COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

BOSTON GAS COMPANY D/B/A NATIONAL GRID

D.P.U. 26-50

DIRECT TESTIMONY OF

NICHOLAS ONYSZCZAK

On behalf of

THE MASSACHUSETTS OFFICE OF THE ATTORNEY GENERAL

May 8, 2026

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I. INTRODUCTION

Q. Mr. Onyszczak, please state your name and business address.

A. My name is Nicholas Onyszczak. My business address is Wired Group, P.O. Box 620756, Littleton, CO 80162.

Q. What is your occupation?

A. I am a gas distribution utility industry consultant specializing in operations, capital investment planning, emissions reduction, leak detection and repair, asset management, and reliability performance. I frequently work with Wired Group to support client projects.

Q. On whose behalf are you submitting testimony?

A. I am testifying on behalf of the Office of the Attorney General ("AGO").

Q. Please describe your work experience and educational background.

A. I have 25 years of distribution utility operations experience, primarily for gas distribution utilities, both for-profit and non-profit. From 2001–2006, I was employed in roles of increasing responsibility for municipal utilities in Oak Lawn, IL, New Lisbon, WI, and Lockport, IL. I was then employed by Nicor Gas from 2006 to 2015 in a series of positions, managing pressure systems, new business development, Department of Transportation ("DOT") relocation projects, and cast-iron and bare-steel pipe replacement programs. I was next employed by Xcel Energy as a Gas Operations Manager in the Denver, Colorado area, and then as Senior Project Manager for Methane Emissions Reduction, leading advanced leak detection and repair programs, from 2022–

2024. After a brief time at the Oregon Public Utilities Commission as a Senior Energy Analyst/Engineer, I transitioned to full-time independent consulting work in 2025.

I hold a bachelor's degree in economics from the University of Toledo and a Master of Public Administration degree from the University of Kansas. I am currently pursuing a Master of Arts degree in Economics at New Mexico State University (expected 2027) with a focus on Public Utility Policy and Regulation.

Q. Have you appeared before the Department previously?

A. Yes. I testified on behalf of the AGO in D.P.U. 25-170, The Berkshire Gas Company's application for approval of an increase in base distribution rates and a performance-based ratemaking plan, and D.P.U. 24-134, NSTAR Gas Company's performance-based revenue adjustment filing. I also helped develop the AGO's comments submitted in D.P.U. 24-53, the Department's investigation into service quality standards for electric distribution companies and local gas distribution companies. My curriculum vitae is attached as Exhibit AG-WG-2.

Q. What is the purpose of your testimony in this proceeding?

A. I have been retained by the AGO to examine Boston Gas Company's, d/b/a National Grid ("Company" or "National Grid") capital spending including recovery on investment in the Mid-Cape Main Replacement Project, performance-based ratemaking ("PBR") metrics, the Company's Gas Safety, Reliability, and Compliance programs, the Non-Pipeline Alternatives ("NPA") Share Savings Mechanism, and the Company's Investigation into Third-Party Contractor Invoicing.

Q. Please provide a preview of your testimony.

A. This testimony outlines recommendations for the Department's consideration and is organized in five sections.

First, I analyze the Company's proposed capital spending and recommend the following: cost disallowances and reductions in the Company's historical capital projects, totaling $67.158 million; the continued disallowance of the Company's proposal to include $123.13 million for the Mid-Cape Main Replacement Project in rate base to earn a return on its investment; and rejection of the Company's proposal to roll in liquified natural gas ("LNG") spending during the PBR term.

Second, I analyze the Company's proposed PRB scorecard metrics and recommend revisions to maximize customer benefits.

Third, I recommend that the Department reject the Company's proposed Gas Safety, Reliability, and Compliance ("GSRC") tracker, approve the capitalization of joint sealing, and I further propose an alternative approach to the Company's proposed Research, Development, and Demonstration program.

Fourth, I recommend modifications to the Company's NPA Cost Sharing Mechanism.

Lastly, I review the findings and proposed remedies regarding the Company's Third-Party Contractor Billing Investigation and recommend additional exclusions from rate base and increased customer refunds based on corrected calculations.

Q. Please provide the customer perspective you ask the Department to consider as it reviews this testimony.

A. The cost of the energy transition is already impacting Massachusetts' consumers and economy, and the Commonwealth has appropriately recognized the need to prioritize electric and gas affordability as this transition progresses.[1] As shown in Figure 1 below, while electric residential rates in Massachusetts have grown at a compound annual growth rate ("CAGR") of 8.1 percent from 2020–2025, gas residential rates have grown at a CAGR of 11.2 percent over the same period.[2] Gas rate increases, like electric rate increases, are driven in large part by increases in distribution capital expenditures. While some increases in distribution capital spending may be warranted, my testimony before the Department in multiple proceedings has identified instances of unnecessary, premature, and cost-ineffective capital projects and programs.[3] I have attributed these significant increases in capital spending in large part to practices such as capital trackers,[4]

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[1] Letter from Governor Healy to the Legislature, filed in House Docket No. 4707 (May 13, 2025); *Gas and Electric Delivery Charges and Bill Redesign*, D.P.U. 25-200, Vote and Order Opening Inquiry, at 1 (Dec. 15, 2025); *see also* Average retail price of electricity, monthly, EIA, https://www.eia.gov/electricity/data/browser/ (select pre-generated report 5.6; filter for Massachusetts; and select the appropriate time series) (showing an average price of 25.91 cents/kWh in November 2025, up from 17.69 cents/kWh in November 2020) and *Massachusetts Price of Natural Gas Delivered to Residential Customers*, EIA, https://www.eia.gov/dnav/ng/hist/n3010ma3A.htm (showing an average price of $21.80/thousand cubic feet in 2024, up from $14.71/thousand cubic feet in 2020).

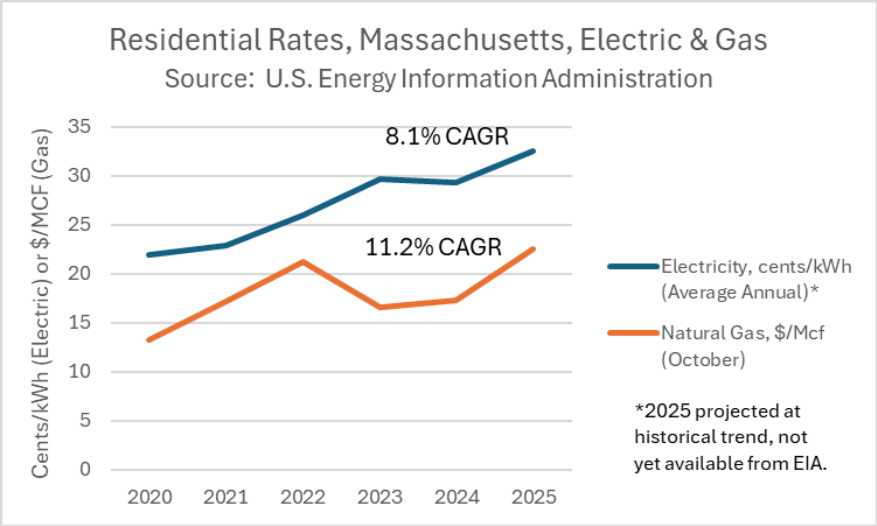
[2] Average retail price of electricity, monthly, EIA, https://www.eia.gov/electricity/data/browser/ (select pre-generated report 5.6; filter for Massachusetts; and appropriate select the time series); Massachusetts Price of Natural Gas Delivered to Residential Customers, EIA, https://www.eia.gov/dnav/ng/hist/n3010ma3A.htm.

[3] *See*, *e.g.*, *Eversource Energy*, D.P.U. 24-134, Exh. AG-WG-1; and *Berkshire Gas Company*, D.P.U. 25-170, Exh. AG-WG-1.

[4] *Id*.

and my Wired Group colleagues and I have observed similar relationships between ratemaking and suboptimal capital spending in other states that employ alternative ratemaking practices.

Figure 1: Residential Rates, Massachusetts Electric and Gas Utilities, 2020-2025.[5]



While inflation and commodity costs also play a role in rate increases, such costs are largely beyond the Department's control. It is therefore imperative that the Department address costs within its control. Accordingly, my recommendations in this case are designed in large part to support increases in capital spending governance and restraint to utility capital spending decisions generally, and to National Grid's capital spending decisions specifically. In following these recommendations, the Department can help ensure that the Company puts capital to its highest and best use, just as businesses that are subject to competition and market forces are forced to do.

[5] Average retail price of electricity, monthly, EIA (for Massachusetts), https://www.eia.gov/electricity/data/browser/; *Massachusetts Price of Natural Gas Delivered to Residential Customers*, EIA, https://www.eia.gov/dnav/ng/hist/n3010ma3A.htm.

II. RECOMMENDED COST DISALLOWANCES IN THE COMPANY'S CAPITAL ADDITIONS

Q. Please introduce this section of testimony.

A. This section is a review of the Company's capital expenditure information. My testimony will first review the Company's capital spending from January 1, 2021, through March 31, 2025, and identify any investments that were not reasonably and prudently incurred. Then, I will discuss the Company's proposal to include post-test-year capital investment in rate base. Third, I will consider the Company's request to be allowed to earn a return on its investment in the Mid-Cape Main Replacement Project, which the Department previously disallowed. Finally, I recommend denying the Company's request to allow a roll-in of LNG spending during the PBR term. In sum, I recommend that the Department:

- Disallow $67,158,010 of the Company's historical capital spending, including:
  - $11,767,447 of the Company's revenue-producing project spending.
  - $22,092,145 of the Company's LNG plant additions.
  - $12,287,630 of the Company's main replacements.
  - $19,407,325 of the Company's farm tap replacements and upgrades.
  - $1,603,463 of the Company's reimbursable DOT projects.
- Exclude post-test-year spending from rate base in this case and defer it to a future proceeding.
- Affirm the Department's decision in 20-120, barring the Company from earning a return on the Mid-Cape Main Replacement Project.
- Deny the Company's request for permission to roll-in LNG costs during the PBR term.

Historical Capital Spending

Q. Please discuss the Company's historical capital spending proposed for inclusion in rate base.

A. The Company has provided exhibits that summarize numerous projects, cost estimates, final project costs, and variances for projects completed January 1, 2021, through March 31, 2025.[6] The spending is categorized by various project types, with supporting exhibits to support project approvals, changes in authorized costs, and variance analysis at project closing.[7] I have reviewed these exhibits and identified several areas of concern. Specifically, thirty-seven of the Company's revenue-producing projects have a negative post-construction internal rate of return ("IRR"), the Company invested in main replacements to increase capacity without supporting the need for additional capacity, replaced farm taps at an unreasonable cost, included costs that will be reimbursed in rate base, and made several imprudent LNG investments.

Revenue-Producing Projects with Negative IRRs

Q. What are your recommendations regarding revenue-producing projects?

A. I recommend that the Department disallow $11,767,447 in capital investment for revenue-producing projects. This figure is the amount by which the revenue-producing projects with negative IRRs exceeded the estimates used to calculate the initial IRR and contribution in aid of construction ("CIAC"). Disallowance of these projects will protect ratepayers from bearing the

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6 Exhs. NG-CAPEX-3; NG-CAPEX-4.

