a further dimension to the risks associated with commodity price volatility. DOE, *Commonwealth LNG, LLC*, FE Docket No. 19-134-LNG, Order No. 4521 (April 17, 2020).

gas will increase permanently, and gas service will be a more expensive option than other alternatives.[45] This winter's gas prices demonstrate this commodity price risk: U.S. gas commodity prices for December 2021 and January 2022 were up 53 percent over the 10-year winter average.[46]

Under the existing regulatory structure, the LDCs are shielded from gas commodity supply costs and pass the risk of price volatility almost entirely to customers.[47] From an affordability, equity, and consumer protection point of view, particularly considering the energy burden of LMI ratepayers, placing all the risk on ratepayers is problematic. With the increasing supply costs compared with the last decade (when gas prices were competitive with or lower than alternative delivered fuel prices), the full assignment of costs and the associated risks to customers are untenable.

B. The Uncertainty of Future Technologies

The gas industry, including the Commonwealth's gas utilities, is advocating for use of decarbonized gas[48] to meet GHG reduction requirements.[49] Decarbonized gas includes Renewable

[45] *See* US Department of Energy Office of Fossil Energy, Lake Charles Exports, LLC, FE Docket No. 11-59-LNG, Order No. 3324 (2013), *available at* https://www.energy.gov/sites/prod/files/2013/08/f2/ord3324.pdf (discussing how U.S. LNG competes with gas production from other producing countries in major global gas markets); NERA Economic Consulting, *Macroeconomic Impacts of LNG Exports from the United States* (2012), at 35, 48, *available at* https://www.energy.gov/sites/prod/files/2013/04/f0/nera_lng_report.pdf.

[46] The U.S. Henry Hub natural gas prices have averaged $5.30/MMBTU for December 2021 and January 2022 compared to the $3.50/MMBTU 10-year winter average. In April, Henry Hub contracts were at $6.48/MMBTU.

[47] Pursuant to 220 C.M.R. 6.00 et. seq, LDCs file a "Gas Adjustment Clause" twice each year to reflect variations in the cost of the gas commodity. Gas customers pay for the gas commodity as a separate charge from gas delivery.

[48] The term "decarbonized gas" is a misnomer. RNG (both biomethane and SNG) is NOT carbon-free. AGO Comments, at 17. When such "carbon-neutral" fuels are burned they release essentially the same CO_2 emissions as with natural gas. *Id.*

[49] *See, e.g.*, LDCs' Net Zero Enablement Plans (March 18, 2022) ("LDCs' Plans"), (each of the five operating gas distribution companies propose the incorporation of "decarbonized" gas into their systems, including RNG, hydrogen, and SNG).

Natural Gas ("RNG"), Synthetic Natural Gas ("SNG"), and "green hydrogen."[50] The supply, cost, and feasibility of these alternatives are unknown and remain highly uncertain.[51]

While the gas utilities optimistically view decarbonized gas as providing cleaner options that might enable LDCs to continue using gas plant already in the ground, there are key uncertainties with these potential gas-like substitutes,[52] including but not limited to:

- supply availability and supply constraints;
- cost uncertainties around producing at scale;
- the sustainability and supply chain certifications of decarbonized gas production;
- accurate measurement of lifecycle methane emissions;
- fugitive emissions from transport, distribution, and storage plant;
- health and safety concerns from combustion, *e.g.*, air pollution from NOx and other toxins,
- the technical limitations on integrating hydrogen into the gas system; and
- the costs of gas system modifications and degree of new gas plant required that would facilitate utilizing other such decarbonized gasses.[53]

Supply availability, as well as the costs associated with producing decarbonized gas at scale, is highly uncertain.[54] While many companies are investing in early-stage efforts to produce decarbonized gas, the supply is currently extremely limited, there are numerous engineering and technological challenges, and the industry has yet to produce decarbonized gas at the scale required to meet potential demand.[55] In addition, the costs of decarbonized gas are far higher than the cost

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[50] *See* Independent Consultant Report, at 9 (defining RNG, SNG, and Hydrogen as renewable gas that are a "climate-neutral source of carbon").

[51] *See* AGO's Initial Stakeholder Comments on Consultants' Technical Analysis (May 6, 2022) ("AGO's Comments") (identifying concerns with reliance on decarbonized gas as means to net-zero 2050).

[52] *See* AGO's Comments (providing AGO observations regarding the technical assumptions underlying the LDCs' Independent Consultant Report).

[53] *See generally*, LDCs' Net-Zero Enablement Plans (noting the need for continued gas system investment to ready system in support of hybrid electrification proposals and use of decarbonized gas); *see also GSEP at the Six-Year Mark* at 45–47 (providing projected GSEP costs).

[54] *See* National Renewable Energy Laboratory ("NREL"), *Energy Analysis: Biogas Potential in the United States*, NREL/FS-6A20-60178 (October 2013), *available at,* https://www.nrel.gov/docs/fy14osti/60178.pdf ; American Geosciences Institute, *What Is Renewable Natural Gas?*, *available at* https://www.americangeosciences.org/critical-issues/faq/what-renewable-natural-gas#:~:text=The%20National%20Renewable%20Energy%20Laboratory,current%20U.S.%20natural%20gas%20consumption.

[55] EEA Roadmap Report, at 65, 69.

of natural gas even under the most optimistic scenarios.[56] While continued efforts may yield some results, a sufficient supply of cost-competitive decarbonized gas cannot be accepted as a given assumption.

Sustainability uncertainties associated with decarbonized gas are especially problematic, considering that sustainability generally, and reducing carbon emissions more specifically, are primary reasons to seek decarbonized gas as an alternative to natural gas. Decarbonized gas production requires land, water, nutrients, and/or energy, on a regional scale.[57] Scaling production to replace fossil fuel for the Commonwealth's heating sector would put substantial pressure on these resources, cause indirect emissions, as well as a range of other environmental and social impacts that are poorly understood or quantified.[58] While niche applications for bioenergy-derived gas may exist, like the conversion of organic waste to energy at anaerobic digester plants, these applications are likely to remain costly and limited in scale.[59]

Finally, with respect to hydrogen, the technical limitations of scaling production to meet demand, the costs of gas system modifications, and the degree to which a new gas plant would be required in order to utilize the existing distribution system are not fully understood and remain uncertain.[60] At the very least, substantial capital investment would be required to modify and

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[56] *See* Energy Innovation, *Assessing the Viability of Hydrogen Proposals: Considerations for State Utility Regulators and Policymakers* (2022) ("Energy Innovation"); Longden et al., *Clean Hydrogen? – Comparing the Emissions and Costs of Fossil Fuel Versus Renewable Electricity Based Hydrogen*" (2022), Applied Energy 306, part B, 118145, *available at* https://doi.org/10.1016/j.apenergy.2021.118145. The three key determinants of the price of green hydrogen are the type of electrolyzer (its cost and efficiency), the cost of renewable electricity used for electrolysis, and the utilization rate of the electrolyzer. The latter two conditions are highly location-dependent (*e.g.*, varying with resource quality and water availability). *See* Lazard, *Lazard's Levelized Cost of Hydrogen Analysis* (October 2021), at 16, *available at* https://www.lazard.com/media/451922/lazards-levelized-cost-of-hydrogen-analysis-version-20-vf.pdf (providing a range of varying costs under some of these assumptions).

[57] EEA Roadmap Report, at 66; U.S. Department of Energy, Alternative Fuels Data Center, *Renewable Natural Gas Production*, *available at* https://afdc.energy.gov/fuels/natural_gas_renewable.html.

[58] EEA Roadmap Report, at 66.

[59] *See* AGO's Comments (noting LDCs assumptions for supply in other parts of the country are faulty).

[60] Melaina et al., *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues,* at 15, *available at* https://www.nrel.gov/docs/fy13osti/51995.pdf ("*NREL Technical Report*").

improve existing gas infrastructure to accept, liquefy, store, and distribute a mixed product of natural and hydrogen gas.[61]

A recent study by Energy Innovation details the challenges of integrating hydrogen into the gas supply.[62] According to the study, using hydrogen in buildings creates major challenges and safety risks throughout the existing natural gas infrastructure system because of the difference in chemical properties between hydrogen and methane (the primary component of natural gas).[63] Further, "[h]ydrogen cannot be readily swapped for methane for use in heating or consumer appliances above a 5 to 20 percent blend with natural gas without enormous costs and disruption, and low blends achieve very few GHG emissions reductions while increasing nitrogen oxide (NOx) pollution."[64] The study also raises significant consumer safety concerns. Since residential appliances are optimized for natural gas, blending hydrogen above 5 percent and up to 20 percent requires extensive testing to limit dangers to consumers, with the safe blending percentage varying based on the appliance type, age, and natural gas composition.[65] "Green hydrogen" is currently 6 to 14 times more expensive than natural gas; even a 20 percent blend of green hydrogen with natural gas could raise the fuel price two to four times more than 100 percent natural gas.[66] This study concluded that, "[i]n sum, hydrogen blending investments risk wasting time and ratepayer money enroute to achieving minimal GHG emissions reductions, only to face daunting financial and logistical roadblocks."[67]

C. The Uncertainty of Customer Adoption of Competitive Alternatives

The pace of customer adoption of alternatives for space and water heating, cooking,[68] and industrial gas supply is a significant uncertainty facing gas industry sales and revenue projections.

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[61] Gas rates will be negatively impacted by the higher gas supply cost of decarbonized gas, coupled with the required additional infrastructure investment. The increased costs could result in significant cost-driven market pressure and customer exit from the gas system. The potential for an uncontrolled exit driven by market economics raises significant additional equity concerns for those ratepayers who cannot afford alternatives. *NREL Technical Report*, at 11.

[62] Baldwin et al., *Assessing the Viability of Hydrogen Proposals: Considerations for State Utility Regulators and Policymakers, Energy Innovation* (March 2022), *available at* https://energyinnovation.org/wp-content/uploads/2022/04/Assessing-the-Viability-of-Hydrogen-Proposals.pdf.

[63] *Id.*

[64] *Id.,* at 3.

[65] Energy Innovation, at 12.

[66] *Id.,* at 12

[67] *Id.,* at 8.

[68] The available electric end-use heating technologies provide competitive energy alternatives for ratepayers, introducing new types of competition for the gas utilities. Air source heat pumps are

Under traditional cost of service principles,[69] a mass exodus of gas customers would shock rates to the detriment of remaining ratepayers and reduce utility revenues jeopardizing the utility's continued provision of safe and reliable service to remaining customers, as well as pose a general safety risk to the public at large. Conversely, less competition might result in slower adoption of alternatives and undermine the achievement of the climate targets.[70]

Typically, competition tends to reduce pricing and improve service quality for customers.[71] In competitive markets, firms that lose sales and customers shrink and eventually go out of business. For a gas utility, however, increasing customer adoption of alternatives will result in the loss of revenue as it loses market share to competition. As a result of this loss of revenue and the escalating GSEP and system maintenance costs facing LDCs today, at some point in the future an LDC's revenue may not cover the going forward and embedded gas system costs. If utilities are then allowed to increase rates, a spiral of increasing costs per customer could cause increasing customer defections further adding predictable pressure on the LDC. At this critical point, a gas utility may be faced with the prospect of reorganization (or bankruptcy) to simply maintain system reliability and minimize all capital investments. Regulators should anticipate this potential point

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becoming readily available and more accessible to consumers. Building supply chains such as Home Depot and Lowes carry heat-pump alternatives for both space and water heating/cooling needs. In the U.S. heat pump installation has increased by 10 percent annually for each of the last five years. International Energy Agency, *Heat Pump Technology Tracking Report* (November 2021), *available at* https://www.iea.org/reports/heat-pumps; *see also* MassSaveData, *available at* https://www.masssavedata.com/Public/MeasuresDetails (providing 2020 Massachusetts annual data). Cold-climate heat pumps have become particularly competitive for winter heating. The current reported efficiencies for air-source heat pumps range from 220–350 percent, compared to fossil fuel furnace and boiler efficiencies which typically range from 65–98 percent. *See* Northeast Energy Efficiency Partnership, *Northeast/Mid-Atlantic Air-Source Heat Pump Market Strategies Report* (2014), at 22. These high efficiencies generally made heat pumps less expensive than oil and propane heating over the last decade. Heat pumps also are a more efficient source of air conditioning than traditional air conditioners providing additional benefits to customers looking for both heating and cooling alternatives. *See* MassCEC, *Air Source Heat Pump Guide*, *available at* https://goclean.masscec.com/wp-content/uploads/2021/01/MassCEC_ASHP_GUIDE.pdf, at 10.

[69] Typically, regulated utilities pass revenue losses to their remaining customer base, leading to higher rates for those who are less likely, or unable to exit the system. *See* Robert J. Graniere, *Decoupling and Public Utility Regulation* (1994), NRRI Whitepaper, at 11.

[70] The LDCs rest the transition to net-zero on customer choice and adoption of alternatives, including electrification and decarbonized gas. *See generally*, LDCs' Plans. The LDCs do not, however, discuss the uncertainty of customer choice. What happens if their current customers do not want decarbonized gas or choose to electrify at a pace faster than the utility planned?

[71] Richard L. Revesz and Burcin Unel, *Managing the Future of the Electricity Grid: Modernizing Rate Design* (2020), 44 Harv. Envtl. L. Rev. 43.

in the future and take steps to minimize the economic and safety risks now as a matter of public interest.[72]

IV. REGULATORY PRINCIPLES TO GUIDE THE TRANSITION TO NET ZERO

The following sections set forth principles for future decision-making for gas regulation, including the near-term and immediate decisions related to the safe, reliable, affordable, and equitable transition from natural gas toward a clean energy and net-zero emissions economy. These principles are intended to guide the decision-making process and align the regulatory framework with the relevant Commonwealth laws and climate objectives.[73] A principle-based redesign of the regulatory framework is essential to meet the newly enacted statewide GHG emissions reduction laws and will provide certainty and predictability to all stakeholders related to the regulatory process during the transition.[74]

PRINCIPLE: Department decision making should be *holistic*, *transparent*, and provide for *robust and meaningful community input*.

The Department's new mandate, including its duties to consider GHG reductions, equity, and affordability,[75] warrants a more holistic approach to regulation, where interconnected issues are recognized, and individual proceedings and companies are not siloed.

To improve accountability and inclusivity, the Department's processes should be *transparent* and facilitate *robust and meaningful community input*. The success of these dockets will in large part be determined by the extent to which the Department considers and integrates stakeholder input into its decision making. Regulatory decisions based on broad participation and input will better support regulatory stability for utilities, energy for consumers, and certainty for business (and consumer) investment decisions.

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[72] Mechanisms to minimize the impacts of long-term competitive losses include, among other measures, abandonment of uneconomic plant to strengthen long-term financial security and public safety, abandoning revenue per customer decoupling, discussed *infra* at 38–39, modifying line extension policies which assume long-term sales revenue, discussed *infra* at 31–32, and shifting revenue from traditional rate base to performance-based mechanisms that incent reduced methane scope 1 emissions and reduced scope 3 combustion emissions, discussed *infra* at 40-41.

[73] *See, e.g.*, Climate Act, § 8 (setting forth directives toward the achievement of a net-zero 2050); Acts of 2008, Chapter 169, *An Act Relative to Green Communities* ("GCA") (providing for expanded energy efficiency investment to, in part, reduce energy consumption).

[74] For additional discussion of gas regulatory transition *see* Anderson et al., *Under Pressure: Gas Utility Regulation for a Time of Transition,* Regulatory Assistance Project (2021), *available at*: https://www.raponline.org/wp content/uploads/2021/05/rap-anderson-lebel-dupuy-under-pressure-gas-utility-regulation-time-transition-2021-may.pdf.

[75] Climate Act, § 15 (amending G.L. c. 25 § 1A to include equity and emissions priorities).

PRINCIPLE: Department analysis and decision making should be based on *up-to-date science*, *relevant data*, and *input from stakeholders and the scientific community*.

To ensure that the up-to-date science and relevant data informs decisions, the Department should rely upon up to date, accurate, and tested: (1) assumptions regarding costs/benefits (including internal and external environmental costs of gas usage, the social value of greenhouse reductions, and the social cost of methane usage); (2) projections regarding gas usage, customer costs, and infrastructure useful life that align with emissions reduction mandates; and (3) data on GHG and other pollutant emissions. As the gas transition continues, the Department will need to consider emerging science, and new approaches to measure and encourage decarbonization. Input from stakeholders and the scientific community is essential to well-informed decision making during this transition.[76]

PRINCIPLE: Department decision making should *account for the Department's statutory mandate as the Commonwealth transitions to net-zero emissions*.

The Climate Act broadened the Department's statutory mandate at a time of significant change for regulated utilities. To adequately protect ratepayers from unnecessary risks and unreasonable costs, the Department must fully consider its mandate to prioritize safety, security, reliability of service, affordability, equity, and reductions in GHG emissions. To achieve these priorities, the Department should align gas company shareholder interest with customer interests and societal goals. To support such an alignment, the AGO recommends that Department apply its statutory mandate it in its decision-making by prioritizing:

- Achieving least risk for customers by minimizing costs, including the long-term costs of delivering natural gas and any potential stranded costs while maximizing customer benefits;
- Promoting equitable distribution of costs, risks, and benefits;
- Protecting low-income customers; and
- Eliminating outdated incentives encouraging the increased sale of gas and gas system expansion.

[76] To illustrate this point, recent field measures and analysis suggest that methane emissions from gas distribution systems in urban streets appear magnitudes higher than LDCs' prior studies indicate. Sargent et al., *Majority of US Urban Natural Gas Emissions Unaccounted for in Inventories* (November 2, 2021), PNAS 118 (44) e2105804118, *available at* https://doi.org/10.1073/pnas.2105804118. These findings suggest that the LDCs' analysis undertaken may have understated the magnitude of methane emissions from Massachusetts' gas distribution systems. Obtaining additional data sets, other forms of peer reviewed or reliable data analysis before continuing to utilize the LDCs' analysis in Department decision making is a primary regulatory prerequisite to thorough regulatory decision-making.

V. RECOMMENDATIONS FOR A NEW REGULATORY FRAMEWORK

As discussed above, over the next two decades, LDCs and their customers will be faced with business uncertainties and risks. Gas utilities will push to make additional gas system investments despite not knowing whether these investments will prove to be stranded or even least-cost for the specific use case or for the gas system as a whole.[77] Customers may face increasing energy costs and difficult decisions about how to heat their homes and businesses. These business uncertainties and customer impacts represent a major departure from the previous decades when assumptions of continued gas use, gas system growth, and rate stability remained constant and guided a relatively static regulatory framework.

The current regulatory system is not positioned to effectively manage the uncertainties and risk associated with the Commonwealth's transition to a net-zero emissions future. For example:

- Current planning mechanisms for programs such as the GSEP do not include the robust review of potentially lower cost alternatives to gas infrastructure investment or an emphasis on less costly repair over replace.[78]
- Current standards of review and planning considerations do not account for the social cost of carbon or methane reduction or impacts to public health attributable to the combustion of fossil fuel when evaluating gas investment or non-pipe alternatives.
- Current regulatory planning continues to incentivize and subsidize long-term infrastructure and the growth of the distribution system through line extensions and service additions, which may result in stranded assets in the future.[79]
- While the Department has instituted several safeguards for LMI ratepayers, such as discount rates and bill impact analyses, these customers continue to be at risk, suffer from disproportionately higher energy burdens, and are not adequately protected, particularly in a period of transition and uncertainty.[80]

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[77] *See* LDCs Plans (generally supporting continued GSEP investment and concerns over recovery of costs).

[78] The AGO recognizes that GSEP is governed by statute. *See* G.L. c. 164, §§ 144–145. Nevertheless, the Department has significant authority to implement the statute to achieve the dual objectives of safe and reliable service and leak mitigation, while also minimizing costly investment in system upgrades that may become stranded assets in the future.

[79] *See e.g.*, D.P.U. 16-79, at 10 (2017) (noting proposal to make natural gas more available, affordable, and feasible for new customers); NYPSC Case No. 12-G-0297, at 1–4 (discussing opportunities to support the expansion of natural gas service).

[80] *See* discussion on Equity and Affordability, *infra* at 46-53.

This section advances specific recommendations for the Department's consideration as it develops a new regulatory framework for gas distribution services. The recommendations fall in four broad areas:

- **Planning the gas system for a zero-emissions future:**
  - The Department should order each LDC to produce comprehensive system and customer mapping data by January 2023.
  - The Department should require each LDC to file a Climate Compliance Plan ("CCP") that demonstrates how over the next ten years the LDC will comply with the mandated emissions sublimits and statutory emissions benchmarks and to make periodic Climate Act Compliance Filings indicating whether the LDC met interim emissions reduction mandates.
  - The Department should open an investigation to address ways to align electric and gas system planning.
  - The Department should reform the criteria to evaluate gas forecast and supply plans.
  - The Department should assess proposals for supply and pipeline capacity contracts against a broad range of potential non-pipeline alternatives.
  - The Department should evaluate its current dockets to ensure effective and comprehensive investment planning.

- **Reforming gas utility capital planning to meet a zero-emissions future:**
  - The Department should consider the Commonwealth's climate objectives as part of its GSEP project review and require LDCs' to demonstrate the proposed investment is the least-cost alternative to improve safety and reduce leaks.
  - The Department should establish a uniform model for determining the cost/benefits of line extensions that incorporates State polices to reduce gas use.
  - The Department should ensure that investments in unproven or uncertain technologies are born entirely by utility shareholders.
  - The Department should utilize an Investment Alternatives Calculator as a mechanism to force transparent consideration of alternatives to traditional gas system capital investments.
  - The Department should create guidelines and principles for treatment of future potential stranded investment.

- **Aligning gas utility revenue with decarbonization:**
  - The Department should replace revenue per customer decoupling with revenue cap decoupling, thereby removing the existing incentive to add gas heating customers.
  - The Department should revisit and revise its existing performance-based ratemaking framework to ensure that any Department approved performance-based ratemaking plan encourages LDC investment consistent with State climate laws.

- **Eliminating outdated rate structures that promote gas system growth:**
  - The Department should not permit the LDCs to recover costs for marketing related to promoting gas service.
  - The Department should conclude its investigation in D.P.U. 18-152 and limit special contracts to only unique and novel public interest circumstances.
  - The Department should explore incentivizing the LDCs to use non-capital options to defer capital investment.

In addition, this section addresses a set of issues that may go beyond the Department's immediate authority to fully resolve yet bear directly upon the gas transition. Those include legislative reform of the GSEP, accounting for methane emissions according to scientific consensus, regulatory treatment of alternative heating technologies, such as ground-source heat pump districts, application of earlier legislative policy encouraging gas expansion, and issues centered around equity and affordability and utility workforce. The AGO makes the following recommendations related to this broader set of issues:

- **GSEP and methane emissions accounting:**
  - The Department should form a working group to make recommendations to the Department and the Legislature on changes to GSEP.
  - The Department should collaborate with other agencies to improve the methodology utilized to account for Massachusetts-specific methane emissions and reductions.

- **Regulatory treatment of alternative thermal technologies:**
  - The Department should open an investigation into the regulatory treatment of geothermal heat districts and alternative thermal technologies.

