

D.P.U. 25-200

**JOINT REPLY COMMENTS OF
CLIMATE, ENERGY EFFICIENCY, AND CONSUMER ADVOCATES**

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Conservation Law Foundation, Vote Solar, Acadia Center, Sierra Club, the Low-Income Weatherization and Fuel Assistance Program Network, the Low-Income Energy Affordability Network (LEAN), the Massachusetts Energy Directors Association (MEDA), the Massachusetts Association for Community Action (MASSCAP), the Environmental Defense Fund (EDF), and the Environmental League of Massachusetts respectfully submit these Joint Reply Comments in the above-captioned proceeding pursuant to the Vote and Order Opening Inquiry issued by the Department of Public Utilities (“Department”) on December 15, 2025, and the Order on Distribution Companies’ Motion for Extension of Time issued by the Department on January 9, 2025, in the above-captioned docket.

Introduction

The significant volume of written comments submitted in this docket underscores the urgent need for solutions to address rising electric and gas bills and ensure a clean, affordable energy future for Massachusetts. As we emphasized in initial comments,¹ addressing energy affordability requires examining the underlying incentive structure and regulatory framework that currently motivate investor-owned utilities to plan their systems and spend ratepayer money. Relatedly, solutions that will contain or reduce costs over the long term must be considered and prioritized alongside measures aimed at providing short-term relief.

In initial comments, the undersigned recommended a range of actions to address cost drivers: (1) shifting many volumetric reconciling charges into base distribution rates; (2) incentivizing utilities to increase electric system utilization and prioritize demand-side flexibility (virtual power plants, non-wires alternatives, and AMI-enabled price signals); (3) implementing time-varying rates paired with protections for low-income and vulnerable customers; (4) investigating reforms to basic service procurement; (5) exploring tools like capex-opex equalization and Totex ratemaking to reduce utilities’ capex bias; (6) advancing regulatory and legislative reforms to ensure the gas transition is managed and cost-effective; and (7) investigating reforms to utilities’ authorized return on equity (“ROE”).

Below we reply to concerns and recommendations raised by other stakeholders on these and other topics. We appreciate the opportunity to provide such a response and again commend the Department for taking proactive steps to identify ways to reduce energy costs and help customers manage their rising utility bills.

I. Many Reconciling Mechanisms Should Be Eliminated or Moved into Base Distribution Rates

As stated in our initial comments, reconciling mechanisms (also referred to as trackers or riders) have served to shift risk from utility shareholders onto utility ratepayers while providing ratepayers limited benefits.² These mechanisms reduce the incentive for utilities to prudently manage their expenses to the benefit of customers since these costs can simply be passed on with

¹ D.P.U. 25-200, Joint Comments of Climate, Energy Efficiency, and Consumer Advocates (April 14, 2026) (hereinafter “Advocates Initial Comments”).

² Advocates Initial Comments at 8-9.

little or no oversight. The rapid growth in reliance on reconciling mechanisms has been a boon to utility interests, as is visible in the astonishing increase in costs recovered through the tracker for the local gas distribution companies' ("LDCs") Gas System Enhancement Program ("GSEP") plans over the last decade.³ Our initial comments did not identify specific trackers that we recommended be moved into base rates; however, we here provide support for (1) the Office of the Attorney General's ("AGO") proposals for legislative and regulatory changes to the GSEP program and its associated trackers that will ultimately eliminate expedited recovery for leak-prone pipe remediation, and (2) the Department of Energy Resources' ("DOER") proposed elimination of several reconciling factors and rolling associated recovery into base rates.⁴

The AGO's GSEP Proposals

GSEP stands unique in the landscape of utility trackers for two reasons: first, the program costs have ballooned tremendously over the life of the expedited recovery mechanism, and, second, the eligibility criteria built into the program itself are being used by the LDCs to perform an end-run around the clear Commonwealth policy directive to decarbonize the gas systems. In the first year with expedited cost recovery, the LDCs spent just under \$300 million on GSEP.⁵ In 2024, "the LDCs spen[t] a combined \$799 million on GSEP investments, which accounted for 53 percent of their total capital expenditures."⁶ Because of the long term of recovery associated with utility infrastructure, it is approximately the case that "for every dollar spent on new pipeline infrastructure, ratepayers incur an obligation to pay back two dollars by the end of the cost recovery period."⁷ The growth of the GSEP program is enabled and encouraged by the availability of expedited cost recovery through reconciliation, and winding down such expedited recovery would rebalance financial risk across utility shareholders and utility ratepayers more fairly, decreasing the rate of program growth and encouraging improved utility management of costs. In addition to the support expressed below in Section VI for the AGO's recommendations with respect to the GSEP program, we reiterate that, as the GSEP program is phased down overall, the reconciliation mechanisms providing accelerated recovery for GSEP program costs should be phased down as well.

DOER's Identified Reconciliation Mechanisms for Rolling into Base Rates

As we noted in our initial comments, base rate treatment of trackers strengthens regulatory oversight by creating a more fulsome forum for costs to be examined for prudence, necessity, and appropriate allocation.⁸ The rate case process, with its opportunities for stakeholder intervention, provides a level of scrutiny that reconciliation dockets do not

³ *Id.* at 25.