7 Exhs. NG-CAPEX-3A; NG-CAPEX-4A.

costs of projects that do not provide a benefit to them. The cost of these projects should be borne by the parties who benefited from them, not by all ratepayers.

Q. Please discuss the issue of revenue-producing projects with negative IRRs.

A. Revenue-producing projects provide service to new customers or expand service to existing customers. The Company calculates an IRR for these projects to determine whether the investment is worthwhile and will generate sufficient future revenue to cover the project's costs.[8] If estimated future revenues are insufficient to cover the project's estimated costs, the Company calculates a CIAC and charges it to the customer requesting the project. CIACs offset the portion of construction costs that cause the project to deliver a negative IRR.

Here, the Company constructed thirty-seven revenue-producing projects that had post-construction IRRs that were negative, resulting from actual construction costs exceeding pre-construction estimates. In deciding to move forward with these thirty-seven projects, the Company calculated an IRR and CIAC based on the estimated construction costs and, when necessary, collected a CIAC payment based on those estimates. However, when actual final construction costs exceeded the estimated costs, the Company chose not to recover the additional costs from the customers benefiting from the projects. The Company should have recalculated CIAC based on the actual construction costs and then charged those customers for the additional CIAC. Instead, the Company is requesting that those additional costs be included in rate base and be paid for by all customers.

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[8] Exh. AG-3-83.

Q. What is an IRR, and how does it affect the cost of service?

A. An IRR measures the return of an investment to expand gas service, based on the Company's weighted cost of capital as defined in the Company's last rate case.[9] Essentially, the IRR is how the Company determines if a revenue-producing project provides benefits to all customers or forces existing customers to subsidize new customers. A positive IRR indicates that the capital addition reduces the net cost of service for all customers, and a project with a positive IRR contributes more to revenue than it adds to the revenue requirement, thus reducing the cost of service for all customers. A project with a negative IRR, however, increases the overall cost of the distribution system in excess of the new revenue it generates, thereby increasing the costs of service for all customers.

Q. Have you reviewed the Company's revenue-producing projects?

A. Yes, I reviewed the Company's revenue-producing projects, and I identified thirty-seven projects that had a negative IRR based on actual construction costs, and I reviewed the Company's variance documentation.[10] The projects with negative IRRs were, on average, 179 percent above the estimate, nearly tripling the estimated construction costs.[11] The Company is including these additional costs in the total investment it is requesting to be included in rate base in this case.

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9 *National Grid*, D.P.U. 20-120, Exh. NG-RRP-2 (C) Recalc.

10 Exhs. NG-CAPEX-3; NG-CAPEX-3A.

11 Variance of $11,767,447 divided by estimated costs of $6,553,766 equals 179 percent.

Q. How can the Company recover these additional construction costs if not through inclusion in rate base and its revenue requirement?

A. When a revenue-producing project's actual costs exceed the estimated construction costs such that the IRR is negative, the Company can seek to recover those costs from the customer for whom the projects were constructed and who will benefit from those projects. It is not equitable to recover the costs of a project with a negative IRR through the revenue requirement that all ratepayers pay, because all ratepayers do not benefit from these projects that incur costs in excess of the revenue that those projects produce.

Q. Can and should new customers be expected to pay the difference between the estimated and actual costs of construction?

A. Yes. If the revenues from new customers and new customer loads are insufficient to cover the costs required to accommodate their addition, such customers should expect to pay CIACs to offset the difference. The CIAC is calculated and paid based on the project's estimated costs and revenues prior to construction, but if the actual construction cost exceeds the estimate to the extent that the post-construction IRR is negative, the same principle that new gas load revenues must cover the costs should still apply.

The Company's Cost Reimbursement Agreement with customers as part of revenue producing projects clearly states: "The Customer agrees to pay the Company all actual costs incurred by the Company and its contractors in connection with the Project. For the purposes of this Agreement, the Company's 'actual costs' shall include all applicable overheads and adders as well as all taxes

applicable to any of the foregoing charges."[12] This provision makes clear that new customers should pay based on the actual cost, not a preliminary estimate. The Cost Reimbursement Agreement is also clear that upon completion of a project, the Company will reconcile any undercharges and provide the customer with a final bill.[13] The Company, however, has chosen not to rebill customers for an adjusted CIAC amount when actual project costs exceed estimates.[14] Accordingly, I recommend that the Department disallow $11,767,447 in capital investment for revenue-producing projects.

LNG Projects

Q. What is your recommendation regarding LNG project costs?

A. I recommend that the Department disallow $22,092,145 in capital investment for three LNG projects that I have identified as imprudent, premature, or lacking in required analysis alternatives and costs.

Q. What LNG projects have you identified for disallowance, and what are your reasons for recommending disallowance?

A. The first project that I recommend for disallowance is the Everett CNG Station, totaling $4,891,249. This project involved the replacement of a compressed natural gas filling station that serves various customers' fleet vehicles. The filling station was constructed 18 years ago[15] with

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12 Exh. Att. AG-3-11-4, at 2.

13 *Id*.

14 Exh. AG-3-10.

15 Exh. NG-CAPEX-4A, at 1494.

an expected lifespan of 30 years.[16] The Company, however, chose to replace the station with about half of its useful life remaining. The disallowance of this investment will protect ratepayers from bearing the cost of the Company's discretionary decision to replace this station prematurely which resulted in the retirement of an asset with additional expected useful life remaining and the incurring of costs for new assets sooner than necessary.

The second project that I am recommending for disallowance is the Salem LNG Packaged Boiloff Compressor unit. I am recommending that $6,257,690 be disallowed, representing the cost of a temporary unit that the Company installed. The Company was planning to replace the Salem LNG Boiloff Compressor with two new compressors of equal capacity to the existing compressor in order to have redundancy.[17] Prior to that replacement being constructed, however, the existing boiloff compressor developed multiple maintenance issues that caused it to be inoperable and the Company purchased and installed a temporary unit at a cost of $6,257,690.[18] The full replacement project will still be necessary, and this temporary unit is an additional cost beyond that project. The need for the temporary unit could have been avoided had the Company managed the maintenance and replacement of its boiloff compressors prudently. The Company should bear the costs related to temporary measures that were necessary to maintain safe and reliable service due to permanent solutions not being constructed in a timely manner.

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16 Exh. AG-13-32.

17 Exh. NG-CAPEX-4A, at 1326–64.

18 *Id*.

The final project for which I am recommending disallowance is the South Yarmouth LNG Boiloff Compressor. I am recommending that $10,943,206 of this project's costs be disallowed, representing half of the total construction costs. The existing boiloff compressors were replaced without a financial analysis of the costs and benefits of the considered alternatives.[19] The Company has therefore failed to show that the expenditure of over $21 million dollars was prudent. My recommendation to disallow half of the investment, rather than the whole, recognizes that some work was required to address reliability of the existing compressors and the work provided benefits, including increased pressure capabilities and reduced emissions due to tank blow downs provided by the new equipment.

Main Replacements (Non-GSEP)

Q. What is your recommendation regarding main replacements?

A. I recommend that the Department disallow $12,287,630 in capital investment for main replacement projects due to the lack of alternatives considered and the lack of justification for replacements. This amount is the actual construction costs of the nine main replacement projects identified in the chart below.

[19] Exh. NG-CAPEX-4A, at 1448–57.

National Grid Project Number	(Work Order Description) Project Name	Location	Program Category	Total Project Costs Through March 31, 2025	Page Numbers
1070879	18-65 WALNUT RD, HAM	WALNUT RD	Gas Planning - Reliability	$485,572	794–797
1172735	WALNUT RD, HAM	WALNUT RD	Gas Planning - Reliability	$1,006,163	798–800
1207223	N MAIN ST, LEO, MILLET,BUONO,WESTLAND	N MAIN ST	Gas Planning - Reliability	$4,527,190	805–808
1207520	CENTRAL ST, SAU	CENTRAL ST	Gas Planning - Reliability	$1,211,729	809–811
1319427	5-33 CHESTNUT ST, GLO, PROSPECT ST, PLEASANT ST	CHESTNUT ST	Gas Planning - Reliability	$1,338,902	812–815
1375109	CASTLE RD, NAH	CASTLE RD	Gas Planning - Reliability	$1,026,322	820–823
1375114	LYNNWAY, REV, JOHN AV Ext	LYNNWAY	Gas Planning - Reliability	$1,209,228	824–827
1375115	FLINT ST, SAL, MASON, NORTH, ORNE ST	FLINT ST	Gas Planning - Reliability	$1,098,473	828–830
1425291	CASTLE RD, NAH	CASTLE RD	Gas Planning - Reliability	$384,050	831–834

Q. What are your concerns with these projects?

A. The Company did not consider alternatives for these projects, other than pipe replacement, and no cost analysis was conducted for possible alternatives. Further, these projects were presented as reliability projects, yet the Company did not include any evidence of reliability issues in its project documentation or responses to information requests related to these projects.[20] According to the Company, these projects were not growth driven and there is no evidence of increased gas load

[20] Exhs. AG-13-21; AG-13-22; AG-13-23; AG-13-24; AG-13-25; AG-13-26; AG-13-27; AG-13-28.

that would have caused reliability concerns.[21] Additionally, several of the mains that were replaced remained in service following construction demonstrating that they were reliable enough to continue to serve customers.[22]

Farm Tap Upgrades and Replacements

Q. What is your recommendation regarding farm tap upgrades and replacements?

A. I recommend that the Department disallow $19,407,325 in capital investment for farm tap upgrade and replacement projects due to the unreasonable costs incurred by these projects and the lack of alternatives considered.

Q. What are farm taps and why is the Company upgrading and replacing them?

A. Farm taps are service lines that are connected directly to high pressure gas mains. This requires additional pressure regulation at the service tap to reduce the pressure using regulators that are more like those used at regulation stations than at typical distribution services. Farm taps are typically installed to offer service in areas where there are high pressure mains, but no lower pressure distribution mains. The Company has identified farm taps as an elevated risk due to the lack of a third layer of over-pressure protection.[23]

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21 *Id.*

22 Exhs. AG-13-23; AG-13-26; AG-13-27.

23 Exh. AG-19-1.

Q. What are your concerns with the farm tap upgrades and replacements?

A. My concern is that the Company has not fully considered alternatives to replacing or upgrading farm taps. Serving these customers often does not make economic sense considering the costs of upgrading or replacing farm taps, which the Company explains ranges from $30,766 to $145,761 per customer.[24] At this high cost, consideration of alternatives, such as electrification, is critical and should have been included. Further, the risks identified by the Company related to farm taps are not caused by degradation of materials by age or from defective components but instead have existed from the time the Company designed and installed regulators on high pressure facilities without a third layer of over-pressure protection. If the Company has now identified that its previous investments were not made with an adequate level of safety protections, the Company should be held responsible for those costs instead of looking to ratepayers to pay to correct investments for which they have already paid for.

