

**COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES**

The Berkshire Gas Company 2025 Climate Compliance Plan	D.P.U. 25-40
Boston Gas Company d/b/a National Grid 2025 Climate Compliance Plan	D.P.U. 25-41
Fitchburg Gas and Electric Light Company d/b/a Unitil 2025 Climate Compliance Plan	D.P.U. 25-42
Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty 2025 Climate Compliance Plan	D.P.U. 25-43
NSTAR Gas Company & Eversource Gas Company of Massachusetts d/b/a Eversource Energy 2025 Climate Compliance Plan	D.P.U. 25-44/45

**INITIAL BRIEF OF THE
MASSACHUSETTS DEPARTMENT OF ENERGY RESOURCES**

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I. INTRODUCTION

On April 1, 2025, the Berkshire Gas Company, Boston Gas Company d/b/a National Grid, Fitchburg Gas and Electric Light Company d/b/a Unitil 2025, Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty, and NSTAR Gas Company & Eversource Gas Company of Massachusetts d/b/a Eversource (together, the LDCs) filed Climate Compliance Plans (CCPs) for approval by the Department of Public Utilities (Department). The LDCs seek approval of the CCPs, Non-Pipeline Alternatives Framework (NPA Framework) and CCP Factor Model Tariff included in their filings.

Early in these proceedings, the Department requested comment on the LDCs' obligation to serve customers.¹ DOER provided initial comment on October 3, 2025, and reply comment on October 22, 2025. DOER refers the Department to its recommendations in those comments as to the LDCs' legal obligations.

DOER hereby submits this initial brief on the LDCs' CCP filings in accordance with the Department's procedural schedule. **DOER maintains that the LDCs' CCPs are inactionable and unenforceable and do not aid the Commonwealth in meeting its emission reduction sublimits. In addition, the NPA Framework will not adequately consider NPAs or implement NPAs on a timeline sufficient to avoid unsustainable investment in the natural gas distribution system. Accordingly, the Department should reject the plans and require that the LDCs refile them, incorporating DOER's recommendations described below.**

¹ Hearing Officer Memorandum Requesting Comments Regarding Legal Issues Associated with Electrification Demonstration Projects By Gas Local Distribution Companies (Aug. 26, 2025).

II. BACKGROUND

In 2008, *An Act Establishing The Global Warming Solutions Act* (GWSA) established a comprehensive regulatory framework to address climate change.² In 2021, *An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy* (Roadmap Act) committed the Commonwealth to achieve net zero Greenhouse Gas (GHG) emissions by 2050.³ The Commonwealth's approach requires careful planning to achieve emission reductions at an appropriate pace, and with an affordable mix of technologies and strategies. In 2024, *An Act Promoting a Clean Energy Grid, Advancing Equity and Protecting Ratepayers* (Grid Equity Act of 2024) made several revisions to the Gas System Enhancement Program (GSEP), and elsewhere granted the Department authority to vary the uniformity of the availability of gas service in the Commonwealth.⁴

The Executive Office of Energy and Environmental Affairs (EEA) has primary responsibility for identifying strategies to meet the Commonwealth's emission limits.⁵ EEA released the *Massachusetts 2050 Decarbonization Roadmap* in 2020, which identified cost-effective and equitable strategies to ensure Massachusetts achieves net-zero GHG emissions (Net Zero) by 2050.⁶ As required by the Roadmap Act, EEA set emission limits for 2025 and 2030,⁷ and, in June of 2022, released the *Massachusetts Clean Energy and Climate Plan for 2025 and*

² St. 2008, c. 169.

³ St. 2021, c. 8, § 8, *enacted as* G.L. c. 21N, §3.

⁴ St. 2024, c. 239.

⁵ G.L. c. 21N, §3.

⁶ EEA, *Mass. 2050 Decarbonization Roadmap* (Dec. 2020), available at <https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download>.

⁷ The interim emission limits must be sector-based and economy-wide; and include Residential Heating and Cooling, Commercial and Industrial Heating and Cooling, Transportation, Electric Power, Natural Gas Distribution and Service, and Industrial Processes sub-sectors. G.L. c. 21N, §3.

2030 (2025/2030 CECP).⁸ In December of 2022, EEA released the CECP for 2050 which provides details on the actions the Commonwealth will undertake to put the Commonwealth on a pathway to achieve Net Zero in 2050 (2050 CECP).⁹

The LDCs must comply with legislative actions and Department directives which prioritize, *inter alia*, reductions in GHG emissions to meet statewide GHG emission limits and sublimits set by EEA.¹⁰ The Department has twice required the LDCs to report on how the LDCs will contribute to emission sublimits.¹¹ In its *Investigation into the Future of Gas*, the LDCs developed Net Zero Enablement Plans (NZEPs) to lay out a future of the gas distribution system consistent with the Commonwealth's GHG limits.¹² The LDCs accompanied the NZEPs with a Pathways Report with multiple scenarios to achieve Net-Zero emissions.¹³

The Department made several findings on the NZEPs in its Order on Regulatory Principles and Framework.¹⁴ The Department explicitly prioritized no pathway or technology, but found the LDCs failed to demonstrate that their core strategies in the NZEPs, namely hybrid heating backup, hydrogen, or low-carbon fuels (LCFs), would achieve the Commonwealth's emission reduction limits affordably and cost effectively.¹⁵ The Department instead directed the LDCs to focus on known and market-ready technologies, with demonstration projects of geothermal and targeted

⁸ Massachusetts Clean Energy and Climate Plan for 2025 and 2030 (2025/2030 CECP); available at <https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030>.

⁹ EEA, Massachusetts Clean Energy and Climate Plan for 2050 (2050 CECP); available at <https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050>.

¹⁰ G.L. c. 25 § 1A; D.P.U. 20-120 at 133 (internal citations omitted).

¹¹ *Vote and Order Opening Investigation*, D.P.U. 20-80 (2020); D.P.U. 20-80-B at 133-134.

¹² See D.P.U. 20-80, Exhs. ES-NZEP at 11; NG-NZEP at 2; UN-NZEP at 3; BGC-NZEP at 8; LU-NZEP at 3.

¹³ Energy+Environmental Economics, Independent Consultant Report, Considerations and Alternatives for Regulatory Designs to Support Transition Plans (Mar. 2022).

¹⁴ D.P.U. 20-80-B.

¹⁵ *id.* at 35, 55-56, 68-70, 79-84.

electrification.¹⁶ The Department found that future LDC operations should lead to a “long-term use of the natural gas distribution system” that is “generally ... limited to strategic circumstances where electrification is not feasible for all natural gas applications, and RNG and hydrogen would be appropriate only for those specific end uses.”¹⁷

III. STANDARD OF REVIEW

The Department directed the LDCs to expand upon the NZEPs in the CCPs, identifying these proceedings as the appropriate forum to adjudicate company-specific plans.¹⁸ The Department established that the CCPs must be actionable and enforceable, not merely a summary of existing plans and processes.¹⁹ The Department will determine if the CCPs respond to their directives, by proposing to (1) contribute to the prescribed GHG emission sublimits set by EEA for both Scope 1 and Scope 3 emissions; (2) satisfy customer demand safely, reliably, affordably, and equitably, using known and market-ready technologies; (3) use pilot or demonstration projects to assist in identifying investment alternatives; (4) incorporate the evaluation of previous metrics, and (5) implement recommendations for future plans.²⁰ The Department will review if the LDCs detail the total investment required and include a description of at least one alternative method to meet the required emissions reductions, providing the estimated costs for the considered alternative, and a demonstration that the proposed plan is superior to the alternative.”²¹

Following DOER’s recommendations on August 21, 2024 (Open Letter), the Department directed the LDCs to include in each CCP a “[d]iscussion of each of DOER’s recommendations

¹⁶ D.P.U. 20-80-B at 134.

¹⁷ *id.* at 70.

¹⁸ *id.* at 133-134.

¹⁹ D.P.U. 20-80, Hearing Officer Memorandum on LDC Climate Compliance Plans at 4 (Jan. 24, 2025).

²⁰ *id.* at 4 (citing D.P.U. 20-80-B at 134-135).

