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

COMMON REGULATORY FRAMEWORK AND OVERVIEW OF NET ZERO ENABLEMENT PLANS

I. INTRODUCTION

A. Overview

On October 29, 2020, the Department of Public Utilities ("Department") issued a Vote and Order, opening an investigation into the role of the gas local distribution companies as the Commonwealth achieves its target 2050 climate goals ("Notice of Investigation" or "NOI").[1] Order at 1, 3. As outlined in the NOI, the Department seeks to explore strategies to reach greenhouse gas ("GHG") emissions goals while protecting customer interests by "ensuring safe, reliable, and cost-effective natural gas service; and potentially recasting the role of LDCs in the Commonwealth." NOI at 1.

[1] The Department's NOI followed from a petition submitted to the Department on June 4, 2020, by the Massachusetts Office of the Attorney General ("Attorney General" or "AGO"), requesting that the Department open an investigation to analyze the future of the gas local distribution companies in light of the Commonwealth's greenhouse gas emission goal of net-zero by 2050.

To further the objectives of the NOI, the Department directed the natural gas local distribution companies ("LDCs")[2] to issue a Request for Proposals ("RFP") for an independent consultant to review the Commonwealth's "Roadmaps;"[3] to identify any pathways not examined in the Roadmaps; and to perform a detailed study of each company that analyzes the feasibility of all pathways (hereinafter, the "Study"). NOI at 5.

On March 1, 2021, in accordance with the Department's directives, the LDCs filed a status update on the retention of independent consultants and progress with respect to the RFP. Through the RFP, the LDCs selected Energy & Environmental Economics ("E3"), with ScottMadden as subcontractor, to be the independent consultant for this Study (collectively, "Consultants"). In addition to retaining E3, the LDCs retained Environmental Resources Management ("ERM") to develop and facilitate the stakeholder process.

On September 1, 2021, in accordance with the Department's directives, the LDCs filed a status update on the Consultants' progress. NOI at 6. The September 1 status update provided an overview of the timeline and progress made on the Consultants' seven workstreams.[4] Additionally, the LDCs provided an update on the ongoing and extensive stakeholder process facilitated by ERM.[5]

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2 For the purpose of this filing, the term LDCs refers collectively to: 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 Company) Corp. d/b/a Liberty (which, as of January 1, 2021 includes the gas distribution assets of the former Blackstone Gas Company), Boston Gas Company and the former Colonial Gas Company, each d/b/a National Grid, and Fitchburg Gas and Electric Light Company d/b/a Unitil.

3 The Department defined "Roadmaps" as the Executive Office of Energy and Environmental Affairs' ("EEA") 2050 Decarbonization Roadmap ("2050 Roadmap") and Interim 2030 Clean Energy and Climate Plan ("2030 CECP"). NOI at 3.

4 See LDC Status Update at 2-6 (September 1, 2021).

5 See id. at 7-2 (September 1, 2021).

On this date, the LDCs present the final work product of this effort, as follows:

(1) Consultant Report on The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals ("Consultant Report"). The Consultant Report includes a Technical Analysis of Decarbonization Pathways Report ("Decarbonization Pathways Report") and Considerations and Alternatives for Regulatory Design to Support Transition Plans ("Regulatory Designs Report");

(2) ERM Stakeholder Engagement Process Report ("ERM Report");

(3) LDC Common Regulatory Framework and Overview of Net Zero Enablement Plans, including a Net Zero Enablement Plan Model Tariff ("Regulatory Framework"); and

(4) LDC-Specific Regulatory Proposals, filed by each individual LDC.

II. EXECUTIVE SUMMARY

The Consultant Report included an economy-wide analysis of eight decarbonization pathways for Massachusetts using analytical methods and data that are similar to the approach applied in the Massachusetts 2050 Roadmap.[6] All eight pathways achieve 90% gross GHG reductions and net zero GHGs by 2050 compared to 1990 levels, as well as interim statutory GHG reduction goals of 50% by 2030 and 75% by 2040.[7] The pathways are designed to reflect different futures for the LDCs and their customers, ranging from ongoing use of the LDCs' distribution networks to 100% decommissioning of gas distribution infrastructure in the Commonwealth.[8]

Based on their comprehensive analysis, the Consultants made the following four key findings:

(1) All pathways imply transformational changes for the Commonwealth, the LDCs and their customers. Strategies that use both the gas and electric systems to deliver low-carbon heat to buildings show lower levels of challenge across a range of evaluation criteria.

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6 Decarbonization Pathways Report at 11.

7 Id.

8 Id.

(2) Achieving net-zero emissions requires early investments in the energy system; those investments must increase over time as energy demand and supply transformations scale. Fossil fuel savings are significant in all pathways. Avoided gas system costs are small relative to the investment costs required in other sectors.

(3) All pathways imply significant change for the LDCs and their customers, raising substantial cost recovery challenges associated with embedded costs for those scenarios with high levels of customer departures.

(4) New regulatory support strategies will be needed to minimize customer cost impacts, regardless of which pathway, or combination of pathways, are pursued.[9]

From these key findings, the Consultants offered the following recommendations:

(1) Despite long-term uncertainty on the direction of decarbonization, there are several low regret decarbonization technologies used across scenarios, including energy efficiency, building electrification, biomethane and renewable electricity.

(2) In addition to these common strategies, several decarbonization technologies are worth further research and development to better understand their costs and resource potential, including hybrid system operation pilots and programs, targeted electrification to enable decommissioning of gas distribution assets, networked geothermal systems and renewable hydrogen.

(3) Balancing across many considerations, decarbonization pathways that strategically use the Commonwealth's gas infrastructure alongside and in support of electrification are likely to carry lower levels of challenge.

(4) The LDCs, together with the Department, should begin implementing decarbonization strategies and regulatory designs to support the Commonwealth's climate goals.[10]

Pursuing these recommendations will require a focused and iterative process from now until 2050 that enables the LDCs to implement decarbonization technologies, while maintaining the safety and reliability of the gas distribution system. At the same time, the Department will need to consider the implications for the reliability and resiliency of the electric system if

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9 Id. at 11-15.

10 Id. at 18-19.

customers migrate to the electric system for heating and cooking, among other uses that are necessary to achieve the Commonwealth's GHG reduction goals (e.g., electric vehicles) and the electric system evolves to expand capacity and further integrate renewable power (e.g. solar distributed generation and offshore wind).

Lastly, the pursuit of net zero must also recognize the significant costs that will need to be incurred to achieve the Commonwealth's decarbonization goals, and ensure such costs are recovered in an equitable manner. Ultimately, the transition will be one that is driven by residential, commercial and industrial customers willingness and ability to support the Commonwealth's environmental goals through investments in their homes, businesses and transportation.

The LDCs appreciate the detailed analyses that were informed by the input of a broad base of stakeholders and produced by the Consultants, and the recommendations associated with them. The LDCs have considered these recommendations and developed:

1. Company-specific, *Net Zero Enablement Plans* for review and approval by the Department.
2. The LDCs are also proposing a Net Zero Enablement Plan Model Tariff that will allow the LDCs to institute and continue decarbonization and electrification efforts, and that will advance over time.
3. In addition, the LDCs seek the Department's authorization for a framework for recovery of costs of renewable gas through the respective Cost of Gas Adjustment Clause ("CGA") tariffs.

4. Also, the LDCs ask the Department to investigate avenues to manage recovery of embedded costs and the incremental costs necessary to meet the Commonwealth's environmental objectives.

To provide a broader context for the LDCs' individual proposed Net Zero Enablement Plans, the LDCs offer the following overview of the Consultant's decarbonization pathway analyses and a summary of relevant Department precedent governing the distribution of natural gas in the Commonwealth.