Reimbursable Project Costs

Q. What is your recommendation regarding Reimbursable Project Costs?

A. I recommend that the Department disallow $1,603,463 in capital investment for projects that were constructed due to DOT projects for which the Company is eligible for reimbursement by the State.

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[24] *Id*.

Q. How was the amount of the disallowance calculated?

A. The amount was calculated based on the actual costs[25] of the DOT Reimbursable Projects for which the Company has not yet requested or received reimbursement.[26] These actual costs were multiplied by 50 percent, which is the typical amount of reimbursement that the Company is eligible to receive from the DOT for these types of projects.[27]

Q. Why should these investments be removed from rate base if reimbursement has not yet been requested or received?

A. These projects were completed and in-service prior to March 31, 2025, therefore the Company has had over a year to request reimbursement from DOT. To allow the Company to include these amounts in rate base at this time would increase the revenue requirement throughout the PBR period and would be compounded by the annual PBR adjustment. This is not an appropriate result given that the Company will not bear long-term financial impacts of these costs. Instead, expected reimbursements should be excluded from rate base to incentivize the Company to seek reimbursement in a timely manner and ensure that customers do not bear unnecessary costs.

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25 Exh. NG-CAPEX-4.

26 Exh. AG-19-14.

27 *Id*. I also reviewed the projects for which the Company stated that it has received reimbursement. I confirmed that the reimbursement was reflected in a reduced investment requested for inclusion in rate base.

Post-Test-Year Capital Spending

Q. What is your recommendation regarding the Company's request to include post-test-year plant additions in rate base?

A. I recommend that the Department disallow $94,083,743 in post-test-year plant additions, which represents all capital spending from April 1, 2025, through December 31, 2025.[28]

Q. What are your concerns regarding the Company's post-test-year plant additions?

A. National Grid's request to include post-test-year capital additions is of concern because rate cases are based on a test year to provide a set frame of reference on which to base revenue requirements, as well as allowing for financial information to be presented with ample time for thorough review. The inclusion of post-test-year expenditures in rate base violates both principles. The inclusion of post-test-year plant additions also amplifies the rate increase, thereby impacting affordability beyond what would otherwise occur. Additionally, the inclusion of post-test year capital expenditures incentivizes the Company to accelerate and expand capital investment to increase the rate base that will be used to calculate revenue limits and adjustments during the PBR term. Allowing this inflation of the rate base beyond what would be allowed within traditional ratemaking weakens a PBR plan and may lead to unnecessary or poorly managed spending. Accordingly, I recommend that the Department exclude post-test year plant additions from rate base at this time, and postpone consideration until the Company's next rate case.

[28] Exhs. NG-CAPEX-3-(Corrected)-Supplemental; NG-CAPEX-4-(Corrected)-Supplemental 2.

Mid-Cape Main Replacement Project

Q. What is your recommendation regarding the Mid-Cape Main Replacement Project?

A. I recommend that the Department reaffirm its decision to disallow the Company from earning a rate of return on the Mid-Cape Main Replacement Project by removing the costs from rate base.[29] I further recommend that the Department continue to exclude the Mid-Cape Main Replacement Project from rate base for the life of the asset. Doing so will ensure that the Company bears the financial consequence of its own imprudence, while customers continue to receive safe, reliable service from the replacement infrastructure for which customers are already paying. Indeed, ratepayers should not be required to subsidize the consequences of the Company's own mismanagement, and allowing a return on this investment would reward poor stewardship at customers' direct expense.

The facts underlying this matter are not in dispute. The original Mid-Cape Main required replacement because the National Grid failed to maintain records, construct the original main to required standards, and perform required inspections.[30] Mismanagement by the Company, not ordinary depreciation, nor changed circumstances, nor customer growth, necessitated the replacement of the Mid-Cape Main. The Department correctly drew that line in D.P.U. 20-120, and that decision was well-supported by the record, consistent with the prudency standard, and fair to all parties.

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29 *National Grid*, D.P.U. 20-120, Order, at 163 (Sept. 30, 2021).

30 *Id*. at 161–163.

Q. Please summarize the Mid-Cape Main Replacement Project.

A. The Mid-Cape Main Replacement Project involved the replacement of approximately 18 miles of existing steel pipeline with a new 12-inch steel pipeline with a maximum operating pressure ("MOP") of 200 pounds per square inch gauge ("psig") and a maximum allowable operating pressure ("MAOP") of 270 psig. The then-existing steel pipeline was constructed between 1962 and 2010 and was uprated from 60 psig to 200 psig in 1998.[31] In 2014, following the Company's discovery that it was serving customers at pressures beyond the rated capacity of its installed pressure regulators, the Department's Pipeline Engineering and Safety Division cited the Company for numerous violations of state and federal pipeline safety regulations.[32] These violations included: (1) nine joint welds that were not considered acceptable under American Petroleum Institute standards; (2) recorded pipe diameter size records that varied from the actual size of the mains in the ground; (3) incomplete pressure test records from the time of the 1998 uprate; and (4) inadequately rated customer service regulators with a maximum MAOP of 125 psig on the pipeline.[33] As a result of these deficiencies, and to maintain the reliability and safety of its system, the Company reduced the operating pressure on the pipeline from 200 psig to 124 psig or lower in mid-2014.[34] The Company also instituted a moratorium on new services and on the growth of existing services in its eastern Cape Cod service territory due to reduced system capacity resulting

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31 Exh. Att. AG-3-86-1, at 8.

32 *Id*.

33 *Id*.

34 *National Grid*, D.P.U. 20-120, Exh. Att. AG-5-5-2, at 7.

from lower operating pressure on the Mid-Cape Main.[35] The Company subsequently received approval to construct a replacement for the existing Mid-Cape Main to provide safe and reliable service to its customers in the area and to lift the moratorium.[36] The replacement project was completed in 2020.

Q. Please summarize your understanding of the Department's ruling regarding the Mid-Cape Main Replacement Project in D.P.U. 20-120.

A. The Department found that the costs for the Mid-Cape Main Replacement Project had been prudently incurred, and that the project was used and useful.[37] However, the Department also found that the Mid-Cape Main was in poor condition and prematurely retired due to the Company's mismanagement.[38] On the basis of these findings, the Department allowed the Company to recover the cost of the Mid-Cape Main Replacement Project, but disallowed the Company from earning a return on the investment and removed it from rate base.[39] In response to the Company's subsequent request for clarification, the Department reiterated that the poor condition and early retirement of the main were due to the Company's mismanagement and that the project's costs could have been avoided had the main been properly maintained.[40] Additionally, the Department clarified that this decision applied to all costs of the Mid-Cape Replacement Main Project, not just

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35 *Id*.

36 Exhs. Att. AG-3-86-24; NG-CAPEX-1, at 29–33.

37 *National Grid*, D.P.U. 20-120, Order, at 161 (Sep. 30, 2021).

38 *Id*. at 162.

39 *Id*.

40 *National Grid*, D.P.U. 20-120-B, Order, at 7

those incurred during the test year, and that it had not set a deadline for the disallowance, nor had it intended to.[41] The Department also concluded that the Company was not precluded from arguing in its next distribution base rate case that the penalty incurred during the PBR plan sufficiently holds the Company accountable for the increased costs resulting from the condition of the main.[42]

Q. With respect to the Mid-Cape Main Replacement Project, what is the Company requesting in this case?

A. The Company is asking the Department to approve the Company's recovery of the return on the value of the Mid-Cape Main Replacement Project that remains on the Company's books as of December 1, 2026.[43] This request raises the issue as to whether the Company has incurred a sufficient financial penalty. The Company states that it has incurred a "penalty" of $50.88 million from not earning a return on its investment during the five-year PBR plan approved in D.P.U. 20-120.[44] The Company estimates that it will incur approximately $9 million in additional annual "penalties" during the proposed PBR term if the Department upholds the disallowance.[45] The Company also notes that it paid a $1.25 million civil penalty for its violations of pipeline safety standards in NOPV D.P.U. 15-PL-04 related to the Mid-Cape Main.

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41 *Id*. at 7–8.

42 *National Grid*, D.P.U. 20-120-B, Order, at 8.

43 Exh. NG-CAPEX-1, at 28–29.

44 *Id*. at 35.

45 *Id*.

Q. What is your opinion on the Company's position that the $50.88 million penalty incurred during the past five years of the PBR Plan is sufficient to hold the Company responsible for any costs that were incurred because of the condition of the Mid-Cape Main?

A. The Company's position is not reasonable and is based on several flawed premises. The fine issued in NOPV D.P.U. 15-PL-04 was the penalty for National Grid's multiple violations of various pipeline safety regulations. Disallowance of earning a return on its investment is not an additional penalty; rather, it is the appropriate consequence of the Company's mismanagement of the Mid-Cape Main. If the Department allows the Company to earn a return on its investment, the Company would be unfairly rewarded for mismanagement of the Mid-Cape Main, and the Department would invite future mismanagement. Further, the Department has already found that the Mid-Cape Main would not have required replacement and an early retirement if not for the Company's mismanagement.[46] As a result of the Company's mismanagement, the Company's customers incurred $123.13 million in costs to replace the Mid-Cape Main, which are being recognized through depreciation of the new main over its lifetime.

Finally, even if the only concern was equalizing costs, the cost to customers far outweighs the foregone revenue to the Company thus far, and customers will continue to bear additional costs for decades to come. However, it is necessary to look beyond costs to the economic incentive that would arise if a company were entitled to earn a return on an investment necessitated solely by its mismanagement and violations of safety standards. It would be in every utility's financial interest to operate its assets in such a manner as to require premature replacement of those assets to increase

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46 *National Grid*, D.P.U. 20-120, Order, at 162.

rate base on which a rate of return is earned. Accordingly, disallowing profits on projects required due to poor maintenance is a reasonable regulatory strategy to encourage good maintenance practices and avoid excess capital investment.

LNG Life-Cycle Integrity Projects and Proposed LNG Investment Roll-in

Q. What are your recommendations regarding the Company's proposed LNG Life-Cycle Integrity Projects and the roll-in of these costs during the PBR term?

A. The Company proposes to roll-in $1.054 billion in LNG project costs during the next proposed five-year PBR term. I recommend that the Department reject the Company's request to roll-in future LNG projects during the PBR term. The planned additional spending during the proposed PBR term should be reviewed as part of the Company's next general rate case and, if found to have been prudently spent for the benefit of customers, included in rate base at that time.

This delay in recovering an investment represents a regulatory lag, which imposes a cost on the Company while awaiting review of the investment and a risk if the investment is not subsequently approved. Regulatory lag is in the customer interest, as it constrains utility capital spending, encourages better capital spending governance, and forces improved project prioritization. A reasonable lag interval ensures that capital is put to its highest and best uses, with lower-priority projects deferred for future consideration. However, when the lag interval is short or non-existent, overcapitalization remains the utility's most profitable course of action.[47] Given depreciation expense, which provides room for capital spending absent capital cost trackers or roll-ins, a five-

[47] E.E. Bailey & R.D. Coleman, *The effect of lagged regulation on an Averch-Johnson model.* BELL JOURNAL OF ECONOMICS, 2, 278-292 (1971).

year PBR term does not present unreasonable regulatory lag, especially given that the LNG investments will be spread across five years (if not fifteen years).[48]

Q. What LNG investments are the Company proposing?

A. The Company is proposing a series of LNG Life-Cycle Integrity Projects to replace assets to continue the safe and reliable operation of the Company's seven LNG facilities and the reliable gas supply provided to the gas system by those facilities. These projects include replacing key equipment at the LNG facilities, increasing the send-out capacity of four LNG plants, constructing four portable LNG projects, and replacing two control buildings to add space.[49] These projects also support reducing the Company's reliance on the Everett Marine Terminal ("EMT") in line with state decarbonization goals.