²¹ D.P.U. 20-80-B at 135.

regarding the key principles, substance, and format for the CCPs.”²² Furthermore, “if an LDC declines to follow any of DOER’s recommendations, identify the recommendation and explain the decision not to follow it.”²³

The LDCs include for review and approval a final NPA Framework to aid the Department in closely scrutinizing additional gas infrastructure investments, minimizing additional investment in gas distribution infrastructure and achieving decarbonization in the residential, commercial, and industrial sectors.²⁴ To receive approval, the NPA Framework must operate in a manner that allows the LDCs to adequately consider the viability and cost-prohibitiveness of each NPA in order to receive full cost recovery for traditional gas system investments.²⁵

On August 7, 2025, the Department issued its *Interlocutory Order on Policies and Practices for Line Extension Allowances and Contributions in Aid of Construction for Gas Local Distribution Companies*.²⁶ In this proceeding, parties were able to submit evidence and brief on the Revised Straw Proposal from the Department’s Interlocutory Order.²⁷ The Department required each LDC to file any proposed revisions to its tariffs necessary to implement the Revised Straw Proposal. The LDCs filed these revisions on October 20, 2025.²⁸

As DOER discusses below, the CCPs and the NPA Framework do not comply with the Department’s directives and limit the Commonwealth’s ability to achieve the GHG emission limits.

²² D.P.U. 20-80, Hearing Officer Memorandum on LDC Climate Compliance Plans at 4 (Jan. 24, 2025).

²³ *id.*

²⁴ D.P.U. 20-80-B at 14; D.P.U. 25-41, Exh. NG-CCP Att. 3 (NPA Framework)

²⁵ D.P.U. 20-80-B at 98.

²⁶ D.P.U. 20-80-E.

²⁷ *id.* at 19.

²⁸ Exhs. 25-40 through 25-44/45, LDCs-1, LDCs-2.

IV. ARGUMENT

A. The CCPs do not provide actionable and enforceable plans and do not contribute to statewide emission reductions

The Department directed the LDCs to move beyond business as usual and provide actionable and enforceable plans in their CCPs, not merely a summary of existing processes.²⁹ The Department specifically required that the CCPs demonstrate how each LDC proposes to contribute to the prescribed GHG emission reduction sublimits set by EEA for both Scope 1 and Scope 3 emissions.³⁰ Instead, the CCPs only reiterate existing initiatives and requirements, and propose to explore, monitor, and analyze circumstances for the next five to ten years, keeping the CCPs in a “pathfinding stage.”³¹

To be considered actionable by the Department, the CCPs should have proposed emission reduction contributions for all EEA sublimits to which their Scope 1 and Scope 3 emissions contribute, proposed initiatives to achieve these reductions on reasonable timelines, and estimated emission reduction potential and costs of these initiatives. Such concrete plans would bridge the gap between emissions reductions from existing programs and the reductions to the LDCs’ Scope 1 and Scope 3 emissions that are necessary for the Commonwealth to achieve its sublimits, thereby describing a pathway to Net Zero by 2050. Because the LDCs failed to provide such plans, the Department should direct the LDCs to refile the CCPs.

Each LDC has the critical role in the transition to not only ensure safety and reliability of its system but also to ensure orderly management so that remaining customers do not face undue financial burdens before transitioning from natural gas.³² The CCPs must reflect the LDCs’ role

²⁹ D.P.U. 20-80, Hearing Officer Memorandum on LDC Climate Compliance Plans at 4 (Jan. 24, 2025).

³⁰ D.P.U. 20-80-B at 134-135.

³¹ See, e.g. D.P.U. 25-41, NG-CCP, Att. 1 at 1; D.P.U. 25-44/25-45, ES-CCP-1 at 16.

³² 2050 CECP at 82-83.

and present the Department, policymakers, and other stakeholders, with transparent, comprehensive plans for affordable decarbonization of the natural gas system.

1. The CCPs as filed will not meaningfully contribute to or advance necessary emission reductions

The Department required the CCPs to include contributions to emission reductions for the LDCs' Scope 1 and Scope 3 emissions under the CECP sublimits.³³ The Commonwealth cannot meet its emission limits equitably and affordably without LDC efforts to reduce Scope 3 emissions. Emissions from the building sector must fall by 93 percent relative to 1990 levels for the Commonwealth to meet Net Zero by 2050.³⁴ Currently, natural gas comprises 63 percent of emissions from the building sector in Massachusetts, and gas consumption for the building sector must fall by a minimum of 86 percent by 2050 to achieve the CECP building sector sublimits.³⁵ Indeed, in order to achieve building sector emissions limits, the Commonwealth needs to reduce the use of natural gas while protecting consumers from overpaying for long-lived investments that may not be needed beyond 2050.³⁶

Scope 3 emission reporting and contribution targets are building blocks for the Commonwealth to evaluate the LDC progress in managing the transition away from natural gas.³⁷ However, the only Scope 3 reductions proposed by the LDCs are under the existing 2025-2027 Three-Year Energy Efficiency Plan (Three-Year Plan).³⁸ The LDCs rationalize the lack of additional Scope 3 reductions, stating it would be “impractical” for the LDCs to propose “targets for their contributions to the greenhouse gas emissions reduction sublimits” for emissions that they

³³ D.P.U. 20-80-B at 134.

³⁴ 2050 CECP at 55.

³⁵ Exh.AG-DL-DM-5, Summary.

³⁶ 2050 CECP at 82-83.

³⁷ D.P.U. 20-80-C at 29; D.P.U. 20-80-B at 134.

³⁸ LDC-Rebuttal-Policy-1 at 31; DPU-Common 1-1; AG-TL-1 at 6 (referring to LDC obligations under G.L. c. 25, §21 and MassDEP regulations at 310 CMR 7.71 and 7.73).

cannot fully control.³⁹ Contrary to the LDC claim, the Department did not limit its requirement to include Scope 3 emissions reporting in the CCPs to those fully within LDC control.⁴⁰ In fact, the Department explicitly denied reconsideration of how the LDCs should treat Scope 3 emissions.⁴¹ The LDCs do not require full control over their Scope 3 emissions to propose contribution targets and action plans for the Department to advance the Commonwealth’s climate goals, and the Department should not accept this omission as reasonable.

2. The LDCs do not build upon the NZEPs, which is inconsistent with the Department’s directives

In describing emission contributions for the CCPs, the Department ordered the LDCs to build upon the NZEPs, as well as provide a cost estimate for a method of emission reductions, and an alternative method, with a demonstration that the preferred method is superior to the alternative.⁴² In Order 20-80-B, the Department found that (1) it will be impractical to maintain the gas distribution system solely for use of hybrid heating systems in cold weather;⁴³ and (2) LCFs, particularly renewable natural gas (RNG), are unproven and expensive strategies for reducing emissions from the gas distribution system.⁴⁴ More broadly, the Department reasoned that a resilient and affordable future gas system would be “limited to strategic circumstances where electrification is not feasible for all natural gas applications.”⁴⁵

The Department’s reasoning is bolstered by the significant challenges in continuing the business-as-usual maintenance of the natural gas distribution system. First, electrification is currently expected to be the least-cost and lowest-risk building decarbonization strategy at the

³⁹ CLF Common 1-3.

⁴⁰ See D.P.U. 20-80-C at 29.

⁴¹ *id.*

⁴² D.P.U. 20-80-B at 135.

⁴³ *id.* at 81.

⁴⁴ *id.* at 68.

⁴⁵ *id.* at 70.

customer and system level,⁴⁶ and presents opportunities for minimizing costs through gas asset decommissioning.⁴⁷ As the Commonwealth pursues and implements electrification, overall demand for natural gas will likely decline.⁴⁸ Second, ratepayers, especially the most vulnerable, face financial risks, because natural gas distribution costs have risen significantly in recent years and will likely continue to rise.⁴⁹ Third, present-day LDC practices for maintaining the existing distribution system are already and increasingly burdening ratepayers to an unacceptable degree.⁵⁰ Indeed, while the gas system will continue to exist in some form after 2050, meeting the Commonwealth’s GHG reduction goals and maintaining affordability requires changes to the LDC business models, careful management of investments, and reduction of costs to maintain the existing natural gas delivery system.⁵¹ **As noted by the Attorney General’s Office, it will be prohibitively expensive to maintain the current gas distribution system for a fraction of existing demand throughput.**⁵² Ultimately, the Commonwealth must effectuate an “orderly and equitable drawdown of fossil fuel use and infrastructure ... to ensure equitable outcomes, so that higher costs are not borne by consumers least able to pay.”⁵³ Transitioning to an appropriately-sized, targeted gas distribution system is an operational imperative for the LDCs, their customers, and the Commonwealth.

⁴⁶ See Decarbonization Roadmap at 22; 2025 CECP at 27.

⁴⁷ See 2050 CECP at 82.

⁴⁸ 2050 CECP at 61.