⁴ See D.P.U. 25-200, AGO Initial Comments at 40-42 (April 14, 2026); D.P.U. 25-200, DOER Initial Comments at 3-4, Table 1 (April 14, 2026).

⁵ Dorie Seavey, *GSEP at the Six-Year Mark: A Review of the Massachusetts Gas System Enhancement Program* at 34 (Oct. 2021), available at <https://static1.squarespace.com/static/634abba43f1e2f4dfd5e07dc/t/63559391bd5978258fc5c52c/1666552722328/GSEPatTheSix-YearMark%5B1%5D.pdf>.

⁶ AGO Initial Comments at 37.

⁷ Dorie Seavey, *GSEP at the Six-Year Mark: A Review of the Massachusetts Gas System Enhancement Program*, at 21 (Oct. 2021).

⁸ Advocates Initial Comments at 9.

successfully replicate. DOER identifies a set of mechanisms whose costs are sufficiently predictable and manageable that continued tracker treatment is difficult to justify on cost-causation or volatility grounds.⁹ Pension adjustments, vegetation management, electronic payment recovery, and the remaining smart grid and advanced metering infrastructure investments share a common characteristic: they are costs utilities can and should be able to manage, and embedding them in base rates recreates the kind of financial discipline that tracker treatment erodes. The transition of these mechanisms at each electric distribution company's ("EDC") next rate case, as DOER recommends, is a reasonable and administrable path forward.

DOER provides further examples of reconciling mechanisms in its Table 2 that may be viable candidates for rolling into base rates but require additional consideration and analysis.¹⁰ While we do not support rolling these additional trackers (from Table 2) into base rates at this time, we are not opposed to their receiving further consideration as circumstances change.

II. Additional Data, Analysis, and Careful Examination Are Necessary to Evaluate DOER's Proposal to Convert the EERF and RAAF to Fixed Charges

DOER's recommendation to convert the EERF and RAAF to non-bypassable fixed charges¹¹ for electric customers raises questions that warrant careful examination before the Department acts. The unsubstantiated theory behind the proposed conversion is that because neither charge bears a causal relationship to volumetric consumption, recovering them volumetrically is not cost-reflective, undermining the efficiency and fairness of rates.¹² However, this theoretical premise is contradicted by powerful academic research cited in the comments submitted by EDF that finds customers are responsive to their *average* rates as reflected in their total bill rather than a *variable* charge that is buried in their billing statement.¹³ Thus, we cannot expect a significant improvement in consumer decision making based on such a generalized untargeted rate change. As EDF points out, all other businesses recover their fixed costs, including government taxes and fees, through variable prices.¹⁴ Utilities are not unique here.

Given that theory is unlikely to deliver the purported benefits in the face of the evidence, we must undertake an evaluation of the distributional consequences. Here, the distributional consequences of the proposed conversion are not uniform, and the utilities concede that their proposal would adversely impact customers who have low usage, have invested in saving energy up to now to the benefit of everyone else, and low-income customers who tend to have lower average usage. Notably, the utilities' bill impacts analyses do not include the new tiered discount rate framework ordered in D.P.U. 24-15.¹⁵ While the tiered discount framework may mitigate adverse impacts of DOER's proposed conversion for some low-income, low-usage customers,

⁹ DOER Initial Comments at 3, Table 1.

¹⁰ *Id.* at 5-6.

¹¹ *Id.* at 15-16.

¹² *Id.* at 9.

¹³ D.P.U. 25-200, EDF Initial Comments at 2, n.1 (April 14, 2026).

¹⁴ *Id.* at 2. EDF's initial comments propose alternatives to fixed charges that, it argues, are better targeted for achieving state policy objectives.

¹⁵ See D.P.U. 24-15-B, Order at 1 (Feb. 17, 2026).

that is not the case for all customers enrolled in the low-income discount rate. When the new framework is implemented, approximately 28 percent of low-income customers will experience higher electric *and* gas bills.¹⁶ When considering proposals to raise fixed charges by any amount, the Department should consider the cumulative impacts of its various rate design changes across dockets on low-income customers. The Department should require the electric utilities to model the bill impacts of DOER's proposed conversion across a range of representative customer profiles, including low-income customers at various low-income discount tiers and usage levels, median-use residential customers, high-use customers with beneficial electrification technologies such as heat pumps and EVs, customers with distributed generation, and small commercial customers, before drawing any conclusions about whether the conversion produces equitable outcomes on balance. Given the evidence against the purported benefits of a fixed charge and the likely adverse effects on fairness, the Department should use a high threshold for approving any fixed charges beyond what are imposed now.

DOER's observation that low-income customers no longer use measurably less electricity than non-low-income customers on average¹⁷ is relevant context, but average consumption data can obscure significant variation within that population. Within that broad income strata, usage is likely still correlated with relative income. A customer at the lower end of the low-income usage distribution could face a materially worse outcome under a fixed charge structure even if the average low-income customer does not.¹⁸ The Department should ensure that any further consideration of this question is informed by granular usage and income data sufficient to evaluate those tail risks.