III. OVERVIEW OF PATHWAY ANALYSES

A. State Net Zero Targets

In 2020, the Baker-Polito administration committed the Commonwealth of Massachusetts to achieving net zero GHG emissions by 2050. The Office of Energy and Environmental Affairs ("EEA") commissioned the 2050 Roadmap to support the Commonwealth's transition to net zero. As stated above, the Department subsequently directed the LDCs to study the Roadmaps and develop LDC-specific proposals. Net zero was defined as:

> "A level of statewide greenhouse gas emissions that is equal in quantity to the amount of carbon dioxide or its equivalent that is removed from the atmosphere and stored annually by, or attributable to, the Commonwealth; provided, however, that in no event shall the level of emissions be greater than a level that is 85 percent below the 1990 level."[11]

Additionally, An Act Creating a Next Generation Roadmap for Massachusetts Climate Policy (the "2021 Climate Act") also creates an obligation for the Department of Energy Resources ("DOER") to establish interim incremental GHG emissions limits every five years until 2050.[12]

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11 Roadmap at 7, n.1.

12 Section 8 of Chapter 8 of the Acts of 2021.

The Roadmap identified eight pathways to reduce GHG emissions to the goal of net zero by 2050.[13] Each pathway identified is capable of achieving the net zero emissions goal.[14] Further, the Roadmap has four analyses by sector: buildings, transportation, non-energy emissions, and carbon sequestration and an economic and health impact analysis.[15]

B. Overview of Consultant Analysis and Pathways Analyzed

As stated above, in accordance with the Department's Order, the Consultants reviewed the Roadmaps, identified pathways not examined in the Roadmaps and performed a detailed study of each LDC that analyzed the feasibility of all pathways.[16] The Consultants developed an economy-wide analysis of eight decarbonization pathways for Massachusetts.

Importantly, all eight pathways achieve the requisite GHG reductions. Three pathways were developed based on the scenarios included in the Roadmap and Interim 2030 CECP. An additional five alternative pathways were developed after consultation with stakeholders and the LDCs. Below, Table 1 provides an overview of the eight pathways.

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13 Roadmap at 7.

14 Id.

15 Id. at 8.

16 Order at 5.

Table 1: Overview of Pathways[17]

Pathway	Summary	Origination
High Electrification	Building sector electrifies >90% of buildings, primarily through the adoption of Air Source Heat Pumps	Inspired by Roadmap "All Options" Scenario
Low Electrification	Building sector electrifies 65% of buildings through the adoption of ASHPs.	Inspired by Roadmap "Pipeline Gas" Scenario
Interim 2030 CECP	Building sector electrifies in an accelerated pace following goals outlined in the Interim 2030 CECP	Inspired by interim 2030 CECP
100% Gas Decommissioning	Building & Industrial sectors fully electrify by 2050. +/- 25% of the building sector converts to networked geothermal systems.	Stakeholder Proposed
Targeted Electrification	>90% of buildings are electrified through a combination of technologies. LDC customers converting to ASHPs do so in a "targeted" approach	Stakeholder and LDC Proposed
Networked Geothermal	LDCs evolve their business model and convert +/- 25% of the building sector to networked geothermal systems. Mix of electrification technologies and decarbonized gas for space heating by 2050.	Stakeholder and LDC Proposed
Hybrid Electrification	>90% of buildings electrify through air source heat pumps paired with decarbonized gas back-up ("hybrid heat pumps") that supply heating in cold hours of the year.	Stakeholder and LDC Proposed
Efficient Gas Equipment	Building sector largely adopts high efficiency gas appliances, supplied by a combination of decarbonized gases by 2050. The industrial sector converts to dedicated hydrogen pipelines.	Stakeholder and LDC Proposed

C. Key Findings and Implications

The Consultant Report provides a comprehensive discussion of the economy-wide analysis of eight decarbonization pathways for Massachusetts. As described therein, there are four key findings.

First, all pathways imply significant changes for the Commonwealth, the LDCs and their customers. Strategies that use both the gas and electric systems to deliver low-carbon heat to buildings show lower levels of challenge across a range of evaluation criteria.[18] Figure 1 of the Consultant Report illustrates that pathways that coordinate utilization of the gas and electric systems, such as the Hybrid Electrification scenario, show lower overall levels of challenge.[19]

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17 Decarbonization Pathways Report at 31.

18 Id. at 11.

19 Id.

The second key finding is achieving net-zero emissions requires early investments in the energy system (in particular, heat pumps, building shell retrofits and initial investments in networked geothermal systems, and renewable gas).[20] Those investments must increase over time as energy demand and supply transformations scale.[21] Additionally, avoided gas system costs are small relative to the investment costs required in the other sectors.[22] Further, the Consultant Report finds that a portfolio of measures that achieves the Commonwealth's decarbonization goals may include aspects of multiple pathways, as well as other strategies that may emerge in the coming decades.[23]

Third, the Consultants found all pathways imply transformational change for the LDCs and their customers, raising substantial cost recovery and potential embedded cost challenges for those scenarios with high levels of customer departures.[24] To achieve net zero, customer end-uses, energy supply and networks must evolve and adapt to the changing environment.

Lastly, the Consultants determined new regulatory support strategies will be needed to minimize customer cost impacts, regardless of which pathway, or combination of pathways, are pursued.[25]

1. Costs

As stated above, one of the key findings of the Consultants was that new regulatory support strategies would be needed to minimize customer cost impacts, regardless of which pathway or pathways are pursued.[26] Customers are at the center of the Commonwealth's decarbonization

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20 Id. at 13.
21 Id. at 13-14.
22 Id. at 14.
23 Id. at 14.
24 Id. at 14.
25 Id. at 15-16.
26 Id.

goals because their decisions about when and how to adopt electrification and efficiency measures drives the nature, scale, and magnitude of electric and gas system transformations.[27]

Across the pathways, customers face a common set of challenges – upfront costs and operating costs of decarbonization options.[28] For electrification measures, the Consultants concluded that, without supportive policy initiatives, these incremental costs are a substantial barrier to achieving adoption.[29]

All pathways result in an increase in customer bills due to delivery and commodity components of gas rates. However, the Consultants found pathways that rely on electrification and gas result in a more "balanced" customer cost impact.[30] The Consultants acknowledge that there are many outstanding questions related to decommissioning portions of the gas system while maintaining system reliability and safety.[31]

Between 2020-2050, relative to the Reference Scenario, the cumulative incremental energy system costs by pathway vary from $64-$94 billion in an optimistic view to $92-$135 billion in a conservative view.[32] By 2050, annual energy system costs range from $3.3–$5.0 billion per year in an optimistic view and $5.0–$7.8 billion in a conservative view.[33] Additionally, the Consultants found the Hybrid Electrification pathway to have the lowest cumulative incremental costs and the 100% Decommissioning pathway shows highest costs on a cumulative basis.[34]

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27 Id.

28 Id. at 16.

29 Id.

30 Id. at 17.

31 Id. at 18.

32 Id. 80.

33 Id.

34 Id.

2. LDC System Implications

The Consultants determined that under all decarbonization scenarios, the LDC load curves will experience significant changes to level of demand and shape of demand, the degree of which varies across scenarios.[35] Changes in total volumes and patterns of natural gas demand will have implications for: resource supply portfolios; performance of the natural gas infrastructure; and upstream pipeline service.[36]

The pathways have various implications for the LDCs' gas system. The 100% Gas Decommissioning scenario fully eliminates the use of gas on the distribution system.[37] The Efficient Gas Equipment scenario has the largest volumes of gas flowing through the distribution system.[38] Further, the High Electrification and 2030 CECP pathways result in a large increase in electricity demand and steep decline in pipeline gas throughput, mostly leaving natural gas in the industrial sector towards 2050.[39]

3. Electric System Impacts

In addition to significant impacts on the gas distribution system, as stated in the Consultant Report, all of the decarbonization pathways indicate an increased reliance on electricity which means electric reliability will take on even greater urgency.[40] Additionally, the Consultants found the scenarios require greater reliance on regional electricity planning and regulation and note electric reliability standards may need to be updated.[41]

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35 Id. at 89.