- **Application of St. 2014, c. 149, § 3:**
  - The Department should not approve LDC plans filed under St. 2014, c. 149, § 3 that are inconsistent with an LDC's CCP.

- **Equity and affordability:**
  - The Department should consider adopting a rate mechanism to protect low- and moderate-income ratepayers from high energy burdens and from potential rate increases related to climate investments by both the gas and electric distribution companies.

- **Workforce:**
  - The Department should regularly engage with workforce stakeholders to better inform the transition of gas distribution services.

A. Plan for a Zero Emissions Future

Effective regulation of the natural gas system begins with robust planning. A revamped planning process is necessary for regulators, LDCs and stakeholders to evaluate alternative investment scenarios, forecast demand accurately, integrate electric and gas investments, and identify long-term trends in system loads. For a planning process to be effective, it must draw upon detailed and accessible information, consider a range of alternative investments, and provide for cost-effective plan implementation.

The fractured nature of gas planning in Massachusetts means that no single proceeding addresses gas issues comprehensively.[81] Multiple overlapping dockets creates a churn of regulatory proceedings that can keep regulatory staffs, LDCs and stakeholders' focused on reproducing business-as-usual outcomes without an opportunity to change the overall strategic course of gas system regulation.[82] As a result, gas planning tends to be not only fractured, but now it is also misaligned, and inconsistent with the Commonwealth's climate mandates.

The current planning process does not ensure proactive consideration or robust review of alternatives to meet demand or alternatives to minimize or avoid additional system investment. For example, GSEP does not consider non-pipe alternatives or less costly repairs or replacement, which could minimize ratepayer impacts and better support the Climate Act objectives. Similarly, forecast and supply planning is intended to ensure least cost procurement and capacity adequacy, but does not accommodate an integrated or systematic approach to considering market alternatives or decarbonization planning. If continued, this method of review will reach poor policy outcomes in a dynamically changing market that must meet the challenges of legally binding decarbonization requirements.

The Department should align gas system planning with the Commonwealth's decarbonization mandates. Using the forecast and supply planning example, the Department should review assumptions underpinning the utilities' forecast planning within the context of the Commonwealth's clean energy objectives. Do the utilities consider the impacts of legislative climate mandates in their forecast modeling? Do historic relationships driving per customer demand and customer counts trends still hold in a decarbonizing future (and if not, does the forecast adjust the historical relationship for these new changes)? Is the decades-old weather data

[81] In Massachusetts, the existing planning process for gas systems occurs in at least nine distinct types of proceedings, each with their own standard of review and its own narrow focus. Current gas planning dockets include Forecast and Supply Plans, Gas Resource Agreements, Asset Management Agreements, Firm Transportation Agreements, Special Contracts, Gas Service Agreements, Money Pool Agreements, Annual Gas Emergency Response Plans, Service Quality Reports, Customer Migration Information.

[82] Moreover, this gas planning system occurs in isolation from electric planning proceedings.

used to develop degree days and forecast needs adequately capturing the more recent weather patterns and disruptions caused by climate change (if not, is it otherwise adjusted)?

Given the urgency of climate action, effective regulatory oversight requires a forum in for the Department to evaluate the utilities' proposed investments, measure the utilities' success toward climate related mandates, and assess impacts and risks to ratepayers. The most essential elements of gas planning reform should include: (1) comprehensive system and customer mapping; (2) comprehensive plans and compliance filings demonstrating compliance with climate requirements; (3) gas and electric coordination plans; (4) reform of gas load forecast and supply plans; (5) review of proposed gas supply and pipeline capacity contracts; and (6) evaluation of current dockets to ensure effective and comprehensive investment planning.

An updated gas planning process should reflect broad principles, including:

- The planning process should increase transparency and information-sharing about current system dynamics and the gas system's current emissions profile.
- The planning process should identify opportunities and synergies for "total energy" or "gas/electric" coordinated planning and investment.
- The planning process should support long-term gas system decision-making that considers repair, replacement, targeted decommissioning, and least cost pathways to meet customer needs and decarbonization requirements.
- The planning process should avoid rate shock and encourage broad stakeholder engagement consistent with conventional ratemaking practice.

1. Comprehensive System and Customer Mapping

RECOMMENDATION: The Department should order each LDC to produce comprehensive system and customer mapping data by January 2023.

The Climate Act directs the Department to establish requirements "for the maintenance, timely updating, accuracy, and security of gas company maps and records. The Department shall incorporate these requirements as a metric in the Department's service quality indicators for gas companies."[83] While the LDCs provide some mapping information to the Department, there is no current requirement for a comprehensive examination of existing infrastructure, emissions sources, and the customer base. This baseline data is essential to effectively evaluate utility planning and

[83] *See* Climate Act, § 86 (directing the Department to establish requirements for gas company maps and records).

investment decisions, and to track progress implementing plans and emissions reduction requirements.[84] The comprehensive system maps should include:

- **Existing Infrastructure Data**
  - Transmission, distribution, and gas service infrastructure (length and diameter of pipelines, pipeline material and pressure)
  - Conditions of pipes, including age, condition, and leak rates
  - Interconnections, gas stations, compressor stations, and any storage facilities, including LNG
  - Throughput and areas of constraint or congestion on the gas distribution system
  - Areas of safety concern and/or areas designated for GSEP investment

- **Customer Base Data**
  - Size of each class of customers
  - Firm versus interruptible customers, including numbers of customers and volume of sales for standard gas residential service, firm and interruptible commercial and industrial service customers
  - An audit of existing special contracts[85]
  - Per capita density of the areas served
  - Designation of areas that are experiencing growth in gas use (by volume and number of customers)
  - Areas that are difficult to serve or that drive higher system costs
  - Areas that are designated as an environmental justice community[86]

- **Emissions Sources and Current Emissions**
  - Detailed accounting of all Scope 1[87] (fugitive and other direct gas system emissions), including a break down by route/section of distribution network
  - Detailed accounting of Scope 3[88] GHG emissions (emissions occurring on-site as the customer burns the gas) by customer class, service district, and regions

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[84] The AGO recommends, *infra* at 24-25, the adoption of a "Climate Compliance Plan," which is similar to the LDCs' proposed Net-Zero Enablement Plan.

[85] The AGO recommends, *infra* at 41-42, that the Department eliminate special contracts except in limited circumstances.

[86] *See* Marcos Luna, *An Environmental Justice Analysis of Distribution-Level Natural Gas Leaks in Massachusetts, USA*, Energy Policy (March 2022).

[87] The U.S. Environmental Protection Agency ("EPA") defines Scope 1 emissions as "direct greenhouse emissions that occur from sources that are controlled or owned by an organization, *available at* https://www.epa.gov/climateleadership/scope-1-and-scope-2-inventory-guidance.

[88] The EPA defines Scope 3 emissions as emissions that "result of activities from assets not owned or controlled by the reporting organization, but that the organization indirectly impacts in its value chain, *available at* https://www.epa.gov/climateleadership/scope-3-inventory-guidance.

Requiring LDCs to provide comprehensive system maps is a vital first step in any regulatory reform. Having this resource will better enable the Department to evaluate proposed gas system investment and alternatives and will enable LDCs to better prioritize projects.[89]

2. *Climate Compliance Plans and Climate Act Compliance Filings*

RECOMMENDATION: The Department should require each LDC to file Climate Compliance Plans and Climate Act Compliance Filings that demonstrate compliance with the mandated emissions sublimits and statutory emissions benchmarks.

On July 1, 2022, the EEA Secretary will set the 2025 and 2030 emissions reduction sublimits for the "natural gas distribution and service," "commercial and industrial heating and cooling," and "residential heating and cooling" subsectors. The 2050 sector-based emissions sublimits will be issued on January 1, 2023.[90] Each sublimit will be accompanied by a roadmap plan outlining policies for meeting the sublimits.[91] With these requirements, the LDCs can no longer argue that their legal responsibility is limited to meeting gas demand. The LDCs are responsible for meeting the sublimits for the natural gas distribution and service sector (Scope 1 emissions) and the Scope 3 emissions that result directly from the intended use of their product for combustion (*i.e.*, customer emissions).

To ensure that the LDCs are proactively planning for and successfully complying with the Commonwealth's statutorily mandated emissions reductions, the Department should require each LDC to file a CCP approximately once every five years.[92] In a CCP, each LDC should demonstrate how it proposes to (1) meet the prescribed GHG emissions reduction sublimits set by EEA for both Scope 1 and Scope 3 emissions; (2) satisfy customer demand safely, reliably, affordably, and equitably utilizing known and market-ready technology available at the time of the filing; and (3) utilize pilot or demonstration projects to assist in identifying investment alternatives. Each CCP should detail the total investment required and should also include a description of at least one

[89] Comprehensive system mapping can inform the prioritization of projects. It can also help LDCs select projects to meet other policy objectives, including but not limited to equity, environmental and health concerns.

[90] *See* Climate Act, § 111 (directing adoption and publication by January 1, 2023, of emissions reduction plan and 2050 limits and sublimits); *see also* Climate Act, §§ 106–111 (setting the following deadlines: the 2025 and 2030 sublimits published July 1, 2022; the 2050 sublimits published January 1, 2023 (allowing modification by later roadmap plans); 2035 by January 1, 2028; 2040 by January 1, 2033, and; 2045 by January 1, 2038).

[91] *See* Climate Act at §§ 107–110 (requiring that roadmap plans must accompany EEA emissions limits to provide clear and specific means to achieve required reductions).

[92] The first CCP would be filed in 2023, six months after EEA establishes the 2025 and 2030 sublimits. Subsequent CCPs would be due in 2029 (6 months after EEA establishes the 2035 sublimits), 2034 (6 months after EEA establishes the 2040 sublimits), and 2039 (six months after EEA establishes the 2045 sublimits).

alternative method to meet the required emissions reductions, providing the estimated costs for the considered alternative, and a demonstration that the proposed plan is superior to the alternative.[93]

The initial CCP should be due January 2023, which is six months after EEA's July 1, 2022, deadline to establish sector-specific 2025 and 2030 sublimits. The initial CCP would include details on the specific actions that each LDC will take to reduce emissions in the next ten years (including how it will meet the 2025 and 2030 interim emissions reduction deadlines).[94]

To track actual (rather than projected) compliance with the Commonwealth's interim emissions reduction deadlines, each LDC also should be required to make a Climate Act Compliance Filing six months after each interim deadline (*i.e.*, 2025, 2030, 2035, 2040) indicating whether or not the LDC achieved the required emissions reductions.

3. *Electric and Gas Planning Coordination*

RECOMMENDATION: The Department should open an investigation to address ways to align electric and gas system planning.

As the Commonwealth transitions toward clean energy and a net-zero economy, an integrated and holistic evaluation of the gas and electric distribution systems will be necessary to assess future investment and other needs. As a result, CCPs and other gas planning must incorporate a meaningful comparison with electric-fueled alternatives. Several obstacles exist to effective electric-gas comparisons, including differing planning processes and timelines, separate personnel within electric and gas utilities and the Department, and a lack of integrated planning tools such as data sets and mapping tools.

Siloed electric and gas planning also limits a gas company from adequately considering "all other resource options on an equal basis" in development of a least-cost supply plan.[95] In

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[93] The AGO, *infra* at 33–35, recommends the Department adopt an Investment Alternatives Calculator. A CCP should use the calculator to justify proposed gas system investment. Additionally, the comprehensive system and customer mapping data, *supra* at 22–24, can be used to inform investment decisions. For example, an LDC can use the mapping to identify areas that may be ideal for targeted electrification and decommissioning or other areas where investment in gas system repairs is appropriate.

[94] *See* Climate Act, §§ 106–111 (setting the following deadlines: the 2025 and 2030 sublimits published July 1, 2022; the 2050 sublimits published January 1, 2023 (allowing modification by later roadmap plans); 2035 by January 1, 2028; 2040 by January 1, 2033, and; 2045 by January 1, 2038).

[95] *Fitchburg Gas & Electric Light Company*, D.P.U. 94-140, at 38 (1994) ("A gas company must establish that the application of its supply planning process, including adequate consideration of energy efficiency and *all other resource options on an equal basis*, has resulted in the addition of resource options that contribute to a least-cost supply plan.") (emphasis added).

practice, there is no consideration of "electric resources" because there is no electric-gas coordination.[96] Similarly, there is no consideration of "electric resources" in gas supply plan evaluations, which are limited to the comparison of pipeline contracts with resources such as LNG, compressed natural gas, or energy efficiency. Thus, there is no effective way for the Department to evaluate shifts in customer load, company investment, existing infrastructure adequacy, and supply cost between electric and gas options on a system-wide basis or even for portions of its system.

In the face of these existing conditions, the Department's Investigation should address the procedural mechanics required for joint gas and electric planning. In particular, this Investigation should examine the timing of gas and electric planning processes, the opportunities to evaluate non-pipeline alternatives, non-wires alternatives, and electric capital plans in concert with each other, with the goal of creating opportunities for geographically targeted programs and cost-efficiencies that promote decarbonization. The Department should require that the electric distribution company ("EDC") operating in a LDC's service area participate in the CCP gas planning process to allow for planning coordination. This requirement would be especially helpful when the Department is asked to review a request for geographically targeted decarbonization investment. Requiring EDC and LDC participation will provide the Department with the opportunity for a fully developed record to evaluate the request.

4. Forecast and Supply Plans

RECOMMENDATION: The Department should reform the criteria to evaluate gas forecast and supply plans.

Every two years, each LDC is required to file a five-year forecast of gas requirements for its market area that includes the gas sendout to serve projected firm customers, and the available supplies to meet demand.[97] The transition to net-zero, however, introduces additional uncertainty into the forecasting process, as the pace of customer adoption of heating and cooking alternatives is unknown. The Department should review and update the forecasting methodologies in consideration of climate policies, energy efficiency and potential electrification. For example, in its review of LDC forecast and supply plans, the Department addresses only the narrow question of "whether the plan is adequate to meet projected customer demand under a range of contingencies."[98]

[96] *See id.*; *Colonial Gas Company d/b/a National Grid*, D.P.U. 93-13, at 88 (1993).

[97] *See* G.L. c. 164, § 69I ("long-range forecasts for electric and gas companies"). The forecast and supply plans should continue to cover a five-year term, which is shorter than the ten-year, longer-term planning process described *supra* at 24–25

[98] Department of Public Utilities, *Annual Report 2021*, at 31.

At the very minimum, the Department should evaluate each LDC forecast and supply plan to ensure that it is consistent with the LDC's approved CCP. In addition, the Department should undergo a deep dive into the utility modeling inputs and assumptions to ensure that the LDC has adequately addressed climate change and clean energy objectives. The Department should work with the utilities and stakeholders to identify whether new modeling assumptions and inputs are required to capture changes that will result from decarbonization activities. For example, considerations could include customer adoption of gas decarbonization technologies (ASHP, efficient gas equipment, non-programmatic energy efficiency) and the volume and the customer bill impact of alternative fuels potentially procured by the utilities (*e.g.*, RNG). A LDC's forecast must also reflect near-term initiatives proposed in the utility's CCP. Additionally, the Department should consider requiring the gas utilities to develop longer-term (*i.e.*, longer than five years) demand forecasts and supply plans to ensure that the utilities are on track to meet the Commonwealth's climate and clean energy policies (for example, utilities in New York and California file 30- and 15-year forecast and supply plans, respectively). A longer-term forecast would provide better visibility related to decarbonization progress and ensures that nearer-term forecast and supply plans are consistent with longer-term outlooks.

To ensure accurate forecast of supply and demand, the LDCs' model should:

- Include realistic assumptions regarding weather (including the impact of climate change on weather patterns) and gas usage[99]
- Include State electrification and climate goals
- Reflect changes in usage patterns/peak as people begin to switch to heat pumps
- Update the drivers for customer models (*e.g.*, economic drivers should not be limited to oil and natural gas conversion savings but should consider likely conversion to heat pumps within the useful life of the gas system investments)
- Include a robust alternative analysis that includes giving preference to non-gas and non-pipeline alternative such as energy efficiency and fuel switching to address peak day constraints
- Demonstrate that any plans for expansion or construction of infrastructure within the five-year period is consistent with the approved CCP and reviewed with the investment alternatives calculator
- Include a look back comparing the previous forecast with the actual demand to determine accuracy.

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[99] Currently, the models perform statistical analyses of *historical* weather data to derive planning standards related to normal year, design winter, cold snap, and design day conditions. *See, e.g.*, *Eversource Gas Company of Massachusetts d/b/a Eversource Energy,* D.P.U. 21-118, Initial Filing, at 59–63 (November 2, 2021) (discussing weather data considered).

A thorough review and revision of the forecast and supply plan process will require input from the LDCs, stakeholders, and Department staff to ensure that the outcome will produce modeling and filing criteria that is complimentary to achievement of our climate objectives and the continued provision of safe, reliable, and affordable gas distribution service. Toward this end, the Department should consider forming a working group of modeling experts or retain an independent consultant to assist in the updating of the forecast modeling.

5. Supply/Capacity Contracts

RECOMMENDATION: The Department should assess proposals for gas supply and pipeline capacity contracts against a broad range of potential non-pipeline alternatives.

Pipeline capacity constitutes an increasing proportion of total gas delivery costs.[100] Gas utilities must obtain Department approval of any supply or capacity contracts with terms over a year.[101] In evaluating a gas utility's resource options for the acquisition of commodity resources, as well as for pipeline capacity, the Department reviews whether the acquisition of the resource is consistent with the public interest.[102] To demonstrate the proposed acquisition is consistent with the public interest, an LDC must show that the acquisition (1) is consistent with the company's portfolio objectives and (2) compares favorably to the range of alternative options reasonably available to the company at the time of the acquisition or contract renegotiations.[103]

Today, there is little effective comparison between gas capacity contracts and potential non-pipe alternative resources. The Department's alternatives review is limited and focused on relevant price and non-price attributes of the proposed resource and current market offerings to ensure that the proposed resource contributes to the strength of the LDC's overall supply portfolio.[104] Pipeline capacity is evaluated within the context of existing gas send-out forecasts.[105] That is, the gas capacity contract planning process occurs within the context of a gas regulatory proceeding and assumes that customers will remain gas customers. In the current market environment in which alternative heating solutions exist, this process is no longer appropriate and should be revisited.

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[100] Natural Gas Intelligence, *Soaring LNG, Pipeline Constraints Threaten New England Grid this Winter* (December 14, 2021).

[101] G.L. c. 164, § 94A (prohibiting gas utility from entering into a supply contract for a period in excess of one year without Department approval).

[102] *Fitchburg Gas and Electric Light Company,* D.P.U. 19-25, at 1 (2019) (citations omitted).

[103] *Id.,* at 2 (citations omitted) (setting forth additional considerations to aid determination of "in the public interest).

[104] *Id.*

[105] *Id.* (noting review of approved forecast and supply plan to determine consistency with the company's portfolio objectives)

Before approving a pipeline capacity contract, the Department should consider whether (1) the contract is consistent with the company's most recent forecast and supply plan and CCP; and (2) compares favorably to alternatives including but not limited to non-pipeline alternatives. Similarly, with regard to gas supply contracts and renewals, the Department should require the LDCs to consider if the need can be met by some other alternatives (again, including but not limited to non-pipeline alternatives), considering costs and GHG policies and mandates.[106]

6. Effective and Comprehensive Investment Planning

RECOMMENDATION: The Department should undertake an evaluation of its current dockets to ensure effective and comprehensive investment planning.

The Department should consider ways to support effective and comprehensive investment planning, which may include consolidating certain proceedings and aligning the outcomes and timing of proceedings to achieve regulatory goals. The future gas business will require greater consistency, agility, and cross-sectoral capabilities that draw upon energy efficiency, gas capital planning, electric capital planning, gas capacity procurement, gas supply procurement, and macroeconomic analysis of the future demand for gas. The Department should review key plans and proposals that affect gas investment planning and consider consolidating proceedings, when possible (*e.g.*, geothermal micro district or targeted gas decommissioning, which could contribute to the need for electric distribution upgrades). Consolidation of key planning procedures will help to ensure that investments collectively achieve regulatory outcomes, including emission reduction mandates. Where consolidation is not feasible, the Department should work to achieve consistent outcomes across different dockets; thereby ensuring synergy in regulatory outcomes. The Department should also examine the timing of proceedings, including when the LDCs make filings and when the Department issues orders, and consider aligning key planning procedures in a way that supports achievement of related outcomes (*e.g.*, targeting energy efficiency to reduce potential GSEP investment). An effective regulatory process should create a reliable cycle of review with timely inputs provided by utilities and outputs from regulators in support of regulatory goals.

Taken together, the AGO's recommendations to reform gas planning will support long-term planning efforts to meet emission reduction mandates and provide regulators and stakeholders with a more transparent and detailed insight into LDC investment proposals, as well as confidence in the LDCs' ability to successfully transition to clean energy economy.

[106] This also presents another application of the AGO proposed investment alternatives calculator.

B. Reform Capital Investment Planning and Policies

The Department is asked to review and approve various kinds of capital investments including investments in pipeline replacement through the GSEP program, line extensions, and investments related to new technologies. Below, are specific recommendations for each type of investment, followed by two universal recommendations that apply to all capital investments: the development of an investment calculator and limiting stranded costs.

> Capital investment decisions should reflect two policy priorities:
>
> 1. All gas system capital investments should require an alternatives review that reflects decarbonization and available alternatives.
> 2. Review of any proposed capital expenditure should consider the possibility of stranded costs and attempt to limit them.

1. Reform GSEP Review

RECOMMENDATION: The Department should consider the Commonwealth's climate objectives as part of its GSEP project review and require LDCs to demonstrate that the proposed investment is the least-cost alternative to improve safety and reduce leaks.

In 2014, the legislature passed An Act Relative to Natural Gas Leaks, which permitted LDCs to submit to the Department annual plans to repair or replace aged natural gas infrastructure in the interest of public safety and to reduce lost and unaccounted for gas.[107] Today, GSEP expenditures account for 40–60 percent of the LDCs' capital expenditures. Despite this massive investment in gas plant infrastructure, recent reports have found that the GSEP program is not reducing pipeline leaks.[108] More important, ratepayers may be spending millions of dollars on new infrastructure that will no longer be needed in the long-term.

The Commonwealth's climate goals and market competition from new electric end-use heating technologies raise serious questions about the continued prudence of accelerated GSEP investment. Today, LDCs operate GSEP programs using approximately the same decision making and project selection approaches employed since the start of their GSEPs, without any shift in response to the State's GHG reduction requirements or the changing gas industry. This business-

[107] *See* 2014 GSEP Act (establishing GSEP and categorizing and prioritizing leaks for repairs)

[108] *See GSEP at the Six-Year Mark,* at 39 (noting GSEP shows minimal progress in either reducing the overall number of leaks in the system or increasing the number of leaks repaired or eliminated)

as-usual approach calls into question whether the replacement plans being proposed year over year can be or will ever be deemed prudent investments. The Department has stated, "[a] prudence review involves a determination of whether the utility's actions, based on all that the utility knew or should have known at that time, were reasonable and prudent in light of the extant circumstances."[109] While it may have previously been reasonable to assume that replacement of a leak-prone pipe was prudent given that the long-term service life of the pipe warranted this decision over any short-term alternative, such as repair. The circumstances today, however, are different. Any replacement project that a company pursues is done so *with the extant knowledge* that the pipe installed will likely have a reduced service life.