Q. What is the estimated cost of these projects, and how does the Company propose to recover the costs?

A. The estimated cost to complete all of the proposed LNG Life-Cycle Integrity Projects is $1.054 billion between 2026 and 2031.[50] The Company proposes that it be allowed to apply once, at its discretion as to which year, during the PBR term, to roll-in LNG capital costs into rate base for recovery,[51] similar to the approach approved in D.P.U. 20-120 for LNG costs under that PBR

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48 As described in D.P.U. 17-170, the Company began work on LNG upgrade projects in 2017 and under its current proposal, has projects continuing through at least 2033—a period of over 15 years.

49 Exh. NG-GRSC-1, at 59–64.

50 Exh. AG-GSRC-1, at 61.

51 *Id*. at 61–62.

plan.[52] The Company proposes this roll-in allowance because it claims the Life-Cycle projects for the LNG plants must be completed in a short period of time, as the plants were all constructed near the same time, about 50 years ago, and are now nearing the end of their useful lives.[53]

Q. Is the proposed LNG capital roll-in an appropriate mechanism for recovering the costs of the LNG Life-Cycle Integrity Projects?

A. No. The Company's proposed roll-in is not an appropriate recovery mechanism because the proposed projects are not all life-cycle projects, and those projects that are life-cycle projects (i.e., projects on assets that are nearing the end of their useful lives), do not have a compressed timeframe for completion as claimed by the Company. For example, the replacement of critical equipment at the LNG facilities is a life-cycle project driven by facility age and is necessary to extend their useful lives. However, projects to expand send-out capacity, add portable LNG units, and construct buildings are not life-cycle projects and should not be included in this program. Instead, the Company should fund these projects as discretionary system expansion and facilities projects.[54]

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52 *National Grid,* D.P.U. 20-120, Order, at 352.

53 Exh. AG-GSRC-1, at 56–58.

54 While the Company is not seeking approval of expansion projects as part of this case, it should be noted that if reliance on EMT is being reduced to align with state decarbonization goals, the expansion of Company-owned LNG plants and the extension of the useful lives of all plants by decades likely merit further consideration. The possibility of future use of alternative pipeline fuels, such as hydrogen and renewable natural gas, should also be examined when assessing the necessity and scale of LNG facilities that may be needed in the coming decades.

Further, the characterization of this group of projects as all life-cycle projects, all coming due in a short period, due to the plants all being of similar age, is refuted by the Company's own testimony in D.P.U. 17-170.[55] In that proceeding, when the Company first proposed to replace vaporizers, boil-off equipment, and other critical components, it supported the need for the LNG Modernization Program by stating that the facilities were built in different periods of time.[56] The Company is putting forth two conflicting narratives—when the National Grid seeks to "modernize" the plants, it asserts that they were built in *different* time periods, but when the Company proposes "life-cycle" project, it asserts that the same plants were built all in the *same* short period of time.

The reality is that equipment in LNG plants is of many different types. Various types of equipment are characterized by design lives of different lengths, and are maintained, repaired, and replaced at a variety of time intervals. This is demonstrated by the Company's LNG Life-Cycle Integrity Projects which have spanned multiple rate cases to date and are not scheduled for completion until 2033.[57] A construction timeframe of over a decade and a half is sufficient for the Company to incorporate these projects into its long-term capital plans.

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55 *National Grid,* D.P.U. 17-170, Exh. NG-GSRP-1, at 20.

56 *Id.*

57 Exh. NG-GSRC-1, at 57.

III. PBR SCORECARD METRICS

Q. Please introduce this section of testimony.

A. Putting aside the merits of the Company's overall PBR proposal,[58] should the Department adopt some form of a PBR plan, we offer the following recommendations PBR scorecard metrics. The Company has proposed six metrics for tracking its performance during the PBR term. These metrics provide quantitative measures of whether the Company's performance is being maintained as it implements efficiency measures under its PBR plan. In this section, I will examine the proposed metrics and recommend specific improvements.

Q: Please provide your overall perspective on PBR scorecard metrics.

A. My overarching concern regarding PBR plans is that the spending required to achieve the levels required by the scorecard metrics is not adequately reflected in the metrics themselves. The overall challenge for utility spending generally, and in capital planning specifically, is how to secure the best outcomes at the least cost. In my experience, few PBR programs are designed to influence utility decision-making to provide customers with the best outcomes at the lowest cost.

Q. Why is it important to include scorecard metrics in PBR plans?

A. If properly designed and implemented, scorecard metrics can provide transparency and accountability regarding a utility's performance under a PBR plan. Using scorecard metrics, the

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[58] For the AGO's position on the merits of the Company's proposed PBRM, *see* Exh. AG-MWD-1, at 3. The AGO's expert, Michael Deupree, recommends that the Department reject the Company's proposed PBRM, noting that while PBRMs may be designed to provide utilities with financial incentives to reduce costs while increasing productivity, as the natural gas industry becomes less productive overtime relative to the overall economy, PBRMs ultimately fail to promote cost efficiencies and instead allow utilities to increase rates faster than inflation.

Department and other intervenors can monitor whether a utility meets performance expectations over the term of the PBR. To serve this intended purpose, scorecard metrics must be well-designed to measure performance across a range of relevant performance categories, measure outcomes achieved, minimize the influence of factors outside the Company's control, and remain consistently defined and measured over the PBR term.

Q. Do National Grid's proposed scorecard metrics function as effective performance measures to ensure that the Company is maintaining or improving performance during the term of the PBR?

A. No. Overall, the Company's scorecard metrics should be better designed to measure outcomes (such as reductions in damages and emissions), rather than activities (such as miles of pipeline replaced), and be set against meaningful baselines that reflect desired and realistic levels of performance. As discussed below, each proposed scorecard metric suffers from one weakness or another and should be revised or replaced.

Q. Please discuss the Affordability metric and any flaws with its proposed design.

A. The Company has proposed a Tier Income-Eligible Discount Enrollment metric as a measure of its performance on affordability. The Company proposes increasing the number of eligible customers enrolled in the income-eligible discount by 32,500 over the course of the PBR term, or 6,500 annually.[59] This metric, however, focuses on only one customer subset and does not actually measure affordability. Indeed, affordability is not limited to low-income residential customers;

[59] Exh. NG-PBRP-1, at 48.

rate increases impact all customers, as well as overall economic productivity and development in Massachusetts.

Additionally, this metric does not measure a significant improvement in affordability. The Company currently enrolls 46 percent of estimated eligible customers in the income-eligible discount, and the metric proposes enrolling an additional 14 percent of eligible customers.[60] The Company's proposal therefore leaves 40 percent of eligible customers without assistance.

Q. How would you recommend improving the Company's Affordability metric?

A. The Company's proposed affordability metric could be improved if it more broadly measured affordability across all customers. Such a revision, however, would require complex calculations, and its meaningfulness would depend greatly on the design of the calculations, and it is not in customers' interests for the Company to be required to perform complex economic analysis to support a scorecard metric.

Accordingly, I recommend that a delinquency and disconnection metric be implemented instead. This metric would measure changes in the number of customers who are delinquent on their bills and the number disconnected for non-payment. This metric would be outcome-based, so the Company would have flexibility to improve its performance through several different efforts, such as low-income discount enrollment, promoting efficiency to reduce usage, or targeting outreach to customers facing the highest affordability burdens.

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[60] Exh. AG-3-29.

Q. Please discuss the Damage Prevention (count) metric and any flaws with its proposed design.

A. The Company proposes three metrics to measure safety and reliability. First, the Company proposes a Damage Prevention (count) metric, which measures the number of damages per 1,000 tickets across five measures.[61] This metric is well-designed to measure damages across the five selected measures. The Company's proposal to use actual 2022–2024 performance as a baseline with no improvement required during the PBR term, however, is a critical flaw. A static baseline may be appropriate in circumstances where performance is high, and the intent is to ensure performance does not slip due to efficiency measures under PBR. Here, however, damages have a direct impact on public safety, and it is reasonable to require improvement over time. Indeed, the Company is investing in improved mapping and documentation systems, as well as increasing personnel, to enhance its understanding of its system and its ability to locate facilities accurately. If customers are expected to pay for these improvements, it is reasonable to expect the Company to deliver improved performance.

Q. How would you recommend improving the Company's Damage Prevention (count) scorecard metric?

A. I would recommend that a target be set to reduce the damage rate per 1,000 tickets annually from the proposed baseline. My recommendation is a 3 percent annual reduction in at-fault damages and a 2 percent annual reduction in not-at-fault damages. These proposed reductions acknowledge that the Company has greater control over at-fault damages. The Company can impact not-at-fault

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61 Exh. NG-PBRP-1, at 50.

damages through educational programs, excavator outreach, and other efforts to encourage safe digging practices and locate compliance. These efforts, however, rely on third-party cooperation to be effective and may take longer to yield results, so, accordingly, I recommend a smaller annual improvement rate for non-at-fault damages (compared to at-fault damages). Overall, it is reasonable to expect the Company to improve its performance in this area.

Q. Please discuss the Damage Prevention (cost) metric and any flaws with its proposed design.

A. The second safety and reliability metric proposed by the Company is a Damage Prevention (cost) metric. This metric measures the annual cost of at-fault damages and the percentage of not-at-fault damage costs recovered from third-party contractors.[62] Both measures, however, are flawed because there is no meaningful measure of an outcome. The cost of the company's at-fault damages, while interesting as a quantitative measure, is not particularly useful, because the risk posed by damage is not necessarily related to its cost. For example, a gouge on a large-diameter steel gas main located under pavement in rocky soil will be more costly to repair than a severed and blowing residential service at a foundation; however, the immediate safety risks do not align with those costs.

Similarly, the percentage of not-at-fault damage costs collected from third-party contractors is not useful and can be easily influenced by outliers. For instance, the inability to collect on a single high-cost damage claim could greatly influence the results. Additionally, the Company states that

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62 Exh. NG-PBRP-1, at 50–51.

there is a lag in collections due to the time it takes to pursue claims through the legal system.[63] This lag could result in variations in third-party damages, with delayed effects on the metric, thereby reducing its usefulness.

Q. How would you recommend improving the Company's Damage Prevention (cost) scorecard metric?

I recommend eliminating the portion of the metric related to the cost of at-fault damages, as explained above, because this measure provides no useful safety performance information. I also recommend modifying the not-at-fault damages collections measure to be based on the percentage of not-at-fault damages for which the Company recovers costs, rather than the percentage of total costs collected. The only relationship between safety and the collection of damages costs is to deter third-party contractors from future unsafe digging practices by increasing the likelihood that the contractors will be held responsible. This deterrence is better strengthened by a high proportion of unsafe diggers being held responsible than by a few with the highest cost damages being held responsible. Also, this change would reduce the variability introduced by varying damage cost calculations.[64]

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63 Exh. AG-3-31.