⁴⁹ See Exh. AG-MJW-1, Appendix A at 4; Decarbonization Roadmap at 15, 51, 52 (increased building electrification is expected to drive down the number of natural gas customers, increasing stranded cost risk, and low carbon fuels (LCFs) are not well positioned to reduce risk); 2025 CECP at 78 (significant rate increases could occur if LDCs continue investing while consumption decreases).

⁵⁰ See, e.g., D.P.U. 24-GSEP-06 at 1.

⁵¹ See Roadmap at 51; 2025 CECP at 28, 78; 2050 CECP at 83.

⁵² AG-DL-DM-1 at 32-33.

⁵³ Decarbonization Roadmap at 53.

Unfortunately, the proposed CCPs do not build on the NZEPs, which had the explicit goal of pursuing a pathway to Net Zero by 2050, despite the time allotted to develop the CCPs.⁵⁴ Rather than propose a method of emission reduction aligned with the Department's findings, the LDCs continue to promote the hybrid heating pathway⁵⁵ and socialization of costs to explore LCFs in the near term, without providing any new information to support divergence from the Department's prior findings.⁵⁶ In addition, the LDCs state that new initiatives proposed, including the NPA Framework and Integrated Energy Planning (IEP) are not designed to reduce emissions.⁵⁷ Furthermore, the LDCs do not conduct analysis to model impact of their proposed actions on emissions reductions or cost savings.⁵⁸ To omit connection between the LDC programs and the Commonwealth's emission limits and affordability goals effectively protects the LDC business-as-usual conduct from Department review.

3. *The Department should direct the LDCs to refile the CCPs to deliver actionable and enforceable plans*

While the Commonwealth is responsible for establishing laws and policies that advance the clean energy transition, the LDCs, as owners and operators of the gas distribution system, are the most-knowledgeable entities to propose specific changes to their operations for maintaining a safe and affordable gas distribution system while pursuing emission reductions. The Department, policymakers, and other stakeholders rely on the LDCs to present workable plans and recommendations for aligning their infrastructure and business practices with the Commonwealth's statewide climate and affordability goals.

⁵⁴ D.P.U. 20-80-B at 134 (allocating sixteen months to LDC development of the CCPs).

⁵⁵ Exh. LDC-Rebuttal-Policy-1 at 29.

⁵⁶ See Exhs. D.P.U. 25-44/45, ES-CCP at 179-180, D.P.U. 25-41, NG-CCP at 94; D.P.U. 25-42, UN-CCP at 59; D.P.U. 25-40, BGC-CCP at 36-37, 46.

⁵⁷ Exh. LDC-Rebuttal-NPA/IEP-1 at 18, 60.

⁵⁸ D.P.U. 25-44/45, AG-2-8; D.P.U. 25-44/45, CLF-Common-1-6.

The LDCs have not provided coherent, actionable plans for moving beyond business-as-usual, despite clear guidance from the Department to describe actionable and enforceable plans charting a pathway to Net Zero by 2050.⁵⁹ In order to effectively advance the Commonwealth's emission reduction goals and meet its requirements, the Department should direct each LDC to refile its CCP. DOER's Open Letter offered the LDCs the contours of concrete, quantifiable and measurable plans, rooted in scenario and impact analyses, identifying various pathways to comply with D.P.U. 20-80-B and the 2025/2030 CECP.⁶⁰ The LDCs declined to adopt DOER's substantive recommendations and provide little explanation for this decision.⁶¹ In addition to refiling the CCPs, DOER further recommends the Department include a requirement to incorporate DOER's recommendations for scenario analysis and quantifiable action plans that align with the sublimits established in the CECP.⁶²

To be actionable and enforceable, the CCPs require several modifications and enhancements prior to Department review, including the following:

1. Estimate and report on all the LDCs' Scope 1 and Scope 3 emissions;⁶³
2. Forecast Scope 3 emission reductions from existing programs;⁶⁴
3. Identify emission reduction targets for Scope 1 and Scope 3 emissions that would align LDC operations with all EEA sublimits to which the LDCs' Scope 1 and

⁵⁹ *supra* at IV.A.1 & IV.A.2.

⁶⁰ Exh. DOER-2 at 3-10.

⁶¹ D.P.U. 25-41 Exh. NG-CCP, Att. 1; *see also* Exh. DOER-1 at 11; Exh. CLF-SC-BC/MF at 27.

⁶² Exh. DOER-2 at 3.

⁶³ D.P.U. 20-80-C at 31.

⁶⁴ Exh. DOER-2 at 5.

Scope 3 emissions contribute, regardless of whether the LDCs have full control over those emissions;⁶⁵

4. Propose strategies and actions necessary to meet these targets, supported by scenario analysis.⁶⁶ However, as stated previously, it is inappropriate for the LDCs to pursue LCFs or hybrid heating as central pillars of an approved pathway to Net Zero by 2050;⁶⁷
5. Identify how targeted electrification of certain portions of the gas system will enable the LDCs to optimize costs to meet these targets, including appropriate levels of geographic detail;⁶⁸
6. Calculate the total investment required to perform the necessary actions to meet these targets;⁶⁹
7. Identify barriers to implementation and present possible solutions to those barriers.⁷⁰

Just as EEA has identified targets via sector-specific sublimits to enable the Commonwealth to achieve its emission limits, the LDCs – as the parties with specific knowledge of their own gas systems – must identify goals for reducing emissions and right-sizing the gas system to enable the Commonwealth to achieve these limits as affordably as possible.

⁶⁵ D.P.U. 20-80-C at 29; D.P.U. 20-80-B at 134.

⁶⁶ Exh. DOER-1 at 12-13.

⁶⁷ *supra* at IV.A.2.

⁶⁸ Exh. DOER-1 at 13; DOER-2 at 4.

⁶⁹ D.P.U. 20-80-B at 134.

⁷⁰ Exh. DOER-1 at 13.

B. The CCPs continue unsustainable investment in the natural gas distribution system

The Department is closely scrutinizing additional investment in the natural gas distribution system to minimize costs that may be stranded in the future as the Commonwealth scales up decarbonization measures.⁷¹ However, to date, the LDCs' primary strategy for reducing their Scope 1 emissions has been to replace leak prone pipelines (LPP) through their Gas System Enhancement Plans (GSEP).⁷² As LDC spending on LPP replacement through GSEP has skyrocketed in recent years – creating significant affordability concern and stranded asset risk without providing commensurate benefits – the LDCs must revise this practice to efficiently transition the gas system.⁷³

In response to the Department's directive to minimize additional investment in the natural gas distribution system, the LDCs instead propose an NPA Framework that is not designed to avoid LPP replacements through NPAs until 2030 at the earliest.⁷⁴ In the interim, the LDCs propose to continue their business-as-usual practice of spending hundreds of millions of dollars each year on GSEP replacement projects.⁷⁵ In light of these significant and potentially avoidable costs, the Department must ensure that the LDCs use an NPA Framework capable of implementing viable, non-cost-prohibitive NPAs in the near term.

⁷¹ D.P.U. 20-80-B at 15.

⁷² See, e.g., D.P.U. 25-40, DPU Common 1-1.

⁷³ See, e.g., D.P.U. 24-GSEP-06 at 1; see also 2050 CECP at 82-83.

⁷⁴ Only National Grid states it might implement NPAs before 2030, and only with respect to demand reduction NPAs. See D.P.U. 25-41, Exh. NG-CCP at 46; see also D.P.U. 25-40, Exh. BGC-CCP at 33-34; D.P.U. 25-42, Exh. UN-CCP at 41; D.P.U. 25-43, Exh. LU-CCP at 28-31; D.P.U. 25-44/25-45, Exh. ES-CCP at 62.

⁷⁵ See D.P.U. 24-GSEP-01 through D.P.U. 24-GSEP-06, Exh. AG-DL-DM-4 (GSEP Capex Summary) at 3.

1. *The NPA Framework will not avoid GSEP replacements on a reasonable timeline*

The GSEP statute requires the LDCs to remove all LPP on an accelerated basis, which may be accomplished through replacement, retirement, or improvement of existing infrastructure.⁷⁶ The Department directed the LDCs to immediately begin evaluating all investments, including removals under GSEP, to determine if an NPA could avoid the need for additional infrastructure investments.⁷⁷ To date, almost two and half years later, the LDCs have not avoided a single infrastructure investment through an NPA.⁷⁸ LPP replacement remains the LDCs' default removal strategy, despite the Department's clear directives to prioritize retirement through NPAs.