Thus, the Department should provide clear direction that going forward it will no longer operate under the assumption that GSEP investment is "per se prudent." Instead, the Department will take into consideration the current climate context when reviewing the prudence of the GSEP projects being sought for cost recovery, either through future GSEP reconciliation or base rate proceedings. In addition, the Department should require the LDCs to use the investment alternatives calculator (discussed *infra*, at 33) to demonstrate that their GSEP investments are the least-cost alternative to improve safety and mitigate leaks.

2. *Reform Cost/Benefit Analysis for Line Extensions*

RECOMMENDATION: The Department should establish a uniform model for determining the costs/benefits of line extensions that incorporates State policies to reduce gas use.

The Department has consistently held that Massachusetts LDCs need not serve new customers in circumstances where the addition of new customers would raise the cost of gas service for existing firm ratepayers.[110] Thus, "when a gas utility company seeks to expand its distribution network by adding a new customer, it must first ensure that the incremental costs to expand its distribution network do not exceed the incremental revenues from such expansion."[111]

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[109] *Eversource Energy*, D.P.U. 17-05, at 85 (2018).

[110] *Boston Gas Company d/b/a KeySpan Energy Delivery New England*, D.T.E. 03-40 (2003), at 48 (2003); *Boston Gas Company*, D.P.U. 88-67 (Phase I), at 282–284. The Department has also recognized that LDCs, unlike electric distribution companies, do not have a universal obligation to serve all customers. Nevertheless, under current Department regulation, once a customer is connected to gas service it "*shall not be terminated for any reason other than failure to pay a bill, unless the Department certifies its approval after giving both parties an opportunity to be heard.*" 220 C.M.R. 25.02(3). As the Department examines electric and gas system coordination (*see* discussion *supra* at 25) and targeted electrification of defined geographic areas, it should carefully consider the consumer protections required for existing gas customers.

[111] *Boston Gas Company d/b/a National Grid*, D.P.U. 20-120 (2021) (citing *Bay State Gas Company*, D.P.U. 12-25, at 379 (2012)).

Ensuring as much prevents the addition of new customers from imposing additional costs on existing firm gas service customers.[112] The DPU has held that "existing customers receive benefits" from the addition of new customers "whenever, all other things being equal, the return on incremental rate base exceeds the Company's overall rate of return."[113]

Currently, however, there is no uniform model or costing matrix for determining the cost/benefit of line extensions or any indication that LDCs are considering the impact of the State's GHG reduction requirements in making their determinations. Thus, as an initial matter, the Department should conduct a review of existing tariff provisions and LDC practices to determine whether the current CIAC/IRR model (1) results in a de facto free extension allowance for most residential customers;[114] (2) accurately reflects the anticipated income or timeframe that a company's investment can be recouped; and (3) is inconsistent with existing State policies by incentivizing new customers to join the gas system and allowing the LDCs to extend their systems through plant additions.[115] In addition, as discussed further below, the Department should require the LDCs to consider alternatives to new customer additions.

3. Limit customer risk for investment in new technologies

RECOMMENDATION: The Department should ensure that investments in unproven or uncertain technologies are born entirely by utility shareholders.

The LDCs seek Department approval and full cost recovery from ratepayers for capital investment in emerging and yet unproven technologies such as RNG and hydrogen. The development of these highly uncertain alternatives presents two kinds of risks to ratepayers: first, that the development of these technologies will not come to fruition and second, that the Commonwealth will have wasted time and ratepayer resources on an expensive dead end.

A proposed investment in decarbonized gas carries significant investment risks and uncertainties. RNG, hydrogen or other claimed decarbonized gases is yet to be proven as a reliable, safe, and affordable alternative to natural gas so remains highly uncertain and speculative.[116] Any assumption that investment in these decarbonized gasses is prudent unduly shifts risk to ratepayers

[112] *Id.*; D.T.E. 03-40, at 48.

[113] D.T.E. 03-40, at 48.

[114] *See NSTAR Gas Company d/b/a Eversource Energy*, D.P.U 19-120 (finding that over the last five years, about 88 percent of NSTAR Gas's potential new customers required no CIAC); *see* also n. 23 *supra* (discussing the conflict between Climate Act and St. 2014, c. 149, § 3).

[115] *See* Ken Costello, *Line Extensions for Natural Gas: Regulatory Considerations*, NRRI Report 13-01 (February 2013).

[116] *See* AGO's Comments (discussing uncertainties around decarbonized gas). As noted above, there also remains an open question as to whether RNG is actually a "decarbonized" gas. *Id.*

for the associated costs.[117] Shifting the risks associated with the use of any emerging technologies to ratepayers remains inappropriate unless or until gas utilities establish that these investments and any associated plant upgrades are a cost-effective, sustainable, and low-GHG alternative. Any utility investment—other than approved pilots or demonstrations—in unproven or uncertain technologies, including investment in decarbonized gas, should be viewed as imprudent today and investment in these highly uncertain alternatives should be born entirely by utility shareholders.[118]

In addition to the specific recommendations discussed above and the recommendation to adopt a CCP, *supra* at 24-25, there are two other significant areas in which the Department can effect change related to capital investment planning and policy. First, the Department should adopt a uniform mechanism to evaluate continued gas infrastructure investment, pilots, and system expansion policies that includes review of alternatives. Second, the Department should develop guidelines for the treatment of potential stranded costs related to gas delivery utility systems.

4. Develop an "Investment Alternatives Calculator"

RECOMMENDATION: **The Department should utilize an "Investment Alternatives Calculator" as a mechanism to force transparent consideration of alternatives to traditional gas system capital investments.**

LDCs routinely make decisions related to investment in their gas system infrastructure based upon a narrow range of assumptions or values, and without robust consideration of alternatives.[119] System investments can be significant, *e.g.*, building an additional LNG facility, or fairly minimal, *e.g.*, adding a service line for a new customer. The limited analysis that does occur is conducted by each LDC internally, using assumptions that continue to favor gas system investment and expansion.[120] Going forward, these investment decisions, as well as those proposed as part of a CCP, must be evaluated in a more open manner and include comparisons of alternative investment scenarios utilizing a variety of variables and inputs (including the cost of avoided GHG

[117] *See id.* (noting the concerns with relying on decarbonized gas as a means to meet emissions reductions).

[118] Likewise, system upgrades to accommodate hydrogen or other decarbonized gases should also belong with LDC shareholders and not be assigned to ratepayers through inclusion in rate base.

[119] *See* David Boonin, *Utility Scenario Planning: Always Acceptable vs. the Optimal Solution*, NRRI Report 11-07 (2011).

[120] For example: the forecast price of delivered gas, the forecast cost of electric end-use technologies, the forecast cost of electricity, an appropriate cost of carbon, and the potential for stranded assets are all factors that require a fuller range of assumption values.

emissions of both methane and CO_2)[121] to a ensure a successful transition to net-zero based upon informed investment decisions.

Toward this end, the Commonwealth, through the Department and/or other agencies, should develop a core mechanism for an effective and rigorous investment and alternatives review process. A properly designed "*investment alternatives calculator*" can be used for review of proposed gas system investments including, but not limited to, service line extensions, GSEP investment, system investments over a threshold amount, and other capital investments. An investment alternatives calculator would provide a prescribed set of assumptions for the cost of carbon, a range of values for the cost of the gas commodity, alternative heat technologies, and would use a defined formula to evaluate the short- and long-term cost-effectiveness of capital investments in an open and transparent way.

To effectively utilize an investment alternatives calculator, the Department could require that an LDC demonstrate that its capital investment proposals are the most favorable option and least cost alternative to achieve a particular outcome (*i.e.*, proposed strategic electrification of a street by an EDC vs. repair of mains and services by the LDC). The LDCs would use the investment alternatives calculator to compare the expected costs of new gas system infrastructure (including, but not limited to, carbon/methane costs and expected stranded costs.) with the short- and long-term costs of alternative solutions, including demand response, energy efficiency, and load management. Finally, the Department should require LDCs to describe the environmental and equity impacts of its proposed investments and demonstrate that the new investment is consistent with current health, environmental protection, and resource use and development policies as adopted by the Commonwealth.[122]

To realize the kind of investment alternatives calculator described here, the Department should convene a technical conference to better understand the internal calculations upon which each utility relies to evaluate capital investment. The Department should further identify

[121] These costs could be forecast through an extrapolation of the current price for the Regional Greenhouse Gas Initiative, the federal Social Cost of Carbon or some other agreed-upon cost calculation adopted by the Department.

[122] In New York, the Department of Public Service has proposed an "Avoided Cost Calculator" for gas non-pipeline alternatives to help quantify the evaluation of gas investments and alternatives. *See* NY Department of Public Service, Case 20-G-0131, Staff Gas System Planning Process Proposal (February 12, 2021) at 18–24 (introducing alternatives analysis and an avoided cost of gas working group). The New York framework quantifies a range of avoided costs with a flexible and customizable tool that reflects the diversity of New York's gas utilities. The types of avoided costs include upstream supply costs, leakage rates, and other losses, "peak gas" value, local avoided infrastructure costs, and avoided GHGs (methane and CO_2). The avoided costs quantified in this type of model function as one side of an equation, to be compared with the proposed gas investment.

assumptions and a range of values to be included in any comparison analysis. Following the technical conference, the Department could either retain its own consultant to design an investment alternatives calculator or alternatively, require the utilities to design for Department consideration a proposed common investment alternatives calculator for use in future gas planning and proposed gas system investment.

A well-designed investment alternatives calculator would better enable stakeholders, including electric-end use technology providers, to examine the assumptions that LDCs present in support of the investments proposed in their CCPs, GSEP, line extensions, and other planned capital investment.

5. *Reform of Asset Depreciation and the Risk of Stranded Assets*

RECOMMENDATION: The Department should create guidelines and principles for treatment of potential stranded investment.

The Department should create guidelines and principles for the treatment of any potential stranded gas system investments, including those created by gas investments in the coming decades. For the purpose of this discussion, stranded investments include investments which have a positive book value that has not been collected from customers.

One proposed approach to manage stranded investments is to "accelerate" depreciation of gas investments to be consistent with decarbonization objectives.[123] Shortening the depreciation life span to be consistent with the timeline for decarbonization has some superficial appeal—if the useful life of the gas system is shorter, should not the depreciation life and amortization schedules be shortened? However, addressing the problem of stranded costs by awarding the LDCs accelerated depreciation payments would be counterproductive for two reasons.

First, an accelerated gas depreciation approach would, clearly, increase the costs of gas service. As costs of gas service increase, customers who can choose alternatives for heating and other gas uses would opt for those alternatives, but other customers, including renters and low-moderate income customers, may not be able to defect from the system and would be subject to the higher rates incorporating accelerated depreciation. Thus, the idea of shortening depreciation life is contrary to the equitable distribution of risk and cost burden between the utility and its ratepayers.

Second, a shortened depreciation approach to stranded investments assumes full collection of investment costs by shareholders on the current and future gas system investments. In this way, shortened depreciation would absolve shareholders from market and climate policy risk and effectively accelerate investment risk from utilities to ratepayers. This shift in investment risk from

[123] NARUC, *Depreciation Expense: A Primer for Regulators* (2021), at 22, *available at* https://pubs.naruc.org/pub.cfm?id=6ADB9EF-1866-DAAC-99FB-DBB28B7DF4FB.

utility shareholders to ratepayers, particularly those customers least able to pay higher bills, is contrary to established regulatory policy and inconsistent with the public interest. It is unrealistic for utilities to continue to invest in fossil infrastructure under a guarantee that they will fully collect their investment and earnings without regard to market risks and the Commonwealth's commitment to decarbonization. A set of regulatory guidelines to balance the risk pertaining to existing and future gas infrastructure investment would incent utilities to carefully consider investments and would avoid perverse outcomes, such as an investment in new gas pipelines in a residential area undergoing rapid building electrification.[124]

The Department may also choose to treat future investment differently from the investments that gas utilities have already made. There is a growing body of literature that establishes "shareholder awareness of risk at the time investments are made" to be the determining factor on who should bear the risk of stranded investments.[125] The current proceeding and State decarbonization policy suggest that it would be reasonable for the Department to clarify the criteria that it will use to assess whether stranded asset costs for gas investments will be borne by gas utility shareholders after a date certain.[126]

With LDC and stakeholder input, the Department can take several actions to clearly establish principles and strategies for the treatment of potential gas stranded assets:

- The Department can order the LDCs to file information on the magnitude of remaining investment value for both individual assets and the gas system as a whole (this would be based on factual information from each LDC within agreed upon geographic sub-units of the gas system).
- The Department can establish clear cost recovery timelines for the assets within each LDC's system by determining how much value has already been recovered and what value still needs to be recovered for each asset category within geographic sub-units for each LDC.
- The Department can establish a minimum threshold level of demand that would determine when an asset is legally considered "used and useful" and allowed to be recovered in rate base.

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[124] A well-designed investment alternatives calculator, as discussed *supra* at 33–35, would help mitigate the potential for future stranded assets.

[125] Several court cases including *Federal Power Commission v. Hope Natural Gas Co*, 320 U.S. 591 (1944), *Market Street Railway Co. v. Railroad Commission of California*, 324 U.S. 548 (1945), and *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989), have considered a variety of scenarios in which regulators must treat stranded costs. *See also*; Kahn, *Competition and Stranded Costs Re-visited,* Natural Resources Journal, Vol. 37, No.1 (1997), at 29–42.

[126] Dates to select for assessing future gas investments differently than past include the enactment of the Climate Act, the Green Communities Act, or the Commonwealth's adoption of an electrification policy for competitive technologies such as heat pumps.

- Based on the timeline, geography, customer class, and type of asset, the Department can develop principles or guidelines to balance costs and responsibilities for potential stranded assets.[127]

Gas ratepayers, shareholders, and regulators will all benefit from clear information and principles in ongoing discussions of treatment of gas assets as electrification advances in discrete areas within each LDC. Undertaking a comprehensive review of both the magnitude of potential stranded investment and principles for the determination of used and useful will inform the Department's consideration of alternatives to accelerated depreciation, like asset securitization.[128]

C. Align Utility Revenue with Decarbonization

Regulatory reform to align utility revenue with decarbonization outcomes should reflect the following policies:

1. Alignment of LDC revenue streams with climate objectives and GHG reduction compliance pathways.
2. Systematic removal of all revenue incentives designed to expand gas customer base and sales, as these incentives are contrary to the public policies of the Commonwealth expressed in the Climate Law and the Green Communities Act.
3. Consideration of the possible regulatory issues raised by an expansion of potential revenue streams allowed by business diversification, *e.g.,* geothermal micro-districts.

[127] *See* Environmental Defense Fund, *Managing the Transition: Proactive Solutions for Stranded Gas Asset Risk in California* (2019), at 13.

[128] Securitization is a method for a company to refinance transition costs. *Boston Edison Company*, D.T.E. 98-118 (1999), at 3. As part of the Electric Restructuring Act (Acts of 1997, c. 164), the Legislature authorized electric utilities to securitize its transition costs by issuing rate reduction bonds to investors that were to be repaid through a portion of the transition charge. *Id.; see also* G.L. c. 164, § 1H (defining "Electric Rate Reduction Bonds"). Rate reduction bonds, if assigned a high credit rating, will have an interest rate lower than the carrying charge paid by ratepayers as part of the transition charge, thereby generating savings to ratepayers. *See* D.T.E. 98-118, at 3. The AGO recognizes that legislative action to facilitate a similar approach for gas utilities would be required.

Specific opportunities for the Department to better align the utility revenue stream with decarbonization include:

1. Reform the gas revenue decoupling mechanism to better align revenues with decarbonization

RECOMMENDATION: The Department should replace revenue per customer decoupling with revenue cap decoupling, removing the existing incentive to add gas heating customers.

Revenue decoupling mechanisms are designed to remove the link between increased consumption and increased profits for utilities.[129] Revenue decoupling is put into place to address the built-in biases in utility cost of service regulation to favor increasing sales volume.[130] There are, however, different forms of revenue decoupling design that accomplish different regulatory objectives. The two types of revenue decoupling are: revenue cap decoupling and revenue cap per customer decoupling. Revenue cap decoupling is a straightforward mechanism that simply takes the total allowed revenue approved in the utility's rate case and compares that to actual revenue received. If too little revenue is collected (*e.g.*, due to energy conservation reducing energy sales), there is a revenue true up in the form of a reconciling surcharge so the utility collects its anticipated revenue requirement. If too much revenue is collected (*e.g.*, due to increases in sales), the surcharge is adjusted to reflect the "refund" in revenue to adjust the utility's recovery within its approved revenue requirements. While different jurisdictions use variations of a "revenue cap" decoupling, this is the general form of the revenue decoupling mechanism approved for the Massachusetts electric utilities.[131]

Unlike with the electric utilities, the Massachusetts gas utilities use a revenue per customer decoupling ("RPC") that is designed to encourage expansion of a utility customer base.[132] An RPC

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[129] See *Investigation into Rate Structures to Promote Efficient Deployment of Demand Resources*, D.P.U. 07-50, at 25.

[130] *Id.,* at 2 (recognizing that distribution companies' incentives to increase sales and avoid any decrease in sales may not be well-aligned with important State, regional, and national goals to: (1) promote the most efficient use of society's resources; (2) lower customer bills through increased end-use efficiency; (3) enhance the price-responsiveness of wholesale electricity markets; (4) mitigate the social and economic risks associated with climate change; and (5) minimize the environmental impacts of energy production, transportation, and use).

[131] *NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy*, D.P.U. 17-05-B; *Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid*, D.P.U. 15-10 (2015) (seeking revisions to its revenue decoupling mechanism).

[132] Investigation to Develop a Model Tariff Governing Revenue Decoupling Mechanisms for Gas Distribution Companies, D.P.U. 17-93 (2017), at Att. A (noting revenue is calculated on a per

applies a total revenue cap target that is adjusted to a per customer sales figure. The calculation is simple: the total revenue cap is divided by the number of customers to establish an allowed revenue per customer figure. Per this calculation, the gas company's revenue increases as the company adds new customers, thereby rewarding the company for expanding its customer base. Conversely, an RPC will discourage a gas company from decreasing customers served because its total revenues will also decrease.

To illustrate: assume a gas company is allowed $20 million in annual revenue in its most recent rate case. The revenue cap method sets the target at $20 million and adjusts actual revenue up or down to allow an actual $20 million in revenue. Thus, the company is neutral to the fluctuations in sales that may occur due to energy efficiency efforts or any decrease or increase in its customer base. Using an RPC mechanism, by contrast, the gas company can increase allowed revenues (*i.e.*, the $20 million) by increasing customer counts because the rate-case-established revenue per customer amount applies to each new customer acquired until the next rate case. Conversely, if between rate cases the gas company loses customers, then the revenue it would receive would be reduced.

An RPC decoupling design made sense when the Commonwealth sought to achieve emissions reductions by encouraging oil-to-natural gas heating conversions. The RPC decoupling design incented the LDCs to promote the oil-to-gas conversion by allowing the LDCs to collect new revenue for every new gas conversion. Now, however, unless the Department changes the RPC decoupling mechanism, the LDCs have no incentives other than through energy efficiency to promote efficient electrification because for every customer that converts from gas to electric heat pumps the gas utility's revenue is also reduced. RPC decoupling discourages the gas utility from promoting gas to electric conversion, *i.e.*, electrification, required under the approved three-year energy efficiency plan[133] and what will be necessary to achieve the climate mandates.

Continuing the use of an RPC decoupling mechanism is not consistent with the reductions in gas use required for the achievement of the Commonwealth's net-zero mandates. The Department should change the revenue decoupling mechanism for LDCs to provide a revenue cap based upon an approved revenue requirement set forth in an adjudicated review of rates.

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customer basis); *see also NSTAR Gas Company Revenue Decoupling Adjustment Clause,* at 2, *available at*, https://www.eversource.com/content/docs/default-source/rates-tariffs/ma-gas/409-tariff-ma.pdf?sfvrsn=e8c1f562_13.

[133] *See Three-Year Joint Energy Efficiency Plans,* D.P.U. 21-120 through 21-129 (2022)

2. *Align Performance-Based Rates with State Climate Laws*

RECOMMENDATION: The Department should revisit and revise its existing performance-based ratemaking framework to ensure that any Department approved performance-based ratemaking plan encourages LDC investment consistent with State climate laws.

In recent Orders, the Department adopted a performance-based ratemaking ("PBR") framework for LDCs, recognizing that "there is a fundamental evolution taking place in the natural gas local distribution industry in Massachusetts."[134] Unfortunately, the approved gas PBR framework serves to incentivize the LDCs for making significant capital investments that the LDCs would likely make in the routine course of their business for the continued safe and reliable operation of their distribution systems.[135] As its name suggests, "performance-based rates" should tie revenue to LDC performance and achievement of the desired outcomes. Meeting the Climate Act mandates should be one of the desired outcomes that PBR is designed to incent.[136]

Currently, the Department requires a utility seeking approval of an incentive proposal like PBR to "demonstrate that its approach is more likely than current regulation to advance the Department's traditional goals of safe, reliable, and least-cost energy service to promote the objectives of economic efficiency, cost control, lower rates and reduced administrative burden in regulation.[137] Thus, the resulting PBR is structured around an increase in LDC productivity, a decrease in administrative costs, and fostering customer growth.[138]. Substantial revision and

[134] *See*, *e.g.*, *NSTAR Gas Company d/b/a Eversource Energy,* DPU 19-120, at 56.

[135] The AGO notes that the GSEP is also intended to ensure the continued safe and reliable provision of gas services. Indeed, underpinning all gas investment is the requirement for the continued safe and reliable provision of gas services. It would seem appropriate to take this time to rethink PBR mechanisms to incent LDC investment or action in ways that are not intrinsic but fundamental to aligning gas distribution with climate objectives.

[136] The energy efficiency performance incentive mechanism that ties utility earnings to demonstrated performance of energy efficiency goals is instructive when considering revisions to the PBR mechanism. *See e.g.,* D.P.U. 21-120 through D.P.U. 21-129, at 177-208 (2022) (discussing current proposed performance incentive mechanism); see also Department Energy Efficiency Guidelines, § 3.6.2 (setting forth principles for the design of performance incentive mechanisms). Energy efficiency performance incentives provide the inducement for a utility to "reduce its sales," an action that is counter to traditional business metrics. Similarly, the PBR mechanism can provide an incentive for an LDC to take the necessary action in furtherance of the Commonwealth's climate policy and mandates to reduce its sales of methane gas through a series of measures to encourage gas efficiency, demand-response, electrification, as well as reducing LDC system and customer emissions of methane and CO_2.

[137] *See NSTAR Gas Company d/b/a Eversource Energy,* D.P.U. 19-120, at 59.

[138] *Id.,* at 56–66 (explaining the rationale for PBR and approving Eversource PBR plan for the ten-year period beginning November 2020).

innovation within the current gas PBR design process is necessary to align gas PBR with the Commonwealth's long-term future of the gas system in a net zero 2050 economy.