36 Id.

37 Id. at 47.

38 Id. at 48.

39 Id.

40 Id. at 90.

41 Id. at 90-91.

The increased reliance on electricity may have several implications for electric system reliability in the future, including determinants and resource contributions towards resource adequacy; generator fuel/energy supply availability and adequacy will need to be reviewed; and critical facility/on-site reliability may need to be considered.[42] Further, the Consultants note that energy system resilience will be increasingly important and the existing gas infrastructure could be utilized strategically to support energy system resilience.[43]

4. Customer Impacts

As stated above, customers are at the center of the Commonwealth's climate goals. Therefore, each pathway has unique and substantial implications for natural gas customers in the Commonwealth.[44] The Consultants found that, in order for net zero climate goals to be met, nearly every LDC customer will need to take action to retrofit their homes and business.[45]

Each pathway will require a focused and tailored communication outreach and program development for environmental justice communities, low-income customers, and landlord/tenants to address challenges and hurdles unique to these customer groups.[46] Successful decarbonization strategies will need to address customer practicality, including pace of technology adoption; lead time for implementation; and customer decision-making, acceptance and choice.[47]

The Consultants found that all pathways, absent regulatory changes, would see volumetric rate increases posing affordability challenges to customers that retain gas service in each scenario.[48] As demonstrated in Figure 37 of the Consultant Report, low-income customers that

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42 Id. at 90.
43 Id. at 91.
44 Id. at 97.
45 Id.
46 Id. at 99.
47 Id.
48 Id. at 101.

are unable to participate in decarbonization are likely to spend an increasingly high share of their income on energy, from approximately 5% today, to over 15% in 2050.[49]

E3 found that with customers migrating from the gas system, cost shifts and equity issues can be observed across generations of LDC customers, migrating vs. non-migrating customers, and between rate classes (residential vs. non-residential).[50] Given the upfront costs required to convert end use applications from natural gas to electricity, those customers that are unable to fund these costs are more likely to remain as LDC customers and bear a disproportionate cost responsibility for LDC distribution system costs.[51]

The Consultant Report highlights that pathways with dramatic reductions in natural gas utilization result in equity issues with recovery of costs left to a declining number of customers.[52] Moreover, there is potential for cost shifting between rate classes with distribution system costs being shifted to harder-to-electrify industrial sectors.[53] There are several customer equity challenges to consider, including: equitable distribution and recovery of LDC delivery costs; procedural equity and inclusive decision making; and decommissioning and construction of energy infrastructure.[54]

5. High Level Review of Qualitative Findings and Considerations

To assess the implications and feasibility of each of the developed pathways, the Consultants considered a broad set of qualitative and quantitative evaluation criteria.[55] As directed in the Department's NOI, the Consultant Report includes a discussion and assessment of

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49 Id. at 102-103.
50 Id. at 106.
51 Id.
52 Id. at 107
53 Id.
54 Id. at 107-108.
55 Id. at 24-25.

qualitative factors for the decarbonization pathways.[56] As part of the Consultants' study, they evaluated qualitative factors including but not limited to, affordability, workforce impacts, air quality, customer practicality, and customer equity.[57] A detailed description of each evaluation criterion can be found in Chapter 5 of the Decarbonization Pathways Report.

IV. CONSIDERATIONS FOR REGULATORY DESIGN TO ENABLE A LOW-CARBON FUTURE ON THE LDC SYSTEMS

A. Introduction and Overview

As described in Section IV, above, the LDCs are subject to a comprehensive suite of federal and state regulations designed to ensure that they provide safe and reliable natural gas service to their customers, at just and reasonable rates. This fundamental regulatory paradigm has been consistent for decades. However, as public policy has been developed over time, particularly since the enactment of the Green Communities Act of 2008 ("GCA"), the Department has adapted this regulatory paradigm to recognize the Commonwealth's goals of promoting gas demand reduction (e.g., the requirement for LDCs to implement all cost-effective energy efficiency) and enhanced public safety measures.

For example, given the GCA's requirement for the LDCs to implement all cost-effective energy efficiency, the Department has approved revenue decoupling tariffs to eliminate the link between customer sales and Company earnings in order to align the interests of the Company and customers with respect to lowering customer usage. In addition, the Department has required the LDCs to analyze non-pipeline alternatives to procuring additional gas capacity when determining whether incremental resources should be approved to meet the demand from customers for natural

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56 NOI at 5; id.

57 Decarbonization Pathways Report at 25.

gas service. More recently, in furtherance of the development of non-pipeline alternatives, the Department has allowed the LDCs to invest capital in geothermal pilots.

The Commonwealth's 2050 Net Zero Enablement goals will require a focused and deliberate approach to regulatory design over the next 28 years that allows the LDCs to both meet the requirements of the Climate Act of 2021, while continuing to provide safe and reliable service to customers that choose natural gas service, at just and reasonable rates. To that end, the LDCs have developed a suite of regulatory initiatives for review, consideration, and approval by the Department, as discussed herein.

B. Overview of Regulatory Proposals

The LDCs' suite of regulatory initiatives is influenced by the recommendations offered by the Consultants to support the Commonwealth's achievement of its climate goals.[58] Table 1 of the Regulatory Designs Report summarizes their recommended regulatory designs. The figure shows six regulatory designs, each with an objective and set of recommendations.[59] The recommendations are in large part enhancements to current ratemaking mechanisms. This approach enables the LDCs and the Department to take early action on the strategies recommended in the Decarbonization Pathways Report.

In general, the Consultants' regulatory designs 1-3 enable LDC strategies to support the Commonwealth's climate goals, such as increasing adoption levels of electrification and blending renewable gas in the gas system, while regulatory designs 4-6 generally support cost and rate mitigation efforts, such as accelerated depreciation.[60]

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[58] Regulatory Designs Report at 8.

[59] Id. at 9.

[60] Id.

Objectives	Recommendations
1. Support customer adoption and conversion to electrified/decarbonized heating technologies.	●Increase funding of energy efficiency programs ●Enhance energy efficiency measures ●Evaluate alternative funding mechanisms. ●Examine electric and gas rate policies to reflect changing demand requirements and cost implications ●Establish customer service standards and procedures.
2. Blend renewable gas in gas-resource portfolios	●Update Forecast and Supply Plan standards to add renewable gas ●Provide customers with an option to purchase renewable gas from the LDC ●Provide customers with an option to purchase renewable natural gas from third parties.
3. Pilot and deploy innovative electrification and decarbonized technologies, such as renewable gas, to determine their role in the transition	●Develop standards for review and approval of pilot and research and development programs ●Design cost recovery mechanisms ●Establish a set of measured outcomes for pilot and R&D programs ●Track and report on performance metrics
4. Manage gas infrastructure investments and cost recovery	●Develop framework to examine and implement opportunities to minimize or avoid gas infrastructure projects through utilization of decarbonized technologies and strategies, while maintain safety and reliability ●Include in framework a standard for review and approval of LDC plans for capital investment ●Also include in the framework a standard to improve coordination between gas and electric system planning and investments ●Revise standards for investments to serve new customers ●Align gas infrastructure cost recovery and utilization.
5. Evaluate and enable customer affordability	● Develop framework to quantify transition costs, including (1) embedded gas infrastructure costs, (2) gas supply portfolio restructuring costs, and (3) other costs, such as workforce transition ●Evaluate impacts of transition costs on customers, particularly low-income and those in EJ communities ●Evaluate approaches to recover transition costs, including from customers who leave the system and more broadly from those who benefit from the transition
6. Develop LDC transition plans and chart future progress	●Develop schedules for Department review and approval of transitions plans that include: (1) strategies and initiatives that support achievement of Commonwealth climate goals and metrics to quantify

Objectives	Recommendations
	progress; (2) resource plans that enable decarbonized strategies and initiatives, including capital and O&M spending plans; and (3) metrics to quantify progress ●Establish an evaluation process for LDC transition plans that includes reporting on customer data, GHG emissions, and rates and customer bill impacts ●Establish framework to optimize gas and electric systems planning, investment and cost recovery ●Establish a framework to modify LDC transition plans based on developments

The LDCs agree with the Consultants' conclusion that regulatory support is needed to enable the LDCs to implement strategies relating to transition of the gas system to net zero emissions as well as to mitigate cost and rate impacts on customers, especially low-income and those in environmental justice ("EJ") communities.[61] From these recommendations, the LDCs have developed company-specific and joint proposals for review and/or approval by the Department.