The Department recently concluded that the GSEP program “is not striking a good balance between safety and affordability.”⁷⁹ LDC capital expenditures through GSEP have increased by an average of 11.9 percent per year for the past decade – from \$291 million per year in 2015 to \$892 million per year in 2025⁸⁰ – and have comprised the majority of all LDC capital expenditure since 2020.⁸¹ As of 2025, annual capital expenditures through GSEP are now more than double all capital expenditures approved for a *five-year period* through the Electric Sector Modernization Plans (ESMP).⁸² In addition to driving up ratepayer bills directly through an accelerated cost

⁷⁶ G.L. c. 164, §145.

⁷⁷ D.P.U. 20-80-B at 15; D.P.U. 20-80-C at 21, 27.

⁷⁸ D.P.U. 25-40 through 25-45, Exhs. RR-AG-Unitil-1; RR-AG-National Grid-1; RR-AG-Eversource-2; RR-AG-Berkshire-1.

⁷⁹ See, e.g., D.P.U. 24-GSEP-06 at 1.

⁸⁰ D.P.U. 24-GSEP-01 through D.P.U. 24-GSEP-06, Exh. AG-DL-DM-1 at 8.

⁸¹ D.P.U. 25-GSEP-01 through 06, Exh. SC-CLF-MF-1 at 33 (citing 24-GSEP-01 through 06, Exh. AG-DL-DM-1 at 9).

⁸² Compare 2 D.P.U. 24-GSEP-01 through D.P.U. 24-GSEP-06, Exh. AG-DL-DM-4 (GSEP Capex Summary) at 3 (\$892 million); with D.P.U. 24-10, Att. B, DPU-Common-13-2 (\$95.0 million); D.P.U. 24-11, Compliance Exh. Spending Cap at 1 (\$389 million); D.P.U. 24-12, Att. DPU-Common-13-2 at 1 (\$19.3 million).

recovery mechanism, GSEP is also a primary driver of proposed base rate increases in the three most recent LDC rate cases.⁸³

NPAs are a promising strategy for retiring LPP and simultaneously making progress toward the Commonwealth's long-term climate and affordability goals.⁸⁴ By their own admission, the LDCs propose an NPA Framework that is not designed to avoid LPP replacements through NPAs until 2030 at the earliest.⁸⁵ This approach continues a business as usual model, allowing the LDCs to avoid retiring LPP for at least seven years since first directed to explore alternatives.⁸⁶ Given the magnitude of increasing pipeline replacement costs through GSEP, prioritizing retirement of LPP through NPAs under the GSEP Program must be a top priority for the Department.

NPAs have demonstrated success in other jurisdictions. In New York, Con Edison has successfully avoided LPP replacements through NPAs on shorter timelines than the LDCs propose through the NPA Framework.⁸⁷ In December 2021, Con Edison petitioned for approval of several proposed LPP replacement NPAs as part of its Electric Advantage Program.⁸⁸ By January 2025, Con Edison had successfully avoided 10 full main replacements and five partial main replacements

⁸³ D.P.U. 26-50, Exh. NG-BOS-1 at 25-26; D.P.U. 25-85, Exh. LU-TR/KMJ-1 at 10; D.P.U. 25-170, Exh. BGC-OVERVIEW-1 at 18-19.

⁸⁴ See D.P.U. 20-80-B at 2 (noting that NPA consideration is necessary to minimize investments in the gas pipeline system that may be stranded costs in the future as decarbonization measures are implemented).

⁸⁵ See Exh. LDC-Rebuttal-NPA/IEP-1 at 22; Exhs. D.P.U. 25-41, NG-CCP at 46-47; D.P.U. 25-40, BGC-CCP at 33-34; D.P.U. 25-42 UN-CCP at 41; D.P.U. 25-43, LU-CCP at 28; D.P.U. 25-44/25-45, ES-CCP at 62.

⁸⁶ D.P.U. 20-80-B at 15.

⁸⁷ Exh. DOER-Surrebuttal-1 at 3.

⁸⁸ Consolidated Edison Company of New York, Non-Pipeline Alternatives Deployment Plan (Con Edison Plan) (Jan. 21, 2025) at 4; available at: <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={90618A94-0000-CF33-A784-CCCF4D97CEC6}>.

through NPAs.⁸⁹ It is reasonable to expect that the Massachusetts LDCs can achieve similar results, and begin avoiding smaller GSEP investments through NPAs prior to 2030. This expectation is not only reasonable – it is necessary to ensure that the LDCs adequately consider NPA opportunities to address this primary driver of increasing gas system costs.

Given the pressing need to address increasing pipeline replacement costs from GSEP and the fact that NPAs are a demonstrated, effective strategy to mitigate the risks of stranded gas infrastructure assets, the Department should direct the LDCs to establish an NPA Framework that enables the LDCs to identify and avoid unnecessary LPP replacements on a reasonable timeline.

2. The Department should direct the LDCs to revise the NPA Framework to address increasing costs

The Department has stated it will closely scrutinize whether additional gas infrastructure investments are necessary, with the express goal of minimizing costs that may be stranded in the future.⁹⁰ In furtherance of that goal, the Department required each LDC, with respect to each traditional gas investment, to demonstrate that it adequately considered an NPA and determined the NPA to be either non-viable or cost-prohibitive in order for the LDC to receive full cost recovery.⁹¹ Further, the LDCs must provide sufficient information for the Department to determine that a traditional investment was necessary and that the LDC reasonably rejected the NPA.⁹²

⁸⁹ Annual Updates to Its Long-Term Plan, Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc., May 15, 2025, at 7; available at: <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={1090D596-0000-CE87-B71A-5D3681052499}&DocTitle=CECONY%20ORU%20GSLTP%20May%202025%20Update>.

⁹⁰ D.P.U. 20-80-B at 15.

⁹¹ *id.* at 98.

⁹² D.P.U. 20-80-C at 27 (directing the LDCs to “show your work” at the time that cost recovery is sought for NPA analysis).

According to the LDCs, the proposed NPA Framework is a uniform process for identifying NPAs, but must also remain flexible in allowing the LDCs to determine viability and cost-prohibitiveness on a case-by-case basis.⁹³ Given the inherent difficulty in balancing uniformity with flexibility, the LDCs must demonstrate the reasonableness of their approach under the NPA Framework. An unreasonable or poorly designed NPA analysis cannot “adequately consider” an NPA, no matter how much time or expense an LDC applies to the analysis.⁹⁴ Otherwise, the NPA Framework would be little more than an expensive box-checking exercise that will harm, rather than benefit, ratepayers. DOER has identified several ways in which the proposed NPA Framework does not reasonably evaluate NPAs, including flaws in the NPA Framework’s design and a lack of sufficient information provided to the Department to support its review. DOER, therefore, recommends several revisions to the NPA Framework to meet the Department’s directives and deliver benefits for ratepayers.

First, the LDCs should develop analyses for three distinct NPA categories – Service Line NPAs, Main Replacement NPAs, and Demand Reduction NPAs – rather than implement a single approach that currently excludes many smaller NPAs (service line replacements) representing a significant amount of infrastructure investment.

Second, the LDCs should provide the Department with specific viability thresholds to both conserve LDC resources and provide the Department with necessary information to efficiently determine that cost-recovery is merited. Currently, the NPA Framework does not define specific thresholds that will trigger a finding that an NPA is non-viable. This approach hinders the Department’s ability to properly assess reasonableness of LDC determinations.

⁹³ Exh. LDC-Rebuttal-NPA/IEP-1 at 17, 44.

⁹⁴ Exh. LDC-Rebuttal-Tariff-1 at 18.

Third, the LDCs should include customer engagement plans for Department review that include reasonable standards for the LDCs to apply when recruiting customers and determining non-viability for lack of customer interest or participation. Currently, the LDCs decline to include any set of standards related to customer engagement.

Fourth, the LDCs should revise their benefit cost analysis (BCA) to better demonstrate both cost-effectiveness and cost-prohibitiveness to the Department. Currently, the NPA Framework includes several tests as part of the BCA that contradict well-established practices, which will cause the LDCs to unreasonably eliminate cost-effective NPAs.⁹⁵ In addition, the LDCs do not provide a clear decision-making framework for how they will determine when NPAs that are expected to increase rates are cost-prohibitive.