The Department should consider amending the existing PBR framework to establish incentives and disincentives designed around the gas utilities progress in compliance with the Climate Act mandates, and achievement of their approved CCP. Updating the PBR framework now to incentivize the reduction of methane and CO_2 emissions—rather than gas system expansion—can guide the Department's review and approval of PBR requests made as part of an LDC's future rate case.[139] In connection with revising its existing PBR framework, the Department should solicit comment on meaningful and trackable metrics that would appropriately measure the LDCs progress toward the Commonwealth's climate goals.

D. Reform Outdated Rate Provisions that Promote Gas System Growth

The Department should also update a range of provisions to existing rates that will better align LDC operations with decarbonization.

RECOMMENDATION: The Department should not permit the LDCs to recover costs for marketing related to promoting gas service.

LDCs include the costs of marketing campaigns to promote gas service as allowed expenses in their periodic rate cases.[140] These kinds of costs are not aligned with the regulatory policies of the Commonwealth and are particularly at odds with the Commonwealth's decarbonization goals. Expansion advertising, ratepayer funded or not, is no longer appropriate and should be eliminated entirely.

RECOMMENDATION: The Department should conclude its investigation in D.P.U. 18-152 and limit special contracts to only unique and novel public interest circumstances.

Gas special contracts allow gas utilities to provide off-tariff pricing for firm transportation customers, upon a showing that the customer has an alternative fuel source available, *i.e.*, dual fuel capabilities and the off-tariff pricing meets or exceeds the utilities marginal costs to supply.[141]

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[139] NSTAR's PBR is in effect until 2030, which is far too long to wait to align NSTAR's PBR with the State's climate objectives. *See id.,* at 66. After adjusting the PBR framework, the Department should consider directing each LDC to submit revised PBR requests instead of waiting for the LDC to file its next base rate case.

[140] *See e.g.,* D.P.U. 19-120 (2020), Exhibit ES-DPH/ANB-1 at 165 (seeking recovery of marketing costs through base distribution rates).

[141] *See Investigation to Review & Revise the Standard of Review & the Filing Requirements for Gas Special Contracts Filed Pursuant to G.L. c. 164, § 94,* D.P.U. 18-152, Vote and Order, at 3–4 (2018) (setting forth the current standard of review for gas special contracts to firm transportation customers as: (1) the customer must ". . . have an ability to bypass an LDC's distribution system,

Existing special contracts include for-profit businesses, colleges/universities, and large non-profits.[142] The practice of allowing "off-tariff" rates for certain commercial/industrial customers is based on premises that, *inter alia*, include the following; specifically, that customers:

(1) have a choice of the fuels they use to heat their buildings (*i.e.*, gas, propane, & oil);

(2) will not join, or may leave, the natural gas system if not allowed a "special" lower rate;

(3) benefit (including both residential and other C&I customers) when customers join, or stay on, the natural gas system because of economies of scale;

(4) best option it is to choose natural gas because it is the "cleanest" fuel choice.[143]

In the 1990's, when special contract pricing was first approved, natural gas prices were high and there was a legitimate risk that the firm transportation customer would bypass the LDC's distribution system and forego distribution service. The same pricing climate does not exist today. Special contracts have simply become a vehicle for large firm transportation customers that have the capability to (but rarely do) burn fuel oil to pay less for gas delivery and also, often times, forego paying into the energy efficiency programs.

Currently, there is no legitimate risk that these dual fuel customers would actually bypass the gas system and utilize fuel oil at a significantly increased cost. Rather, these special contracts provide a negotiated rate to large customers, often at the expense of other C&I customers that fund energy efficiency and to the detriment of the energy efficiency program itself. Collectively, the

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such as an ability to connect directly to an interstate gas pipeline or the ability to use a competitive alternative fuel[]"; and (2) the special contract's negotiated rate ". . . must exceed the Company's marginal cost to provide the service in order to avoid subsidization between ratepayers paying tariffed rates and ratepayers on special contracts[]").

[142] *See e.g.*, *Boston Gas Company, d/b/a National Grid,* D.P.U. 22-GC-01 through D.P.U. 22-GC-17 (pending 2022 special contract dockets filed through April 30, 2022).

[143] D.P.U. 18-152*,* at 3 (noting the premise of the Department's standard is that "other ratepayers benefit from a utility company's providing a service to a customer that would not otherwise be served under a company's general rate schedule due to competitive market forces." (citing, *Boston Gas Company,* D.P.U. 92-259, at 28 (1993)); *Boston Gas Company*, D.P.U. 17-GC-22, at 25 (2018) (stating that special contracts must provide net benefits to ratepayers); D.P.U. 17-GC-22, at 25 (stating that special contracts given to customers with the ability to bypass an LDC's distribution system achieve net benefits because the alternative is that the customer leaves the distribution system and no longer contributes anything to the overall distribution system costs).

amount of lost energy efficiency revenue yearly could be significant.[144] More importantly, revisiting the propriety of these special contracts seems appropriate since the Commonwealth is looking to its energy efficiency programs as a foundational pillar to achieve its climate objectives.[145]

The Department should conclude its investigation in D.P.U. 18-152 and limit special contracts to unique and novel circumstances that demonstrate:

(1) net benefits to customers, and

(2) that the customer's use of natural gas is no more harmful in terms of GHG and air pollutant emissions than the customer's alternative energy resource(s).

RECOMMENDATION: The Department should explore incentivizing the LDCs to use non-capital options to defer capital investment.

Just as current regulatory policy has prioritized the expansion of the gas system, a revised regulatory policy should seek to promote the most efficient use of capital, recognizing the possibility of an orderly decommissioning of all or parts of the gas system over the next several decades. To incent LDCs to develop innovative strategies that do not rely upon capital investment, the Department should explore how to incentivize the LDCs to use non-capital options to defer capital investment; in that way, the LDCs can be motivated to make choices that save ratepayers money.

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[144] For example, during 2019, approximately 10 million dollars in energy efficiency contributions were avoided as a result of the special contract pricing approved. *See National Grid,* D.P.U. 19-GC-01 through D.P.U. 19-GC-60. In addition, since it is not clear exactly how many special contracts are currently in effect, the Department should direct the gas companies to include in their system and customer mapping filing, *supra* at 18, a special contract audit that includes each existing special contract, the customer name and location, rate and average yearly usage, contract expiration date and provisions for term extensions, the AGO recognizes that such an audit may raise customer confidentiality concerns and can be made available under motion for protective treatment.

[145] After a request by the AGO, the Department opened a docket to investigate the practices for offering and pricing of special contracts. *See* D.P.U. 18-152 (2018), *supra*, at n. 141. This docket remains open.

E. Broader Legislative and Regulatory Reforms

There are four significant issues that raise unique barriers to decarbonization and adoption of clean energy resources that directly relate to the future of the gas system. For most of the recommendations, the Department has substantial existing authority to take action now. As a source of institutional knowledge and regulatory expertise, the Department can also engage in stakeholder information gathering and technical sessions to clarify issues and make recommendations to assist in consideration for either Legislative amendments or further Department action.

1. Further Examination of Additional Gas Safety Enhancement Program Reform and Improvement of Methane Emissions Accounting

RECOMMENDATION: The Department should form a working group to make recommendations to the Department and the Legislature on changes to GSEP.

Aligning GSEP with the Commonwealth's climate goals is a necessity and should be a priority of both the Department and the Legislature. Present GSEP initiatives rest on the underlying assumptions that (1) natural gas throughput will remain steady or increase indefinitely into the future; and (2) GSEP investment and special cost recovery is the most cost-effective means to reduce methane emissions from gas infrastructure and ensure safe and reliable gas distribution system now, and into the future. Beyond the immediate changes to GSEP recommended *supra*, at 30, the AGO also recommends a fresh look at the GSEP to allow for a more focused, in-depth, and inclusive review of the myriad of safety, reliability, and cost recovery issues raised by the GSEP. The Department should convene a working group to make recommendations to the Department and the Legislature on necessary changes to the GSEP. The primary objective of the working group would be to develop comprehensive recommendations to ensure that gas system leak mitigation is consistent with the Commonwealth's climate mandates, while maintaining a safe and reliable gas distribution system.[146]

RECOMMENDATION: The Department should collaborate with other agencies to improve the methodology utilized to account for Massachusetts-specific methane emissions and reductions.

The manner by which LDCs account for methane should be revisited. Currently, the LDCs rely upon a potentially flawed methodology to calculate emission reductions from distribution mains and services (either in CCPs, GSEP, energy efficiency plans or to comply with DEP regulations).[147] The LDCs should use an updated and more robust methodology. Gas utilities

[146] AGO and DOER Joint Letter (February 14, 2022)

[147] The LDCs are relying on a bottom-up leak count which measures emissions based on an estimate of leaks per mile. Using this method, it has been estimated that transmission and

should no longer rely on formulaic calculations of emissions reductions that simply multiply miles replaced by a nationwide and generic emission reduction numbers for the type of pipe replaced. At the very least, emission reduction factors should be based on Massachusetts data. The Department, in collaboration with the Department of Environmental Protection, should update how the State calculates methane emissions and reductions.

2. *Geothermal Heat Districts and Alternative Thermal Technologies*

RECOMMENDATION: The Department should open an investigation into the regulatory treatment of geothermal heat districts and alternative thermal technologies.

Ground-source heat districts offer an innovative approach to transitioning components of the gas system to electric heat. The Department has approved two gas utility pilot projects for exploration of the feasibility and viability of the ground source heat pump technologies.[148]

The opportunity to offer renewable thermal services to existing gas customers presents new regulatory questions. Given its potential to provide heating and efficient energy consistent with current law, the Department should continue to learn about the costs, feasibility and scalability of ground-source heat districts through pilot programs. The Department should open an investigation to examine possible regulation and ownership frameworks for this technology. Some questions for examination include:

1. Should existing LDCs receive an exclusive monopoly to provide renewable thermal service within their service territories?
2. Should new companies be granted exclusive monopolies to provide renewable thermal service, and if so, over what scale of territory? City blocks? Neighborhoods? Towns? Regions?
3. Should renewable thermal service be a regulated activity, or should it be a competitive industry with basic oversight for safety and reliability? If so, how should EDCs and LDCs

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distribution emissions from 2012 to 2018 were reduced by 15 percent (based on estimated leaks per miles). *See* Dorie Seavey, *GSEP at the Six-Year Mark* (2021), at 39. However, recent, top-down studies indicate that the actual reduction is much less. Indeed, it is very likely that there are large missing sources of emissions in the DEP bottom-up methane inventory related to natural gas distribution and, in particular, end use. *See* McKayne et al., *Majority of US Urban Natural Gas Emissions Unaccounted for in Inventories*, in Earth, Atmospheric, and Planetary Sciences (October 21, 2021), at 118; P. M. B. Saint-Vincent and N. J. Pekney, "*Beyond-the-Meter: Unaccounted Sources of Methane Emissions in the Natural Gas Distribution Sector*, I Environmental, Science and Technology 54, at 39–49 (2020).

[148] *See Boston Gas Company d/b/a National Grid,* D.P.U. 21-24, (geothermal pilot project); *NSTAR Gas Company d/b/a Eversource Energy,* D.P.U. 21-53 (same). In addition, the Department has also approved the settlement as part of D.P.U. 20-59 that provides funding for an AGO and DOER administered geothermal pilot in the Merrimack Valley.

be allowed to compete against third party providers given their existing advantages in controlling gas infrastructure conduit, current expertise in some of the areas?

4. Should regulatory treatment of renewable thermal depend upon decommissioning of individual or collective gas service?

3. *St. 2014, c. 149, § 3*

RECOMMENDATION: The Department should not approve LDC plans filed under St. 2014, c. 149, §3 that are inconsistent with an LDC's CCP.

St. 2014, c. 149, § 3 ("Section 3") authorizes the Department to allow gas companies "to design and offer programs to customers which increase the availability, affordability and feasibility of natural gas service for new customers." The Department has interpreted Section 3 as requiring approval of proposals designed to increase affordability of gas service to new off-main customers, which "necessarily will result in investments in new main and service extensions and increased use of natural gas." Under Section 3, the DPU has approved proposals designed to "mitigate financial barriers and improve the affordability of obtaining new gas service."[149]

Section 3 is not consistent with the goals of the Climate Act and should be rescinded. In the meantime, the Department should encourage LDCs not to file any plans under this statute and decline to approve any plans filed that are inconsistent with an LDC's CCPs

4. *Equity and Affordability*

In this time of dynamic market and regulatory transition, the gas regulatory framework must protect LMI customers from the consequences of bad investments, poor planning, or risky resource allocation decisions made by the gas utilities. Absent a proactive approach, as customer base and sales volume decrease with customers migrating to other energy sources, the associated rate increases will be significant for remaining customers. The following illustration from the Haas Energy Institute shows graphically how gas utility bills rise non-linearly for remaining customers as customers exit the gas system:[150]

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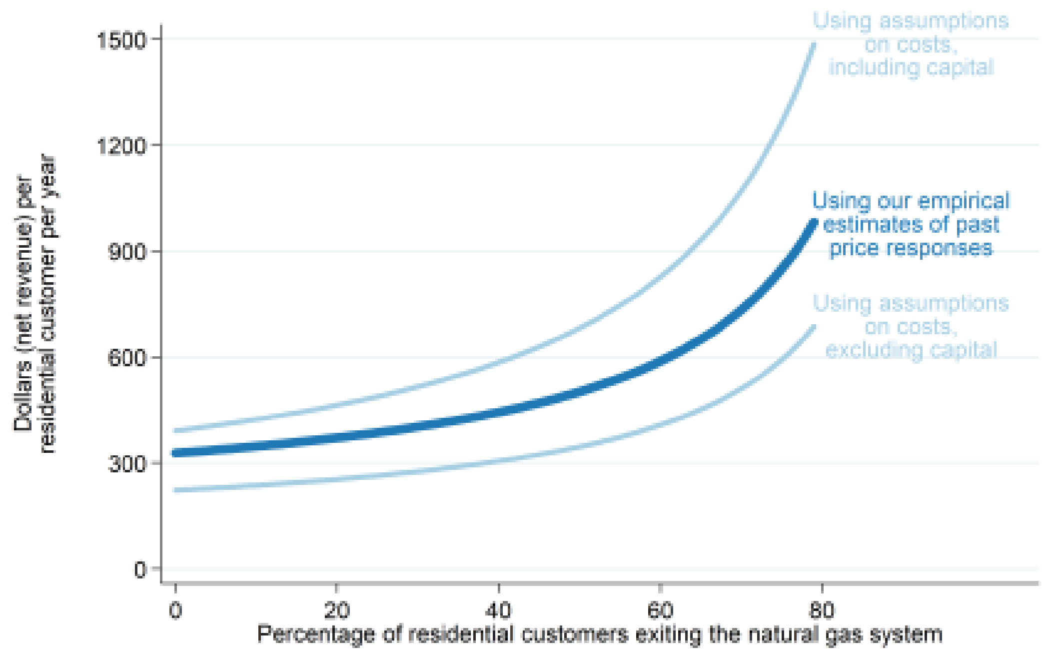
[149] *See* D.P.U. 19-120 (allowing new on-main customers who may be subject to a CIAC the option to pay a surcharge instead of the CIAC); *see also* D.P.U. 16-79 (allowing a pilot program permitting eligible customers to pay the CIAC over a 10-year period, instead of in a single up-front payment).

[150] Lucas Davis and Catherine Hausman, *Who Will Pay for Legacy Utility Costs?* (Revised March 2022), Fig. 4, at 25, *available at* https://haas.berkeley.edu/wp-content/uploads/WP317.pdf.



If adequate protections are not in place, the remaining customers on the system left shouldering these costs are likely to be disproportionately LMI customers, and rates are likely to be higher than customers can afford. The current framework does not include protections to keep vulnerable customers from carrying an increasing and excessive energy burden; nor does the current framework ensure that vulnerable customers will have access to clean energy alternatives.

LMI households often lack savings, disposable income,[151] and access to credit, leading to fewer choices related to housing, structural improvements (such as improving insulation), and energy infrastructure.[152] While alternative energy resources can offer long-term savings, without incentives or other government support, these customers are less likely[153] to transition to

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[151] Disposable income refers to the monthly total income minus monthly rent or mortgage costs.

[152] A. Drehobl and L. Ross, *Lifting the high energy burden in America's largest cities: How energy efficiency can improve low income and underserved communities* (2016), at 11, *available at* https://www.aceee.org/sites/default/files/publications/researchreports/u1602.pdf. In addition, low-income families and families who experience sudden economic hardship "often live in older, less efficient housing stock, which means that their homes require more energy for heating and cooling than newer, more efficient housing." *Id*. At the same time, energy retrofits may not be available due to structural deficiencies. *Id*.

[153] "[R]enewable energy and energy efficiency can be inaccessible to LMI customers for multiple reasons, including: large upfront capital requirements; reduced access to desirable financing; customers' low credit scores; lack of homeownership; inability to access tax incentives; residence in multi-family housing; residence in inefficient manufactured housing; [and] lack of roof access." Jocelyn Durkey and Megan Cleveland, *State Policies for Low- and*

alternatives, such as heat pumps, as these technologies require high upfront investment. Relatedly, renters are similarly poorly positioned. A renter has no control over the unit's heating system, as a renter cannot change a heating system without a landlord's permission; and a landlord may not be motivated to make the upfront investment required.

Low-income households consistently spend a higher percent of their income on electricity and gas bills than any other income group, despite decades of bill assistance and weatherization programs.[154] A 2020 study estimates that low-income households in the U.S. spend 8.1 percent of household income on energy costs, which is three times more than the energy costs for non-low-income households, which spend 2.3 percent.[155] In Massachusetts specifically, the average energy burden per household is 3 percent, but for low-income populations, the number climbs to approximately 10 percent, and reaches as high as 31 percent in certain neighborhoods.[156, 157]

Moderate-Income Customer Access to Renewable Energy and Energy Efficiency (September 23, 2021), National Conference for State Legislatures *available at* https://www.ncsl.org/research/energy/state-policies-for-low-income-and-moderate-income-customer-access-to-renewable-energy-efficiency.aspx (formatting and capitalization altered).

[154] Brown et al., *High energy burden and low-income energy affordability: conclusions from a literature review* (2020), at 5, *available at* https://iopscience.iop.org/article/10.1088/2516-1083/abb954/pdf. Notably, "low-income households consume less energy per capita and they spend less on energy per square foot of living space than any other households." *Id*.

[155] Drehobl et al., *How High Are Household Energy Burdens?: An Assessment of National and Metropolitan Energy Burdens across the US* (2020), at iii. The report looked to data from the American Housing Survey. Nationally, 67 percent of low-income households experience a high burden, compared with 25 percent of all households. *Id*., at 11.

[156] Metropolitan Area Planning Council, *Reducing Energy Burden: Resources for Low-Income Residents*, *available at* https://www.mapc.org/planning101/reducing-energy-burden-resources-for-low-income-residents/ (data source is the U.S. Department of Energy Low-Income Energy Affordability Data).

[157] While "[m]ore than three in every ten households in the United States have difficulty paying basic energy bills" and suffer from energy insecurity, New England states, "among the wealthiest in the country, . . . suffer the second-highest rate of household energy insecurity in the Unities States" (approximately 36 percent of households have difficulty paying utility bills). David Littell and Joni Sliger, *Making Basic Service More Affordable: Electricity Rates for Low- and Moderate-Income Ratepayers* (October 2019), at 1–2, *available at* https://www.raponline.org/wp-content/uploads/2019/10/rap_littell_sliger_new_england_rate_design_lmi_2019_october-1.pdf (citing information from the U.S. Energy Information Administration).
Drehobl et al., *How High Are Household Energy Burdens?:An Assessment of National and Metropolitan Energy Burdens across the US* (2020), at iii, 11, *available at* https://www.aceee.org/sites/default/files/pdfs/u2006.pdf.

Energy burden is defined as the percent of income a household spends meeting their energy needs. When a household spends a relatively high percentage of their income meeting their energy bills (>6 percent),[158] that household may not be able to afford other basic needs, such as quality food, or medical care, or may be at risk of disconnection if they cannot pay their bills.[159] In addition, some households may seek to reduce their energy consumption, thereby reducing energy costs, by restricting usage or even turning off their household heating systems in the winter. This type of energy limiting is dangerous. First, looking to lower heating costs, people may heat their homes with electric space heaters or their ovens, which are less safe heating sources compared with gas or electric household heating.[160] Second, pipes can freeze if household temperatures are very low, putting households at risk of a water shortage and costly repairs.

The disparity, where certain groups are more likely to have a higher energy burden than other groups, also exists between minority and non-minority groups. In the U.S., the median energy burden for Black households (4.2 percent of household income) is 43 percent higher than the median energy burden for white households (2.9 percent), while the median energy burden for

[158] High energy burden refers to when a household spends more than 6 percent of total household income on energy costs, while 10 percent is considered a severe energy burden. A high energy burden contributes to energy insecurity, which is the uncertainty that a household can pay utility bills. Energy poverty refers to living in a home without access to enough energy to meet essential needs. *See* Drehobl et al., *How High Are Household Energy Burdens?:An Assessment of National and Metropolitan Energy Burdens across the US* (2020), *available at* https://www.aceee.org/sites/default/files/pdfs/u2006.pdf; Brown et al., *High energy burden and low-income energy affordability: conclusions from a literature review* (2020), *available at* https://iopscience.iop.org/article/10.1088/2516-1083/abb954/pdf.

[159] *See* A. Drehobl and L. Ross, *Lifting the high energy burden in America's largest cities: How energy efficiency can improve low income and underserved communities* (2016), at 9, 13 *available at* https://www.aceee.org/sites/default/files/publications/researchreports/u1602.pdf

[160] *See, e.g.*, J.S. Held, *Common Causes of Electric Space Heater Fire Examined* (2022), *available at* https://jsheld.com/insights/articles/common-causes-of-electric-space-heater-fires-methods-of-prevention.

Hispanic households is 20 percent higher than that for non-Hispanic white households (3.5 percent versus 2.9 percent).[161, 162]

Pursuant to the Department's new statutory mandate, it should consider the disproportionate and inequitable distribution of burdens and benefits that currently exist when making regulatory decisions that could potentially exacerbate those inequities, especially those decisions transitioning the Commonwealth to a net-zero future.[163]

Equity considerations should reflect three policy priorities:

1. Center LMI ratepayers in the transition.
2. Provide equitable access to clean technologies to all ratepayers in the Commonwealth.
3. Consider energy-related inequities and the disproportionate impacts to health and safety experienced in certain communities (e.g., due to pollution or energy infrastructure siting), including environmental justice communities.

RECOMMENDATION: The Department should consider adopting a rate mechanism to protect low- and moderate-income ratepayers from high energy burdens and from potential rate increases related to climate investments by both the gas and electric distribution companies.