64 An alternative recommendation for a metric to reduce third-party damage is to measure and report on the timeliness of locates performed by the Company, as delays in locates can increase the likelihood of contractors digging without locates.

Q. Please discuss the Pipeline Safety Management System ("PSMS") Maturity Score metric and any flaws with its proposed design.

A. The Company proposes to measure its scores on the ten elements in the Conformance and Effectiveness categories of the PSMS using a baseline performance score of "implementing."[65] PSMS provides an important framework for the Company to improve its processes and performance related to pipeline safety; however, using the scores as a metric, particularly with a static baseline, is flawed. PSMS measures the activities performed by a utility instead of the outcomes achieved by those activities, and this alone makes this a flawed metric for measuring safety performance. Additionally, the proposal to maintain a baseline of "implementing" for the next five years would result in no progress towards maturing the Company's pipeline safety processes.

Q. How would you recommend improving the Company's PSMS Maturity Score scorecard metric?

A. My recommendation is to eliminate this metric. The Company's PSMS efforts should be encouraged; however, the frequency of assessment should be based on best practices for developing its pipeline safety efforts, not on meeting a PBR scorecard metric. If the Department were to keep this metric in place, I would recommend setting targets that require progress in PSMS maturity scores, such as improvement from "implementing" level to "sustaining" level.

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65 Exh. NG-PBRP-1, at 52.

Q. Please discuss the Digital Customer Engagement metric and any flaws with its proposed design.

A. The Company proposes to measure the number of digital customer engagements using the Company's self-service tools, such as web portals, mobile apps, Integrated Voice Response, and digital assistant.[66] The Company proposes a baseline of 7,153,685 transactions based on its 2024 performance.[67] The target would be set equal to the baseline, which would require no additional digital transactions during the PBR term, which is a very low bar to set considering the movement of customers towards digital tools.

The Company wants to focus on digital engagement because it believes that a higher volume of digital transactions indicates that customers' needs are being met through intuitive, reliable experiences.[68] In my opinion, this metric measures the wrong outcomes and has an insufficient target. A count of transactions does not indicate whether those transactions were successful or improved customer satisfaction. Additionally, the Company reported that there were 8,182,959 digital transactions in 2025, over one million more than the proposed baseline target.[69] This was an over 14 percent increase in digital transactions from the previous year, demonstrating that the proposed target is insufficient.

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66 Exh. NG-PBRP-1, at 53.

67 *Id*. at 54.

68 Exh. AG-3-34.

69 Exh. AG-3-33.

Q. How would you recommend improving the Company's Digital Customer Engagement scorecard metric?

I recommend eliminating this metric in favor of one that measures actual customer satisfaction. A possible example would be the proposed First Call Resolution metric with the improvements described below. If the Digital Customer Engagement metric is retained, I would recommend setting an escalating target to recognize year-over-year increases and the Company's efforts to increase digital tool usage, such as auto-enrolling customers in paperless billing.

Q. Please discuss the First Call Resolution metric and any flaws with its proposed design.

A. The Company proposes to measure the percentage of inquiries that are resolved on the first call,[70] which would be done using a call center analytics solution to replace the current post-call customer survey. The purpose of this would be to increase the sample size beyond those willing to take the survey.[71] The weakness of this metric is that it assumes that if a customer does not call back within seven days, their inquiry has been successfully resolved. This ignores the possibility that customers get frustrated with the process and give up, or that they postpone a follow-up call for more than a week, which risks missing potentially numerous customers who were unable to resolve their issues. This measure also does not assess whether the customer is satisfied with the resolution and level of customer service, beyond simply calling back and trying again. The Company's baseline of resolving 74 percent of inquiries on the first call also leaves many customers having to call multiple times to resolve their inquiries.

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70 Exhs. AG-3-35, NG-PBRP-1, at 54.

71 Exh. NG-PBRP-1, at 54.

Q. How would you recommend improving the Company's First Call Resolution scorecard metric?

A. I recommend measuring customer satisfaction with the service received and the ability to resolve the issue satisfactorily. Automated measurement of issue resolution that does not require customer participation has value; however, the risk of mismeasurement when results are based on the assumption that no additional calls will be received within seven days is concerning. Accordingly, I recommend continuing to use surveys to validate automated results and identify any gaps in measurement. Additionally, I recommend expanding the metric beyond first call to first contact. As the Company is striving to increase the number and proportion of customer inquiries handled through digital channels, any measure of resolution should include such channels as well.

Q. Please discuss the Methane Emissions metric and any flaws with its proposed design.

A. The Company proposes to measure its annual methane emissions by assuming a constant rate from the remaining inventory of leak-prone pipe that is GSEP-eligible.[72] The emissions will be calculated using the Massachusetts Department of Environmental Protection ("MassDEP") emissions factors, which are consistent with MassDEP's reporting requirements under 310 CMR 7.73. The Company will report estimated emissions reductions based on the remaining miles of GSEP-eligible main and services. The Company proposes a baseline of 81,544 metric tons carbon dioxide equivalent (CO_2e).[73] This metric, however, has several flaws.

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72 *Id*. at 55.

73 *Id*.

First, this metric is based on emissions factors that, by their nature, assume that every mile of a particular material pipe emits the same amount of emissions regardless of the pipe's actual condition or leak history. This incentivizes replacing mains based on ease of construction and permitting, or cost per mile of replacement, rather than on risk factors such as leaks and pipe condition. Second, this metric ignores methane emission reductions from solutions other than pipe replacements. Other, lower-cost opportunities to reduce emissions include joint sealing, repair of known leaks, and reductions in venting and flaring of gas. By excluding these solutions for methane emissions reduction, the Company is discounting the value of measurable and potentially lower-cost methods in favor of capital-intensive pipe replacements. The metric as proposed measures miles of pipe replaced, which is an activity, not an outcome, which can be achieved through various opportunities, as described.

Q. How would you recommend improving the Company's Methane Emissions scorecard metric?

I recommend revising this metric to also measure the reduction in Scope 3 emissions and progress towards 2030 statutory greenhouse gas limits and the 2050 net-zero requirement in addition to measuring Scope 1 emissions. For the Company to reduce Scope 3 emissions, it must undertake multiple efforts that utilities have been reluctant to embrace fully, including electrification, alternative pipeline fuels, system trimming, increased energy efficiency, and thermal heating solutions. If greenhouse gas and emissions reduction targets are to be met in the Commonwealth, utilities must take an active role in reducing Scope 3 emissions and not leave it to customer decisions to guide the market. Emissions reductions are an important performance element that

the Company needs to measure and demonstrate progress on. To measure Scope 3 emissions, the metric should be adjusted to use reductions in actual measured emissions from all pipe-related activities rather than just pipeline replacement based on emissions factors.

Q. Is the Company proposing any Performance Incentive Mechanisms ("PIMs")?

A. No. The Company has only proposed scorecard metrics that do not incentivize or penalize performance. Scorecard metrics provide valuable information on Company performance, but do not provide a means to ensure that performance is maintained or improved. Notably, in justifying another PBR term, the Company has not cited its performance on any of its previous PBR scorecard metrics. Additionally, the Company was unable to cite any means by which PBR scorecard metrics hold it accountable for ensuring that customers receive the benefits promised by PBR, instead citing only "transparency" as a benefit.[74] Unlike scorecard metrics, which lack any enforcement mechanism, PIMs provide an opportunity to hold utilities accountable for their performance under PBR plans. PIMS are particularly useful for initiatives that require going beyond the status quo or business as usual, such as reducing Scope 3 emissions. A well-designed PIM can help ensure that the cost reductions achieved by the Company are achieved through efficiency and not reductions in performance. Accordingly, if the Department chooses to approve some form of a PBR plan, I recommend that one or more PIMs be included to ensure that the

[74] Exh. AG-3-42 ("As noted in the pre-filed testimony of the Performance-Based Ratemaking ("PBR") Panel (Exhibit NG-PBRP-1), the proposed scorecard metrics provide transparency and enable monitoring of the Company's performance during its PBR term.").

Company maintains areas of performance offering valuable impacts and improves performance in significant ways during a PBR term.

Q. Are the any specific PIMs that you recommend?

A. Yes. I recommend that a Methane Emissions Reduction scorecard metric as revised and recommended above be implemented as a PIM. There should be annual targets for both Scope 1 and Scope 3 emissions with targets set to match the incremental progress needed to meet the Commonwealth's 2030 and 2050 emissions reduction goals. The measurement of Scope 1 emissions should be based on actual measurements of emissions from all known distribution system sources, not just an estimate of emissions from leaks based on emissions factors that do not take actual pipe condition into account. The measurement of Scope 3 emissions should be based on the emissions attributable to the natural gas delivered by the Company to customers.

Moreover, the incentives and penalties should be set to provide consequences for failure to meet minimum expectations and motivation for the Company to exceed the targets. The Commonwealth's targets for Scope 3 emissions reductions will not be met if the Company continues business as usual.[75] A PIM can encourage the Company to consider ways to reduce Scope 3 emissions beyond its current business practices, without the Department dictating the specific programs and actions the Company must undertake. This allows the Company to use its knowledge of its system and customers to best develop the methods to meet this important goal.

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[75] Exh. DPU-8-5.

Q. What do you recommend for levels of incentives, penalties, and deadbands?

A. Emission reductions required to meet the Commonwealth's 2030 and 2050 goals, and/or emission reductions associated with the Company's Climate Compliance Plan, can be calculated. But the rate at which the Company should be expected to make progress towards these goals is a matter of significant debate. In short, while I believe PIMs are an important part of PBR, and while I recommend the Department require Scope 1 and Scope 3 emission reductions as PIMs, I do not have sufficient information to make recommendations on levels of incentives, penalties, and deadbands.

Q. Without specifics, how do you suggest the Department proceed?

A. One option is to start Scope 1 and Scope 3 emission reduction metrics as scorecard metrics and then transition them to PIMs over time. The Department could establish a schedule for such transition in the instant proceeding, adding a sense of urgency for stakeholders to propose and finalize the PIM.

In National Grid's most recent electric distribution rate case, which did involve a PBR plan and PIMS, the Department considered establishing a separate proceeding for full PIM development.[76] Though the Department declined to establish such a proceeding at that time, the circumstances presented by this docket—a gas distribution company proposing a PBR plan with no PIMS—may require such a process. I therefore recommend the Department: 1) establish a Scope 1 and Scope 3 emissions metric as a scorecard metric for now; 2) define a schedule for transitioning the metric

[76] *National Grid*, D.P.U. 23-150, Order, at 162 (Sep. 30, 2024).

to a PIM; and 3) establish a separate proceeding for developing the scorecard metric into a PIM in accordance with that schedule.