Fifth, the LDCs should report on and update the NPA Framework on an annual basis to promote near-term progress and quickly identify and address barriers to NPA implementation. As proposed, the LDCs will share updates on the Framework with the Department once every five years.⁹⁶ However, this proposed reporting cadence does not reflect the urgency of the Department's directive for the LDCs to minimize unnecessary additional gas system investment.⁹⁷

These changes will enable the LDCs to demonstrate to the Department that they have adequately considered NPAs and make reasonable, near-term progress on minimizing unnecessary investments – particularly GSEP investments. The Department should direct the LDCs to refile the NPA Framework, consistent with DOER's recommendations below.

⁹⁵ *infra* at IV.B.d.i.

⁹⁶ NPA Framework at 25.

⁹⁷ 20-80-B at 15; 20-80-C at 27.

a. The LDCs should create three NPA programs tailored to different customer engagement strategies and analyze Service Lines under the NPA Framework

The level of customer participation required for an NPA is the primary factor that differentiates NPA projects.⁹⁸ However, the LDCs propose a single NPA review process that treats every investment the same regardless of the level of customer participation involved. Differentiating NPA analysis based on customer participation promotes more efficient and effective NPA analysis and implementation.

The Department should direct the LDCs to streamline analysis for NPAs into three project groupings: (1) projects requiring a single customer to disconnect from the gas system (Service Line NPAs); (2) projects requiring a geographically contiguous group of customers to disconnect from the gas system (Main Replacement NPAs); and (3) projects avoiding investments through aggregate demand reduction from impacted customers (Demand Reduction NPAs).⁹⁹

This approach has proven effective for programs spearheaded by Consolidated Edison of New York (Con Edison). Con Edison developed three distinct NPA programs that align with these three categories.¹⁰⁰ The Con Edison NPA programs include the Electric Advantage Program (for avoiding main replacements), the Energy Exchange Program (for avoiding service line replacements), and the Area Load Relief Program (for addressing load growth through NPAs).¹⁰¹ Con Edison successfully avoided multiple traditional gas investments through the first two programs, including abandoning ten full mains and five partial mains through its Electric Advantage Program as well as four service lines through its Energy Exchange Program.¹⁰²

⁹⁸ Exh. LDC-Rebuttal-NPA/IEP-1 at 47.

⁹⁹ Exh. DOER-1 at 24.

¹⁰⁰ Exh. DOER-Surrebuttal-1 at 2-3.

¹⁰¹ *id.* at 2-3.

¹⁰² *id.* at 3.

Several LDCs have already tested distinct NPA review processes for investments that can be addressed by aggregate demand reduction, such as Liquefied Natural Gas (LNG) investments.¹⁰³ This reinforces the appropriateness of distinguishing between Main Replacement and Demand Reduction NPAs more broadly. To date, however, all LDCs have declined to evaluate service line replacements for NPAs.¹⁰⁴

Service line NPAs are an important opportunity for the LDCs to avoid significant GSEP infrastructure investments. For example, Eversource anticipates spending \$500 million over the next 5 years to replace 30,000 leak prone service lines.¹⁰⁵ There are likely many instances where a Service Line NPA could be viable, even if a Main Replacement NPA is not viable in the same location.

Additionally, electrifying individual customers through Service Line NPAs in the near-term will increase the viability of larger Main Replacement NPAs in the long-term. This approach is comparable to the LDCs' efforts to electrify individual customers through Mass Save in the near term, which the LDCs claim improves NPA viability in the long term by reducing the number of customers involved to implement a larger NPA in the future.¹⁰⁶ It is reasonable to expect that Service Line NPAs, which require many of the same building decarbonization measures offered through Mass Save, will provide the same benefit.

Electrification of a building as part of a service line NPA is likely to be more cost-effective than electrifying a building as part of a standalone energy efficiency program. The NPA Framework already proposes to use the Massachusetts Total Resource Cost (TRC) test, which is

¹⁰³ D.P.U. 25-41, Att. CLF 3-3-2 at 3; D.P.U. 25-GSEP-06, Exh. ES-OPS-3 at 15.

¹⁰⁴ D.P.U. 25-40, Exh. DOER Common 1-3; D.P.U. 25-41, Exh. DOER Common 1-3; D.P.U. 25-43, Exh. DOER Common 1-3.

¹⁰⁵ See D.P.U. 25-44/45, DOER-Common 3-3(e).

¹⁰⁶ Exh. LDC-Rebuttal-NPA/IEP-1 at 26-27.

used to evaluate the cost-effectiveness of Mass Save’s building decarbonization program.¹⁰⁷ As applied to a service line NPA, the TRC test will likely involve similar costs and benefits for electrification of a single customer or building, including the avoided energy costs from reduced gas consumption and the avoided social cost of carbon.¹⁰⁸ In addition, a service Line NPA includes the added benefit of avoiding the cost of the service line. Con Edison states that it conducted a BCA for a portfolio of 100 service line NPAs that identified the portfolio as cost-effective.¹⁰⁹ The LDCs should, therefore, not exclude this category from consideration and instead consider them alongside Main Replacement NPAs and Demand Reduction NPAs as part of the NPA Framework.

b. The LDCs should propose transparent and reasonable viability testing criteria and thresholds

The Department should direct the LDCs to propose clear and reasonable Initial Viability Testing criteria and thresholds in the NPA Framework, particularly regarding risk, and number and types of customers. The LDCs should apply the Initial Viability Test proactively, particularly to their LPP inventory, rather than on a case-by-case basis. Eliminating unlikely NPA candidates from the outset will help the LDCs to avoid expending resources evaluating and attempting to implement NPAs that are unlikely to be viable.

These specific viability criteria and thresholds are a starting point that the LDCs may deviate from if unexpected circumstances arise.¹¹⁰ This approach encourages transparency, while

¹⁰⁷ NPA Framework at 19.

¹⁰⁸ *id.*

¹⁰⁹ See Consolidated Edison Company of New York, Benefit Cost Analysis: Non-Pipes Alternative to Gas Service Replacements (July 2024) at 3-4; available at: <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={D005DC90-0000-C230-8FC2-3759556D71AA}&DocTitle=Con%20Edison%20Energy%20Exchange%20BCA%20Filing>.

¹¹⁰ Exh. DOER-Surrebuttal-1 at 5.

also ensuring that the LDCs retain final decision-making authority over their systems to ensure safe and reliable service.

i. LDCs should not limit Initial Viability Testing to a reactive, case-by-case basis for LPP removals

The Department should direct the LDCs to proactively evaluate safety and reliability risks for NPAs to avoid unreasonably slowing NPA evaluation and implementation, particularly for LPP replacements, as the LDCs are required to eventually retire their entire LPP inventory.¹¹¹ This would include evaluating risk, including hydraulic risk, on the entire inventory of LPP mains prior to conducting NPA analysis. For example, Con Edison in New York proactively identified its entire inventory of 2,491 leak prone radial mains (mains with a single source of supply) that have no detrimental impact on system safety or reliability, and prioritizes among those mains for NPA review and implementation.¹¹²

Additionally, the Department recently issued guidance improving the transparency and consistency of risk prioritization within GSEP filings.¹¹³ The LDCs should refine their practices for risk prioritization in response to the Department. If the LDCs identify specific risk factors that would reasonably prevent the LDC from implementing an NPA, the LDC should proactively exclude projects with those risk factors from NPA analysis to avoid expending unnecessary resources. The LDCs should subsequently evaluate NPAs based on project characteristics not related to risk, such as number and type of customers

DOER acknowledges that the LDCs must remain responsive to the dynamic conditions of their systems and that situations may arise in which the LDC may need to unexpectedly abandon

¹¹¹ G.L. c. 164, §145.

¹¹² Con Edison Plan at 7.

¹¹³ D.P.U. 25-GSEP-01 through D.P.U. 25-GSEP-06, GSEP Risk Assessment Prioritization Guidance (Sep. 26, 2025).

an NPA.¹¹⁴ While it is reasonable to consider the possibility of unexpected circumstances terminating an otherwise viable NPA, the circumstances that the LDCs cite, namely the breaking or encroachment of pipelines,¹¹⁵ can occur at any point during NPA evaluation or implementation and regardless of how much lead-time an LDC has for a given NPA.¹¹⁶ The LDCs should present the Department with proactive and transparent criteria and thresholds for assessing risk for Department approval as a starting point, with the understanding that the LDCs may need to deviate from their plans if unexpected circumstances arise.¹¹⁷

ii. The Department should narrow the scope of review in Initial Viability Testing

The Department should direct the LDCs to initially narrow the scope of review for Service Line NPAs and Main Replacement NPAs. For Service Line NPAs, DOER recommends that the LDCs initially limit their NPA analysis to projects impacting residential or small commercial customers, similar to Con Edison's Energy Exchange Program for service line replacement NPAs, through which Con Edison is initially prioritizing recruitment of single-family residential customers.¹¹⁸

For Main Replacement NPAs, DOER recommends that the LDCs initially limit their analysis to NPAs that involve a maximum of five customers and that involve either small residential or small commercial customers. The limitation is reasonable as no other U.S. utility to date has successfully completed an NPA requiring geographically coordinated electrification of

¹¹⁴ Exh. LDC-Rebuttal-NPA/IEP-1 at 24.