Massachusetts ratepayers can access several important programs to help heat their houses (*i.e.*, reduce their bills) and keep the lights on (*i.e.*, avoid disconnection). The Low Income Home Energy Assistance Program ("LIHEAP"), a federal program, provides assistance with home heating costs for income eligible households (including costs related to oil, electricity, gas,

[161] Drehobl et al., *How High Are Household Energy Burdens?:An Assessment of National and Metropolitan Energy Burdens across the US* (2020), at iii, 11, *available at* https://www.aceee.org/sites/default/files/pdfs/u2006.pdf. Although data related to similar disparities in Massachusetts is limited, the available data suggests that these disparities exist in most states. *See* National Consumer Law Center ("NCLC"), *Massachusetts Residential Utility Customers Still Owe Nearly $100M More in Arrears Than at the Start of the Pandemic* (February 2022), at 1, *available at* https://www.nclc.org/images/pdf/special_projects/covid-19/IB_MA_Arrears.pdf.

[162] NCLC has raised concerns about the lack of data necessary to track similar disparities in Massachusetts and has stated that data from a small number of states suggests that similar disparities exist in most states and that it is reasonable to assume that minority communities are disproportionately experiencing the negative impacts associated with a high energy burden. *See* NCLC, *Massachusetts Residential Utility Customers Still Owe Nearly $100M More in Arrears Than at the Start of the Pandemic* (February 2022), at 1, *available at* https://www.nclc.org/images/pdf/special_projects/covid-19/IB_MA_Arrears.pdf.

[163] *See* G.L. c. 25, § 1A; St. 2021, c. 8, § 15.

propane, kerosene, wood, and coal).[164] Another federal program, the Emergency Rental Assistance Program ("ERAP"), passed in response to the COVID-19 pandemic, provided assistance, including for utility bills, to renters experiencing a COVID-related financial hardship who were struggling to remain in their homes.[165] Massachusetts households that earn 60 percent or less than the State median income or who receive income-eligible benefits from the State or federal government can qualify for low-income discount rates from their gas utility, which reduce a participant's total gas bill by 25 percent.[166] These same customers can also participate in Arrearage Management Plans ("AMPs"), whereby eligible residential customers can reduce their utility arrearages through a monthly payment arrangement that results in the utility forgiving the remaining arrearage balance after the customer successfully makes payments pursuant to the agreement.[167] The AGO also offers the Residential Energy Assistance Grant ("REAG") program,[168] providing grants to agencies that use the funding to assist moderate-income residents

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[164] To qualify for LIHEAP assistance, household income cannot exceed 60 percent of the estimated State Median Income. *See* https://www.mass.gov/service-details/learn-about-low-income-home-energy-assistance-program-liheap. For fiscal year 2022, 60 percent of the estimated State Median Income was $78,751 for a family of four. *See* https://www.mass.gov/doc/cold-relief-brochure-0/download.

[165] The Massachusetts Department of Housing and Community Development stopped taking new applications on April 15, 2022; applications received before then will be considered until funds are exhausted. To qualify for ERAP, applicants could earn up to 80 percent of the Area Median Income ("AMI"). *See* https://www.mass.gov/info-details/emergency-housing-payment-assistance-during-covid-19#details-on-the-emergency-rental-assistance-program-(erap)-.

[166] *See* G.L. 164 § 1F(4); D.P.U. 19-120, at 436 (retaining the 25 percent discount rate). The low-income discount rate is also available for electric customers, with total bill reductions between 32 and 36 percent. *See, e.g.*, *Massachusetts Electric Company and Nantucket Electric Company,* D.P.U. 18-150, at 519 (increasing the low-income discount rate from 29 to 32 percent); D.P.U. 17-05-B, at 158 (2018) (authorizing a 36 percent discount rate). The statute requiring LDCs to offer a low-income discount rate does not apply to municipal utilities.

[167] *See Investigation into Expanding Low-Income Customer Protections and Assistance,* D.P.U. 08-4; *2021 Arrearage Management Plans,* D.P.U. 21-AMP. As of February 2022, the 323,620 residential gas utility customers in arrears owed approximately $243 million on their gas bills.

[168] The REAG program provides assistance to low-income ratepayers; as well as to moderate-income ratepayers, who make 60–80 percent of the State's median income and are ineligible for LIHEAP. The grant is funded through a settlement reached in September 2020 with the competitive electric supplier, Starion Energy, for using unfair and deceptive sales tactics. The grant expands on the AGO's prior National Gas Fuel Assistance grant program by expanding the fuel types eligible for assistance to include electricity, oil, and propane, as well as natural gas.

with their heating bills. Finally, utilities cannot disconnect service to customers with financial hardship during cold winter months.[169]

These various programs offered by the federal government, the utilities, the AGO, and the protections established by the Department and by statute all provide much-needed assistance to LMI households. These protections should be retained, strengthened, and improved. However, these existing programs are insufficient to protect our most vulnerable residents from high energy burdens and the associated negative impacts to their health, safety, and well-being during the transition to a net-zero economy. Protection for LMI ratepayers must be directionally consistent with reducing dependence on natural gas and should minimize risk that customers unable to migrate end up with a disproportionate share of transition, embedded, and/or stranded costs.

The Department should consider establishing a program that directly targets the energy burden of ratepayers by imposing an upper bound on the amount a household spends on energy bills across the gas and electricity sector.[170] A cap on the amount a low- or moderate-income ratepayer is billed, such as an energy wallet, or a similar rate mechanism that focuses on the burdens and impacts experienced by LMI ratepayers, will serve to protect residents from a high energy burden and from energy insecurity.

The Department should also consider how programs can be designed to facilitate opportunities for vulnerable residents to access cleaner energy alternatives, considering that LMI ratepayers and ratepayers in certain communities, including environmental justice communities, may have more barriers to adoption of cleaner energy alternatives,[171] and may experience

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[169] *See* G.L. c. 164, § 124F; 220 C.M.R. 25.03. Disconnection protection is also available to other qualifying households, including households with an infant (under 12 months), a seriously ill resident, or with elderly residents. *See* G.L. c. 164, §124A, H; 220 C.M.R. 25.03, 25.05. The Department ordered the utilities to discontinue disconnections due to the COVID-19 pandemic. This moratorium on disconnections expired on July 1, 2021. *See Inquiry into Establishing Policies and Practices Regarding Customer Assistance and Ratemaking Measures in Connection to the State of Emergency Regarding the Novel Coronavirus,* D.P.U. 20-58.

[170] *See, e.g.*, Illinois Percentage of Income Payment Plan (providing low-income residential customers with reduced utility bills based on total household income), *available at* https://www2.illinois.gov/dceo/CommunityServices/UtilityBillAssistance/Documents/PIPP%20brochure-2019.pdf; Department of New York Public Service Commission's Order in Case 14-M0565 (adopting a policy that an energy burden of 6 percent (or below) of household income is the target level for household energy burdens for all low-income customers, instituting a phased approach to implement changes, and establishing a process) (May 20, 2016), *available at* https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=47031&MNO=14-M-0565.

[171] *See* Jocelyn Durkay and Megan Cleveland, *State Policies for Low- and Moderate-Income Customer Access to Renewable Energy and Energy Efficiency* (2021), National Conference of State Legislatures.

disproportionate hardship from high energy costs and energy burdens.[172] By providing targeted support, the Department can ensure that the Commonwealth meets its decarbonization mandates with participation from all segments of the population.[173] For example, Eversource and National Grid each have petitions pending before the Department that would provide low-income customers with direct incentives to access community solar programs at no cost.[174] New York, California, Oregon, Colorado, and the District of Columbia[175] have also pursued or are pursing strategies (particularly to facilitate installation of solar panels and solar water heating) to ensure that barriers to accessing cleaner energy alternatives are minimized and the benefits of clean energy are shared more widely.[176]

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[172] Drehobl et al., *How High Are Household Energy Burdens?:An Assessment of National and Metropolitan Energy Burdens across the US* (2020), at iii, 11, *available at* https://www.aceee.org/sites/default/files/pdfs/u2006.pdf; Office of the Attorney General, *Covid-19 's Unequal Effects in Massachusetts: Remedying the Legacy of Environmental Injustice & Building Climate Resilience* (2020), at 37, *available at* https://www.mass.gov/doc/covid-19s-unequal-effects-in-massachusetts/download.

[173] There is existing precedent, both in Massachusetts as well as in other jurisdictions, for such an approach. The three-year energy efficiency programs in Massachusetts have provided no cost energy efficiency-related support for low-income households. *See, e.g.*, D.P.U. 09-116 through 09-119; 09-121 through 09-128 (approving low-income programs providing 100 percent incentives); D.P.U. 12-100 through 12-110 (same); D.P.U. 15-160 through 15-169 (same). More recently, there has been additional attention and support for other "hard to reach" customers, including renters, English-isolated, and moderate-income households.[173] With regards to community solar, the Department has stated that "there is a public policy benefit to prioritizing direct incentives for low-income customers consistent with State law and policy." *Joint Petition of Electric Distribution Companies for Approval of Model Solar Massachusetts Renewable Target Tariff*, D.P.U. 17-140-A, at 62 (2018). Consistent with the Department's determination that a "no-cost credit allocation would be an appropriate mechanism to reduce low-income barriers." *Id.*, at 71.

[174] *See Joint Petition for Approval of Revised Model Solar Massachusetts Renewable Target Program Tariff,* D.P.U. 20-145, Office of the Attorney General Initial Brief on Phase II Issues (November 9, 2021), at 36.

[175] The Affordable Solar Program provided no-cost solar panels to income-qualified residents living in single family homes. The program closed on September 30, 2016. *See* Department of Energy & Environment, D.C., *The Affordable Solar Program*, *available at* https://doee.dc.gov/service/affordable-solar-program#:~:text=The%20Affordable%20Solar%20Program%20helped,much%20as%20%24500%20each%20year; *see also* NREL, *Low- and Moderate-Income Solar Policy Basics*, *available at* https://www.nrel.gov/state-local-tribal/lmi-solar.html.

[176] NREL, *Low- and Moderate-Income Solar Policy Basics*, *available at* https://www.nrel.gov/state-local-tribal/lmi-solar.html.

5. *Workforce*

RECOMMENDATION: The Department should regularly engage with workforce stakeholders to better inform the transition of gas distribution services.

The Department should ensure that the gas utility workforce and representatives from organized labor are included in discussions regarding the clean energy transition and that input from these important stakeholders informs decision-making during this transition. According to the U.S. Bureau of Labor Statistics, there are approximately 568,000 workers in the Commonwealth in the combined trade, transportation, and utilities sector.[177] Of all workers in the Commonwealth, approximately 12.6 percent are union members.[178] Not only are gas utility workers essential to safe and reliable gas operations, but they are also essential partners as the industry changes and aligns to the Commonwealth's emissions reduction mandates. The AGO continues to appreciate the expertise and the ongoing dialogue with representatives from unions and labor focused stakeholders through its Labor Advisory Group. The AGO recommends that the Department proactively engage with workforce stakeholders on an ongoing basis. For instance, the Department could convene a labor advisory committee, or, to the extent that the Department convenes working groups to inform its decision making related to decarbonization, the Department should ensure that each working group has a labor representative.

VI. CONCLUSION

The structure of the gas industry and its regulatory framework have taken shape over the last 100 years. Today, the combination of the Commonwealth's commitment to a zero-emissions future and new competitive pressures facing the gas industry have created a moment of uncertainty and potential change for the industry. This moment offers the opportunity for a reformed regulatory framework to appropriately guide gas utilities and customers. The regulatory changes recommended in this report represent important steps toward a new regulatory framework. By adopting these recommendations, the Department will protect ratepayers and reduce the risk to the Commonwealth. These recommendations are the first step in a future that will require the Department's sustained regulatory focus.

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[177] U.S. Bureau of Labor Statistics, *Databases, Tables & Calculators by Subject, State and Area Employment, Hours, and Earnings for Massachusetts, Trade, Transportation, and Utilities*, *available at* https://data.bls.gov/timeseries/SMS25000004000000001?amp%253bdata_tool=XGtable&output_view=data&include_graphs=true.

[178] U.S. Bureau of Labor Statistics, *New England Information Office, Union Members in Massachusetts* (2021), *available at* https://www.bls.gov/regions/new-england/news-release/unionmembership_massachusetts.htm.

The AGO appreciates the opportunity to offer these recommendations and participate in this ground-breaking and nation-leading effort to achieve a net-zero emissions economy for the Commonwealth.

ACKNOWLEDGMENTS

The Office of the Attorney General would like to acknowledge and thank the contribution and support received from our consultant team in the drafting of this report and the development of the regulatory recommendations.

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The Brattle Group:

Dr. Dean Murphy is an economist with a background in engineering and expertise in energy systems and their transformation in response to climate change. His work, initially centered in the electric industry, has broadened to include decarbonization of other energy sectors—heating, transportation, and industrial energy use. He has performed several long-term energy planning and forecasting studies that examine the transition to decarbonization in the heating and electricity sectors and has studied how existing zero-emitting resources like nuclear plants can support progress toward climate goals. Dr. Murphy has expertise in competitive and regulatory economics, finance, and quantitative modeling, and experience in renewable solicitations, resource and investment planning, and competitive industry structure and market behavior. He has addressed these issues in the context of business planning and strategy, legislative and regulatory hearings, compliance filings, litigation, and arbitration. He has examined these issues from the perspectives of investor-owned and public electric utilities, consumers and regulators, independent power producers and investors, and industry groups.

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Dr. Destenie Nock is an Assistant Professor of Engineering and Public Policy and Civil and Environmental Engineering at Carnegie Mellon University. Dr. Nock has expertise in energy justice, environmental justice, decision analysis, and the energy-poverty-climate change nexus. In her current work she is developing a framework for understanding the sustainability and equity trade-offs for different power plant investments across the US. In another project she is creating a new measure of energy poverty to help utility companies identify households at risk of utility shut-offs and defaulting on their utility bills. Prior to her current position at CMU, Dr. Nock received her PhD in Industrial Engineering and Operations Research from the University of Massachusetts Amherst, where she performed energy systems modeling and analysis in both New England and Sub-Saharan Africa, using multi-criteria decision analysis and applied optimization to better equip policy makers to understand energy planning options and energy justice. Dr. Nock uses mathematical modeling tools to address societal problems related to sustainability planning, energy policy, equity, and engineering for social good, particularly as it relates to electricity systems and other critical infrastructure. In addition to her PhD from UMass Amherst, Dr. Nock earned her MsC in Leadership for Sustainable Development from Queen's University of Belfast and her BS in Electrical Engineering and Applied Mathematics from North Carolina A&T State University.

APPENDIX A

OVERVIEW OF D.P.U. 20-80 PROCEDURAL HISTORY

On June 4, 2020, pursuant to its statutory[1] and common law authority to act in the interest of the Commonwealth, the Massachusetts Office of the Attorney General ("Attorney General" or "AGO") filed a petition (hereafter the "AGO Petition") with the Department of Public Utilities (the "Department" or "DPU") requesting it conduct an open investigation into the future of LDC's planning and operations in light of the Commonwealth's legally binding statewide limit of net-zero greenhouse gas ("GHG") emissions by 2050.[2] The Attorney General specifically asked that a Department investigation: (1) examine the natural gas industry within the Commonwealth and its governing regulatory framework, and identify the changes needed to support the Commonwealth achieve its 2050 net-zero goal; (2) identify the regulatory changes necessary to maintain a safe and reliable distribution system; and (3) address a myriad of related issues including consideration of necessary equity protections for the Commonwealth's low-moderate income residents.

On October 29, 2020, the Department issued an Order that opened D.P.U. 20-80, An Investigation Into the Role of Local Gas Distribution Companies As the Commonwealth Achieves Its Target 2050 Climate Goals.[3] Within its Order, the DPU outlined the primary objective of its investigation would be to explore strategies to reach the net-zero 2050 emissions goal to be presented in the Executive Office of Energy and Environmental Affairs 2050 Decarbonization Roadmap ("2050 Roadmap") and 2030 Clean Energy and Climate Plan, while simultaneously "ensuring safe, reliable, and cost-effective natural gas service; and potentially recasting the role of LDCs in the Commonwealth."[4] The DPU ordered LDCs to retain an independent consultant to review the Commonwealth's "Roadmaps" to identify any pathways not examined within the 2050 Roadmaps report and to perform a detailed study that analyzes the feasibility of all pathways.[5]

On November 6, 2020, the AGO filed a motion requesting the Department clarify a number of ambiguities it identified in its opening Order.[6] Specifically, the AGO requested, among other things, that the Department clarify the opportunity for stakeholder engagement throughout the Investigation.[7] On February 10, 2021, the Department issued its Order on the AGO motion.[8] The

[1] *See* G.L. c. 164, §§ 76, 105A; G.L. c. 12, §§ 11E, 10.

[2] *See* AGO Petition (June 4, 2020), at 16.

[3] *See* Order (October 29, 2020).

[4] *See id.,* at 1.

[5] Subsequently, pursuant to this directive, the LDCs selected Energy & Environmental Economics ("E3") as their independent consultant to perform scenario analysis, as well as ScottMadden to provide the regulatory recommendations.

[6] *See* AGO Motion for Clarification (November 11, 2020).

[7] *See id*.

[8] *See* Order (February 10, 2021).

Department restated its original directives to the LDCs regarding stakeholder involvement and the opportunity to provide input throughout the LDCs' report development process.[9]

On September 1, 2021, in accordance with the Department's directives, the LDCs filed a status update on the Consultants' progress.[10] This update provided an overview of the timeline and progress made on the Consultants' seven workstreams. Additionally, the LDCs provided an update on the ongoing and extensive stakeholder process facilitated by its Consultants.

On February 14, 2022, the AGO and the Department of Energy Resources ("DOER") jointly filed a letter proposing a procedural schedule for the Department's review of the anticipated LDCs' March filing. The proposed schedule contemplated a three-component and concurrent review of: (1) the LDCs' technical analysis of pathways to a net-zero 2050; (2) the development of a regulatory framework to guide the LDCs' transition to 2050 and; (3) the convening of a GSEP working group to prepare recommendations for the Department and legislature on aligning GSEP with the Commonwealths' climate objectives. The proposed schedule also provided for continued robust stakeholder input and involvement.[11]

On March 18, 2022, pursuant to the Department's directive, the LDCs filed their individual Net Zero Enablement Plans ("NZEP") and *jointly* filed a joint regulatory summary and proposal, as well as the Independent Consultants' reports and analyses.[12]

Following the LDCs March filing, the DPU issued a procedural schedule that provides for at least two technical sessions, multiple rounds of comments soliciting input from stakeholders and the LDCs and Department led discovery. The procedural schedule concludes with final comments on August 10, 2022.[13]

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[9] *See* Order (February 10, 2021), at 15 (directing the LDCs to also provide status updates regarding the stakeholder process)

[10] *See* LDC's Joint Letter, Update of the Local Distribution Companies on the Solicitation Process (September 1, 2021).

[11] *See* Joint Letter of the AGO and DOER (February 14, 2022).

[12] *See* LDC's Joint Letter (March 18, 2022), Reports by Energy & Environmental Economics ("E3"), with Scott Madden as subcontractor (collectively, "Consultants"), including: (a) Technical Analysis of Decarbonization Pathways Report ("Decarbonization Pathways Report") and (b)Considerations and Alternatives for Regulatory Designs to Support Transition Plans Report ("Regulatory Designs Report"); A Stakeholder Engagement Report by Environmental Resources Management ("ERM") to develop and facilitate the stakeholder engagement process; and The LDCs' Common Regulatory Framework and Overview of Net Zero Enablement Plans ("Framework and Overview") and Net Zero Enablement Plan Model Tariff ("Tariff").

[13] *See* Department Procedural Schedule (March 24, 2022). The Department declined to convene a GSEP working group and is proceeding with concurrent review of the E3 and Scott Madden reports, as well as the LDCs' proposed NZEPs and regulatory requests.

APPENDIX B

OVERVIEW OF COMMONWEALTH AND LDC NET-ZERO ANALYSES

1. THE EEA ROADMAP AND DRAFT 2030 CLEAN ENERGY AND CLIMATE PLAN

A. EEA Roadmap

In December 2020, the EEA published its Massachusetts 2050 Decarbonization Roadmap, available here: https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download (the "Roadmap"). The Roadmap identified eight "Net-Zero compliant pathways, as follows:

Pathway	Key Finding
All Options	Deep electrification and broad renewable buildout create a reliable energy system that is only marginally more expensive than today.
Limited Off-Shore Wind	Clean resources including new nuclear power must be built to serve MA, costs increased modestly.
Limited Efficiency	Limiting efficiency gains results in a higher demand for zero-carbon electricity and fuel resources, costs increase significantly.
Pipeline Gas	Requires a substantial increase in imported low-carbon fuels, possibly technically feasible quantities. Most of this fuel goes to high-value sectors to compensate for continued emissions from buildings using a fossil/clean fuel blend, costs increase significantly.
100 Percent Renewable Primary Energy	Reliance on zero-carbon fuels needed for grid balancing and end uses leads to dramatically higher costs in 2050: demand may exceed feasible supply. Would likely require technological breakthroughs yet to be identified to meet resource constraints and contain costs.
No Thermal	Substantially higher reliance on solar power, particularly ground-mounted and new, long-duration utility scale energy storage to provide grid balancing, leading to dramatically higher costs.
Regional Coordination	Additional transmission increases access to, and the ability to share, additional low-cost clean energy resources across the Northeast lowering costs overall.
Distributed Energy Resources Breakthrough	Additional demand flexibility lowers local electricity system upgrade costs, very high rates of rooftop solar reduce- but do not eliminate- the need for ground mounted solar.

The above information can be found at Roadmap, p. 15, Table 1.

The Roadmap further identified sector transformations necessary to achieve a net-zero 2050. These are as follows:

Transportation Sector	Cars, trucks, and buses are emissions free and mostly electric, zero-carbon fuels like hydrogen help power the rest of the transportation system.
	A healthy public transit system, bike lands, sidewalks, and transit-oriented development complement vehicle electrification and help to reduce congestion.
Buildings Sector	High performance heat pumps provide clean, energy-saving heat and air conditioning for most homes.
	More energy efficient buildings and electric appliances help reduce monthly energy bills for most families and small businesses.
Energy Supply Sector	Wind and solar power are widely deployed to decarbonize the grid and meet the growing demand for clean electricity.
	A diverse mix of energy resources ensures year-round reliability.
Non-Energy Sector	Organic wastes are composted at greater rates, single-use plastics are reduced and recycled, and waste generation overall is minimized.
	Agriculture and industry are managed responsibly to reduce emissions.
	Potent industrial greenhouse gasses are replaced by climate-friendly alternatives.
Land Use Sector	Forests and other natural and working lands are managed strategically to enhance carbon sequestration while maintaining and building ecosystem health and resiliency

The above information can be found at Roadmap (abridged), available here: https://www.mass.gov/doc/ma-decarbonization-roadmap-abridged-english/download at p. 22.