1. <u>Approval of LDC Net Zero Enablement Plans</u>

Each LDC is submitting an initial transition plan ("Net Zero Enablement Plan" or "NZEP") on this date for review and approval by the Department, designed to both continue efforts underway in their respective three-year energy efficiency plans to significantly advance decarbonization in the Commonwealth and advance the Consultants' recommended regulatory designs in the short term. These LDC-specific initial transition plans are being filed on this date under separate cover. They are intended to cover the period between now and the next three-year Net Zero Enablement Plans. These initial Net Zero Enablement Plans pursue a portfolio of the various decarbonization pathways analyzed by the Consultants in an effort to meet the

61 <u>Id</u>. at 8.

Commonwealth's 2050 Net Zero Enablement goals, while maintaining the safety and reliability of the gas distribution system.

In addition, the LDCs seek Department approval of a framework for future iterations of LDC-specific Net Zero Enablement Plans. The LDCs jointly propose the following framework for future plans, which will be designed to continue the advancement of decarbonization initiatives identified by the Consultants, and additional decarbonization initiatives that may materialize following approval of the initial Net Zero Enablement Plans:

(i) LDCs will propose to file Net Zero Enablement Plans on a 3-year cycle, to align with 3-year energy efficiency cycle, using a 5 and 10-year planning horizon to allow for review, evaluation of progress, plan updates and proposed modifications to the LDC Net Zero Enblement Plan, as warranted or appropriate.

(ii) LDCs will demonstrate evaluation of non-pipeline alternatives to mitigate the need for incremental investments in gas infrastructure, as applicable.

(iii) LDCs will provide data to inform decision making during the transition.

(iv) LDCs will provide periodic updates regarding progress towards addressing transition issues, including EJ issues.

(v) Other enabling proposals under consideration by LDCs.

To this end, the LDCs propose that the Department review their respective initial and future three-year transition plans Net Zero Enablement Plans pursuant to the following standard of review:

The LDC's transition portfolio is reasonably designed to contribute to the reduction of GHG emissions to meet net zero emissions by 2050, without compromising the safety, reliability and affordability of service offered to current customers.

1. <u>Approval of Net Zero Enablement Plan Factor Model Tariff</u>

To focus and fund the transition, the LDCs are submitting a Net Zero Enablement Plan Factor Model Tariff (the "Model Tariff") for review and approval by the Department. The Model

Tariff is provided as Attachment A.

The Model Tariff provides for the recovery of incremental costs associated with each LDC's NZEP approved by the Department. To be eligible for recovery, NZEP costs must be: (1) incurred within in the scope of project categories authorized by the Model Tariff in furtherance of the LDC's Department-approved Net Zero Enablement Plan, in effect from time to time; (2) incremental to the LDC's 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 operation and maintenance ("O&M") expenses; (4) exclusively attributable to enabling Net Zero investments; and (5) recorded as in-service by December 31 of each NZEP Investment Year..

The Model Tariff would provide cost recovery for various decarbonization activities proposed by an LDC including, but not limited to:

(i) Air Source Heat Pumps (to the extent not funded through EE Plans)
(ii) Efficient Gas Equipment
(iii) Hybrid Heating Systems
(iv) Hydrogen blending interconnections and installations
(v) Networked Geothermal Pilots/Programs
(vi) Renewable gas blending interconnections or installations.
(vii) Other projects, initiatives, or strategies as proposed by the LDC.[62]

In addition, the Model Tariff authorizes cost recovery for administration of these proposals, data collection, workforce development, customer education, potential customer incentives and reports on an LDC's progress toward the Commonwealth's decarbonization goals.

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[62] This list of decarbonization activities is not intended to reflect any particular LDC's priority of activities. It is merely intended to list the potential suite of activities that any LDC may decide to propose for implementation through their LDC-specific Net Zero Enablement Tariff.

3. Authorize Decarbonized Gas Cost Recovery Through CGA Clause

As noted previously, a gas company has a statutory obligation to serve its customers in an efficient and cost-effective manner. G.L. c. 164, §691. The Decarbonization Pathways Report recommends LDCs develop a procurement strategy to add renewable gas supply to the resource portfolio.[63] The Consultant Report concludes that blending limited amounts of renewable gases into the pipeline results in a reduction of GHG emissions without substantially increasing gas costs.[64] The Consultants recommend the LDCs develop procurement strategies for renewable gases, starting with relatively low-cost resources.[65] Early actions include investigating the deliverability of biomethane, hydrogen and synthetic gases from a broader range of sources and regions.[66]

However, presently, renewable gas does not meet the Department's "least cost" supply planning standards if the Department were to focus solely on the cost of renewable gas as compared to alternative commodity options.[67] The LDCs request that the Department review proposals for renewable gas and develop a standard of review for gas procurement that allows cost recovery for renewable gas even it is not the least cost commodity option.

As noted previously, the Department reviews a gas company's five-year supply plan to determine whether it minimizes cost subject to trade-offs with adequacy.[68] Moreover, with respect to long term (i.e., a term of over one year) gas supply and transportation contracts, the Department considers both price and non-price factors, such as reliability, flexibility and diversity of the supply

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63 Regulatory Designs Report at 25.

64 Id.

65 Id.

66 Id.

67 Id.

68 See, Fitchburg Gas and Electric Light Company d/b/a Unitil, D.P.U. 21-10, at 18 (2022).

option requested by the LDC for approval.[69] The Department should review future long-term contracts that include the procurement of renewable gas by including the potential decarbonization benefits of renewable gas as a non-price factor to be balanced with other non-price factors, and price considerations.

2. Investigate Potential Cost Recovery Options

Currently, the costs of natural gas distribution in the Commonwealth are recovered from customers served by the gas distribution system through supplier charges, distribution charges (including distribution adjustment charges) and through revenue decoupling. The scope of these costs will change significantly as the LDCs implement Net Zero Enablement initiatives. Moreover, the timetable to recover them will likely need to be addressed to ensure that they are recovered in a fair and equitable manner.

a. Revenue Decoupling

As noted above, presently, LDCs have a revenue decoupling mechanism that is designed to recover or refund differences between actual and Department-authorized revenues.[70] The revenue decoupling mechanism is currently designed on a "per customer" basis, enabling the LDCs to retain the incremental revenues associated with serving new customers to offset the incremental costs until rates are reset.[71] The mechanism has worked well in the past since the LDCs historically experienced an increase in customers.[72] However, the decarbonization pathways project service to fewer customers over time; thus, a revenue decoupling mechanism

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69 National Grid, D.P.U. 20-137, at 21.