¹¹⁵ *id.*

¹¹⁶ NPA Framework at 24.

¹¹⁷ Exh. DOER-Surrebuttal-1 at 5.

¹¹⁸ Exh. DOER-1 at 29-30 (citing Con Edison Plan at 18).

more than five customers.¹¹⁹ Allowing the LDCs to gain experience implementing smaller and more numerous NPAs before focusing significant resources pursuing larger Main Replacement NPAs at scale through the NPA Framework will promote efficient use of LDC resources. However, as the LDCs gain experience implementing smaller Main Replacement NPAs and the required targeted electrification demonstration projects, the Department should direct the LDCs to expand these thresholds.

In addition, the LDCs should partner with municipalities participating in DOER's Fossil-Fuel-Free Demonstration Program,¹²⁰ DOER's Climate Leader Communities Program,¹²¹ or that have adopted the opt-in Specialized building codes,¹²² to identify potentially viable NPAs exceeding these thresholds (e.g. greater than five customers or that represent large commercial or industrial loads). During hearings, the LDCs stated their willingness to collaborate with municipalities to advance strategic electrification¹²³ but identified limitations around data-sharing as a barrier.¹²⁴ The Department should direct the LDCs to identify the types of data they would need to share in order to collaborate with interested municipalities.

¹¹⁹ D.P.U. 24-194, TEP-2 at 17 (citing Rocky Mountain Institute & National Grid, *Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization* (May 2024), available at: https://www.nationalgridus.com/media/pdfs/other/CM9904-RMI_NG-May-2024.pdf).

¹²⁰ DOER, *Municipal Fossil Fuel Free Building Demonstration Program*, <https://www.mass.gov/info-details/municipal-fossil-fuel-free-building-demonstration-program> (last visited Apr. 13, 2026).

¹²¹ DOER, Climate Leader Communities, <https://www.mass.gov/info-details/climate-leader-communities> (last visited Apr. 13, 2026).

¹²² DOER, 2025 Massachusetts Building Energy Codes, <https://www.mass.gov/info-details/2025-massachusetts-building-energy-codes> (last visited Apr. 13, 2026).

¹²³ D.P.U. 25-GSEP-01 through 06, SC-CLF-MF-1 at 47.

¹²⁴ Tr. Vol. I at 89.

c. The LDCs should propose specific customer engagement plans

DOER recommends that the LDCs submit customer engagement plans and standards for Service Line NPAs, Main Replacement NPAs, and Demand Reduction NPAs. The LDCs acknowledge that the success of NPAs will rely heavily on effective customer engagement, which aligns with findings from other jurisdictions.¹²⁵ As proposed, the LDCs will classify an NPA as non-viable and proceed with implementing a traditional gas investment if they do not obtain sufficient participation.¹²⁶ The final decision on viability is significantly dependent on the LDCs' efforts to engage customers, and is likely to occur after an LDC has already devoted significant resources to evaluation of the initial viability and cost-prohibitiveness of an NPA. Robust planning for customer engagement is therefore essential for the LDCs to both demonstrate that an NPA was non-viable and avoid wasting resources. However, the LDCs propose to begin recovering costs for NPA analysis without providing any plan for engaging customers or standards for how they will determine that an NPA is non-viable due to insufficient customer participation, instead proposing to submit customer engagement plans at an unspecified later date.¹²⁷

The Department should direct the LDCs to submit specific customer outreach plans for Main Replacement NPAs, Service Line NPAs, and Demand Reduction NPAs, including the methods and approximate duration of outreach they intend to perform. The plans should include how the LDCs will handle non-responsive or disinterested customers and how the LDCs would approach a project with sufficient customer interest for a partial NPA. For example, Con Edison has shared specific customer engagement plans for its Energy Exchange and Electric Advantage

¹²⁵ NPA Framework at 23; Exh. DOER-1 at 20 (citing RMI & National Grid, *Non Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization* at 12 (May 2024), available at: https://www.nationalgridus.com/media/pdfs/other/CM9904-RMI_NG-May2024.pdf).

¹²⁶ NPA Framework at 24.

¹²⁷ *id.* at 22.

Programs, explaining different strategies that Con Edison uses and plans to use to engage customers, including engagement with local officials.¹²⁸ For its Electric Advantage Program for main replacement NPAs, Con Edison lays out a clear plan for how it handles projects with limited customer interest.¹²⁹ Adopting a framework with clear procedures here will best ensure that customer participation and engagement is both performed and evaluated properly.

If an LDC performs less or different outreach than proposed in its customer engagement plan before determining that an NPA is non-viable due to lack of customer interest, the LDCs should provide the Department with a detailed explanation for the deviation. This structure gives the LDCs the flexibility to deviate from their plans if they identify that certain outreach approaches are more or less effective in certain cases than anticipated, while also expediting the Department's review of their final viability determination. The LDCs should adjust these plans as they gain more experience implementing NPAs and provide updates to the Department in annual compliance filings. This approach promotes transparency and efficiency for both the LDCs and the Department and would facilitate scaling up of NPA implementation efforts.

d. The LDCs should appropriately balance cost and rate impacts when evaluating NPA cost-prohibitiveness

The Department directed the LDCs to determine the cost-prohibitiveness of an NPA as part of the NPA Framework.¹³⁰ The LDCs propose to first perform a Benefit Cost Analysis (BCA) comprising four tests to evaluate cost-effectiveness: the Massachusetts TRC test, the Participant Cost Test (PCT), gas Rate Impact Measure (RIM) test, and electric RIM test.¹³¹ Through the BCA, the LDCs will deem NPAs which pass all four tests to be cost-effective and not cost-prohibitive,

¹²⁸ Con Edison Plan at 10-11, 17-18.

¹²⁹ *See id.* at 11.

¹³⁰ D.P.U. 20-80-B at 98.

¹³¹ NPA Framework at 16-20.

and deem NPAs that fail a single test to be not cost-effective but potentially not cost-prohibitive.¹³² This proposal is insufficient, first because the LDCs should not use the PCT and RIM tests to screen NPAs for cost-effectiveness, as doing so contradicts well-established practices for performing BCAs and will cause the LDCs to unreasonably conclude that certain projects are not cost effective.¹³³ Second, the LDC proposal does not include a framework for how they will determine cost-prohibitiveness in situations where an NPA fails the RIM test and thus is expected to increase rates.¹³⁴

DOER recommends that the LDCs instead conduct a BCA using the TRC test alone to evaluate cost-effectiveness and then perform a Rate and Bill Impact Analyses (RBA) to evaluate rate impacts. Appropriately balanced, cost-effectiveness and rate impact tests allow the LDCs to demonstrate if an NPA is cost-prohibitive.

i. The LDCs should only evaluate cost-effectiveness using the Total Resource Cost Test

The LDCs propose to evaluate cost-effectiveness using four tests, the PCT, TRC, gas RIM test, and electric RIM test. However, the RIM tests and PCT should not be used to evaluate cost-effectiveness because doing so contradicts well-established practices for performing BCAs¹³⁵ and will cause the LDCs to inappropriately conclude that certain projects are not cost-effective even if they provide net benefits to customers.¹³⁶ Accordingly, the only test that the LDCs should use to evaluate cost-effectiveness is the TRC.

Fundamentally, any method used to evaluate cost effectiveness and cost-prohibitiveness of an NPA should appropriately segment cost impacts from rate impacts. Using rate impacts to

¹³² See, e.g., D.P.U. 25-40, Exh. DOER Common 4-7.

¹³³ *infra* at IV.B.d.i.

¹³⁴ Exh. DOER-TW-Surrebuttal-1 at 8; e.g., D.P.U. 25-40, Exh. DOER Common 4-7.

¹³⁵ Exhs. DOER-TW-1 at 13-14; DOER-TW-Surrebuttal-1 at 12.