IV. GAS SAFETY, RELIABILITY, AND COMPLIANCE

Q. Please introduce this section of testimony.

A. This section includes a review of the Company's Safety and Compliance Program, new work efforts in response to 220 C.M.R. 101, the proposed GSRC Recovery tracker, capitalization of cast iron joint repair, and a proposed Research, Development, and Demonstration program.

Q. What efforts has the Company undertaken since its last rate case to address safety, reliability, and compliance?

A. The Company in its testimony describes its efforts in the following areas: (1) PSMS; (2) organizational structure; (3) proactive system reinforcement; (4) gas planning and reliability; (5) in-sourcing of damage prevention work; (6) leak-prone pipe ("LPP") replacement program under the Gas System Enhancement Plan ("GSEP"); and (7) implementation of the Dynamic Risk Report recommendations through the following programs: (a) Low-Pressure System Elimination Program, (b) Periodic Regulator Inspection Program, (c) Regulator Station Inspection Program, (d) Transmission Station Integrity Program, and (e) Transmission Integrity Verification Program and Transmission Integrity Management Program.[77]

[77] Exh. NG-GSRC-1, at 11.

Q. Do you have any concerns about any of these efforts?

A. Yes. The Proactive System Reinforcement Projects and GSEP are of particular concern because these projects encourage excessive capital spending, are not tied to demonstrated needs, and do not provide benefits proportional to their costs.

Q. What are your specific concerns about the Proactive System Reinforcement Projects?

A. Proactive system reinforcements are meant to increase pressures in areas where pressure drops are expected to fall below Company standards due to growth.[78] Over the past six years, the Company has reported 193 gas outages affecting 4,139 customers; only two of those outages and eight customers were due to poor pressure.[79] There is, therefore, almost no performance improvement opportunity to begin with. The cost to reinforce a system is significant, as it typically involves replacing mains with larger diameters and replacing or modifying regulator stations, which is all capital-intensive work that provides a return to the Company but does not significantly reduce customers' outage risk.

Additionally, the need for reinforcements is based on anticipated growth that may not occur. In fact, the Company has reported declining residential gas usage overall and per customer over the past fifteen years, as well as significant energy savings from energy efficiency programs.[80] New growth in gas usage is not occurring among existing customers, who are increasing efficiency and

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78 *Id*. at 15.

79 Exh. Att. AG-3-12.

80 Exh. Att. AG-3-18.

reducing gas usage. Any growth is likely to be due to specific customers increasing usage for new processes or equipment, or new customers being added to the system. The Company maintains mechanisms to attribute that cost to those customers (like CIAC, as described earlier), rather than socializing such costs to all customers and subsidizing growth. There are also non-pipeline alternatives that can be considered to address growth in forecasted gas usage, such as demand management to curtail or shift load, targeted efficiency programs in capacity-constrained areas, or partial electrification. The Company has not pursued non-pipeline alternatives,[81] instead preferring solutions that further expand rate base, on which it earns a return on equity, and increasing customer bills for projects with little or no benefit to those customers.

Q. What are your specific concerns about the GSEP program?

A. The GSEP program was meant to incentivize utilities to replace leak-prone pipes on an accelerated basis. This program, however, has evolved into a tool for system-wide infrastructure upgrades, as the plans are not narrowly focused on the highest-risk pipes.[82] The replacement of pipes is not focused on the highest-risk sections, but instead on replacing all leak-prone pipes. Further, the Company's do not follow their GSEP plans, as demonstrated by the fact that 80 percent of the Company's GSEP projects completed in 2024 were not in accordance with the Department-approved plan.[83] Additionally, the cost of pipe replacement has grown significantly in recent years. In fact, the Company experienced a 57 percent increase in the cost per mile to replace main

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81 Exh. AG-3-7.

82 *See National Grid*, D.P.U. 24-GSEP-03, Order, at 54 (Apr. 30, 2025).

83 *National Grid*, D.P.U. 25-GREC-03, Exhs. AG-BLC-1, at 21–22, 31–32; NG-GPP-7.

and a 51 percent increase in the cost to replace a pipe between 2020 and 2024.[84] The Company's incentive to replace all leak-prone pipe based on material type rather than the actual pipe's risk assessment has led the Company to overspend and increase customer bills, without regard for risk reduction and cost containment.[85]

Q. Are there any additional safety, reliability, and compliance efforts you would like to comment on?

A. Yes. The Company's Reliability Projects and the Pressure Regulating Proactive Facilities Program are designed to address reliability in ways that cannot be addressed otherwise and to reduce the risk of outages by targeting weak spots in the system and addressing system deficiencies. The risks addressed by these projects cannot be mitigated by reducing gas usage or implementing non-pipeline alternatives. Additionally, the reliability and safety benefits of these projects will continue to benefit customers regardless of the number of customers or usage on a particular system. These factors differentiate these projects from those described above.

Q. What new work efforts is the Company undertaking to comply with 220 C.M.R. 101?

A. The Company's efforts involve installing overpressure protection at all pressure regulating facilities; identifying and remediating meter, regulator, and vent proximity clearances; adjusting training to new operator qualification requirements; increasing oversight of work performed by contractors to ensure that contractors are properly trained; maintaining operator qualification

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[84] Exh. Att. AG-5-17.

[85] Because this level of spending has already been approved by the Department in the GSEP and GSEP reconciliation proceedings, we are prevented from evaluating the prudence of GSEP investments in the context of the Company's total capex and overall requested rate increase.

records for contractors; and maintaining accurate and complete maps and records.[86] The Company has detailed the operation and maintenance ("O&M") and capital costs associated with these efforts, as well as the additional employees hired to perform them.

Q. Are these efforts necessary, and are the costs justified?

A. Yes. The new regulations enacted in 220 C.M.R. 101 either specifically require these efforts or establish changes in regulations that these efforts are meant to comply with. The Company is unable to avoid taking these actions; however, these regulations are not without precedent and expand upon efforts already underway by the Company. For example, the Company identified distribution overpressure protection as a safety risk in its Distribution Integrity Management Plan beginning in 2012, prior to the Merrimack Valley incident, the Dynamic Risk Report, or the enactment of new regulations.[87] Likewise, mapping and records issues had been previously identified and were being addressed prior to the new regulations.[88] The Company has accelerated efforts in these cases and also now has specific regulatory requirements to guide the work. And, in other cases, such as vent clearances, the new regulations require action beyond what the Company previously did, but which was already being done by other gas utilities. These efforts have come with unavoidable costs and are largely justified.

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86 Exh. NG-GSRC-1, at 36–40.

87 Exh. AG-3-50, Att. AG-3-50-1, at 39.

88 Exh. AG-3-64.

Q. If these costs are largely justified, what are your concerns?

A. My concern is that the Company portrays some costs as ongoing, though they are likely temporary or will respond to cost reduction efforts over time. For example, as to the costs of the regulator inspection and vent clearance programs, once all this equipment is inspected and corrections are made, there will be minimal future work. If regulators are properly selected and recorded going forward, once the initial inventory is addressed, future inspections become much simpler. Future inspections will also be combined with meter replacement work occurring on an existing seven-year cycle, further reducing costs. Records and mapping issues are similar in that once existing deficiencies are corrected, the overall work required will decrease over time. Changes in technology and the ability to digitally track and collect information will likely yield future efficiencies, reducing the labor and costs required to monitor contractor training and qualifications. Records and mapping are also likely to experience efficiency gains as more digital tools become available to field employees for generating digital as-builts, verifying existing maps and records, and using automated tools to identify discrepancies.

Q. How does the Company propose to pay for these compliance efforts?

A. The Company was approved to recover most of the O&M costs related to these efforts in its 2025 PBR Adjustment filing in D.P.U. 25-74, and has included these costs and the costs of six previously disallowed positions in the test-year labor component in its cost of service in this rate case.[89] The Company is proposing to recover incremental costs for overpressure protection and control line

[89] Exh. NG-GSRC-1, at 41–43.

work through a separate capital recovery tracker as part of its PBR Plan.[90] The projected CY 2026-2030 spending on overpressure protection and control line work is $348,320,688, with baseline spending of $142,500,000 and incremental spending to be recovered by the tracker of $205,820,688.[91]

Q. Is the use of a tracker an appropriate means of recovering these costs?

A. No. The use of a tracker to recover these costs is not appropriate for several reasons. First, these are not new or unexpected costs. The Company has identified the need for overpressure protection since at least 2012, and the need has become more evident following the Merrimack Valley incident in 2018. Since then, the Company has had years to develop plans to complete this work, and it has included such plans in its long-term capital planning. Separating these costs into a tracker allows the Company to increase its baseline capital spending by over $40 million per year and to avoid the revenue constraints imposed by a PBR plan. Additionally, the modernization of facilities is not a one-time project focused on only one type of asset. While the gas system continues to exist, technological and engineering advances will necessitate modernizing facilities to meet revised industry standards and practices. Removing this from baseline capital spending will incentivize utilities to build only to current standards without concern for potential future requirements, as it is financially advantageous to be able to earn a return on the initial investment as well as future updates, especially if freed of capital spending constraints.

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90 *Id*. at 45.

91 Exh. NG-GRSC-1, at 45, Table GSRC-4.

Q. What are your recommendations regarding the proposed GSRC Recovery tracker?

A. I recommend that the Department deny the Company's request to put a tracker in place to recover the incremental costs of overpressure protection and control line work. These programs are important and should be continued within the Company's capital spending plan and within the revenue constraints of the PBR plan. The constraints within a PBR plan encourage efficiency, require evaluations of costs and benefits in investment decisions, force prioritization of capital projects, and result in reduced customer rate increases. If a tracker circumvents these constraints to allow increased spending to encourage worthwhile projects, the result is higher overall capital spending and higher customer bills.

Q. Does the Company have any additional proposals within its GSRC Panel testimony?

A. Yes. The Company has two additional proposals within the panel testimony. First, the Company proposes to capitalize all large diameter (>16" diameter) cast-iron joint repairs, instead of the current requirement that at least three joints must be repaired to be capitalized unless the repair was made using a cast-iron sealing robot ("CISBOT").[92] The Company is also requesting $1.005 million for internal Research, Development, and Demonstration projects, as well as memberships to NYSEARCH and Operations Technology Development ("OTD").[93]

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92 Exh. NG-GSRC-1, at 55.

93 *Id*. at 64.

Q. Do you have any recommendations regarding these proposals?

A. Yes. Both these proposals support the Company's move towards solutions to address leak-prone pipes, rather than relying solely on capital investments in pipe-for-pipe replacements and should be supported, but with modifications.

The capitalization of cast iron joint repairs is reasonable, as the repairs extend the life of the cast iron main by at least 50 years[94] and address almost all large-diameter cast-iron leaks.[95] Allowing large-diameter cast-iron joint repairs to be capitalized will incentivize the Company to perform these repairs rather than replace the main, and could lead to lower customer costs spread over a longer period. My recommendation is to allow capitalizing single large-diameter cast iron joint repairs, subject to the restriction that any repaired pipes would not be eligible for replacement cost recovery under GSEP or any other safety or reliability program.