B. Draft Interim 2030 Clean Energy and Climate Plan

Most recently, on April 14 and 15, 2022, the EEA held public hearings in which it presented its proposed interim emissions reduction targets and carbon sequestration goals for 2025 and 2030, as well as the proposed plan to achieve those targets and goals. The presentation materials can be found here: https://www.mass.gov/doc/2025-2030-cecp-public-hearings-presentationenglish/download. The proposed 2025 and 2030 sector sublimits are as follows:

Sector	2025 GHG Emissions Proposed Sublimits		2030 GHG Emissions Proposed Sublimits		
	MMTCO2e	% change from 1990	In Interim 2030 CECP	MMTCO2e	% change from 1990
Power (including all building & transportation electricity)	13.2	53%↓	8.5–9.4	8.5	70%↓
Transportation	23.1	24%↓	22.5–22.7	18.7	39%↓
Residential Heating	11.1	27%↓	6.1	8.6	44%↓
C&I Heating	11.4	20%↓	7.8	7.5	47%↓
Industrial Processes	3.64	49%↑	2.5–4.4	2.5	281%↑
Natural Gas Distribution & Service	0.4	82%↓	0.4	0.4	82%↓
All other Sources (waste, agriculture, no sublimits)	1.0	72%↓	0.9	0.9	73%↓
TOTAL	63.8	32%↓	49.1–52.1	47.2	50%↓ (48%–45%↓)

The above information can be found at the presentation materials at slide 10 (noting "the sublimits shown may be updated with additional policy feedback. Modeling will also be updated to reflect proposed changes to MassDEP GHG Inventory protocols).

2. THE LDC REPORT

On March 18, 2022, the LDCs filed in D.P.U. 20-80 the final Independent Consultant Reports, prepared on their behalf by Energy + Environmental Economics and ScottMadden Management Consultants ("E3 Report"). The technical analysis of the decarbonization pathways modeled the following scenarios to a net-zero 2050:

Scenario	Overview
Low Electrification (inspired by EEA "Pipeline Gas")	High electrification in the transportation sector. Buildings partly electrify. Building sector electrifies 65 percent of buildings through the adoption of ASHPs; gas customer count declines by 40 percent compared to today.
High Electrification (inspired by EEA "All Options")	High electrification in both buildings and transportation sector. Building sector electrifies >90 percent if buildings primarily through the adoption of ASHPs.
Interim 2030 CECP	Accelerated electrification and building shell measures based on the interim 2030 building sector target.
Hybrid Electrification	Heat pumps are paired with gas or fuel oil backup to mitigate electric sector impacts. >90 percent of buildings electrify through ASHPs paired with renewable gas back-up (hybrid heat pumps) that supply heating in cold hours of the year.
Networked Geothermal	Part of the gas system is strategically replaced by networked geothermal systems. LDCs evolve their business model and convert +/- 25 percent of the building sector to networked geothermal systems. Remaining gas customers use renewable gas as their main source of heating by 2050.
Targeted & Optimized Electrification	Part of the gas system is strategically decommissioned with customers adopting ASHPs. >90 percent of buildings are electrified through a combination of technologies. LDC customers converting to ASHPs do so in a "targeted" approach.
Efficient Gas Equipment	Building sector will adopt increasingly efficient gas appliances supplied by decarbonized gas. The industrial sector converts to dedicated hydrogen pipelines.
100 Percent Gas Decommissioning	Building sector and industry will fully electrify allowing for 100 percent decommissioning of the gas distribution system. Building and industrial sectors fully electrify by 2050. +/- 25 percent of the building sector converts to networked geothermal systems.

The above information can be found in the E3 Report, Part 1, at 29-32.

APPENDIX C

MATRIX OF LDCS' NZEP AND AGO RESPONSE

<table>
<tr><th>I.</th><th><u>SUMMARY OF LDC NZEP PLAN PROPOSAL</u></th><th><u>COMMON REGULATORY PROPOSAL NZEP AND MODEL TARIFF</u></th><th><u>COMMENTS OF THE OFFICE OF THE ATTORNEY GENERAL</u></th></tr>
<tr><td>Eversource</td><td>Eversource structures its NZEP as a portfolio of elements from the identified pathways or scenarios to meet the net-zero policy goals and associated milestones. It identifies six new initiatives as core to its “operational plan” in addition to continued energy efficiency. These are (1) develop and propose a hybrid heat pump pilot; (2) build and operate its geothermal project in Framingham; (3) track and collaborate on the development of production certified gas; (4) conduct and validate market assessments for use of RNG; (5) pursue small scale pilot targeting use of hydrogen for C&I customers and; (6) partner with industry leaders to evaluate emerging technologies.</td><td rowspan="3">NZEP: The LDCs jointly propose the NZEP is filed every 3 years, same as EE, 5–10-year planning horizon, demonstrated evaluation of non-pipe alternatives to mitigate gas infrastructure investment, provision of data to inform decisions on transition, periodic updates on progress. See D.P.U. 20-80, Common Regulatory Framework and Overview of Net Zero Enablement Transition Plans, dated March 18, 2022.

Proposed Standard of Review: “The LDC’s transitional portfolio is reasonably designed to contribute to the Commonwealth’s achievement of GHG emissions reductions to meet the 2050 net zero-goal, without compromising safety, reliability and affordability of service offered to current customers.” Id.

Model NZEP Tariff: Provides for recovery of incremental costs associated with each LDC’s NZEP approved by the Department. Recovery if costs are incurred: (1) within the scope of project categories authorized in furtherance of the approved NZEP, (2) incremental to the LDCs current investment projects or associated with the implementation of new types of technology, (3) incremental to costs that the LDC currently recovers through base distribution rates for O&M, 4) exclusively attributable to NZEP investments and (
5) recorded by 12/31 of each NZEP year. Id.</td><td rowspan="3"><u>The LDCs’ Net Zero Enablement Plans Generally</u>
Collectively, the AGO finds the Net Zero Enablement Plans (“NZEP Plans”) disappointing as the LDCs place themselves as passive participants in the transition to clean energy and resist change in their business model; the LDCs intend to continue to maintain gas systems and selling natural gas unless or until the Commonwealth, the Department, or their customers demand change.
With little exception, the LDCs’ plans align around an energy strategy they term “hybrid electrification”—i.e., promoting the electrification of building heating while still fully maintaining the natural gas system, to serve as a back-up heating source during periods of extreme cold temperatures where the heating efficiency from air source heat pumps declines and the electric grid may be stressed. The utilities thus recommend continued increased investment in GSEP to ensure the gas distribution system is adequate to support their hybrid electrification recommendation and the future use of decarbonized gas (e.g., Renewable Natural Gas (“RNG”) or Hydrogen). The utilities also want ratepayers to fund additional costs related to early-stage, yet unproven, and costly technologies such as RNG and hydrogen as a means to meeting climate change initiatives, with these costs fully recovered from ratepayers even though these technologies may never be cost effective or capable of the scale required to meet the energy needs of the Commonwealth.
The Department gave the LDCs ample time to examine the realities for gas distribution in a net-zero emissions future. The LDCs produced a business-as-usual report that seeks approval and cost recovery for unproven technologies and continued investment in gas system enhancements. It is now time for the Department to turn to other voices to design a regulatory framework for the future. The Commonwealth needs transformational leadership and thinking. Like the telephone and cable TV companies that transformed from voice and video offerings into high-speed data and internet access providers, the gas utilities need to reinvent themselves as low carbon thermal energy providers to be viable in a world that must reduce greenhouse gas emissions. Business as usual will meet no one’s needs.
We need regulatory review that centers around customer protections and the minimization of utility costs. We need the utilities to be proactive</td></tr>
<tr><td>Berkshire</td><td>Berkshire’s NZEP is largely a repetition of the E3/Scott Madden analysis; and does not advance many specifics beyond what’s enunciated in the E3/Scott Madden report. Berkshire believes it its “too soon” to commit to an approach. As such it generally cites its intent to engage in activities that will push the energy transition forward, while maintaining customer optionality and a choice for the longer term to balance cost and risk. As such, Berkshire proposes to pursue the pathways identified within the E3/Scott Madden report with a “customer centered” approach that focuses on education, monitoring of customer decarbonization decisions, stakeholder engagement, and potential pilot programs.</td></tr>
<tr><td>Unitil</td><td>Unitil’s NZEP proposal is a “portfolio” of short and long-term specific actions and larger initiatives that center around its plan to incorporate decarbonized and certified gas into its existing distribution system.
Within its NZEP, Unitil outlined its intent to seek approval of a “voluntary” “opt-in” renewable gas program that requires consumers to affirmatively elect their own individual participation in order for them to recoup program benefits.</td></tr>
</table>

	Unitil's portfolio also includes energy efficiency enhancement efforts via an expansion of its pre-existing investments in (*inter alia*): (1) consumer education, (2) availability and affordability of consumer options in related technology, and (3) promoting building electrification (including hybrid strategies and that targeting a reduction in space heating demand). Unitil avers that its portfolio approach is sufficient to satisfy its mandatory GHG reduction requirements while also simultaneously accommodating the specific needs of its consumers and satisfying its greater public duty requirement of providing safe and reliable service to its consumer base.		leaders in the transition and not passive bystanders, focused primarily on embedded cost recoveries, system longevity and future business hopes predicated on the availability and scalability of decarbonized gases. We need the utilities to fully embrace the climate goals and recognize that their "business as usual" approach will not get the Commonwealth to its mandatory net-zero goal. Finally, before the Department considers the proposed NZEP Plans it first needs to establish the regulatory framework to do so. This investigation is for the purpose of assisting the Department in its decision making by advancing recommendations for regulatory change for its consideration. It cannot be a one-sided adjudication of the LDC NZEP proposals. ***The NZEP Plan Requirement*** The AGO agrees that the Department should adopt a planning docket for the purpose of ensuring the LDCs' compliance with climate objectives and the achievement of climate mandates. *See* D.P.U. 20-80, Regulating Uncertainty, The Office of the Attorney General's Regulatory Recommendations (May 6, 2022) ("Regulating Uncertainty"), at 24-25 (proposing a Climate Compliance Plan ("CCP")). The AGO recommends that the Department consider the requirements and timing of such a filing. In contrast to the LDCs proposal, the AGO recommends that a CCP is filed by January 2023 and updated in the year following the issuance of the EEA's sector sublimits. *Id.* (also providing suggested components to a CCP, as well as compliance filings). ***The Net Zero Enablement Model Tariff*** The LDCs are requesting approval of a proposed Net Zero Enablement Model Tariff ("NZEP Tariff"). The NZEP Tariff provides for the recovery of incremental costs associated with an LDC's approved decarbonization investment. For example, the NZEP Tariff provides for recovery of hydrogen blending and/or interconnections and installations; RNG blending and/or interconnections and installations, hybrid heating systems and efficient gas equipment. *See* D.P.U. 20-80, Common Regulatory Framework and Overview of Net Zero Enablement Transition Plans, dated March 18, 2022, at Appendix A. The LDC's request for approval of the NZEP Tariff is premature. First, approval of a utility tariff cannot occur within the context of a Department investigation. *Attorney General v. Department of Public Utilities*, 453 Mass. 191 (2009) (requiring adjudicatory proceeding to review and approve changes in rates). Second, the purpose of this investigation is to assist the Department in developing a regulatory
Liberty	Liberty advances a "portfolio" of action that centers around the incorporation of decarbonized gas into its distribution system. Liberty plans to seek approval of an "opt-in" RNG proposal. In addition, Liberty's portfolio includes continued energy efficiency investment focused on weatherization, efficient appliances and the development of hybrid electrification through energy efficiency investment in ASHPs. Liberty states that its approach will provide for the required emissions reductions while accommodating the needs of its unique customer base.		
National Grid	National Grid relies on the E3 finding that a "coordinated gas and electric decarbonization strategy, utilizing a diverse set of technologies and strategies is likely to be better able to manage the costs and feasibility risks…" to propose a portfolio approach proposing increased investment in energy efficiency, the use of RNG and hydrogen, hybrid electrification that will require the continue the use of the gas distribution system (and thereby reduce the demand on the electric distribution system) and targeted electrification to provide non-pipe alternatives where safe and cost-effective. National Grid characterizes its plan as most similar to the hybrid electrification pathway as it projects 60 percent reduction in gas demand, stable customer counts, the incorporation of 100 percent decarbonized		

	gas (RNG and hydrogen) by 2050 for the residential sector and significant customer adoption of hybrid heating. Its plan differs from the hybrid electrification pathway by adding investment into non-pipe alternatives (targeted electrification/geothermal), promoting 100 percent decarbonized gas for commercial customers and increasing investment into energy efficiency. The Company emphasizes that it is critical to pursue multiple decarbonization approaches simultaneously to maximize the likelihood that net zero targets are achieved.		framework to guide the safe, reliable, affordable and equitable provision of gas distribution services as the Commonwealth transitions to a net-zero emissions economy by 2050. The utilities' request for tariff approval is putting the cart before the horse.
II.	**<u>RELIANCE ON "DECARBONIZED GAS"</u>** **(Type and Proposed Method of Acquisition)**	**<u>COMMON REGULATORY PROPOSAL</u>**	**<u>COMMENTS OF THE OFFICE OF THE ATTORNEY GENERAL</u>**
Eversource	One of the main priorities of Eversource's operating plan is the development of a decarbonized gas network that focuses on the procurement of low carbon fuels (including RNG and Hydrogen) and investment in its pipeline network to deliver these fuels to gas customers. Toward this end, Eversource has conducted a request for information to explore RNG opportunities and is looking to pursue a small-scale hydrogen pilot.	The LDCs' request that the Department develop a standard of review for gas procurement that allows cost recovery for renewable gas even if it is not the least cost commodity option.	Each of the LDCs propose the use of decarbonized gas as part of its plan to meet the 2050 net-zero emissions mandate. Decarbonized gas includes RNG, hydrogen, and synthetic natural gas. There are significant questions regarding the feasibility, availability, and scalability of these decarbonized gases to fill the role proposed. *See e.g.*, D.P.U. 20-80, AGO Initial Stakeholder Comments on Consultants' Technical Analysis (May 6, 2022) ("AGO Initial Comments") (detailing concerns with LDCs' proposed use of decarbonized gases) There is no credible support that decarbonized gas can be made available in Massachusetts at the volumes needed to support 2050 residual gas use under hybrid electrification. *Id.* Thus, any assumption that investment in these decarbonized gasses is prudent is premature and unduly shifts risk to ratepayers for the associated costs. Prior to approval of any investment in unproven technologies, the Department should evaluate the proposal by undertaking the thorough consideration of alternatives. The AGO proposes the adoption of an investment alternatives calculator to evaluate future gas investment and non-pipe alternatives. *See* Regulating Uncertainty, at 33-35.
Berkshire	Berkshire plans generally cites that "small quantities (5–10 percent) of alternative fuels (such as biomethane from landfill gases) will be necessary in the short term to support the Commonwealth's interim (2030) climate goals. Berkshire does not commit to replacing a specific amount of natural gas, nor does it propose a specific plan targeting decarbonization goals tailored to it. Instead, the plan annunciated within its NZEP is to: (1) continue monitoring its customer's migration to alternative fuel use, (2) research hybrid electrification options and opportunities to incorporate RNG into its portfolio via a pilot program, and (3) "consider" installing a geothermal pilot project in its Eastern District. Berkshire also plans to develop a decarbonized tariff option for its natural gas customers who wish to pay a		

	premium to purchase RNG and intends to work with its C&I customers to identify and customize pilot programs to help them achieve their sustainability goals.		
Unitil	Unitil plans to replace a portion of its natural gas supply portfolio via the procurement and utilization of biomethane. Unitil proposes an opt-in RNG option for its consumers.		
Liberty	Liberty is proposing an opt-in RNG option for its customers. It intends to monitor the results of hydrogen and SNG pilots being conducted by other Algonquin affiliates. It expects that hydrogen will contribute up to 7 percent by energy content to the energy mix delivered to its customers. It also contemplates the use of SNG depending on results of pilots.		
National Grid	National Grid proposes to incorporate 100 percent decarbonized gas for residential and commercial customers by 2050. It asks for ability to procure non-fossil fuels such as RNG and hydrogen and to allow for longer contracting to allow for development. It also would like to offer customers the ability to elect a higher proportion of clean heating fuel based on their own climate goals or obligations.		
III.	**<u>REVENUE DECOUPLING</u>**	**<u>COMMON REGULATORY PROPOSAL</u>**	**<u>COMMENTS OF THE OFFICE OF THE ATTORNEY GENERAL</u>**
Eversource	Eversource adopts by reference.	The Department should investigate transitioning from a per customer reconciliation of actual and authorized revenues to a reconciliation of total revenues (like in place for Massachusetts electric utilities). *Id.*	The AGO agrees with the LDCs that current "per customer" revenue decoupling mechanism is no longer appropriate. The AGO recommends the Department should replace a revenue per customer decoupling with revenue cap decoupling, removing the existing incentive to add gas heating customers. *See* Regulating Uncertainty, at 38-39.
Berkshire	Berkshire adopts by reference.		
Unitil	Unitil adopts by implication.		
Liberty	Liberty adopts by reference.		
National Grid	National Grid adopts by reference		

IV.	<u>**ACCELERATED DEPRECIATION**</u>	<u>**COMMON REGULATORY PROPSAL**</u>	<u>**COMMENTS OF THE OFFICE OF THE ATTORNEY GENERAL**</u>
Eversource	Eversource adopts by reference.	The Department should investigate the role of accelerated depreciation to align cost recovery of gas distribution costs with the utilization of the distribution system, rather than the useful life of the assets that make up the distribution system. *Id.*	The AGO recommends the Department, with LDC and stakeholder input, undertake a comprehensive review of both the magnitude of potential stranded investment and principles for the determination of used and useful to inform the Department's consideration of alternatives to accelerated depreciation. *See* Regulating Uncertainty, at 35-37.; *see also Boston Gas Company d/b/a National Grid,* D.P.U. 20-120 (2021), AGO Initial Brief (June 17, 2021), at 96 (opposing Grid's request for adoption of accelerated depreciation as premature).
Berkshire	Berkshire adopts by implication.		
Unitil	Unitil adopts by implication.		
Liberty	Liberty adopts by reference.		
National Grid	National Grid adopts by reference. National Grid proposes the implementation of a "depreciation advance contribution" to allow collection from current gas customers of funds that can be applied to offset future depreciation expenses.		

V.	<u>**GSEP INVESTMENT**</u>	<u>**COMMENTS OF THE OFFICE OF THE ATTORNEY GENERAL**</u>
Eversource	Eversource proposes to continue its GSEP investment, which will support safety and reliability and provide a system that can support its proposed adoption of decarbonized gas.	Whether expressly or impliedly stated, each of the LDCs' NZEP Plans require continue investment in gas system enhancements. Under a hybrid electrification model, the gas system is necessary to provide service during periods of extreme cold. Likewise, the LDCs plans include customer adoption of efficient gas equipment for heating and cooking purposes. As such, GSEP investment would be necessary to upgrade the system to ensure continuing safe and reliable service, as well as leak mitigation. Additionally, all of the LDCs incorporate the blending of decarbonized gas, including hydrogen, into the distribution system to meet the climate mandates, which will also require upgrades to the gas distribution system. With respect to GSEP, the Commonwealth's climate goals raise serious concerns about the continued prudence of accelerated GSEP investment. *See* Regulating Uncertainty, at 30-31. At a minimum, going forward, the LDCs' GSEP plans should not be approved without demonstration that the investment is the least-cost alternative to achieve the desired outcome. *Id.* The AGO recommends that the Department convene a GSEP working group to develop recommendations for the regulatory and legislative changes that will be necessary to align the GSEP with
Berkshire	Berkshire plans to continue to manage embedded natural gas infrastructure costs via GSEP; sites its "business as usual" approach, *i.e.*, its plan to continue participation in the program via its replacement of leaking/aging infrastructure pursuant to it, as an example of one of its NZEP planned efforts to help reduce its contribution of GHGs emitted into the atmosphere.	
Unitil	Unitil plans to continue to manage embedded natural gas infrastructure costs via GSEP as well. Unitil outlined that it intends to join in on the process of developing a new infrastructure and investment framework that aligns with the net-zero 2050 goal. However, in stark conflict with this intention it outlined--Unitil also explicitly detailed its expectation that the faulty assumption underlying the current framework (*i.e.*, that customer acquisition growth will continue to drive the industry and its business) will remain untouched in the process of shaping new GSEP infrastructure and investment standards. In addition, Unitil proposes to review cost recovery and rate structures that optimize benefits and consumer costs associated with both the natural gas and electric systems. In light of its continuing duty to affordably service its customers, Unitil proposes to evaluate an accelerated depreciation method to better align its recovery of GSEP-related costs and natural gas system utilization during the transition period.	
Liberty	Liberty's proposal does not include any comment on GSEP.	

National Grid	National Grid's proposal does not include any comment on GSEP. It is implied that gas system investment is required to support the continued use of the distribution system in support of hybrid electrification and the use of decarbonized gas.	applicable climate mandates. *See* D.P.U. 20-80, AGO/DOER Joint Letter, dated February 14, 2022. To maximize the benefits of a GSEP working group, the AGO recommends that members include a broad array of stakeholders and governmental entities including LDCs, the Department, the representatives from labor, environmental justice, low-income, environmental and municipal groups. *Id.*
VI.	**ENERGY EFFICIENCY INVESTMENT**	**COMMENTS OF THE OFFICE OF THE ATTORNEY GENERAL**
Eversource	Eversource's portfolio relies on continued energy efficiency investment to support hybrid electrification.	The AGO acknowledges the importance of energy efficiency and its foundational role in the achievement of Commonwealth's climate objectives. The AGO, however, also recognizes that the primary source of energy efficiency funding falls on ratepayers through the energy efficiency surcharges. The recently approved 2022-2024 Three-Year Statewide Joint Energy and Gas Efficiency Plans advances significant investment in programs to promote heat pump adoption and to foster a more equitable delivery of energy efficiency to those historically underserved populations. It comes, however, at a significant budget and associated bill impacts for customers. To best utilize the available energy efficiency dollars in support of the State's climate mandates, it may become necessary for three-year plans to favor investment in climate/GHG reducing measures over those measures that directly reduce energy consumption. While the AGO supports energy efficiency investment, it is also mindful of the ratepayer impacts of the budgets that may be required to support the Commonwealth's decarbonization efforts and encourages consideration of other sources of funding beyond the energy efficiency surcharge.
Berkshire	Berkshire's portfolio relies on continued energy efficiency investment to support hybrid electrification.	
Unitil	Unitil's portfolio relies on continued energy efficiency investment to support hybrid electrification.	
Liberty	Liberty's portfolio relies on continued energy efficiency investment to support hybrid electrification.	
National Grid	National Grid's portfolio relies on continued energy efficiency and states that deep energy efficiency measures would be focused on non-hybrid heating customers since more cost-effective.	
VII.	**USE OF CERTIFIED GAS**	**COMMENTS OF THE OFFICE OF THE ATTORNEY GENERAL**
Eversource	Eversource's portfolio incorporates the use of certified gas into its operational plan.	*See* Appendix C, at Section IV (AGO's comments on decarbonized gas). The AGO would propose the use of the investment alternatives calculator to determine if the investment required to procure certified gas was the best alternative available. *See* Regulating Uncertainty, at 33-35
Berkshire	Berkshire does not incorporate the use of certified gas into its NZEP.	
Unitil	Unitil proposes to incorporate Certified Gas into its distribution system in the same way it proposes to incorporate renewable gas. *See* "Reliance on decarbonized gas" summary above.	
Liberty	Liberty does not incorporate the use of certified gas into its NZEP.	
National Grid	National Grid does not discuss the use of certified gas but does propose the adoption of a renewable heating fuel standard that requires sellers of gas to procure a growing proportion of their supply from qualifying fuels such as RNG or low carbon hydrogen.	