The Department should also recognize that DOER's proposal to convert EERF and RAAF to non-bypassable fixed charges is, in functional terms, a minimum bill concept applied to specific policy costs. The principle behind the conversion is not primarily about grid access or cost causation in the traditional sense. It is about the policy judgment that customers who are connected to the grid should contribute to programs that benefit the broader system regardless of how much electricity they consume. Under the current volumetric structure, customers who reduce their energy consumption through efficiency investments, distributed generation, or other means also reduce their contribution to the EERF and RAAF, resulting in a greater share of those policy costs falling on customers who have not made such investments. Evaluated through this lens, the relevant question for the Department is not simply whether a fixed charge is more cost reflective than a volumetric one, but whether the underlying policy costs are ones that all connected customers should bear as a condition to grid participation.

III. Net Energy Metering Should Compensate for Net Benefits Provided; the Focus on Avoided Costs Misses the Forest for the Trees

Scope and Framing

¹⁶ D.P.U. 25-200, LEAN Initial Comments at 3 n.6 (April 14, 2026).

¹⁷ DOER Initial Comments at 15-16.

¹⁸ LEAN Initial Comments at 4 (April 14, 2026).

We feel compelled to address net metering given the volume of comments this topic has attracted, but reiterate the position we took in our initial comments: this docket is not the appropriate vehicle for systemically altering net energy metering (“NEM”) compensation.¹⁹ The instant docket was opened to conduct a comprehensive review of electric and gas bill charges and reconciling mechanisms, and the targeted, cost-reflective adjustments we recommend here can advance this proceeding’s stated objectives without requiring a wholesale reexamination of how distributed solar is compensated. Moving forward on a set of unexamined assertions is not appropriate here. That issue should be addressed in a more comprehensive investigation of the value of solar and storage. This proceeding would benefit from further clarification from the Department on the extent to which net metering compensation will be examined.

Insufficient Evidentiary Record

The initial comments of MIT CEEPR frame solar customers as cost avoiders as follows: “By paying for ‘fixed’ costs such as grid modernization through a volumetric rate, rooftop solar owners pay less towards these costs, often even zero, than other households connected to the grid, even though rooftop solar households are still benefiting from their services.”²⁰ That characterization applies equally to any customer who reduces consumption through efficiency, demand response, conservation—even parents with a newly empty nest. The cost-allocation pattern it describes is a function of volumetric cost recovery applied to customers with varying consumption profiles, not a property of distributed generation specifically. We agree that “the rate structure must carefully balance fixed and volumetric charges as they have different implications for technology adoption,”²¹ but we do not reach the same conclusion.

More importantly, the cost-avoider characterization accounts only for what solar customers avoid paying, not for what they provide. National Grid even admits its “analysis does not quantify certain benefits of solar resources (such as reduced energy procurement, peak demand reductions, and wholesale price suppression).”²² The point of encouraging distributed solar is incurring those very benefits and those must be entered into any equation about compensation. Avoided transmission charges from ISO New England, avoided capacity costs for load-serving entities, ancillary services reductions, demand reduction induced price effects, and progress toward the Commonwealth’s net-zero goals are only some of the real and measurable values that belong in any accounting to understand true value. None of these values have been independently quantified for Massachusetts. An estimate that accounts for costs but entirely omits benefits cannot support a compensation determination. The Department should commission an independent Value of Solar Study, developed with qualified expertise, to establish both what distributed solar costs and what it contributes to the Massachusetts grid before any compensation conclusions are drawn.

The claim that rooftop solar expansion causes higher residential electricity prices rests on a national panel analysis pooling state-year observations across 48 states over 25 years.²³ A

¹⁹ Advocates Initial Comments at 14.

²⁰ D.P.U. 25-200, MIT CEEPR Initial Comments at 7 (April 14, 2026).

²¹ *Id.* at 6.

²² D.P.U. 25-200, National Grid Initial Comments at 43 (April 14, 2026).

²³ MIT CEEPR Initial Comments at 13.

recent critique found serious flaws in this study, noting the confusion of correlation with causation.²⁴ That level of aggregation cannot support jurisdiction-specific conclusions for Massachusetts at current penetration levels under current program design, and the Department should not treat it as a sufficient evidentiary basis for a compensation determination here.

Principles and Recommendations to Guide Any Future NEM Reform

Before adjusting NEM compensation rates, the Department should first examine whether NEM customers are appropriately contributing to fixed costs through the existing rate structure. These are distinct questions: whether NEM customers are paying fixed costs equitably is a rate design question, and whether the NEM credit rate is set correctly is a compensation question. DOER has recommended converting EERF and RAAF to non-bypassable fixed charges applicable to all customers, but this should not be a determination about the adequacy of NEM compensation.²⁵ The Department should not conflate the two, and should not use one as a proxy for resolving the other.

The current SMART program provides an adder for storage paired with solar, but that incentive is tied to installation rather than to active dispatch. A customer who installs a battery to qualify for the adder but charges and discharges it to maximize self-consumption rather than grid benefit is acting entirely consistently with the current program design. Incentivizing the construction of a storage resource and incentivizing its active dispatch as a grid asset are distinct policy objectives, and the current framework addresses only the former. A virtual power plant (a.k.a., a community power network) program incentivizes active dispatch as a grid asset. Expanding storage adoption more broadly, including through installation-based incentives, remains a legitimate and complementary policy goal that should not be displaced in the process. NEM and SMART must be evaluated together. Reducing NEM compensation while expanding SMART does not necessarily reduce total ratepayer costs; it may reallocate costs across customer classes in ways that are not visible in program-specific analysis.