Many of the Company's proposed Research, Development, and Demonstration projects would support emissions reductions, extend the lives of existing assets, and reduce customer costs. However, the Company's proposal offers only possible research topics and grants, allowing the Company great latitude in selecting them. My recommendation is that the Department consider a separate innovation filing for all natural gas utilities, including parameters for which types of research or goals would be prioritized, as well as project evaluation criteria. This would allow

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94 Exh. AG-3-71.

95 Exh. AG-3-68.

utilities to propose specific projects along with costs and expected benefits for the Department to consider and approve as part of a targeted program.[96]

V. NON-PIPELINE ALTERNATIVES SHARED SAVINGS MECHANISM

Q. What are your recommendations regarding the proposed NPA Cost Sharing Mechanism and the recovery of NPA operating costs?

A. My first recommendation is that the Company be allowed to create an NPA Cost-Sharing Mechanism with a 90/10 customer/Company split of the savings, excluding the social cost of carbon. Additionally, I recommend that the Company be allowed to defer the operating costs for completed NPA projects as a regulatory asset with a 15-year recovery period and a carrying cost set equal to the Company's cost of long-term debt.

Q. Describe the Company's proposal for an NPA Shared-Savings Mechanism and the recovery of NPA operating costs.

A. The Company is proposing an NPA Shared-Savings Mechanism that would split the present value of the net benefits created by NPA projects that defer, reduce, or replace traditional gas pipeline investment.[97] The Company would split the net present value of net benefits, with thirty percent accruing to the Company and the remaining seventy percent accruing to customers.[98] The

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96 *See*, *e.g.*, Minnesota Statute 216B.2427 Natural Gas Utility Innovation Plans. The Minnesota Natural Gas Innovation Act set a spending limit as a percentage of a distribution company's annual revenue and required the distribution company to propose a slate of innovation projects within that limit. The Commission there held proceedings to review the proposed innovation projects for each utility, including review and testimony by interveners, before ultimately approving those projects which were found to provide value and meet the requirements to advance emissions reduction. *See* Minnesota P.U.C Dockets 23-518 and 23-215.

97 Exh. NG-PRBP-1, at 38.

98 *Id*.

Company proposes to base the net present value of an NPA on a Total Resource Cost ("TRC") test, as proposed in the Company's Climate Compliance Plan filed in D.P.U. 25-41.[99] Additionally, the Company proposed to defer NPA-related operating costs that would otherwise be recovered through PBR revenues to a regulatory asset, with associated costs to be recovered over 15 years.[100] The Company proposes to apply a carrying charge equal to the authorized weighted average cost of capital ("WACC") on the regulatory asset.[101]

Q. What is included in the TRC test?

A. The TRC test includes the costs and benefits for the NPA project that are experienced by customers, the Company, and society in general. Some of the costs included in the TRC are program costs, behind-the-meter incentives, performance incentives, marketing and administrative costs, and participant costs not covered by incentives.[102] Some of the included benefits are avoided energy costs, avoided gas revenue requirements, the social cost of carbon, non-energy impacts, and other resource benefits.[103]

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99 *Id*.

100 *Id*. at 41.

101 *Id*.

102 Exh. NG-PBRP-1 at 39, Table 1.

103 *Id*.

Q. How was the 70/30 customer/Company split of NPA Savings determined?

A. The Company selected this split because, in its opinion, this represents a reasonable distribution of benefits between customers and shareholders.[104] This is a weak rationale on which to base this determination; however, there are parallels in the gas and electric industries that we can look to for guidance.

Q. What are the parallels that we can look to?

In the gas industry, utilities often sell excess capacity that may exist on their systems to third parties. As gas systems are paid for by ratepayers, commissions have recognized that profits on such capacity are made possible by ratepayers and should accrue mostly to ratepayers as a result.[105] A similar situation exists in the electric industry. Many states remain vertically integrated, meaning that for-profit utilities own electric generating plants as part of their rate bases. When electricity generated by such plants is not needed to meet captive customer needs, utilities are allowed to sell excess electricity to other utilities and market participants. Given that customers are paying for these plants and may even have paid off the total capital cost of such plants, many regulators have correctly recognized that profits from such sales would not have been possible without customer payments and should be used to reduce customer costs.

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104 Exhs. DPU-22-8; DOER-1-2.

105 For example, the Pennsylvania Public Utilities Commission requires the Philadelphia Gas Company to apply 75 percent of profits from off-system gas sales as credits toward customer revenue requirements. *See* Pennsylvania Public Utilities Commission Docket No. R-2024-3045966, Letter from utility counsel (May 30, 2025).

Of the states that have recognized this issue, most require that profits from off-system energy sales be credited 100 percent to customers, typically as credits to fuel cost and power supply adjustment riders. However, other states have recognized that it could make sense to let utilities retain some of these profits as a "sales commission," which would incentivize utilities to maximize off-system sales revenue and profits, as well as the associated fuel and power supply cost credits customers would enjoy.

Q. In these situations, what percentages of off-system sales have regulators allowed vertically integrated electric utilities to retain?

A. Again, most regulators appear to require all such profits to be credited to customers. But among those regulators that do permit utilities to retain a portion of revenues as a sales commission, there are many examples well below the 30 percent that the Company is proposing here. The Oklahoma Corporation Commission permits Oklahoma Gas and Electric to retain a 20 percent commission on sales of renewable energy certificates.[106] In Kentucky, the Public Service Commission originally allowed Kentucky Power to retain 25 percent of the profits on off-system sales, but this has since been revised to 0 percent.[107]

Q. Based on these examples, what percentage of NPA savings do you recommend the Department permit the Company to retain?

A. While it appears most commissions require 100 percent of savings generated by utility efforts to be shared with customers, the Department has expressed an interest in providing incentives for

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106 Oklahoma Gas and Electric Company tariff, Sheet 50.80.

107 Kentucky PSC Case No. 2020-00174, Order, at 84 (Jan. 13, 2021).

utilities to maximize such savings. Accordingly, I recommend no more than a 10 percent share be allocated to the Company. Such a percentage is consistent with the concept of a sales commission and will provide a more reasonable incentive.

Further, a 90/10 split recognizes that the costs of NPAs are recovered from customers, and the risks of the benefits not materializing or falling short are borne by customers. The NPA savings are the benefits ratepayers receive in exchange for these costs, and customers should therefore retain the vast majority of benefits. Additionally, while ratepayers bear the risk that NPAs will not deliver expected savings, the Company will receive its share of the NPA savings with no adjustment based on actual performance.[108] As such, the Company bears no risk if the NPA fails to deliver expected savings, and this reality warrants a much smaller share of savings for the Company than the Company proposes.

Q. Should there be any exclusions or exceptions to what is included in NPA Savings?

A. Yes, the social cost of carbon should be excluded from the NPA Savings calculation. It is reasonable to consider the social cost of carbon when determining the benefits provided by an NPA in relation to its costs. However, a reduction in the social cost of carbon does not accrue to customers, as it is spread beyond the borders of the Company's service territory and even well beyond the Commonwealth. The Company should not receive a portion of the reduction in the social cost of carbon through customer rates when those savings are so diffusely spread. The Company has not paid the social cost of carbon on the natural gas it has historically and continues

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[108] Exh. DOER-1-5.

to deliver, so it should not now expect to receive a share of the social cost of carbon for avoided natural gas sales.

Q. Is the deferral of NPA operating costs to a regulatory asset with a 15-year recovery period appropriate and would doing so provide ratepayer benefits?

A. Yes, the deferral of NPA operating costs, for completed projects, to a regulatory asset with a 15-year recovery period provides ratepayer benefits and is appropriate. Currently, any NPA operating costs are collected in full each year, which could result in a significant increase in rates as the number of NPAs grows. Deferring these costs to a regulatory asset spreads recovery over a longer period. It matches the increased expense with savings from reduced revenue requirements resulting from avoided capital investments in gas mains and services.[109] However, I recommend setting the carrying cost applied to the regulatory asset at an amount equal to the Company's cost of long-term debt, currently 4.55 percent,[110] rather than the Company's WACC.

Q. Why do you recommend the Company's long-term debt rate over the Company's WACC?

A. The Company's WACC includes profits for shareholders, while the long-term debt rate does not. Profits are intended to compensate shareholders for the risks inherent in investing in capital plant, but such risks do not exist for regulatory assets. Also, recall that the Company earns a share of NPA savings with zero capital investment. Further, allowing profits on an NPA-related regulatory asset would encourage the Company to overspend on NPA services and operations, and to classify as much operations spending as NPA-related as possible. For all these reasons, the Company's

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109 Exh. Att. DOER-1-3.

110 Exh. NG-RRP-4, at 8.

long-term debt rate is more appropriate to apply to NPA-related spending and regulatory assets than the Company's WACC.

Q. Should all NPA operating costs be eligible for deferral as regulatory assets?

A. No, some NPA operating costs should not be eligible for deferral as a regulatory asset. Any NPA costs related to projects that are not constructed should not be deferred into a regulatory asset. The Company should be encouraged to complete the NPAs for which it has incurred costs, such as design, marketing, and customer outreach. The Company can work to increase the number of completed projects by expanding customer outreach, tailoring incentives, and finding alternative solutions when barriers are encountered. Further, excluding the costs of uncompleted NPAs from becoming a regulatory asset provides the Company with an incentive to complete them, while simultaneously discouraging spending not likely to result in a completed project.

Q. Are there precedents for excluding costs not associated with completed projects?

A. Yes. This situation is no different from applications for new gas service from potential customers. The Company incurs costs to process service applications, engineer connection designs, and estimate costs. But when a potential customer chooses not to move forward with new gas service, the Company is unable to include those costs as part of a capital project and must instead write those costs off as operating expenses. This encourages the Company to minimize application costs and encourages the types of spending most likely to result in project construction.

VI. INVESTIGATION INTO THIRD-PARTY CONTRACTOR INVOICING

Q. What are your recommendations regarding beyond-scope invoicing and addressing the financial impact on ratepayers?

A. My recommendation is that the Company remove $5,728,409 in capital investments in service from rate base, exclude $44,175 in capital additions not in service from being included in future rate base, and refund $4,517,714 to customers, which is the amount collected for assets in rate base plus interest.[111]

Q. Please discuss the Company's investigation into third-party contractor invoicing and the results of the investigation.

A. In July 2022, the Company became aware of concerns about the billing practices of "Contractor A" during a Gas Operations department project focused on potential cost and process efficiency opportunities.[112] This led to a series of internal reviews that also examined "Contractor B," "Contractor C," and "Contractor D," and their billing practices for both concrete and asphalt restoration. These reviews raised concerns about billing practices for restoration work performed by both "Contractor A" and "Contractor B," and a particular subcontractor both contractors employed.

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[111] These amounts were calculated by applying the corrected calculation of "Total Extrapolation Adjusted Beyond Scope Quantity Dollar Percentage," *see infra* at 58–60, to the calculations the Company provided in Exhibit Attachment 2-1-8_Redacted. These increased amounts represent the correct calculation of the financial impact on ratepayers from beyond-scope work and are the proper corrective actions to remove that impact.

[112] Exh. Att. DPU-2-1-1, at 9–10.