¹³⁶ Exh. DOER-TW-1 at 5.

evaluate cost-effectiveness, in this case through the RIM tests, is inappropriate because there are situations where an NPA may reduce costs but increase rates due to the recovery of lost revenues.¹³⁷ Using the RIM test to evaluate cost-effectiveness could inappropriately fail an NPA where the TRC determines that the NPA is cost-effective.

The *National Standard Practice Manual for Benefit-cost Analysis of Distributed Energy Resources* (NSPM) is the industry's primary source for guidance on BCA practices for distributed energy resources.¹³⁸ The NSPM clearly states that the RIM test should not be used to evaluate cost-effectiveness, because using RIM tests in this way combines cost-effectiveness with rate impacts, thereby conflating the two.¹³⁹ Additionally, using the RIM test for BCAs inappropriately includes sunk costs to evaluate cost-effectiveness. According to economic theory, sunk costs should not be included in a BCA because they have already been incurred and cannot be changed. BCAs should instead focus on future, incremental, long-term costs.¹⁴⁰ As discussed below, the RIM test has its place in an NPA Framework, but it should not be used to evaluate cost-effectiveness under the BCA.

The NSPM similarly states that the PCT is not appropriate for evaluating cost-effectiveness.¹⁴¹ Rather, the LDC can use the PCT to design participant incentive levels to achieve potentially conflicting goals when implementing cost-effective NPAs.¹⁴² First, to provide participating customers with as much incentive as needed to participate. Second, to minimize the

¹³⁷ Exh. DOER-TW-Surrebuttal-1 at 11.

¹³⁸ Exh. DOER-TW-1 at 2.

¹³⁹ *id.* at 12 (citing National Energy Screening Project, *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, at 2-8 (Aug. 2020) (NSPM)); *see also*, Exh. DOER-TW-1 at 19.

¹⁴⁰ NSPM at 2-3, Table 2-1.

¹⁴¹ NSPM, App. E.5.

¹⁴² Exh. DOER-TW-1 at 14-15

incentive to the participating customer, in order to minimize costs on the non-participating customers. The PCT is not relevant to determining whether an NPA is cost-effective. In response to discovery, the LDCs agree that the PCT is “primarily informative.”¹⁴³ The Department should require the LDCs not to use the PCT to evaluate the cost effectiveness of an NPA.

Of the four tests that the LDCs propose, the TRC is the only test that is appropriate for evaluating the cost-effectiveness of NPAs, as it indicates whether the NPA reduces costs and provides net benefits. The TRC is well established for evaluating energy efficiency programs and is required by the Department’s EE Guidelines.¹⁴⁴ While energy efficiency and NPA evaluations might require different values due to the nature of their impacts (e.g., some NPAs might require avoided distribution costs based on the value at specific locations, while most EE programs do not), the test itself (i.e., the type of costs and benefits to evaluate) should remain the same.¹⁴⁵

DOER recommends that if the LDC determines through the TRC that an NPA is not cost-effective, the NPA should not proceed.¹⁴⁶ If, however, the NPA passes the TRC test then the LDCs should move to an analysis demonstrating the rate impacts of the NPA. Taken together with the results of the TRC, a rate impact analysis will enable the LDCs to strike the balance between net benefits and increased rates to demonstrate cost-prohibitiveness.

¹⁴³ See, e.g., D.P.U. 25-40, DOER-Common-3-4 (noting that some customers may decide they want to participate despite incurring net costs and these decisions would not impact the LDCs or non-participating customers).

¹⁴⁴ Exh. DOER-TW-1 at 14.

¹⁴⁵ *id.*

¹⁴⁶ See D.P.U. 25-41, DOER Common 4-7 (concurring that a cost-effective and viable NPA may proceed).

ii. The LDCs should conduct rate analyses at the conclusion of the BCA to demonstrate whether an NPA is cost-prohibitive

The LDCs' proposal does not include a framework for how they will determine cost-prohibitiveness in situations where an NPA is expected to increase rates.¹⁴⁷ While cost-prohibitiveness is best evaluated by balancing cost-effectiveness and rate impact tests, the RIM tests alone do not provide sufficient information, including the magnitude of rate impacts, or put the rate impacts in meaningful terms (e.g., in terms of \$/MWh or percent increase in rates) to demonstrate whether an NPA is cost-prohibitive.¹⁴⁸

DOER recommends that, as a first step to demonstrating rate impacts, the LDCs conduct the gas and electric RIM tests for NPAs identified as cost-effective through the BCA. If the RIM tests conclude that implementing an NPA will likely cause electric and gas rates to decrease, the Company should find that the project is not cost-prohibitive and proceed with the NPA. If the RIM Tests conclude that an NPA will likely cause electric or gas rates to increase, the Company should conduct an RBA to assess potential impacts on electric and gas customers' rates.¹⁴⁹

The information provided by an RBA allows the LDCs, and ultimately the Department, to make informed decisions on whether a particular rate impact is reasonable in light of the net benefits of NPAs. In practice an RBA will allow LDCs to move forward with advantageous, cost-effective, NPAs that have a *de minimis* rate impact. A strict application of the RIM test, by contrast, would eliminate those opportunities.

The LDCs can efficiently conduct RBAs. RBAs use most of the same information and a similar analytical framework as BCAs and require only one additional task: creating a forecast of

¹⁴⁷ *E.g.*, D.P.U. 25-40, DPU-Common 1-7; NPA Framework at 20.

¹⁴⁸ Exh. DOER-TW-1 at 18.

¹⁴⁹ *See id.* at 23-37 (including additional context for conducting efficient RBAs).

electricity and gas rates in a scenario without the NPA to compare with a scenario with the NPA.¹⁵⁰ These parallels between RBAs and the methodologies, inputs, assumptions, and practices already developed for the BCAs allow the LDCs to conduct RBAs efficiently.

Electric and gas utilities in Rhode Island and Nova Scotia are now using RBAs alongside BCAs when evaluating energy efficiency programs.¹⁵¹ The RBA methods and assumptions are sometimes modified over time as better practices become available, in much the same way that BCA practices are improved over time.

DOER recognizes that challenges exist to use RBAs efficiently. DOER therefore recommends that the LDCs first limit RBAs for use in assessing the rate impacts of NPAs, as this is the most relevant information for assessing affordability. Rate impacts are also much easier to estimate than bill impacts, because they do not require estimates of changes to participants' electricity and gas consumption. However, once the LDCs and Department have established methods for estimating and applying the rate impacts, they can develop methods for estimating bill impacts at a later date to provide a more complete picture of affordability in implementing NPAs.

Additionally, there may be challenges associated with the timing of benefits for avoided transmission and distribution costs and price suppression effects.¹⁵² The LDCs can address these issues by focusing their rate analysis on the long-term average rate and bill impacts, which does not require a precise estimate of when certain benefits or costs occur. The Department has further

¹⁵⁰ Exh. TW-Surrebuttal-1 at 3.

¹⁵¹ *id.* at 4 (citing RIPUC Docket No. 25-37-EE, *The Narragansett Electric Company d/b/a Rhode Island Energy's 2026 Annual Energy Efficiency*, Schedule A, 2026 Annual Plan at 47 (Oct. 1, 2025); and EfficiencyOne, *Application to the Nova Scotia Energy Board For Approval of the 2026 DSM Extension for Demand-Side Management Activities*, App. B, Rate and Bill Impact Analysis of the 2026 DSM Extension (Apr. 30, 2025)).

¹⁵² *id.* at 5 (citing D.P.U. 08-50-D at 10).

identified challenges in developing assumptions regarding the level of efficiency savings that occur in the absence of the efficiency programs.¹⁵³ The LDCs can address this by making the same assumptions that are used in the BCAs for the scenarios where the NPAs are not implemented.

RBA estimates inherently involve some level of uncertainty because they require forecasts. BCAs also involve uncertainties for the same reasons, yet regulators, utilities, and others have nonetheless all become accustomed to using BCAs for decision-making purposes. When designing RBAs for NPAs, it is essential to not let “the perfect be the enemy of the good.” RBAs need to provide reasonably reliable estimates, roughly on par with the reliability of estimates made for BCAs, so that utilities, the Department, and others have enough information to strike the key balance between net benefits and increased rates to determine cost-prohibitiveness.

iii. The Department should allow portfolio level review to promote efficient NPA analysis

DOER recommends that the Department revise its directive to the LDCs to apply NPA analysis to all investments at a project level.¹⁵⁴ While DOER agrees that project level review is appropriate in most cases, project level review will be difficult and burdensome with respect to Service Line NPAs, particularly for the purposes of evaluating cost-effectiveness and cost-prohibitiveness.¹⁵⁵ If, however, the Department directs the LDCs to implement portfolio level review for aspects of NPA analysis, it will significantly improve the efficiency and speed of the NPA Framework.