<table>
<tr><th>VIII.</th><th><u>LEVEL OF ELECTRIFICATION ANTICIPATED</u>
(Either ASHP or Geo-thermal)</th><th><u>COMMENTS OF THE OFFICE OF THE ATTORNEY GENERAL</u></th></tr>
<tr><td>Eversource</td><td>Eversource does not specify the level of electrification but does recognize that electrification is necessary as part of its hybrid electrification strategy. To be effective, Eversource is looking at coordinated planning between its gas and electric businesses to maximize infrastructure build out and electrification measures where possible.</td><td rowspan="5">The level of electrification required will be a function of the investments and actions proposed under an LDC's CCP (see Regulating Uncertainty, at 24-25) and to ensure meeting the sublimits as set forth by the EEA. The proposed LDC CCP should be reviewed and approved upon a showing that the plan is likely to achieve the necessary GHG reductions mandated by statute.

The Commonwealth's electrification efforts should also be guided by issues of equity and affordability. See Regulating Uncertainty, at 46-53 (suggesting the implementation of mechanisms to shield vulnerable customers from undue energy burden and ability to adopt new technologies). Low- and moderate- income ("LMI") households often lack the capability to transition to alternatives, such as heat pumps, as these technologies require high upfront investment. Id,</td></tr>
<tr><td>Berkshire</td><td>Berkshire does not specify the level of electrification it anticipates; instead, it implies its commitment will match that necessary to achieve its statutory mandate. Berkshire proposes to invest in geothermal. [See summary of geothermal intentions outlined in section IV, "reliance on decarbonized gas," outlined above.</td></tr>
<tr><td>Unitil</td><td>Unitil's NZEP proposes to prioritize electrification programs targeting customers that currently heat their homes with natural gas or electric resistant heating, which Unitil estimates constituted 59 percent of the homes within its service area). Unitil anticipates that savings will most likely be achieved via a transfer to heat pump technology. Unitil does not propose any geo-thermal investment and instead intends to monitor those run by other LDC's. Unitil' does not commit to any specific level of electrification.</td></tr>
<tr><td>Liberty</td><td>While not specific in the level of electrification needed, it appears that Liberty will be tying its electrification commitment to that required to achieve its energy efficiency goals. Liberty does not propose any geo-thermal investment and will monitor the results of the other LDC run geo-thermal pilots.</td></tr>
<tr><td>National Grid</td><td>National Grid does not provide for the level of electrification it is proposing beyond its energy efficiency plan and utilizing targeted electrification to provide as a non-pipe alternative.</td></tr>
<tr><th>IX.</th><th><u>PROPOSED PILOTS AND R&D</u></th><th><u>COMMENTS OF THE OFFICE OF THE ATTORNEY GENERAL</u></th></tr>
<tr><td>Eversource</td><td>Eversource has an approved geothermal pilot to be developed in Framingham, Massachusetts. The Company also proposes additional pilots and R&D to better understand the viability of decarbonized gas, as well as emerging technologies.</td><td rowspan="5">The AGO proposes the adoption of an investment alternatives calculator to be used to evaluate proposed gas investment and alternatives. See Regulating Uncertainty, at 33-35.</td></tr>
<tr><td>Berkshire</td><td>Berkshire plans to consider the use of a pilot program in its Eastern District but has not specified any details beyond that.</td></tr>
<tr><td>Unitil</td><td>Unitil plans to file a petition with the Department seeking its approval of an opt-in RNG proposal that will allow it to purchase RNG for use by its customers.</td></tr>
<tr><td>Liberty</td><td>Liberty will be seeking approval of an opt-in RNG proposal that will allow it to purchase RNG for use by its customers. Liberty does not propose any other investment in pilots or other R&D.</td></tr>
<tr><td>National Grid</td><td>National Grid does not propose any specific pilot or demonstration beyond its networked geothermal demonstration project. It does seek to establish demonstration project programs which support achievement of its net-zero pathway while safely and reliably meeting customers' energy needs. The results of the demonstration projects can then inform future policy and regulatory action. It looks to have demonstrations that optimize the use of the existing gas infrastructure, evaluates the delivering decarbonized gas, improving leak detection and mitigation and demand reductions.</td></tr>
</table>

X.	MISCELLANEOUS REGULATORY REQUESTS NOT OTHERWISE COVERED ABOVE	COMMENTS OF THE OFFICE OF THE ATTORNEY GENERAL
Eversource	N/A	The AGO agrees with National Grid that the forecast and supply planning should be reviewed to ensure alignment with the transition to net-zero. *See* Regulating Uncertainty, at 26-28
Berkshire	N/A	
Unitil	N/A	
Liberty	Liberty supports its portfolio approach with significant evidence on the unique characteristics of its service territory, *i.e.*, large percentage of LMI and older/multi-family housing stock.	
National Grid	National Grid acknowledges that forecast and supply planning will need to be reviewed to ensure that it keeps pace with the transition. National Grid recommends a technical session to explore forecasting during demand uncertainty. National Grid also recommends coordinated planning across gas and electric utilities to promote efficiency in investment.	

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Investigation by the Department of Public Utilities on its own Motion into the Role of Gas Local Distribution Companies as the Commonwealth Achieves its Target 2050 Climate Goals	)))))	**D.P.U. 20-80**

THE OFFICE OF THE ATTORNEY GENERAL'S INITIAL STAKEHOLDER COMMENTS ON CONSULTANTS' TECHNICAL ANALYSIS OF DECARBONIZATION PATHWAYS REPORT

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TABLE OF CONTENTS

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Investigation by the Department of Public Utilities on its own Motion into the Role of Gas Local Distribution Companies as the Commonwealth Achieves its Target 2050 Climate Goals	)))))	**D.P.U. 20-80**

THE OFFICE OF THE ATTORNEY GENERAL'S
INITIAL STAKEHOLDER COMMENTS
ON CONSULTANTS' TECHNICAL ANALYSIS
OF DECARBONIZATION PATHWAYS REPORT

I. EXECUTIVE SUMMARY

Massachusetts stands at the crossroads of a clean energy transition that will transform the utilization of energy in our homes and the workplace. Aggressive, nation-leading emission reduction mandates touching all aspects of our energy economy have been enacted by the General Court. Implementation plans are underway among several state agencies charged with executing on the statutory mandates. The Secretary for Energy and Environmental Affairs (EEA) has observed that nearly a third of Massachusetts' GHG emissions stem from on-site fossil fuel consumption to satisfy building thermal needs.[1] Reducing buildings emissions by nearly one-half by 2030 is required to meet overall emission reduction mandates.[2]

[1] *See* e.g., EEA, *Interim 2030 Clean Energy and Climate Plan*, ("Interim 2030 CECP") (Released December 30, 2020), at 27, *available at* https://www.mass.gov/doc/interim-clean-energy-and-climate-plan-for-2030-december-30-2020/download

[2] *See* EEA, *CECP Public Hearing Presentation* (April 15, 2022), at 10, showing required residential heating emission reductions by 2030 of 44 percent and Commercial & Industrial heating emission reductions of 47 percent, *available at* https://www.mass.gov/doc/2025-2030-cecp-public-hearings-presentationenglish/download

Critical to achieving required building emission reductions is the strategy to transition building thermal requirements from on-site combustion of fossil fuels to the adoption/installation of efficient electric heat technologies in very many buildings, and maybe nearly all. EEA has determined that at least 60 percent and as much as 95 percent of Massachusetts buildings must transition to efficient electric heating by 2050, under any plausible decarbonization scenario, for the Commonwealth to deliver on the statutorily mandated emission reductions. Interim 2030 CECP, at 13, 27. A recent EEA presentation on an updated 2030 CECP finds that for emission reductions to stay on target, nearly a third of all homes in the Commonwealth must be moved to efficient heat pumps and tighter building envelope improvements by 2030.[3]

Against this factual and policy backdrop, the gas distribution companies were asked to consider and present their enablement plans to aid the Commonwealth and its citizens in achieving "net zero" emissions in a just and equitable fashion. A year later, their collective response has been underwhelming and somewhat dissembling. Rather than lead an energy transformation, the gas companies largely stick to their century-old business plan: deriving a profit by delivering gas via underground pipes. The centerpiece of their plans and the gas industry's public relations juggernaut is to double-down on pipeline-delivered gas in a scenario they term "hybrid electrification." Under hybrid electrification, residents install air source heat pumps in their homes and businesses but they simultaneously install gas fired, backup heating systems for use in the coldest winter weather. Compliance with all emission reduction mandates under hybrid electrification can be attained *if and only if* sufficient quantities of carbon-neutral or carbon-free "renewable natural gas" can be secured by the local distribution companies

[3] EEA, *CECP Public Hearing Presentation* (April 15, 2022), at 12, *available at* https://www.mass.gov/doc/2025-2030-cecp-public-hearings-presentationenglish/download

("LDCs") to replace present natural gas throughput over time. And the upshot of the hybrid electrification plan for the gas companies is that they keep virtually all their building heat customers and fully retain and upgrade all of their existing gas delivery infrastructure and future improvements on which they are assured a Department-authorized return on investment.[4]

How the Department elects to think about the challenge ahead has major consequences for the Commonwealth. Prioritizing what can be done to ensure the continued profitability of gas utilities implies different action than how best to prepare Massachusetts residents for an equitable carbon-free energy future. As discussed below, the purported allure of the hybrid electrification scenario as envisioned by gas companies as good for the environment, good for customers, and good for gas utilities does not stand up to close scrutiny. There are too many known and unknown weaknesses in the gas companies' planned hybrid electrification strategy – in terms of customer cost and prospects of reducing emissions – to merit further consideration as a serious building emission reduction strategy. The Department should reject the hybrid electrification scenario proposed by the gas companies[5] from further policy consideration.

II. BACKGROUND

On March 18, 2022, the Massachusetts investor-owned gas local distribution companies ("LDCs")[6] filed with the Department of Public Utilities ("Department") in this proceeding,

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[4] Department-allowed returns on equity (ROE) for investment by gas companies typically fall in the range of 9.0 to 10.0 percent.

[5] As more fully discussed in Section IV below, much of the transitional benefits of hybrid electrification can be attained by apportioning the Commonwealth's total building heat load – not the demand of each individual building customer – between electric and gas delivery systems for a transitional period.

[6] The LDCs in this proceeding include The Berkshire Gas Company, NSTAR Gas Company and Eversource Gas Company of Massachusetts, each d/b/a Eversource Energy, Liberty Utilities (New England Natural Gas Corp.) d/b/a Liberty, Boston Gas Company and the former Colonial Gas Company d/b/a National Grid and Fitchburg Gas and Electric Light Company d/b/a Unitil.

among other things, their *Independent Consultant Technical Analysis of Decarbonization Pathways* ("Technical Report"). The Technical Report undertakes a comprehensive economy-wide analysis of eight sample pathways Massachusetts might undertake to successfully achieve its goal of "net zero" greenhouse gas ("GHG") emissions by 2050, or an 85 percent reduction in GHG emissions from 1990 baseline levels. The approach used in the Technical Report by the Consultants (Energy and Environmental Economics, Inc ("E3") and ScottMadden Inc.) is similar to the analysis the Commonwealth employed in the 2050 Roadmap analysis. The E3 analysis also was designed to ensure each pathway achieves the interim statutory emission reduction mandates required by 2030 (50 percent emission reduction from 1990 levels) and 2040 (75 percent reduction from 1990 levels).[7]

The Technical Report cautions, however —repeatedly and throughout— that the pathways *are not forecasts* of future decarbonization strategies or tactics. Compliance with all emission reduction mandates is assumed, not proven, within each scenario. Instead, each pathway represents a "what if" consideration of the factors, features and challenges of different plausible energy futures. Technical Report, at 11. Each pathway is first *assumed* to achieve all required GHG emission reductions and then E3 undertakes to catalog, compile, and model the myriad assumptions on customer adoption rates, costs, technical challenges and risks needed to bring about successful emission compliance within each pathway.

The eight studied pathways include three that are roughly analogous to pathways examined in the Massachusetts 2050 Roadmap: (1) a "high electrification" scenario; (2) a "low electrification" scenario; and (3) a 2030 interim CECP-compliant approach. To the foregoing

[7] *See* Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy ("Climate Act"), St. 2021, c. 8, §§ 8, 10.

pathways E3 added five additional scenarios developed to pose and examine outcomes of specific interest to various stakeholders, including: (4) hybrid electrification; (5) targeted electrification; (6) networked geothermal heating; (7) efficient gas equipment; and (8) 100 percent gas system decommissioning.

Again, it bears repeating that the scenario analysis undertaken in the Technical Report *does not predict* the success of any particular future outcome, *nor is the scenario analysis intended or capable of forecasting* which pathway or portfolio of pathways might achieve effective results (in terms of emission reduction compliance at the overall least cost). Instead, the scenario analysis was cast by E3:

> [to] identif[y] decarbonization pathways that may be adopted and/or combined to transition to the Commonwealth's climate goal of net-zero [GHG] emissions. The pathways share a set of commonalities that are likely part of any decarbonization strategy, while maintaining optionality for longer-term technological advancements.

Consultant Report on *Considerations and Alternatives for Regulatory Designs and Support Transition Plans* ("Regulatory Design Report") (March 18, 2022), at 8. These commonalities among all studied pathways include energy efficiency, building electrification and the introduction/blending of biomethane as a purportedly "renewable natural gas." *Id.* By comparing and contrasting the relative costs, features, feasibility, and risks of the studied pathways, the Technical Report advances general conclusions as to the relative merits/drawbacks of each studied pathway.

All eight pathways are similar in that they each entail the transition of varying levels of building heating requirements to efficient electric technologies, coupled with the introduction of "renewable natural gas" into the pipeline system to decarbonize (in effect) the residual energy uses of natural gas. However, the outcomes of certain pathways (*e.g.*, the high electrification scenario or the 100 percent gas decommissioning scenario) rely to a greater extent on efficient electric heating alternatives while other pathways (*e.g.*, efficient gas equipment and hybrid electrification) rely on the future availability and affordability of renewable natural gas to a much larger extent.

By Hearing Officer Memorandum dated March 24, 2022, the Department elected to proceed with an evaluation of the Technical Report, but not through a formal, adjudicatory proceeding entailing full discovery, cross-examination of witnesses and presentation of opposing studies/analysis/testimony. Instead, the Department has invited stakeholder written comment by May 6, 2022 limited to:

> (1) the developed pathways set forth in the Report and the assumptions and modeling underlying the Report; and (2) the regulatory framework necessary to support the equitable and safe transition to net-zero greenhouse gas emissions by 2050.

Hearing Officer Memorandum, at 3. The Department subsequently advised: "The Department encourages comments that raise issues with the consultants' reports and the LDCs' individual proposals and comments that make alternative proposals, particularly alternative regulatory framework proposals." April 15, 2022 Hearing Officer Memorandum, at 2.

III. <u>THE TECHNICAL REPORT'S PROMOTION OF A HYBRID ELECTRIFICATION PATHWAY RESTS ON UNSOUND AND UNPROVEN ASSUMPTIONS</u>

A conclusion drawn by E3 in the Technical Report, which the LDCs then take as the keystone of their proposed recommendations and so-called "enablement plans," is that the pathway that the Consultants term "hybrid electrification" shows lower levels of challenge across a range of evaluation criteria. As characterized in the report, hybrid electrification entails broad customer-driven installation of air source heat pump ("ASHP") heating technologies, but with each customer also installing/retaining a gas-fired backup heating system which, over time, is fully transitioned to carbon-neutral fuels. The ASHP is used for heating and cooling whenever outside ambient air temperatures remain moderate, but building heat during the coldest winter weather (where ASHP efficiency and heating performance decline) would switch to the backup gas system which is assumed to deliver increasing shares of carbon-neutral gas.[8] Thus, while as many as 90 percent of buildings under hybrid electrification will adopt ASHP heating by 2050, all hybrid electrification participants remain customers of the LDCs, relying on renewable gas in winter peak periods. In this way, hybrid electrification ostensibly offers the most promising focal point of all the LDCs' near-term decarbonization strategies, because it offers the possibility of lowering overall emissions *but* retaining virtually all existing building heat customers, as well as full retention (albeit utilized only for limited times of the year – winter peaks) of each LDC's gas infrastructure.

From a general review of the Technical Report in the time available, the AGO and its Consultants, The Brattle Group, discern several significant weaknesses in the hybrid electrification approach touted by the gas industry participants.

It is suggested at several junctures in the Technical Report that the hybrid electrification scenario entails lower overall costs than alternative pathways. "A hybrid [electrification] strategy reduces the cumulative cost of achieving net zero GHGs through 2050 by between $23-43 billion relative to scenarios that primarily rely on all-electric strategies …." Technical Report, at 14. The putative cost savings are perceived to be generally attributable to lower future electric system augmentation costs (that under hybrid electrification will not need to be scaled up to serve the winter extreme cold spells)[9] as well as up-front savings in ASHPs acquisition costs, due to (1) initial purchase of smaller and/or less efficient ASHPs and (2) a savings in extensive

[8] *See e.g.*, Technical Report, at 31.

[9] *See* Technical Report, at 60 and Figure 20.

building shell enhancements and weatherization improvements that would otherwise be needed to accommodate year-round occupant comfort and safety in an ASHP-only heating environment.[10]

Compliance with all statutory emission reduction mandates is achieved with the hybrid electrification approach *only* by burning large volumes of renewable natural gas that is assumed to be "carbon-neutral." Thus, E3's conclusions favoring a hybrid electrification pathway rest *on assumptions* of renewable natural gas availability and cost that have not yet been well studied or supported, and in some respects are simply wrong. As more fully discussed below, the Technical Report makes several forced errors and unsupported suppositions as to the availability, cost and climate efficacy of burning renewable natural gas in the hybrid electrification scenario as a decarbonization strategy for the Commonwealth.

A. There is no credible support that renewable natural gas can be made available in Massachusetts at the volumes needed to support 2050 residual gas use under hybrid electrification.

A key tenet of all decarbonization pathways is that whatever residual demand remains for gas for heating applications, after evaluating contributions from efficient electric heat technologies, will be met through delivery and consumption of "renewable natural gas" that is assumed to have net-zero emissions. For purposes of the Technical Report, E3 defines renewable natural gas ("RNG") as an umbrella term to include both (i) biomethane produced through anaerobic digesters or gasification, as well as (ii) renewable (a/k/a "green") hydrogen and (iii) synthetic natural gas ("SNG") produced with renewable hydrogen combined with a climate-neutral source of carbon (*e.g.*, either a by-product of biogas development or from direct air capture). Technical Report, at 9.

[10] *See* Technical Report, at 55.

The annual volumes of RNG needed in Massachusetts by 2050 under a hybrid electrification pathway were determined by E3 as roughly 70 trillion Btu (TBtu). Technical Report, at 50, Figure 15. But according to a gas industry report (Am. Gas Foundation, Dec. 2019 Report), the total available RNG output – nationwide – as of 2020 was only approximately 50 TBtu.[11] An additional complicating factor regarding future RNG availability in Massachusetts acknowledged in the Technical Report is that relatively limited resources for developing RNG presently exist in New England.[12]

The Technical Report overcomes the present insurmountable supply obstacles by extrapolating exponential growth in RNG production in the coming years. The Technical Report assumes future available RNG stocks will appear and be available in Massachusetts from among all states east of the Mississippi River. Appendix 1 to Technical Report ((Modeling Framework and Assumptions), at 16. The Report reasons that RNG stocks anywhere east of the Mississippi can be purchased and delivered to Massachusetts using the existing network of interstate gas pipelines (just as the pipelines are used today by the LDCs to obtain natural gas supplies). *Id.*

The Technical Report reasons that the availability in Massachusetts of 70 TBtu of RNG needed for the hybrid electrification scenario is feasible if RNG production nationwide grows precipitously *and* Massachusetts secures its "fair share" of available RNG supplies. Appendix 1 to Technical Report, at 16-17. E3 derives that "fair share" to be 3.7 percent of all RNG produced

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[11] *See* American Gas Foundation, *Renewable Sources of Natural Gas: Supply and Emission Reductions Assessment*, at 10 n.5 *available at* https://gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/

[12] *See* Appendix 1 to Technical Report, at 16 ("It is important to note that biomass resource availability in New England is relatively low compared to other regions in the United States. [] New England has an estimated 0.63 dry tons of feedstocks available per person per year, whereas the average availability of feedstocks for the U.S. as a whole is 2.47 dry tons per person per year.") Thus, New England has only one-quarter as much biomass feedstock, per person, as the national average.

annually in all states east of the Mississippi River. *Id.* This assumption that 70 TBtu of RNG represents 3.7 percent of RNG available in the eastern half of the country implies that total RNG supplies in all states east of the Mississippi will be nearly 2,000 TBtu [2,000 x 0.037 = 74 TBtu] by 2050. However, RNG production in 2020, *from all states* in the U.S. was only 50 TBtu. For 2,000 TBtu of RNG to appear by 2050 in the eastern United States suggests nationwide RNG annual production climbs from 50 TBtu in 2020 to 4,000-6,000 TBtu by 2050. As a point of reference, total annual natural gas delivery nationwide averaged 4,846 TBtu between 2009 and 2018 for the residential sector alone. American Gas Foundation 2019 Renewables Study, *supra* at 2 n. 11. Growth in RNG production by 2050 can be expected, but the kind of exponential growth prospect assumed by the Technical Report is without precedent.

Further troubling, beyond the assumption of a phenomenal RNG supply growth rate by 2050, is the Technical Report's derivation of the Massachusetts "fair share" of available RNG supply at 3.7 percent. The Report undertakes no technical, commercial, or probabilistic analysis of RNG amounts that can be acquired by the LDCs but *assumes* the Commonwealth can lay claim to 3.7 percent of the RNG supply merely because Massachusetts represents roughly 3.7 percent of the population east of the Mississippi (and despite that New England has a much smaller share of biomass resources). Appendix 1 to Technical Report, at 16-17. Perhaps if a product or commodity's supply and availability were truly unlimited, it might be reasonable to assume that supply in a competitive market is distributed roughly by relative population shares. But there is likely to be fierce competition among all states – indeed, among nations – for available RNG production by 2050, and even greater competitive pressure to obtain RNG from "hard-to-decarbonize," "hard-to-electrify" energy applications. (By contrast, the Commonwealth's use of gas for building heating is a reasonably "easy-to-electrify" application that can be met more efficiently and likely at lower costs through electrification, rather than needing to rely on RNG). The Technical Report's *assumption* that Massachusetts will successfully acquire all RNG stocks needed in the hybrid electrification scenario to meet its 2050 emission reduction mandate (and all interim reduction mandates) in proportion to its share of the relative population is unintuitive and unsupported.