The Company's investigation concluded that both contractors had performed the work invoiced; however, the quantities of concrete restoration work performed were inflated beyond what was expected based on the pipeline work completed and the field conditions.[113] The investigation further concluded that the asphalt restoration was properly billed, and the quantities performed were within a reasonable tolerance of the expected quantities.[114] The investigation also concluded that there was no collusion between any Company employees and either contractor in the inflating of concrete restoration work performed.[115]

Q. What actions has the Company taken because of this investigation?

A. The Company has taken several actions in response to the results of the investigation to put an end to the practices that were occurring, address the impacts of the beyond-scope contractor invoicing, and prevent similar issues from occurring in the future. The Company has, for the most part, acted quickly to identify and move forward with these responses.

Q. What steps did the Company take to end the practice of beyond-scope contractor invoicing?

A. The Company directed both "Contractor A" and "Contractor B" to cease using the identified subcontractor company for restoration work as of the fall of 2022.[116] "Contractor A" told the Company that it had ceased using the subcontractor for concrete restoration in July 2022, and

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113 *National Grid*, D.P.U. 25-176, Report on Investigation of Gas Restoration Beyond Scope Contractor Invoicing, at 1 (Oct. 31, 2025).

114 *Id*.

115 *Id*.

116 Exh. DPU-16-4.

"Contractor B" provided invoice data demonstrating that it last used the subcontractor in November 2022. The Company also sent demand letters to both "Contractor A" and "Contractor B" seeking to recover costs invoiced for beyond-scope work based on provisions in the contracts between the Company and both contractors.[117] The Company also implemented process improvements to prevent beyond-scope invoicing for restoration and other ancillary services provided by contractors for capital construction projects going forward.

Q. How is the Company handling the financial impacts to ratepayers of having included beyond-scope costs in its rate base?

A. Following the analysis of a sample of concrete and asphalt restoration invoiced by "Contractor A" and "Contractor B" for 2021–2022, the Company extrapolated those results across concrete restoration work performed in 2021–2022 by both contractors. The Company calculated the percentage of work beyond scope for those years and applied that percentage to all concrete restoration performed by the two contractors from 2014–2020.[118] As a result of these calculated quantities of beyond-scope concrete restoration, the Company determined the investment previously placed in rate base and the revenue collected to assess the financial impact on ratepayers. As a result of these calculations, the Company is proposing to remove $4,240,736 in capital investments in service from rate base, exclude $31,022 in capital additions not in service

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[117] Exh. Att. DPU-2-1-1, at 25–26. The Company, however, is unable to pursue a similar claim against the subcontractor company due to the lack of a direct contract and the statute of limitations for a tort action.

[118] Exhs. Att. DPU-2-1-1, at 20–22; DPU-22-1.

from being included in future base, and refund $3,386,748 to customers, which is the amount collected for assets in rate base plus interest.[119]

Q. Are the calculations for the removal of costs from rate base and refund of costs to ratepayers accurate?

A. No. When calculating the amount of beyond-scope work in the samples, the Company included projects that had a Change Control Form ("CCF") approved by a supervisor, or where the expected scope of restoration was unable to be determined as having zero deviation from the expected amount of work.[120] By including those instances as part of the count of projects in the samples, the denominator used to divide the total amount of beyond-scope costs and determine the average beyond-scope costs per project increased. This, in turn, reduced the percentage applied to each sample stratum, contractor, and year as part of the extrapolation calculations, resulting in extrapolated cost estimates that were lower than they would have been otherwise. This reduced extrapolation thereby reduced the estimate of excess work billed for 2014–2020 to be removed from rate base and refunded to customers.

Q. Why should projects with an "indeterminate" conclusion have been excluded from the calculations?

A. There were ten projects for which it was not possible to determine the expected quantities of restoration due to field conditions or lack of documentation. The changing nature of the sites where the work took place can make it impossible to accurately know what work would have been

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119 *Id*. at 20.

120 Exhs. Att. DPU-2-1-6; Att. DPU-2-1-1, at 15.

required in prior years. This was why the restoration performed in 2014–2020 was not part of the sampling and was estimated using results from more recent sampling. That same logic should have been applied to the projects that had indeterminate conclusions, which could have been accomplished by removing them from the samples and adjusting the sample sizes and calculations accordingly.

Q. Why should projects that had a CCF approved by a Company Supervisor have been excluded from the calculations?

A. The investigation did not calculate expected quantities or costs of restoration for projects that had a CCF executed and approved, because the Company had approved the increased restoration work, and thus there could be no beyond-scope work on these projects. However, Company Supervisors did not determine or record the amount of concrete restoration required nor review or approve the quantities of restoration, they relied on the integrity of the contractors' invoices due to a focus on safety and quality,[121] and they did not use field observations or photographic documentation when approving CCFs for concrete restoration.[122] This lack of actual control over the work performed and ultimately invoiced by contractors defeats the purpose of a change control process and renders a CCF a meaningless document that fails to indicate that any additional work was necessary.

Ideally, the investigation would have calculated expected quantities and costs of concrete restoration for the projects with CCFs in recognition that a CCF did not provide evidence of the amount of restoration that was necessary. However, without that analysis and calculation of

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121 Exh. AG-3-89.

122 Exh. AG-3-90.

expected restoration, the next best alternative is to exclude projects with CCFs from the samples, adjust the sample sizes accordingly, and use the extrapolation process to estimate the amount of beyond-scope work for the entire year, including these projects in the total population.

The projects with approved CCFs pose a difficulty for the Company, as they have approved this work, albeit without proper oversight and control, making it more difficult to hold the contractors responsible for reimbursing the Company for those expenses. However, that difficulty stems from the Company's poor management practices and ineffective oversight. Ratepayers should not bear any costs for the Company's failures in overseeing restoration work, as the consequences should be borne by shareholders, as management acts on their behalf.

Q. Please provide and describe the corrected calculations.

A. Removing the projects with CCFs and the projects with "indeterminate" conclusions from the various sample strata results in changes to the results and extrapolation for each contractor shown in Exhibit Attachment DPU-2-1-3.[123] The results are an increase in the "Total Extrapolation Adjusted Beyond Scope Quantity Dollar Percentage" for each contractor. The corrected results are shown below.

[123] Exh. Att. DPU-2-1-3, at 13-14

Total Extrapolated Adjusted Beyond Scope Quantity Dollar Amount:	**$ 1,158,829.94**
Total Extrapolated Adjusted Beyond Scope Quantity Dollar Percentage:	17.24%

Contractor A 2021-2022 Revised Extrapolation

Year	Strata	Population Size	Total Population Invoice Line Cost	Sample Size	Total Sample Invoice Line Cost	Adjusted Beyond Scope Quantity Dollar Amount in Sample	Extrapolated Adjusted Beyond Scope Quantity Dollar Amount
2021	1	12	$ 1,236,376.17	1	$ 134,879.36	$ 6,159.82	$ 73,917.86
	2	52	$ 1,851,584.81	2	$ 60,091.64	$ 4,506.87	$ 117,178.70
	3	433	$ 1,135,790.26	6	$ 19,132.50	$ 7,017.60	$ 506,436.58
2022	1	6	$ 713,020.77	2	$ 244,882.33	$ 32,574.53	$ 97,723.59
	2	25	$ 1,114,745.74	2	$ 124,696.88	$ 21,718.76	$ 271,484.55
	3	291	$ 671,100.03	8	$ 18,150.63	$ 2,531.65	$ 92,088.67
Total		**819**	**$ 6,722,617.78**	**21**	**$ 601,833.34**	**$ 74,509.23**	**$ 1,158,829.94**

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Total Extrapolated Adjusted Beyond Scope Quantity Dollar Amount:	**$ 920,258.79**
Total Extrapolated Adjusted Beyond Scope Quantity Dollar Percentage:	23.85%

Contractor B 2021-2022 Revised Extrapolation

Year	Strata	Population Size	Total Population Invoice Line Cost	Sample Size	Total Sample Invoice Line Cost	Adjusted Beyond Scope Quantity Dollar Amount in Sample	Extrapolated Adjusted Beyond Scope Quantity Dollar Amount
2021	1	9	$ 634,260.07	4	$ 265,568.75	$ 101,373.97	$ 228,091.43
	2	35	$ 1,011,860.61	5	$ 163,971.04	$ 36,753.84	$ 257,276.89
	3	94	$ 479,294.53	3	$ 18,879.78	$ (5,501.61)	$ (172,383.86)
2022	1	15	$ 1,078,503.33	4	$ 290,396.20	$ 114,480.97	$ 429,303.65
	2	20	$ 461,935.08	3	$ 72,155.10	$ 15,765.78	$ 105,105.23
	3	82	$ 192,854.86	3	$ 7,107.53	$ 2,665.81	$ 72,865.45
Total		**255**	**$ 3,858,708.48**	**22**	**$ 818,078.40**	**$ 265,538.77**	**$ 920,258.79**

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3 The corrected calculations and results above should then be applied to the concrete restoration
4 work identified by the Company as having been completed in 2014–2020, as well as to recalculate

the financial impact on ratepayers and adjust the Company's proposed amounts for removal from rate base, exclusion from rate base in future proceedings, and refunding to customers.

VII. REVIEW AND SUMMARY OF RECOMMENDATIONS

Q. Please review your testimony and summarize your recommendations.

A. In summary, the Department should prioritize affordability as the Commonwealth pursues its climate objectives, particularly when it comes to constraining for-profit utility investments in the Commonwealth's gas distribution systems. To that end, I recommend that the Department:

- Disallow $67,158,010 in the Company's historical capital spending, which includes projects I identified as unnecessary, premature, or cost-ineffective;
- Disallow the inclusion of any post-test year capital spending in rate base as part of this case;
- Disallow the Company's proposal to begin earning a return on its investment for the Mid-Cape Replacement Project;
- Reject the Company's proposal to roll-in LNG spending during the PBR term;
- Adopt my recommendations regarding improvements to the Company's proposed PBR scorecard metrics to better measure the Company's performance and ensure that ratepayers benefit from the PBR plan;
- Deny the Company's proposed GSRC Recovery Tracker and proposed Research, Development, and Demonstration Project spending;
- Adopt my recommendations regarding changes to the Company's proposed NPA Shared Savings Mechanism, including setting the customer/Company split at 90/10, and allowing regulatory asset treatment for *completed* NPAs with a 15-year recovery and carrying charges based on the Company's cost of long-term debt, currently 4.55 percent.
- Increase the amounts removed from rate base to $5,728,409 and the amounts refunded to customers to $4,517,714, for the Company's investigation into third-party contractor invoicing issues.

Q. Does this conclude your testimony?

A. Yes, but I reserve the right to supplement this testimony should new information become available.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Boston Gas Company d/b/a National Grid	**D.P.U. 26-50**

AFFIDAVIT OF NICHOLAS ONYSZCZAK

Nicholas Onyszczak does hereby depose and say as follows:

I, Nicholas Onyszczak, on behalf of the Massachusetts Attorney General's Office, certify that the testimony, including information responses, which bear my name was prepared by me or under my supervision and is true and accurate to the best of my knowledge and belief.

Signed under the pains and penalties of perjury this 8th day of May, 2026.

N. Onyszczak

Nicholas Onyszczak