A revised approach should differentiate by customer class and by program objective. Connecticut's compensation framework—which distinguishes between customers with storage and those without—provides a relevant structural reference for how compensation can be organized to account for the different grid contributions of solar-plus-storage versus solar-only systems.²⁶ Massachusetts should consider a comparable approach, though any such differentiation must be carefully designed to avoid adverse market effects for installers and customers who participate in solar-only programs, which remain a critical pathway for expanding distributed generation access.

²⁴ See Richard McCann, *Discerning what drives rate increases is more complex than shown in LBNL study*, Economics Outside the Cube (Oct. 21, 2025), <https://mcubedecon.com/2025/10/21/discerning-what-drives-rate-increases-is-more-complex-than-shown-in-lbnl-study>.

²⁵ DOER Initial Comments at 8.

²⁶ See Energy Storage Solutions, Conn. PURA, <https://portal.ct.gov/pura/electric/office-of-technical-and-regulatory-analysis/clean-energy-programs/energy-storage-solutions-program>; Residential Renewable Energy Solutions, Conn. PURA, <https://portal.ct.gov/pura/electric/office-of-technical-and-regulatory-analysis/clean-energy-programs/residential-renewable-energy-solutions-program>.

Time-of-use (“TOU”) pricing creates direct price signals for customers to optimize the timing of generation export and energy consumption, and provides a market-consistent motivation for storage deployment. For residential customers, the Department should retain NEM and pair it with a transition to TOU rates. This approach is structurally more efficient than layering additional programmatic incentives. Any such transition must be sequenced appropriately: (a) NEM customers should not be moved to TOU rates until adequate storage adoption pathways are accessible and affordable; and (b) moving NEM customers to TOU rates needs to be part of a transition of all customers to TOU rates.²⁷ Imposing time-varying pricing in advance of accessible storage options does not advance affordability objectives and would impose a financial burden on customers whose systems cannot respond to price signals without storage. A transition to TOU rates for only NEM customers (as opposed to all customers) would create a barrier to adoption (e.g., some customers would be reluctant to transition to an unfamiliar rate design), and would be inconsistent with the Commonwealth’s goals.

For larger non-residential systems, the Department should consider a transition away from NEM toward a compensation structure that reflects the time-varying and location-specific value of distributed generation. New York’s Value of Distributed Energy Resources (“VDER”) framework provides the most developed jurisdictional example.²⁸ VDER compensates distributed generation based on marginal capacity value, energy value, environmental value, and locational system relief value, each calculated to reflect actual grid conditions at the time and location of generation. This approach captures the locational dimension of distributed resource value that NEM cannot replicate and directly addresses the concern that current compensation structures do not adequately harness distributed resources to serve grid needs.

The Net Metering Recovery Surcharge cost allocation methodology, which uses a base-distribution revenue allocator rather than a credit-proportional allocation by customer class, may cause residential customers to bear a disproportionate share of non-residential NEM costs in ways that are not fully transparent. The Department should require integrated modeling of the combined ratepayer impact of any proposed changes before acting on either program independently, and should develop a breakdown of NEM cost allocation by customer class as part of that analysis.

Safeguards and Sequencing

Furthermore, current NEM participants must first be transitioned to a TOU rate structure before any changes to NEM compensation take effect, with legacy protection ensuring a defined period during which they continue to receive compensation under the terms that influenced their original investment decision, honoring the reasonable expectations customers held when they chose to install solar. NEM customers must not be punished for committing a good deed. Any such changes to NEM compensation should be preceded by the completion of an independent

²⁷ We discuss TOU rates in more detail below.

²⁸ AGO Initial Comments at 28 (citing New York State Public Service Comm’n, Case No. 15-E-0751, Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (Mar. 9, 2017), available at <https://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=180197&MatterSeq=49770>).

Value of Solar Study so that adjustments rest on a complete and thoroughly evaluated body of evidence.

IV. Time-of-Use Rates Can Provide Household and System-Wide Savings but Should Be Designed to Protect Vulnerable Customers

Some commenters, including the Low-Income Network, raised important concerns about the equity implications of mandatory TOU rates.²⁹ We take these concerns seriously and share the underlying commitment to protecting vulnerable customers from bill harm. Addressing these concerns requires careful implementation design but should not detract from considering default TOU as the foundational rate structure.

We reiterate the position in our initial comments that flat rates are not a neutral baseline. They can embed hidden insurance premiums, subsidize on-peak consumption at the expense of off-peak users, and deprive the grid of demand flexibility essential to managing costs as electrification accelerates.³⁰ Default TOU can provide a more accurate way of pricing electricity, and the benefits of this additional accuracy flow broadly to ratepayers and the grid alike.