70 Regulatory Designs Report at 23.

71 Id. at 23-24.

72 Id. at 24.

designed on a "per customer" basis would no longer ensures that the LDCs will recover the Department-authorized revenues.[73]

The Consultants note that an approach to address this is to revise the revenue decoupling mechanism from a "per customer" reconciliation of actual and authorized revenues to a reconciliation of total revenues, similar to the approach currently in place for Massachusetts electric utilities.[74] The LDCs encourage the Department to investigate this option in the future to the extent that the number of gas customers decreases over time as the LDCs pursue decarbonization and electrification strategies.

b. *Role of Accelerated Depreciation Expense to Align Recovery and Utilization*

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. The Consultants' offered an example, known as the Units of Production ("UOP") depreciation method.[75] The UOP method is recognized by the National Association of Regulatory Utility Commissioners.[76] The LDCs encourage the Department to investigate this cost recovery option in order to mitigate customer affordability and equity concerns to the extent that gas customers decrease over time as the LDCs pursue decarbonization and electrification strategies.

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73 Id.

74 Id.

75 Id. at 37.

76 Id.

c. *Address Customer Affordability Issues Through Alternative Cost Recovery Approaches.*

The Consultants have identified several categories of transition costs associated with decarbonization, including: (1) uncollected costs from customers who have departed the gas system, (2) costs associated with restructuring or realignment of gas supply portfolios, including cost of restructuring supply, storage and pipeline agreements, and (3) other costs, such as workforce transition costs and costs associated with design and implementation of transition efforts, including geographically targeted electrification, non-pipeline solutions, coordinated planning efforts between electric and gas utilities, and accelerated depreciation.[77]

The LDCs support the Consultants' recommendation for the Department to evaluate the impact of transition costs on customers.[78] Although some pathways help reduce the amount of transition costs, under all pathways, there will be a substantial impact on rates by the end of the pathway.[79] As recommended by the Consultants, the Department should evaluate cost recovery from customers leaving the gas system.[80] The Department should also evaluate the sharing of transition costs with non-LDC customers.[81] Lastly, securitization has been used in the utility industry to finance recovery of extraordinary costs.[82] The Department should evaluate securitization as a potential method to finance transition costs in the future and over time.[83]

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77 Id. at 42.

78 Id.

79 Id.

80 Id. at 42-43.

81 Id. at 43.

82 Id. at 45.

83 Id.

APPENDIX A

MODEL TARIFF

NET ZERO ENABLEMENT PLAN MODEL TARIFF

1.0 APPLICABILITY

This Net Zero Enablement Plan tariff ("NZEP Tariff") provides for the recovery of incremental costs associated with the Company's Net Zero Enablement Plan ("NZEP") approved by the Department of Public Utilities (the "Department"). Costs eligible for recovery are: (1) incurred within the scope of project categories authorized by this tariff in furtherance of the Company's Net Zero Enablement Plan, in effect from time to time; (2) incremental to the Company's current investment projects or associated with the implementation of new types of technology; (3) incremental to costs that the Company currently recovers through its base distribution rates for operation and maintenance ("O&M") expense; (4) exclusively attributable to enabling Net Zero investments; and (5) recorded as in-service by December 31 of each NZEP Investment Year.

The Company's rates for firm distribution service are subject to adjustment to reflect the operation of this NZEP Tariff.

2.0 DEFINITIONS

2.1 Allowed O&M Expense ("O&M") is the incremental O&M expense that is incurred by the Company as a result of implementing its NZEP and is solely attributable to Net Zero furthering investments, including but not limited to, incremental NZEP development and evaluation costs, customer education costs and workforce training costs, the cost of which is not being recovered in base distribution rates or through another reconciling mechanism. Allowed O&M Expense are the actual monthly NZEP-related O&M expenses incurred in the NZEP Investment Year prior to the Recovery Year. Allowed O&M Expense shall exclude pension and post-retirement benefits other than pension costs recovered through another reconciling mechanism.

2.2 Eligible NZEP Investments are the cumulative capitalized costs of Eligible NZEP Projects recorded as in-service, including cost of removal, and are used and useful at the end of the NZEP Investment Year that is prior to the NZEP Recovery Year.

2.3 Eligible NZEP Project is a project, initiative, or strategy undertaken within a category of projects, initiatives, or strategies approved by the Department as a reasonable component of the Company's NZEP, on the basis that the activity contributes to the achievement of the Commonwealth's Net Zero emissions goals without compromising the safety, reliability, and affordability of the Company's distribution and supply service provided to customers. Eligible NZEP Projects may include, but not be limited to:

i. *Air Source Heat Pumps*

ii. *Efficient Gas Equipment*

iii. *Hybrid Heating Pumps*

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iv. *Hydrogen blending interconnections and installations*

v. *Networked Geothermal Pilots/Programs*

vi. *Renewable gas blending interconnections and installations*

vii. *Other projects, initiatives, or strategies as proposed by the Company*

The Company's cost of providing gas supply to its customers are recoverable through its Cost of Gas Adjustment Clause ("CGAC"). Commodity costs associated with an Eligible NZEP Project may be recoverable through the CGAC, where first presented to the Department for specific review and approval by the Department.

Depreciation expense associated with gas infrastructure at the end of the test year in the Company's last base distribution rate case, as adjusted by the provision of its Performance-Base Ratemaking Plan, as applicable, is recovered through the base distribution rates and may be appropriate for acceleration to mitigate future impacts on customers arising from the implementation of NZEP initiatives. Accelerated depreciation expense, or contributions thereto, may be recoverable where first presented to the Department for specific review and approval by the Department.

2.4 Net Zero is: (1) a level of statewide greenhouse gas emissions that is equal in quantity to the amount of carbon dioxide or its equivalent that is removed from the atmosphere and stored annually by, or attributable to, the Commonwealth; provided, however, that in no event shall the level of emissions be greater than a level that is 85 percent below the 1990 level; or (2) the definition of Net Zero established by the Commonwealth from time to time.

2.5 NZEPF is the Net Zero Enablement Plan Factor that recovers the annual NZEP Revenue Requirement approved by the Department and shall be determined in accordance with Section 3.0 below.

2.6 NZEP is the Company's Net Zero Enablement Plan in effect from time to time.

2.7 NZEP Investment Year is the annual period beginning on January 1 and ending on December 31.

2.8 Recovery Year is the 12-month period during which the NZEPF is in effect beginning on November 1 and ending on October 31 of each year.

2.9 NZEP Revenue Requirement is the revenue requirement associated with Eligible NZEP Investments for each NZEP Investment Year prior to the Recovery Year, plus Allowed O&M Expense. For the year in which an Eligible NZEP Investment is placed into service, the NZEP Revenue Requirement will be calculated on a monthly basis. The NZEP Revenue Requirement for subsequent years shall be calculated based upon the average of the beginning and ending calendar year balances. The NZEP Revenue Requirement will be calculated to recover (1) the monthly revenue requirement for Eligible NZEP Investments placed into service in the NZEP

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Investment Year immediately prior to the Recovery Year; (2) the average annual revenue requirement for the calendar year ending December 31 of the NZEP Investment Year two years prior to the Recovery Year, for cumulative Eligible Investments placed into service in the NZEP Investment Years two years prior to the Recovery Year; (3) the average annual revenue requirement for the calendar year following the most recent NZEP Investment Year on cumulative Eligible NZEP Investments recorded as in service through the NZEP Investment Year immediately prior to the NZEP Recovery Year; and (4) Allowed O&M Expense.

2.10 Property Tax Rate is the Company's composite property tax rate determined in the Company's most recent base distribution rate case, calculated as the ratio of total annual property taxes paid to total taxable net plant in service.