Further eroding E3's RNG availability assumptions in the hybrid electrification scenario is how RNG would be transported to the LDCs for delivery in Massachusetts. The Technical Report assumes that natural gas pipelines east of the Mississippi used by the LDCs to transport natural gas today to New England will be increasingly re-purposed for transport of RNG. But these pipes are common; there is no practical way to segregate and transport separately within the pipes the RNG molecules from natural gas molecules. Thus, under E3's transport assumptions all off-takers of the interstate gas pipeline system, and all state and federal administrative agencies that regulate such facilities and users, must agree to the regulatory and technical risks to comingle RNG and natural gas within the pipes. While a future can perhaps be imagined where modest amounts of biomethane are blended and commingled with natural gas without material operational complications or administrative objection, recall that "RNG" for purposes of the Technical Report also includes hydrogen and hydrogen-derived SNG. Not all shippers and end-users, as well as the regulatory agencies overseeing such markets, might willingly and unanimously assent to commingling natural gas with hydrogen. Further complicating the permitting and approval process for transporting hydrogen is that the Federal Energy Regulatory Commission ("FERC"), the federal agency with preemptive siting and regulatory oversight of interstate natural gas pipelines, does not and cannot now regulate interstate transport of hydrogen.[13]

For all the foregoing reasons, the Department should hold grave doubts that (1) the RNG stocks needed to ensure the environmental success of the hybrid electrification pathway will grow sufficiently in total supply east of the Mississippi and can actually be acquired by the LDCs in sufficient quantities as needed; and (2) that all users and regulators of interstate gas pipelines with eight decades of experience under the Natural Gas Act and comparable state laws will pivot, in unison, to timely embrace under Massachusetts emission reduction timetable the complex blending of gas, biomethane, hydrogen and SNG. The availability of RNG in sufficient quantities in Massachusetts for the hybrid electrification pathway to successfully achieve all GHG emission reduction mandates is thus an unsound and unsupported assumption.

B. E3's estimation of RNG supply costs runs counter to its own modeling methodology and competitive market outcomes.

Even if the Department accepts all of E3's assumptions on future RNG availability (which as discussed above, it should not), the Technical Report deliberately and significantly understates in its hybrid electrification analysis the costs of obtaining RNG. Curiously, the Technical Report does so by first correctly explaining the economic and pricing dictates of a

[13] The Federal Energy Regulatory Commission's jurisdiction is limited under the Natural Gas Act of 1938 to the interstate transportation and sale for resale of natural gas. 15 U.S.C. §717. Thus, legal commentators have noted FERC's jurisdiction over pipeline siting and regulation does not extend to hydrogen. Safety and operations concerns regarding shipment of hydrogen by pipeline fall under the federal Pipeline and Hazardous Material Safety Administration (PHMSA) and limited economic interest of pipeline delivery of hydrogen are regulated by the federal Surface Transportation Board. *See generally* https://www.bakerbotts.com/thought-leadership/publications/2021/october/us-lawmakers-contemplate-regulatory-framework-for-hydrogen-transportation

competitive commodity marketplace, but then discarding, without explanation, its own economically correct commodity pricing constructs when it comes to RNG.

To estimate the cost of the future RNG supplies necessary for the climate success of hybrid electrification, E3 first constructs its own supply cost curves. *See, e.g.*, Appendix 1 to Technical Report, at 20, Figures 9 and 10. For convenience, these Figures are reproduced below.

Figure 9. Renewable gas supply curves in 2050 for optimistic and conservative Efficient Gas scenario.

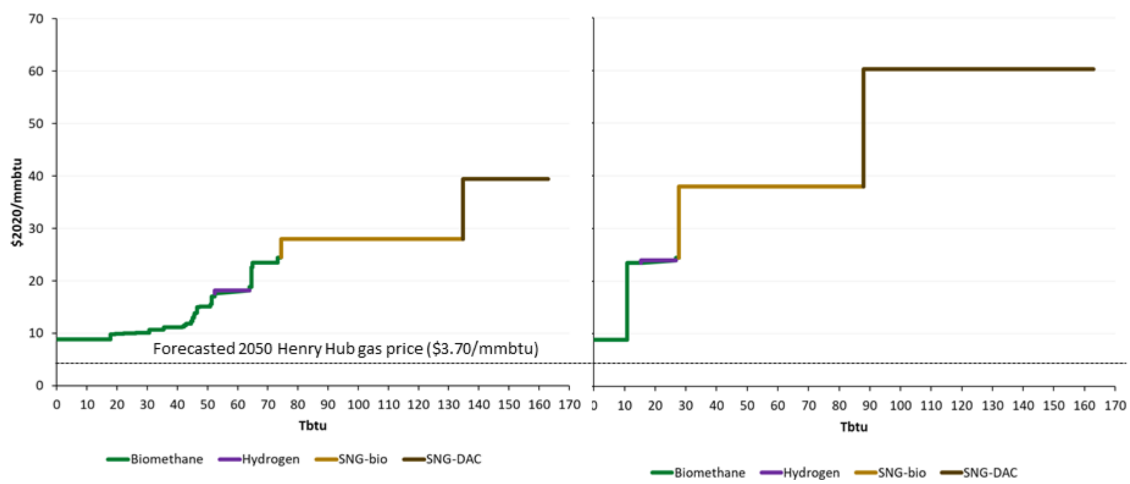
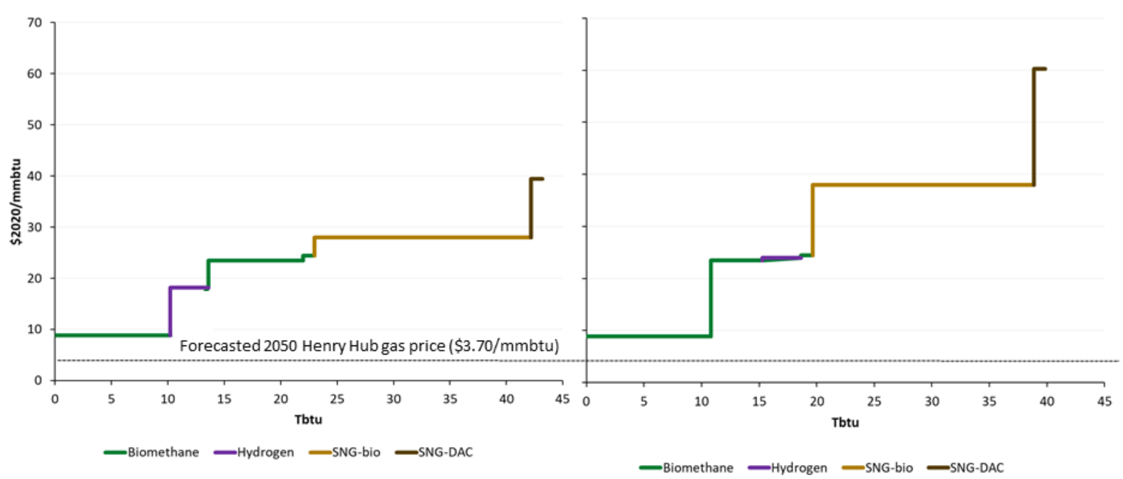


Figure 10. Renewable gas supply curves in 2050 for optimistic and conservative High Electrification scenario. Note the different horizontal axis compared to Figure 9.



To capture the future uncertainty in RNG pricing, E3 develops, to its credit, both "optimistic" and "pessimistic" views on renewable fuel supply curves. The x-axis (horizontal) on each graph represents quantities of RNG available and the y-axis (vertical) corresponds to the unit price at each level of demand. The upward "steps" in prices as quantities increase along the x-axis reflects the much higher production cost for incremental quantities of biomethane, then hydrogen, and finally SNG as demand overall for RNG increases. (The AGO has not independently confirmed the reasonableness of the forecast quantities and prices of RNG in the foregoing cost curves, but for the sake of argument here assumes them to be reasonable.)

The Technical Report proceeds to explain how to properly employ such cost curves in a competitive commodity market:

> The cost of renewable gas in each pathway is based on the *market clearing price* of the above supply curves each year. That is, if 60 TBtu of biomethane would be needed from the Efficient Gas pathway (Figure 9), hydrogen *sets the market clearing price* of ~$17/MMBtu *for all 60 TBtu* in the optimistic case.

Appendix 1 to Technical Report, at 20 (emphasis supplied). This competitive commodity pricing determination of "market clearing price" is grounded in basic economics and is a mainstay of economic modeling. As E3 acknowledges above, when overall market demand rises in the hybrid electrification scenario to 70 TBtu, no competitive supplier of biomethane will agree to sell at anything less than the market clearing price. Thus, all supplies are "priced at the margin" because that is how competitive commodity markets work in practice. In the optimistic case of Figure 9, above, no supplier will agree to sell 10 MMBtu at something like $8 if the market is currently obtaining $17 per MMBtu at the margin. Accordingly, as the authors of the Technical Report readily acknowledge, the entire supply stack must be priced at the incremental price of the last (or marginal) unit of supply.

Inexplicably, and contrary to sound economic theory and its own pricing convention, the Technical Report disregards marginal (*i.e.*, market clearing) pricing when SNG is needed, in pathways with high gas demand. Whenever total RNG demand outstrips biomethane supplies in

E3's analysis, reaching into the SNG portion of the supply curve, the Technical Report abandons the concept of marginal pricing and a market clearing price. Instead, E3s pricing model is constructed to price the relatively small marginal quantities of SNG at the cost of SNG, but then proceeds to price the remaining RNG quantities at the lower cost of biomethane, below the margin of the supply curve.

> An exception is made for SNG, which is modeled as a separate market, with utilities procuring resources through bilateral market contracts. Therefore, SNG supply is assumed to be blended in at the weighted average price of biomethane and SNG.

Technical Report, Appendix 1, at 20.

What results from the Technical Report's special SNG pricing contrivance is a kluge of out-of-market RNG prices that imagines that most RNG is obtained at the (relatively low) cost of biomethane, and only the last, small incremental RNG requirement is priced at the much higher cost of SNG. In short, the Consultants' approach disregards competitive economics and the notion of a market clearing price. The resulting "weighted average" of lower contrived prices for biomethane but higher prices *only* for limited SNG quantities is counterfactual and economically unsupported, and significantly understates the cost of the gas-reliant pathways.

This pricing contrivance for SNG is no small error. As can be readily seen from Figures 9 and 10, above, the marginal, market-clearing prices of SNG ($28-$40/MMBtu for "optimistic" and $40-$60/MMBtu for "conservative" case) are multiples higher than the price for other RNG stocks. In the "optimistic" case, the Study assumes 63 TBtu (of the total 2050 requirement of 70 TBtu) can be attained from biomethane and hydrogen (Technical Report, at 52, Figure 16) leaving only 7 TBtu of higher cost SNG to be acquired at bilateral contract prices. But under the "conservative" case, only 16 TBtu of biomethane is available and the balance of 54 TBtu must be acquired from higher cost SNG stocks.

The resulting "Commodity Cost of Gas" shown in Figure 11 of Appendix 1 to the Technical Report could, if SNG were priced correctly, be roughly twice the cost E3 uses in its analysis. Market pricing of RNG would likely yield overall commodity gas costs far higher than the $22-$28 range shown for the Hybrid scenario in Figure 11. How much higher is not readily determined from the available information. The Department should insist that E3 correct its faulty SNG pricing contrivance and re-calculate the costs for all scenarios. The results would show that the overall savings the hybrid electrification scenario purportedly enjoys over high electrification scenarios would likely disappear (assuming, without conceding the point from Section III.A, that sufficient stocks of RNG could be found *at any price*).

What is clear is that the conclusions drawn by the LDCs on the putative merits of hybrid electrification are faulty because the Technical Report's pricing of RNG supplies, necessary for a hybrid electrification scenario to meet the emission reduction mandates, is unsound and unsupported.

C. The success of the hybrid electrification pathway at attaining all required GHG emission reductions hangs on a questionable and highly contentious assumption that RNG is truly "carbon-neutral."

Laying aside the problems discussed above regarding RNG availability and price, there is still a more foundational weakness in the hybrid electrification scenario —indeed on any pathway premised on high reliance on so-called renewable, "carbon-neutral" fuel substitutes. In fact, most RNG (both biomethane and SNG) is NOT carbon-free. When such "carbon-neutral" fuels are burned they release essentially the same CO_2 emissions occasioned when burning natural gas. Moreover, when biomethane or synthetic methane escapes from leak-prone gas infrastructure it has the same climate impacts as leaked methane from natural gas would – and these can be significant.[14]

What enables proponents of RNG to claim a favorable environmental impact from purportedly "carbon-neutral" fuels is only an assumption that is incorporated within the present regime of accounting for GHG emissions. In general, if methane from an agricultural practice that *would otherwise reach the atmosphere* can be captured and re-purposed as biomethane RNG, its resulting emissions in effect are "credited" for the emissions saved in the agricultural sector.

Longer-term, however, there is wide concern among experts on the practicality and efficacy of trading emissions on the GHG emission ledger sheet. What is needed to address the world's climate change dangers is a radical and permanent reduction in emissions from *all* sources, both agricultural and oil/gas in this example. Some level of emission exchanges will be necessary particularly to reduce emissions in the hard-to-electrify, hard-to-decarbonize sectors of the world energy economy. But to consume emission flexibility on "renewable" building heating fuels in New England (that can more directly be decarbonized through efficient electric heating technologies) will not suffice as a reasonable, sustainable long-term emission reduction strategy.

There are other environmental concerns with RNG. Its emissions perhaps appear today as "carbon-neutral" under present GHG accounting, as measured as a direct emission. Again, there is growing consensus among experts to instead measure and consider full life-cycle

[14] Importantly, leakage from distribution pipelines does not decline with reductions in throughput. Therefore, in scenarios that assume a robust continued use of the full gas distribution system, even for greatly reduced volumes, the emissions from methane leakage remain.

emission profiles that capture emissions gains and losses throughout the entire production process.

The Technical Report acknowledges both of these uncertainties and concedes (tacitly) that if the GHG emission accounting conventions change, the eligibility of RNG as a "carbon-neutral" fuel vanishes, in which case: "If th[e] [GHG inventory] framework changes, the GHG emission savings from biomethane will diverge from the values identified in this Study." Technical Report, at 18 n. 12. Thus, E3 cautions: "As discussed in Consultant Decarbonization Pathways Report, renewable fuels are *assumed* to have net zero GHG impact under the Massachusetts GHG accounting framework." Regulatory Designs Report, at 8 n. 7 (emphasis supplied). The Technical Report, at 14, adds: "pathways that rely more heavily on renewable fuels carry risks related to lifecycle emissions and GHG accounting methods." "Following the [present] conventions of the Massachusetts Greenhouse Gas Inventory, this study treats renewable fuels as carbon neutral. In practice, the lifecycle emissions of renewable fuels may vary …." *Id.*, at n. 11.

Finally, there is this more robust acknowledgment in Appendix 1 to the Technical Report, at 27-28:

> As described above, an important component of the GHG emissions accounting framework is the treatment of renewable fuels. In this study, consistent with the Massachusetts GHG Inventory, the use of renewable fuels throughout the economy *is assumed to not result in any net emissions* []. Similarly, the gross emissions accounting framework does not account for lifecycle emissions of fuels []. . . . .
>
> *The Consultants realize that treating renewable fuels as carbon neutral is a simplification of the complex carbon flux associated with fuel production.* For example, fossil fuel use in feedstock production or key feedstock conversion steps *can increase the embodied carbon emissions of renewable fuels*. . . . .
>
> As a result, treating renewable fuels as having net-zero carbon emissions may overestimate their decarbonization potential, especially considering that emissions accounting frameworks in the Commonwealth may evolve.

> *Such an overestimation increases the risk of not meeting the Commonwealth's decarbonization goals, especially under those economy-wide transitions that rely on high levels of renewable fuels, such as the Efficient Gas Equipment pathway.*

Id. (emphasis supplied). To reiterate E3's professional disclaimer above —over-reliance on the carbon neutrality of RNG, long-term, "increases the risk of not meeting the Commonwealth's decarbonization goals, especially under those economy-wide transitions [such as the hybrid electrification pathway] that rely on high levels of renewable fuels …."

Accordingly, for all the foregoing infirmities regarding RNG (i) availability, (ii) price and (iii) environmental efficacy, the Department should reject any reliance on the hybrid electrification pathway advocated by LDCs and steer away from all decarbonization transitions heavily reliant on the substitution of RNG in place of natural gas.

IV. CLAIMED BENEFICIAL IMPACTS OF HYBRID ELECTRIFICATION ON ELECTRIC SYSTEM INFRASTRUCTURE ADDITIONS CAN BE ATTAINED BY FOCUSING ON BUILDING ELECTRIFICATION IN THE NEAR TERM

A major premise in the Technical Report's predisposition towards hybrid electrification is that retaining some gas use for winter peak heating needs will result in savings in future costs, largely by avoiding the need to augment the electric system to accommodate full building electrification and the resultant winter heating peak. But the Commonwealth need not and should not commit to individual building hybrid electrification to attain this tradeoff.

Even under aggressive, full and efficient building electrification (*i.e.*, where efficient cold climate ASHP and building shell improvements are undertaken as the whole heating solution for many buildings) the majority of gas heating customers in 2030, who in the near term have not yet migrated to efficient electric heat, will stay on gas during winter peaks. This full and efficient building electrification strategy provides the same level of flexibility in winter energy sources as if, under hybrid electrification, 90 percent of customers electrify but retain gas heating for winter peaks. For example, assume for the next ten years Massachusetts aggressively promotes full electrification and that 40 percent of customers adopt efficient electric heat technologies in this period. With this initiative the electric system is not confronted with an extreme level of winter peak demand because 60 percent of customers remain (for now) on natural gas heating. There will be time between 2030 and 2040 to assess the impact on electric system costs of full building electrification and to make compensating adjustments in the pace of full building electrification.

Additionally, EEA has already determined that the number of buildings that need to convert to efficient electric heat by 2030, for Massachusetts to stay on target with its required emission reduction trajectory, is essentially the same under any alternative pathway.

> [T]o achieve Net Zero in 2050 via either a lower-risk, lower-cost "high electrification" scenario or a higher-risk, higher-cost "decarbonized gas" scenario, the core required transformations in the building sector over the next 10 years are the same. The number of buildings using natural gas, fuel oil, and propane for space and water heating must begin to steadily and permanently decline.

2030 Interim CECP, at 27. Accordingly, for at least the coming decade Massachusetts can achieve the same flexibility in the diversity of winter heating sources under an aggressive electrification pathway as it could attain under the LDCs' hybrid electrification. Moreover, full electrification (for now) of a subset of buildings maintains flexibility later to pursue either (a slightly different version of) hybrid electrification, or a high electrification pathway.

The claimed system cost savings through hybrid electrification are illusory. When the hybrid electrification scenario fails to achieve the required emission reduction mandates (and for the reasons discussed in Section III, *infra*, it likely will fail) all investments in hybrid electrification will be sunk. All of the low-efficiency ASHPs installed under hybrid electrification will now need to be replaced with high-efficiency units. EEA estimates that nearly a million gas/oil/propane furnaces and boilers will reach end-of-life status in the next ten years. Interim 2030 CECP, at 28. It will be a colossal, wasted opportunity if they are replaced with low-efficiency ASHPs, which customers will not prematurely update with more efficient units. Moreover, all amounts spent maintaining the present gas infrastructure under hybrid electrification (for seasonal winter peaks) instead of looking for gas system cost reduction opportunities through targeted electrification and ASHP deployment also will be sunk when the Commonwealth must ultimately pivot towards full electrification. Accordingly, the likely sunk costs of hybrid electrification makes it a strategy that limits, not enlarges, the Commonwealth's subsequent policy options to modify implementation based on later-acquired facts.

The Department should reject consideration of the LDCs' hybrid electrification scenario in favor of measured, yet aggressive, adoption targets for efficient building electrification (with no provision for backup gas heating).

V. <u>E3's TECHNICAL REPORT FAILED TO VIGOROUSLY PURSUE POTENTIAL GAS INFRASTRUCTURE COST SAVINGS</u>

The Technical Report (at 12, Figure 1) suggests a \$23-\$43 billion savings in cumulative energy system costs by 2050 from the hybrid electrification scenario compared to a full electrification pathway. However, as shown in Section III, *infra*, E3's cost analysis significantly understates RNG supply costs under hybrid electrification. It is likely that any cumulative cost savings advantage of hybrid electrification will disappear once RNG supply is properly priced.

A further conceptual weakness in the Technical Report's comparative cost analysis is that the analysis fails to undertake any rigorous consideration of future gas system cost savings (both capex and op-ex) enabled by electrification scenarios. While the Technical Report advises that gas system cost reduction measures were considered, there is little description how such savings were calculated. To the contrary, the Technical Report advises:

> In scenarios with declining customers, throughput, and/or demand on the gas system, there may be opportunities to reduce gas system costs

> relative to a static system. However, these opportunities are uncertain. There is little historical evidence for what level of cost reductions may be possible, as few gas utilities have faced declining throughput and no gas utilities have seen widespread customer departure.

Appendix 1 to the Technical Report, at 49. E3 cautioned "there are many open questions about how targeted electrification could be achieved"[15] and that the cost savings it purportedly identified "are not based on empirical data from Massachusetts LDCs." Appendix 1 to the Technical Report, at 49. Accordingly, the Technical Report puts off, for another day, any "detailed study by the LDCs [] required to establish LDC-specific ranges of potential cost avoidance opportunities." *Id.*

What is clear is that E3 assumed in its analysis all existing capital assets are replaced routinely at their end of life. Appendix 1 to Technical Report, at 45. It also appears E3 included in its analysis all $15.9 billion of the "business as usual" LDC-proposed future GSEP spending. *Id.,* at 43. Also, E3 breaks all capital spending in its model into two broad categories: "Meters and Services" and "Mains and Other." While E3 apparently enabled future investment in Meters and Services to vary somewhat as customers left the distribution system, the Mains and Other category "reflects assets that are used by many gas distribution customers or by the LDC as part of its standard operations and cannot necessarily be decommissioned with customer departures." *Id.*, at 42.

The picture that emerges from the Technical Report not only understates the cost of the hybrid electrification, but also overstates the cumulative system cost of aggressive electrification pathways by including no (or minimal) gas system cost savings as offsets to the costs of electrification. The Department cannot let the LDCs put off to another proceeding any serious consideration of capital costs savings, including planned costs for future GSEP spending, that

[15] Technical Report, at 18.

can be avoided with aggressive and targeted electrification pathways. The Department should insist that E3 re-do its scenario analysis with reasonable and realistic savings opportunities in all capital and O&M spending – particularly including "business as usual" GSEP spending – that can reasonably be avoided through targeted electrification initiatives.

VI. CONCLUSION

The analysis in the Technical Report, which tilts heavily towards a hybrid electrification pathway to emission reduction mandates in the buildings sector, rests on too many assumptions that are untried, untested and/or unsupported. Under any successful decarbonization pathway Massachusetts must aggressively begin to transition its building stock to clean, efficient electric heating technologies. Hybrid electrification, as posed by the LDCs, is a diversion that is unlikely to succeed due to its heavy reliance on expensive, unproven renewable natural gas. Any cost advantages claimed for hybrid electrification are due to incorrect assumptions about the availability and pricing of RNG supplies, and from the Technical Report's failure to reasonably evaluate and consider future gas infrastructure cost savings achievable through aggressive and targeted electrification scenarios.

Respectfully submitted,

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