A well-designed framework should include mandatory shadow billing before, and for a period during, any broad rollout, with no implementation proceeding absent a Department finding that the structure delivers net benefit across the customer population.³¹ The Department should consider customers enrolled in LIHEAP or income-qualified discount programs and those with life-critical medical equipment to be defined as opt-in classes.³² TOU rates should also stack with existing low-income protections in ways that can affirmatively benefit lower-income customers who can shift load.³³

We look forward to engaging in this topic further in D.P.U. 26-62, Petition of the Massachusetts Department of Energy Resources Requesting that the Department of Public Utilities Open an Investigation into Time-Varying Rates. The issues raised by National Grid on the effects of time-varying rates and the applicability of demand charges should be deferred to that docket; it is premature to address those issues here.³⁴

V. The Department Should Investigate Basic Service Procurement Reform to Reduce Inflated Retail Premiums and Ensure Basic Service is Affordable for Ratepayers

As set forth in our initial comments and those of several other stakeholders including the Clean Energy Parties, National Grid, DOER, and the AGO, reforms to basic service are necessary to reduce high retail premiums paid by basic service customers and to ensure basic

²⁹ See LEAN Initial Comments at App. B; Advocates Initial Comments at 19-20.

³⁰ Advocates Initial Comments at 19.

³¹ *Id.* at 20.

³² *Id.*

³³ *Id.*

³⁴ See National Grid Initial Comments at 24-25.

service is an affordable option for ratepayers.³⁵ As outlined in the initial comments of the Clean Energy Parties, there are several potential reforms that could be implemented to ensure ratepayers pay a fair price for electricity and to help alleviate rising electricity costs in Massachusetts.³⁶ The Department should evaluate these options for basic service reform, either in this proceeding or in a separate, dedicated proceeding. While Eversource asserts that only ~10 to 15 percent of its customer load remains on basic service and therefore changes to basic service procurement would have limited reach within its service territory,³⁷ this likely still represents a significant number of residential households that could benefit from reduced retail premiums included in basic service pricing. Across the Commonwealth, 35 percent of customers remained on basic service as of 2024.³⁸ Further, retail premiums likely affect electricity prices not only for basic service customers, but also for customers who receive their electricity through community choice aggregation and retail choice because basic service pricing often serves as a price heuristic for other types of service.³⁹ Changes to address the inflated risk premiums included in basic service pricing would therefore benefit customers beyond only those taking basic service.

VI. Avoiding Unnecessary, Costly Gas Pipeline Replacement and Coordinating Customer Exits from the Gas System Are Critical for Long-Term Affordability

Ensuring the transition away from the gas system is managed and orderly is crucial for containing customer costs over the medium and long term.⁴⁰ Below we respond to other commenters' concerns and recommendations regarding three core aspects of a cost-effective transition away from gas: (1) deploying non-pipeline alternatives ("NPAs") instead of replacing gas pipelines, (2) phasing out GSEP, and (3) requiring gas utilities to do long-term gas system planning.

Non-Pipeline Alternatives Are an Affordability Measure

A central component of a managed transition is deploying lower-cost alternatives that can avoid gas investments altogether (e.g., NPAs) or can safely defer the need for pipeline replacement (e.g., pipeline repair). Using a remediation strategy such as repair to push out the need for pipe-for-pipe replacement to a later date can enable NPA implementation, allowing for the repaired pipeline to be decommissioned and avoiding the need for an expensive replacement project.⁴¹

In initial comments submitted in this proceeding, the Feeney Brothers express concerns that using pipeline repair measures to defer replacement work adds unnecessary costs because

³⁵ See Advocates Initial Comments at 21-23; D.P.U. 25-200, Clean Energy Parties Initial Comments at 21-23 (April 14, 2026); National Grid Initial Comments at 31-32; DOER Initial Comments at 19-20; AGO Initial Comments at 34-35.

³⁶ See Clean Energy Parties Initial Comments at 21-23.

³⁷ D.P.U. 25-200, Eversource Initial Comments at 30 (April 14, 2026).

³⁸ Clean Energy Parties Initial Comments, Attachment at 4.

³⁹ Clean Energy Parties Initial Comments at 21.

⁴⁰ Advocates Initial Comments at 24-26.

⁴¹ Jamie Van Nostrand, *Erase and Replace: The Throwaway Culture of Fixing Old Pipes* (April 29, 2026), <https://basedrates.substack.com/p/erase-and-replace-the-throwaway-culture>.

the pipeline will still ultimately need to be replaced.⁴² This argument misses the point of repair, which, as the Department has recognized, can mitigate the safety risk in a more affordable way for customers and avoid unnecessary investment in potential stranded assets.⁴³ The Department responded to a similar argument by the LDCs in its recent GSEP orders, stating that it “fails to account for the cost of stranded assets to customers and the benefits of avoiding financial exposure to such assets, as well as reducing greenhouse gas emissions in compliance with the [chapter 21N] limits and sublimits.”⁴⁴ Increasing the longevity of an existing gas pipe extends the time window in which the LDC can evaluate and deploy an NPA and then decommission the pipeline, consistent with D.P.U. Order 20-80-B and the Commonwealth’s emissions reduction mandates for the buildings sector.