While DOER agrees that the LDCs should evaluate Main Replacement and Demand Reduction NPAs for cost-effectiveness at the project level, Service Line NPAs are more numerous,

¹⁵³ Exh. TW-Surrebuttal-1 at 5.

¹⁵⁴ D.P.U. 20-80-C at 23.

¹⁵⁵ See Exh. DOER-TW-1 at 30.

and have lower and less variable costs.¹⁵⁶ Thus, a project level review for each service Line NPA unduly burdens the LDCs and the Department. While a portfolio level review could theoretically result in approval of some non-cost-effective service line NPAs, the entire portfolio still must be determined cost-effective to move forward. The benefits of the LDCs attempting service line NPAs at scale, as well as the efficiency gained by conducting the BCA at a portfolio level, justify the potential for a small number of non-cost-effective service line NPAs to be implemented, if they exist. Indeed, Con Edison has efficiently utilized a portfolio-level BCA for its service line NPA program.¹⁵⁷

In addition to portfolio analysis for efficient evaluation of cost-effectiveness for Service Line NPAs, DOER also recommends a portfolio approach for the RBA to assess rate impacts of each of the three NPA categories proposed above, because conducting RBAs at the project level can be burdensome and might not offer enough additional information to be worthwhile.¹⁵⁸

The LDCs should not perform an RBA in every case. DOER recommends instead that the LDCs take the following approach across project categories:

- The LDCs should conduct the BCA and RIM tests at the portfolio level for service line replacements.
- The LDCs should conduct the BCA and RIM tests at the project level to assess Main Replacement and Demand Reduction NPAs.

¹⁵⁶ See D.P.U. 25-41, NG-CCP at 38; D.P.U. 25-44/45, ES-CCP at 48.

¹⁵⁷ See Exh. DOER-Surrebuttal-1 at 4 (citing Con Edison, *Con Edison Energy Exchange BCA Filing* (Jul. 2024), available at:

[https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={D005DC90-0000-C230-8FC2-3759556D71AA}&DocTitle=Con%20Edison%20Energy%20Exchange%20BCA%20Filing\)](https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={D005DC90-0000-C230-8FC2-3759556D71AA}&DocTitle=Con%20Edison%20Energy%20Exchange%20BCA%20Filing}))

¹⁵⁸ Exh. DOER-TW-1 at 30.

- If the RIM tests indicate that a project or (in the case of Service Line NPAs, a portfolio) is likely to decrease rates, the LDCs should move forward with implementation.
- If the RIM tests indicate that a Main Replacement or Demand Reduction NPA is likely to increase rates, the LDCs should incorporate the NPA into a portfolio with other NPAs in the same category and then apply the RBA to the portfolio. If the RIM tests indicate that a portfolio of Service Line NPAs is likely to increase rates, the LDCs should perform an RBA on that portfolio.

iv. The Department should convene technical sessions for how to balance net benefits and rate impacts of NPAs

As discussed above, DOER recommends that the LDCs conduct an RBA in the event that a RIM test concludes an NPA will likely cause electric or gas rates to increase, which will enable the LDCs strike a balance between net benefits identified through the BCA and rate impacts identified through the RBA.¹⁵⁹ Working with stakeholders to develop (1) a method for using the RBA to estimate rate impacts and (2) a method for balancing net benefits against rate impacts, would allow the LDCs to determine cost-prohibitiveness in a transparent and efficient way.¹⁶⁰ DOER recommends that the Department convene a short series of technical sessions to establish this methodology. DOER welcomes the opportunity to submit a more detailed initial proposal for those technical sessions, to expedite the discussion with stakeholders.

e. The LDCs should update the NPA Framework on an annual basis

The Department should require the LDCs to submit annual compliance filings including progress on NPA analysis and implementation according to the categories DOER proposed above,

¹⁵⁹ *supra* at IV.B.d.ii.

¹⁶⁰ Exh. DOER-TW-1 at 6; Exh. DOER-TW-Surrebuttal-1 at 8-9.

as well as the results of the cost-effectiveness and cost-prohibitiveness screenings.¹⁶¹ As proposed, the LDCs will share updates on the NPA Framework with the Department once every five years, in line with their future CCP filings.¹⁶² This proposed reporting cadence does not reflect the urgency of the Department’s directive for the LDCs to minimize unnecessary additional gas system investment.¹⁶³ Annual filings enable the LDCs to more frequently demonstrate progress and enables the Department to provide timely guidance to the LDCs.

The compliance filings should highlight challenges encountered in NPA analysis and implementation and propose areas for improvement, particularly regarding testing criteria, thresholds, and customer engagement practices. The Department should approve changes to the LDCs’ testing and engagement criteria and thresholds on an annual basis, in response to the LDC compliance filings. This reporting schedule is appropriate and necessary to accelerate the NPA learning process and scale NPA deployment in time for the LDCs to make legitimate attempts at avoiding a meaningful share of GSEP investments.

C. The Department should convene technical sessions regarding customer connections and line extension policies

DOER continues to support Department directives that (1) revise LDC line extension policies to align with state climate law, and (2) allow NPA and demonstration projects to proceed absent 100 percent customer participation.¹⁶⁴ However, given that customer connections and disconnections from the natural gas distribution continue to raise complex policy questions, DOER

¹⁶¹ *supra* at IV.C.2.a.

¹⁶² NPA Framework at 25.

¹⁶³ D.P.U. 20-80-B at 15; D.P.U. 20-80-C at 27.

¹⁶⁴ D.P.U. 20-80, DOER Comm. on Line Extension Policies of the Mass. Gas Local Distribution Companies at 4-7 (Oct. 11, 2024); DOER Comm. on Proposed Line Extension Policies at 4-5 (Apr. 3, 2025); D.P.U. 25-40 through 25-45, DOER Rep. Comm. on Electrification Demonstration Projects at 5-6 (Oct. 24, 2025).

recommends that the Department convene technical sessions to further develop policies to protect customers who may be impacted as the Commonwealth transitions from natural gas.

Specifically, DOER believes that the Revised Straw Proposal on line extension policies would benefit from further clarity on the proposed exception criteria as well as on process and standards for implementation. With respect to the obligation to serve, the Department should convene a technical session to further develop the process and procedures necessary to equitably move forward with targeted electrification demonstration projects and NPAs. DOER believes that technical sessions will better enable the Department, LDCs, and other stakeholders to develop a clear pathway to success for this new line extension policy.

V. CONCLUSION

DOER respectfully requests that the Department direct the LDCs to refile the Climate Compliance Plans and NPA Framework, consistent with DOER's recommendations as summarized below. The refiled CCPs should:

1. estimate and report on all the LDCs' Scope 1 and Scope 3 emissions;
2. forecast Scope 3 emission reductions from existing programs;
3. identify emission reduction targets for Scope 1 and Scope 3 emissions that would align LDC operations with all EEA sublimits to which the LDCs' Scope 1 and Scope 3 emissions contribute;
4. propose strategies and actions necessary to meet these targets, supported by scenario analysis;
5. identify how targeted electrification of certain portions of the gas system will enable the LDCs to optimize costs to meet these targets, including appropriate levels of geographic detail;

6. calculate the total investment required to perform the necessary actions to meet these targets; and
7. identify barriers to implementation and present possible solutions to those barriers.

The refiled NPA Framework should:

1. evaluate three distinct project categories for Service Line NPAs, Main Replacement NPAs, and Demand Reduction NPAs;
2. disclose specific viability criteria and thresholds;
3. provide complete customer engagement plans for Department review; and
4. appropriately demonstrate if an NPA is cost-prohibitive.

The Department should order the LDCs to submit annual compliance filings that include progress on NPA analysis and implementation, highlight challenges, and propose areas for improvement. The Department should use these filings to provide timely guidance to the LDCs in updating the NPA Framework.

Finally, DOER requests that the Department convene technical sessions implementation of to further develop policies to protect customers who may be impacted as the Commonwealth transitions from natural gas.

Respectfully submitted,

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF ENERGY RESOURCES

By its attorneys:

/s/ Joshua Williams

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DATE: April 21, 2026

Certificate of Service

I hereby certify that I have this day served the foregoing documents upon all parties of record in this proceeding in accordance with the requirements of 220 CMR 1.05(1).

/s/ Joshua Williams

DATE: April 21, 2026