3.0 NET ZERO ENABLEMENT PLAN FACTOR ("NZEPF")

3.1 Rate Formula

$$NZEPFr = \frac{(NZEPRR + PPRA) \times DRAr}{A{:}TPvolsr}$$

And:

$$NZEPRR = (RB \text{ X } PTRR) + DEPR + PTE + O\&M$$

And:

$$RB = [(GP_P - ARD_P + ADIT_P) + (GP_C - ARD_C + ADIT_C)] \div 2$$

Where:

r Designates a separate factor for each rate class grouping.

p The prior year.

c The current year.

NZEPFr The Net Zero Enablement Plan Factor, by rate class grouping, as defined in Section 2.5.

NZEPRR The NZEP Revenue Requirement as defined in Section 2.9.

PPRA The Past Period Reconciliation Amount defined as the difference between (a) the amount authorized to be recovered through the prior year's NZEPFs as approved by the Department and (b) the actual revenue billed through the applicable

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NZEPFs. Interest calculated on the average monthly balance using the consensus prime rate as reported by *Bank of America*, shall also be included in the PPRA.

DRAr The Distribution Revenue Allocator representing the percentage of final revenue requirement allocated to each rate class group as determined in the Company's most recent general rate case as follows:

Rate Class Grouping	DRA

RB The average annual Rate Base associated with the cumulative Eligible NZEP Investments, based upon the beginning of the year and end of the year GP, ARD, and ADIT balances of the respective NZEP Investment Year. For the year in which Eligible NZEP Investment is recorded as in-service, Rate Base shall be calculated using actual beginning and end of month balances for GP, ARD, and ADIT balances.

PTRR The pre-tax rate of return shall be the after-tax weighted average cost of capital established by the Department in the Company's most recent base distribution rate case, adjusted to a pre-tax basis by using currently effective federal and state income tax rates applicable to the period for which the NZEP Revenue Requirement is calculated.

DEPR The annual depreciation expense associated with the average annual cumulative Eligible NZEP Investments placed into service through the end of the calendar year prior to the Recovery Year. For the year during which the Eligible NZEP Investment is placed into service, the Company shall calculate depreciation expense for use in the NZEP Revenue Requirement by: (1) dividing the annual depreciation accrual rates, determined in the Company's most recent base distribution rate case, and any allowable accelerated depreciation accrual rates, or at rates approved by the Department, by 12; and (2) applying the resulting rate to the average monthly plant balances during the year. Depreciation expense for subsequent years may be calculated based on the average of the beginning and end of year plant balances.

PTE The property taxes calculated based on Eligible NZEP Investments multiplied by the Property Tax Rate as defined in Section 2.10. Property taxes will be excluded in the NZEP Revenue Requirement in the first Recovery Year following the NZEP Investment Year in which the eligible taxable plant went into service. Property

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taxes will be included in the NZEP Revenue Requirement beginning in the second Recovery Year at 50% of the annual property tax amount. In subsequent years, the NZEP Revenue Requirement will reflect a full year of property taxes.

O&M The Allowed O&M Expense as defined in Section 2.1.

GP The cumulative Gross Plant Investments, or capitalized costs of Eligible NZEP Investments recorded on the Company's books for Eligible NZEP Projects. Actual capitalized cost of Eligible NZEP Projects shall include applicable overhead and burden costs subject to the test provided in Section 4.0.

ARD The Accumulated Reserve for Depreciation, including cost of removal, associated with cumulative Eligible NZEP Investments as of the end of the respective NZEP Investment Year. For the year in which the Eligible NZEP Investment was placed into service, the ARD will be determined on a monthly basis. The ARD for subsequent years shall be calculated based upon the average of the beginning and ending calendar year balances.

ADIT The Accumulated Deferred Income Taxes associated with cumulative Eligible NZEP Investments as of the end of the respective NZEP Investment Year. For the year in which the Eligible NZEP Investment was placed into service, the ADIT will be determined on a monthly basis. The ADIT for subsequent years shall be calculated based upon the average of the beginning and ending calendar year balances.

A:TPvols Forecasted annual throughput volumes for each rate class grouping, inclusive of all firm sales and transportation throughput.

3.2 Request for NZEPFs

The Company shall submit annually to the Department its proposed NZEPFs by July 1 to become effective for usage on and after November 1.

3.3 Application of NZEPFs on Customer Bills

The NZEPF ($/therm) for each rate class grouping shall be calculated to the nearest hundredth of a cent per unit and will be applied to each customer's monthly firm sales and firm transportation volumes.

4.0 OVERHEAD AND BURDEN ADJUSTMENTS

For purposes of NZEP calculations, the actual overhead and burdens shall be reduced to the extent that actual O&M overhead and burdens in a given year are less than the amount included

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in base distribution rates as determined in its most recent base distribution rate case. Such reduction shall be the difference between the actual O&M overhead and burdens and the amount included in base distribution rates. The Company shall determine whether such reduction is required for all reconciling mechanisms that require such a determination once each year, and the determination shall be included in the Company's annual Gas System Enhancement Reconciliation Adjustment Factor filing. In addition, the percentage of capitalized overhead and burdens assigned to Eligible NZEP Projects shall be set equal to the ratio of NZEP to non-NZEP direct costs in any given year.

5.0 FILINGS WITH THE DEPARTMENT

5.1 NZEP Term Filing

The first three-year short-term investment plan will apply to Eligible NZEP Projects included in the Company's NZEP approved in D.P.U. 20-80, for the NZEP Investment Years 2023 through 2025 (first term). The Company shall submit a subsequent NZEP term filing including the next three-year investment plan for NZEP Investment Years 2026 through 2028 (second term) and further terms on a three-year cycle thereafter.

5.2 Annual NZEP Cost Recovery Filing

The annual NZEP cost recovery filing shall be submitted to the Department by July 1 and include, but not be limited to:

(1) A description of the project activities undertaken and completed in the prior year as part of the NZEP most recently approved by the Department;

(2) Project authorizations and documentation for Eligible NZEP Investments, demonstrating the capital investment recorded as in-service during the prior NZEP Investment Year and Allowed O&M Expense, with narrative providing justification that the costs meet the cost recovery eligibility requirements in Section 1.0;

(3) Supporting information demonstrating that the costs sought for recovery meet the criteria for Eligible NZEP Projects and that the costs presented for recovery are reasonable and prudently incurred;

(4) Any cost variances as defined in the Company's capital authorization policies;

(5) A demonstration that the NZEP Revenue Requirement(s) are calculated appropriately;

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(6) A reconciliation of the amount recoverable through prior NZEPFs, as appropriate;

(7) A demonstration that the proposed NZEPFs are calculated appropriately; and

(8) Bill impacts.

This information shall also be included in the Term Report indicated below.

5.3 Net Zero Enablement Plan Annual Notice

The Net Zero Enablement Plan Annual Notice shall be submitted to the Department by April 1 of each year in the first term (2023 through 2025). This informational notice shall list the Net Zero Project categories and/or any projects the Company expects to undertake in the upcoming calendar year.

5.4 Net Zero Enablement Plan Term Report

The Net Zero Enablement Plan Term Report shall be submitted to the Department by July 1, 2026 following the completion of the three-year investment plan for 2023 through 2025.

APPENDIX B

SUMMARY OF RELEVANT DEPARTMENT AUTHORITY

Pursuant to G.L. c. 164, §76, the Department has "general supervision of all gas and electric companies" and is directed to make all necessary examinations of the companies to be informed of the condition of the properties and the manner in which they are conducted. Additionally, pursuant to M.G.L. c. 164, Section 94, the Department has broad authority to design and set rates that gas companies may collect.[84]

A. Distribution Charges

Distribution charges recover the cost of delivering natural gas through the intrastate gas pipeline system to customers. Rates have traditionally been established to allow gas companies to support their obligation to provide safe and reliable service at the lowest cost to their existing customers. Gas infrastructure must be used and useful for customers. The Department is not compelled to use any particular method to establish rates, provided that the end result is neither excessive nor confiscatory (i.e., deprives a distribution company of the opportunity to realize a fair and reasonable return on its investment).[85]

3. Cost of Service and Rate of Return

The Department traditionally has relied on cost of service and rate of return regulation to establish just and reasonable rates. Cost of service and rate of return regulation permits companies to charge rates which allow them (1) to recover prudently incurred investment and operating expenses, and (2) a reasonable opportunity to earn a fair return on investment.