Other concerns raised in the Feeney Brothers initial comments unintentionally underscore the urgent need for geographically targeted electrification projects and decommissioning of the gas system. For example, the Feeney Brothers highlight the impacts of gas capital projects on neighborhoods, stating that “residents often ask whether the crew will finally fix the problem once and for all, so the same street does not have to be dug up again, and its residents can stop worrying about the health and safety implications of lost gas.”⁴⁵ The company adds that persistent gas leaks can damage trees, worsen urban heat, and negatively impact local air quality; such impacts are often concentrated in environmental justice communities.⁴⁶ Incredibly, the Feeney Brothers cite these impacts in an attempt to justify the need for faster pipeline replacement. But replacing gas pipelines locks communities into a cycle of disruptive construction work, health and safety risks, and expensive utility bills that will only continue to climb as the pool of gas customers shrinks. *The only way to “fix the problem once and for all” is to substantially reduce or eliminate reliance on gas distribution infrastructure.* Through implementing NPAs and decommissioning gas mains and services, in alignment with state legislative requirements and Department orders, the gas utilities can resolve residents’ concerns about the health and safety risks of gas leaks, halt the harmful impacts of leaks on the local environment, and end the need for pipe replacement and all the attendant costs and disruptions.

The Feeney Brothers also raise concern about uncertainty for the gas distribution workforce as the gas utilities are asked to pursue lower-cost alternatives to pipeline replacement.⁴⁷ This concern underscores the need for both clear, decisive regulatory direction

⁴² D.P.U. 25-200, Feeney Brothers Utility Services Initial Comments at 2-3 (April 13, 2026). The Feeney Brothers misconstrue gas utilities’ obligations to address safety risks under state law and regulations. *See id.* at 1-2. LDCs are required to address leak-prone pipe, but no state or federal law or regulation limits a gas utility’s remediation strategy to pipeline replacement. Under state law, Grade 1 leaks must be repaired immediately, and Grade 2 leaks require repair or replacement. G.L. c. 164, § 144(b)(2)-(3). State regulations require compliance with minimum federal safety standards under 49 C.F.R. 192, which states that “[h]azardous leaks must be *repaired* promptly,” and “[e]ach segment of pipeline that becomes unsafe must be *replaced, repaired or removed from service.*” 49 C.F.R. 192 (emphasis added). 22 CMR 101.01. Nowhere in the GSEP statute, G.L. c. 164, § 145, does the Legislature require accelerated pipeline replacement. Rather, the statute requires each LDC to plan “to *address* aging or leaking natural gas infrastructure” and to “include a timeline for *removing or remediating* all leak-prone infrastructure on an accelerated basis.” G.L. c. 164, § 145(b)-(c) (emphasis added).

⁴³ *See, e.g.*, D.P.U. 24-GSEP-03, Order at 49.

⁴⁴ *E.g.*, D.P.U. 25-GSEP-03, Order at 25.

⁴⁵ Feeney Brothers Initial Comments at 3.

⁴⁶ *Id.* at 3-4.

⁴⁷ *Id.* at 4-5.

and proactive utility planning for a just workforce transition. In its Future of Gas Order 20-80-B, the Department instructed the LDCs to “provide an update on [a] just transition framework” for gas industry workers and people who have been left out of the clean energy workforce in the Climate Compliance Plans.⁴⁸ To date, however, the LDCs have not studied the impact of the energy transition on their workforce, and their “just transition framework” updates in the Climate Compliance Plans largely fail to include plans for stakeholder engagement and actionable steps to prepare gas workers for the transition necessary to meet the Commonwealth’s emissions reduction mandates.⁴⁹ As the energy transition advances, pathways to employment in the clean energy sector and measures to ensure family-sustaining wages for current gas workers are important. Additionally, as segments of the gas system are decommissioned, maintaining an experienced gas workforce to ensure the safety of remaining gas infrastructure is critical. Achieving these outcomes will require utility planning that is responsive and proactive.

GSEP Should Be Phased Out

We reiterate our recommendation in initial joint comments that the Department continue to lower the GSEP cap—as it did in its recent orders in D.P.U. 25-GSEP-01 through 06—and formally request that the Legislature amend the GSEP statute to phase out the program entirely.⁵⁰ To that end, we support the AGO’s recommendation to gradually lower the GSEP cap to 0 percent by 2030 and remove the GSEAF and GSERAF charges from customers’ bills at that time.⁵¹ We also support the AGO’s recommendation to remove section (c) of the GSEP statute, which requires the LDCs to include “a timeline for removing or remediating all leak-prone infrastructure on an *accelerated basis*.”⁵² We agree with the AGO that, regardless of whether the Legislature passes these reforms, the Department should continue to lower the GSEP cap to the statutory minimum of 1.5 percent.⁵³ We additionally support the AGO’s suggestion that the Department consider more aggressive use of its authority under G.L. c. 164, § 145(h) to “discontinue a plan and require a gas company to refund any costs charged to customers due to a failure to substantially comply with a plan or failure to reasonably and prudently manage project costs.”⁵⁴

The LDCs routinely spend above their GSEP cap and then seek to recover the deferred balances.⁵⁵ As discussed in initial joint comments, the accelerated cost recovery under GSEP comes at significant cost to ratepayers without providing commensurate safety benefits or greenhouse gas emissions reductions.⁵⁶ As the Department found in its recent GSEP orders, GSEP spending has “continued to increase at a troubling pace”: the LDCs spent \$230.7 million more on GSEP in 2024 than 2023, when GSEP program spending was \$583.7 million, yet the

⁴⁸ D.P.U. 20-80-B, Order at 54.

⁴⁹ See D.P.U. 25-40 through 25-45, CLF-EDF-SC Initial Brief at 68-69.

⁵⁰ Advocates Initial Comments at 27.

⁵¹ See AGO Initial Comments at 41.

⁵² *Id.*; G.L. c. 164, § 145(c) (emphasis added).

⁵³ AGO Initial Comments at 41.

⁵⁴ *Id.*

⁵⁵ See Advocates Initial Comments at 26; AGO Initial Comments at 38.

⁵⁶ Advocates Initial Comments at 25-26.

program replaced fewer miles of leak-prone mains and services.⁵⁷ By phasing out this accelerated cost recovery mechanism that incentivizes LDC overspending, the Department and the Legislature can reduce upward pressure on customer bills.

The Need for Long-Term Gas System Planning

As we stated in initial joint comments, the Department should require long-term decarbonization planning that prioritizes decommissioning leak-prone pipe without replacement and minimizes overall costs for customers.⁵⁸ In the Climate Compliance Plan proceedings, three of the environmental intervenors made the specific recommendation that the Department require bi-annual gas infrastructure planning proceedings in which the Department and stakeholders can review each LDC's planned investments (including GSEP investments while the GSEP program continues to exist) and corresponding NPA analysis in advance.⁵⁹ The AGO makes a similar recommendation for long-term gas system planning.⁶⁰ As the AGO emphasizes, such long-term plans should geographically coordinate customer exits from the gas system to allow the LDCs to decommission leak-prone pipe (which would avoid some of the \$16.9 to \$25.9 billion in anticipated GSEP spending).⁶¹ A proactive planning approach like this would minimize the stranded asset risks and intergenerational equity concerns that multiple stakeholders describe in submitted comments.⁶²

In the same vein, we support Black Swan Lab's recommendation to require each gas utility to file a 25-year phased plan to scale down its residential gas distribution system.⁶³ As Black Swan Lab describes, such a plan should include sufficient detail to allow for specific pipe segments to be permanently retired in a coordinated manner, rather than replaced with infrastructure that may become stranded as the Commonwealth decarbonizes the buildings sector consistent with statutory climate mandates.⁶⁴ Taking this targeted approach, as well as ensuring proactive and coordinated planning between the gas and electric utilities, will be necessary to facilitate a cost-effective transition.⁶⁵

VII. Utilities Continue to Misplace Blame on Public Policy Charges

The framing of public policy charges as the primary driver of rising energy bills, as provided across the EDCs' and LDCs' affordability reports and carried through their initial comments, does not withstand scrutiny.⁶⁶ Supply and delivery charges constitute a substantially

⁵⁷ *E.g.*, D.P.U. 25-GSEP-03, Order at 23.

⁵⁸ Advocates Initial Comments at 27.

⁵⁹ *See* D.P.U. 25-40 through 25-45, CLF-EDF-SC Initial Brief at 52.

⁶⁰ *See* AGO Initial Comments at 42.

⁶¹ *Id.*

⁶² *See* Advocates Initial Comments at 26; D.P.U. 25-200, EDF Initial Comments at 5-6, 8 (April 14, 2026); D.P.U. 25-200, Black Swan Lab Initial Comments at 2; AGO Initial Comments at 39.

⁶³ Black Swan Lab Initial Comments at 4.

⁶⁴ *Id.* at 4.

⁶⁵ Advocates Initial Comments at 27.

⁶⁶ *See, e.g.*, D.P.U. 25-200, National Grid Report on Energy Bill Affordability at 4; Eversource Initial Comments at 2-3.

larger share of Massachusetts energy bills and a larger share of recent bill growth.⁶⁷ Utilities are granted their monopoly as a matter of public policy, and singling out a subset of spending as “public policy driven” implies the remainder operates in an idealized realm of agreed-upon utility responsibility somehow outside the purview of public policy. This is deeply and deliberately misleading: due to having been granted the franchise, *everything* a utility does is pursuant to public policy. Utilities are not free-market firms—they have unique obligations. The original and continued existence of investor-owned utilities is a public policy decision, as is the regulation thereof. To refuse to acknowledge such and, instead, artificially divide utility responsibilities into policy and non-policy driven activities explicitly undermines the very tools designed to reduce costs over the medium and long term.

The Clean Energy Parties reinforced this point in their initial comments, emphasizing that rate design changes must not undermine critical programs like net metering, SMART, and Mass Save, which exist precisely to advance the Commonwealth’s statutory priorities of greenhouse gas emissions reduction, affordability, and equity.⁶⁸ We agree that these programs deliver real system benefits, including avoided capacity investment, reduced peak demand, and downward pressure on wholesale prices, that are systematically omitted when utilities present public policy charges as costs without corresponding benefits.⁶⁹

Eversource goes so far as to diminish the benefits of these programs. In its comments, Eversource states: “Energy efficiency can do little to mitigate any bill increases for low-use customers that may result from a move to fixed charges. This highlights the importance of aligning a fixed charge with either distribution system cost causation or customer equity in the achievement of a public policy objective.”⁷⁰ This statement ignores the fact that reducing demand lowers energy prices for everyone.⁷¹ These policy charges are delivering real benefits and should be considered to be equivalent to paying generators for their power.