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84 See Boston Real Estate Board v. Department of Public Utilities, 334 Mass. 477, 485 (1956).

85 Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, at 19 (1978).

Under cost of service and rate of return regulation, rates are set in a base rate proceeding and generally are not adjusted until a gas company's next rate case. The Department must approach the setting of rates and charges in a manner that: (1) meets their statutory obligations under G.L. c. 164, § 94, to ensure rates that are just and reasonable, not unjustly discriminatory, or unduly preferential; and (2) is consistent with long-standing ratemaking principles, including fairness, equity, and continuity.

2. Performance Based Ratemaking

Although the Department traditionally has relied on cost of service/rate of return regulation to establish just and reasonable rates, the Department has authorized electric and gas distribution companies subject to the Department's jurisdiction to operate under Performance Based Ratemaking ("PBR") Plans.[86]

Rates established pursuant to a PBR plan must meet the same traditional goals of safe, reliable, and least-cost energy service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation, but also allow for annual rate adjustments in between rate cases to address changing industry dynamics.

Specifically, the Department has recognized the fundamental evolution taking place in the natural gas local distribution industry in Massachusetts. This evolution has been driven, in large part, by two primary factors (1) the need to address climate change; and (2) evolving safety standards, practices, protocols, and procedures, to enhance safety and reliability of the natural gas distribution system.[87] To that end, the Department has approved PBR Plans for gas companies that allow them to best meet their public service obligations for providing safe, reliable, and least-

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[86] See e.g., D.P.U. 20-120; D.P.U. 19-120; D.P.U. 17-05; D.T.E. 05-85; D.T.E. 05-27; D.T.E. 03-40; D.T.E. 01-56; D.T.E. 01-50; D.T.E. 99-47, at 4-14.

[87] NSTAR Electric Company d/b/a Eversource Energy, D.P.U. 17-05 at 373-374 (2017).

cost service to customers as well as to ensure that the Commonwealth's emission reduction and pipeline safety goals are met.

B. Supplier Charges

The supplier charge is associated with the supply of gas; these costs are recovered through the Cost of Gas Adjustment ("CGA") charge, on a dollar per unit consumed basis. Additionally, following Department review and approval, the charges are updated every six months for peak or off-peak pricing.[88] There are two components to supplier charges: commodity and transportation. Costs incurred by the LDCs for the purchase, storage, and interstate transportation of gas (referred to as gas supply costs) are currently recovered via the CGA on a dollar-for-dollar basis.[89] That is, LDCs do not profit on the gas commodity component of a gas bill, and the cost of gas is a straight pass-through.[90] A gas company has a statutory obligation to serve its customers in an efficient and cost-effective manner.[91] Where it does so, a gas company is entitled to an opportunity to recover its legitimately-incurred gas costs.[92]

Gas transportation is procured through short-term and long-term contracts from interstate gas pipeline companies. Rates for long-term contracts with interstate gas pipeline companies are regulated by the Federal Energy Regulatory Commission ("FERC"). Although FERC regulates the rates of these contracts, the contracts must be submitted to the Department for review and approval. The long-term contract must be in the public interest and the LDC must demonstrate the acquisition (1) is consistent with the company's portfolio objectives and (2) compares

88 220 CMR 6.00 et. seq.

89 See 220 C.M.R. §6.00.

90 Cost of Gas Adjustment Clause, D.T.E. 01-49 et seq., at 4 (2001).

91 See G.L. c. 164, §691.

92 220 C.M.R. §6.00 et seq.

favorably to the range of alternative options reasonably available to the company at the time of the acquisition or contract renegotiation.[93] Additionally, the Department reviews the contract to ensure it is consistent with the Global Warming Solutions Act by reducing GHG emissions.[94]

C. Forecast and Supply Plans

The LDCs must submit a five-year forecast and supply plan ("F&SP") every two years to the Department for review and approval.[95] The Department's review of a gas company's process for identifying and evaluating resources needed to provide safe and reliable supply to customers focuses on whether the company: (1) has a process for compiling a comprehensive array of resource options – including pipeline supplies, supplemental supplies, energy efficiency, and other resources; (2) has established appropriate criteria for screening and comparing resources within a particular supply category; (3) has a mechanism in place for comparing all resources, including energy efficiency, on an equal basis, i.e., across resource categories; and (4) has a process that, as a whole, enables the company to achieve an adequate, least-cost supply plan.[96]

The Department's review of adequacy includes a review of reliability, which is a necessary element of the supply plan. To establish adequacy, a gas company must demonstrate that it has an identified set of resources that meets its projected sendout under a reasonable range of contingencies.[97] Supply plans must provide for reliable supply during normal periods and peak demand periods. If a company cannot establish that it has an identified set of resources that meets sendout requirements under a reasonable set of contingencies, the company must demonstrate that

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93 Boston Gas Company d/b/a National Grid, D.P.U. 20-137, at 2-3 (2021).

94 Id. at 27.

95 M.G.L. c. 164, §69I.

96 See, Fitchburg Gas and Electric Light Company d/b/a Unitil, D.P.U. 21-10, at 18 (2022).

97 Id. at 19.

it has an action plan that meets projected sendout in the event that the identified resources will not be available when expected.[98]

Lastly, the Department reviews a gas company's five-year supply plan to determine whether it minimizes cost subject to trade-offs with adequacy.[99] 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.[100] As part of this review, the Department requires gas companies to show, at a minimum, that they have completed comprehensive cost studies comparing the costs of a reasonable range of practical alternatives prior to selection of major new resources for their supply plans.[101]

D. Distribution Adjustment Charges

Distribution Adjustment Charges cover the costs of various program that are allowed to be recovered outside of base rates, including the costs of energy efficiency and the Gas System Enhancement Program ("GSEP").

1. Energy Efficiency

The gas (and electric) Program Administrators ("PAs") are required by statute and Department precedent to acquire all available cost-effective energy efficiency ("EE") and demand reduction resources in an integrated and coordinated statewide manner that achieves the GHG emissions reduction goals, is sustainable, appropriately sensitive to customer bill impacts, minimizes administrative costs, and utilizes competitive procurement.

98 Id.

99 Id.

100 Id.

101 Id.

EE costs include: (1) program implementation costs; (2) program participant costs; and (3) performance incentives. Program implementation costs include all costs incurred by a PA to implement its energy efficiency programs, including, but not limited to: (a) program planning and administration; (b) marketing and advertising; (c) program participant incentives; (d) sales, technical assistance, and training ("STAT"); and (e) evaluation and market research.

Program participant costs must include all expenses incurred by a program participant as a result of its participation in an energy efficiency program, including, but not limited to: (a) the net cost of energy efficient equipment; (b) the cost to plan for and install energy efficient equipment; and (c) the cost of energy efficiency services.

The inclusion of performance incentives as part of the Plan is expressly mandated by the GCA, which specifies that a three-year energy efficiency plan "shall include…a proposed mechanism which provides performance incentives to the companies based on their success in meeting or exceeding the goals in the plan[.]"