MCSE includes in their initial comments a data point that public policy costs grew 152 percent from 2015 to 2025, compared to 77 percent for delivery and 42 percent for supply.⁷² However, a charge that starts at a small base can grow in absolute size much less than a charge that starts at a high base and still show a larger *percentage* increase. Table 2 of MCSE’s filing illustrates that public policy charges represent 27 percent of a typical bill while delivery represents 41 percent.⁷³ The faster growth *rate* of a smaller billing category does not mean it is the primary affordability problem, particularly as the category of “public benefits charge” contains several line items that actually serve to *reduce* delivery costs. Percentage growth and proportional bill burden are two entirely different metrics. Distribution and transmission together

⁶⁷ Advocates Initial Comments at 8.

⁶⁸ Clean Energy Parties Initial Comments at 3.

⁶⁹ *Id.* at 18-19.

⁷⁰ Eversource Initial Comments, at 18.

⁷¹ The cost reductions from energy efficiency are similar to those realized from DER solar. *See* Synapse Energy, Solar Savings in New England (Dec. 2020), https://www.synapse-energy.com/sites/default/files/Solar_Savings_in_New_England_20-082.pdf.

⁷² D.P.U. 25-200, MCSE Initial Comments at 10 (April 10, 2026).

⁷³ *Id.* at 7.

still constitute the largest share of the bill in dollar terms, and transmission alone grew 137 percent over the last decade.⁷⁴

MCSE also characterizes programs like the Renewable Portfolio Standard, Mass Save, and Residential Assistance as opaque and poorly understood by ratepayers.⁷⁵ These programs passed the legislature after public debate and were approved through open Department proceedings—they are among the most scrutinized costs on a utility bill. Calling the Renewable Portfolio Standard and other program costs contained in the supply charge “hidden” fails to account for the reality of the legislative and regulatory process behind those programs. It is also disingenuous, given that delivery charges are hardly more transparent than supply charges on customer bills. Furthermore, MCSE never quantifies what would happen to Massachusetts energy costs without these programs, including the avoided costs of carbon damages.

The Department must reject the narrative that public policy programs are cost drivers to be curtailed. The more accurate framing is that everything a utility does is pursuant to public policy—there is no picking and choosing obligations. When it comes to the programs that have been summarily labeled “public policy programs,” it is vital to recognize that they are, in fact, cost containment tools, and that eroding them in pursuit of short-term bill relief risks locking ratepayers into higher long-term costs driven by the infrastructure overinvestment and fossil fuel dependence that the programs are designed to address.

VIII. D.P.U. 25-200 Scope and Cross-Docket Coordination

The Department’s stated objectives for this investigation—containing customer costs, reducing bill volatility, and increasing bill transparency—are complex endeavors, and the lengthy list of issues and policy ideas discussed in submitted comments reflects this. Additionally, as the Green Energy Consumers Alliance observes, several ongoing Department proceedings may materially impact the same questions of energy affordability, bill volatility, and transparency.⁷⁶ These proceedings include D.P.U. 26-62 (time-varying rates), D.P.U. 25-40 through 25-45 (climate compliance plans), D.P.U. 25-08 (seasonal heat pump rates), D.P.U. 25-188 and 25-189 (EV infrastructure program), D.P.U. 25-20 (long-term electric system planning), D.P.U. 24-15 (energy burden), and others.

As a next step, we urge the Department to provide clarity around the scope of this investigation and the scope of any future comment opportunities in this investigation. For out-of-scope topics, we request that the Department indicates where it plans to address those topics moving forward.

We also reiterate our recommendation that the Department expand the scope of this proceeding and/or open another proceeding focused on strategies to reduce overall customer costs.⁷⁷ Certain issues—such as utility return on equity, performance-based ratemaking, “CapEx-

⁷⁴ *Id.* at 10, Chart 1.

⁷⁵ *Id.* at 4-5.

⁷⁶ D.P.U. 25-200, GECA Comments at 1 (April 14, 2026).

⁷⁷ Advocates Initial Comments at 32.

OpEx equalization,” and basic service procurement reform—hold significant potential for improving short- and long-term energy affordability and deserve exploration outside of base distribution rate cases. Relatedly, the Department should consider expressly requiring distribution companies to demonstrate exhaustion of demand-side alternatives before adding capital investment to rate base. This could include (1) mandatory NWA/NPA screening triggers with enforceable thresholds; (2) VPP integration requirements tied to AMI deployment timelines; and (3) performance-based incentives that reward utilities for demand-side cost reductions rather than capital deployment. Rate redesign that reallocates costs without addressing the underlying capital bias will not produce durable affordability for ratepayers.

Conclusion

The undersigned appreciate the Department opening this proceeding and providing the opportunity for stakeholders to comment. As discussed above, we urge the Department to shift many volumetric reconciling charges into base distribution rates and to facilitate the development of a full record before further considering proposals to convert certain reconciling charges into fixed charges. We also urge the Department, in this proceeding or a separate investigation, to examine the underlying utility incentive structure and explore the measures discussed in our initial comments to contain or reduce costs for customers. We look forward to continuing to engage with the Department, the utilities, and other stakeholders on issues impacting energy affordability in this proceeding and beyond.

Very truly yours,

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