EE Plans are updated and approved every 3 years. The Program Administrators' most recent Three-Year Plan was approved, with modifications, on January 31, 2022 for the 2022-2024 plan term.[102]

2. GSEP

G.L. c. 164, Section 145 permits gas distribution companies to, in the interest of public safety and to reduce lost and unaccounted for ("LAUF") natural gas, submit to the Department annual plans to repair or replace aging or leaking natural gas infrastructure. Any plan filed with the Department shall include, but not be limited to the following: (i) eligible infrastructure replacement of mains, services, meter sets, and other ancillary facilities composed of non-

[102] Petitions of Program Administrators for Approval by the Department of Public Utilities of Three-Year Energy Efficiency Plans for 2022-2024, D.P.U. 21-120 through D.P.U. 21-129 (January 31, 2022).

cathodically protected steel, cast iron, and wrought iron, prioritized to implement the federal gas distribution pipeline integrity management plan annually submitted to the Department; (ii) an anticipated timeline for the completion of each project; (iii) the estimated cost of each project; (iv) rate change requests; (v) a description of customer costs and benefits under the plan; (vi) the relocations, where practical, of a meter located inside of a structure to the outside of said structure for the purpose of improving public safety; and (vii) any other information the Department considers necessary to evaluate the plan.[103]

The Department may modify a plan prior to approval at the request of a gas company or make other modifications to a plan as a condition of approval.[104] The Department is required to consider the costs and benefits of the plan including, but not limited to, impacts on ratepayers, reductions of LAUF natural gas through a reduction in natural gas system leaks, and improvements to public safety.[105] The Department is also required to give priority to plans narrowly tailored to addressing leak-prone infrastructure most immediately in need of replacement.[106] If a plan complies with Section 145, and the Department determines that it reasonably accelerates eligible infrastructure replacement and provides benefits to customers, the Department must preliminarily accept the plan either in whole or in part.[107] The gas company may begin recovering the estimated plan revenue requirement beginning on May 1 of the year following submission of the plan.[108]

Subsequently, on or before May 1 of each year, the gas company must file final project documentation for construction completed the previous calendar year in order to demonstrate

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103 G.L. c. 164, §145(c) as amended by Acts of 2021, Chapter 8, Section 88; Fitchburg Gas and Electric Light Company d/b/a Unitil, D.P.U. 20-GSEP-01, at 4-5 (April 29, 2021).

104 Section 145(d); D.P.U. 20-GSEP-01, at 5.

105 Id.

106 Id.

107 Section 145(e); D.P.U. 20-GSEP-01, at 5.

108 Id.

substantial compliance with the plan and to demonstrate that the costs were reasonably and prudently incurred.[109] In reviewing the proposed rate change submitted each May 1, the Department shall determine whether the gas company has over- or under-collected its requested revenue requirement. If the Department determines that any of the costs were not reasonable or prudently incurred, the Department shall disallow the costs and direct the gas company to refund the full value of the costs charged to ratepayers with the appropriate carrying charges (interest) on the over-collected amounts.[110]

If the Department determines that any of the costs were not in compliance with the approved GSEP, the Department shall disallow the costs from the cost recovery mechanism and shall direct the gas company to refund the full value of the costs charged to ratepayers with the appropriate carrying charges (interest) on the over-collected amounts.[111] The Department also may discontinue the replacement program and require a gas company to refund any costs charged to customers due to failure to substantially comply with a plan or failure to reasonably and prudently manage project costs.[112]

Annual changes in the revenue requirement eligible for recovery pursuant to the plan shall not exceed (i) 1.5 percent of the gas company's most recent calendar year total firm revenues, including gas revenues attributable to sales and transportation customers, or (ii) an amount determined by the Department that is greater than 1.5 percent of the gas company's most recent calendar year total firm revenues, including gas revenues attributable to sales and transportation customers.[113] The allowable amount of the increase in any given year may not exceed 3 percent of

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109 Section 145(f); D.P.U. 20-GSEP-01, at 6.

110 Section 145(g); D.P.U. 20-GSEP-01, at 6.

111 Id.

112 Section 145(h); D.P.U. 20-GSEP-01, at 6.

113 Section 145(f); D.P.U. 20-GSEP-01, at 6-7.

the product of (1) the historical average cost of gas per therm from the period starting in 2013 and ending with the most recent year that actual data is available, and (2) the average of weather normalized sales from the period starting in 2013 and ending with the most recent year that actual data is available.[114] The portion of the current year revenue requirement not currently recoverable due to application of the GSEP Cap may be deferred for recovery in future periods.

E. Revenue Decoupling

The purpose of the Revenue Decoupling Adjustment Clause ("RDAC") is to establish procedures that allows a gas company to adjust, on a semi-annual basis, its rates for firm gas sales and firm transportation service in order to reconcile Actual Base Revenue per Customer with Benchmark Base Revenue per Customer.[115] The Company's RDAC eliminates the link between customer sales and Company earnings in order to align the interests of the Company and customers with respect to lowering customer usage.

F. Gas Safety

The LDCs are required to comply with both state and federal requirements governing the safe and reliable distribution of natural gas in the Commonwealth. G.L. c. 164, §105A governs the storage, transportation and distribution of natural gas. In addition, every gas piping system and liquefied petroleum gas plant in Massachusetts shall be constructed, operated, and maintained, except as otherwise provided in 220 C.M.R. 101.00, in compliance with federal pipeline safety standards as set forth in 49 C.F.R. Part 192 -- Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards (MFS Standards). In addition, each operator of pipeline facilities used for the transportation of natural gas or hazardous liquids and each operator of

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114 See D.P.U. 18-GSEP-04.

115 See Revenue Decoupling Adjustment Factor Filing Procedures, D.P.U. 21-RDAF-01 Hearing Officer Memorandum (Jan. 27, 2021); NSTAR Gas Company d/b/a Eversource Energy, D.P.U. 21-15.

liquefied petroleum gas facilities shall comply with the provisions of 49 CFR Parts 40 and 199. 220 C.M.R. 101.01.

The Commonwealth's gas safety requirements must be consistent, although may exceed, minimum requirements established by these federal standards, governed by the United States Department of Transportation ("DOT"). Specifically, the DOT's Pipeline and Hazardous Materials Safety Administration ("PHMSA") promulgates regulations applicable to the LDCs. Of note, PHMSA's distribution integrity management program ("DIMP") regulations require the Company to evaluate its distribution system, assess risks to the system, and develop methods to reduce such risk.[116]

G. Service Quality

Pursuant to G.L. c. 164 §1E, the Department first established service quality ("SQ") guidelines for electric and gas distribution companies in 2001. The SQ Guidelines were subsequently amended in D.P.U. 04-116-C and D.P.U. 12-120-D. The purpose of the SQ Guidelines is to ensure that every gas and electric distribution company provides adequate service to customers in the Commonwealth.[117] The LDCs annually report on two categories of metrics: (1) Reliability and Safety Performance Metrics and (2) Customer Service and Satisfaction Performance Metrics.

The LDCs are required to report on gas safety. Each LDC reports on Odor Call response. The LDCs are required to respond to 97% of all Class I and Class II Odor Calls within 60 minutes.[118] A Class I Odor Call is defined as "calls involving a strong odor of gas throughout a

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[116] See 49 C.F.R. § 192.1007.

[117] SQ Guidelines, §1.A.

[118] Id., §4.B.

household or outdoor area, or a severe odor from a particular area." A Class II Odor Call is defined as "calls involving an occasional or slight odor of gas at an appliance."[119]

For Customer Service and Satisfaction Performance Metrics, the LDCs report on service appointments kept as scheduled; complaints to the Consumer Division; and customer credit cases.[120] Compliance with the Odor Call Response, service appointments, and customer complaints and credit cases metrics are subject to possible revenue penalties.[121]

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119 Id., §1.B.

120 Id., §2.

121 Id., §§4.B, 5.B.2.