The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 25-200-A November 13, 2026

Investigation by the Department of Public Utilities on Its Own Motion into Gas and Electric Delivery Charges and Bill Redesign.

PHASE I ORDER ON REVIEW OF CHARGES AND RECONCILING MECHANISMS

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SUMMARY

In this Order, the Department of Public Utilities addresses energy affordability in four key ways: First, we identify 15 reconciling mechanisms for elimination; second, we establish a new standard for future reconciling mechanisms; third, we direct each utility to provide information in its next base rate case that will allow us to re-evaluate the design of carrying charges applied to reconciling mechanisms; and fourth, we direct gas and electric utilities to improve public reporting on how customer rates change over the course of each year. In so doing, we are increasing the transparency of utility regulation, reducing bill volatility, and enhancing the incentives for utilities to control costs, thereby containing costs for consumers.

Electric and gas utilities collect costs from customers through base rates and reconciling mechanisms. Base rates are designed to recover the utility's cost to operate and maintain its distribution system and are approved by the Department every few years (the timing depends on when utilities seek to change their base rates). Reconciling rates recover separate costs and change on an annual or semi-annual basis. In this Order, we explicitly articulate a preference for cost recovery through base rates rather than through reconciling rates. Further, we review 40 electric and gas delivery rates and find that 15 of them should be eliminated.

Going forward, when a utility wants to create, revise, or continue a reconciling rate, it must meet a higher standard. The Department expects cost recovery to occur through base distribution rates unless the cost in question meets all the following criteria: (1) volatile in nature; (2) large in magnitude; and (3) beyond the utility's control.

The Department further recognizes that, currently, there is no consistent approach to the application of carrying charges, with different interest rates used across and within the utilities. The Department directs that each utility provide detailed information in its next base rate case about the implications of various interest rate options, including how the proposed carrying charge rate is an accurate reflection of the actual cost to finance over- and under-recoveries.

Finally, the Department directs the utilities to file a revised reporting template explaining how each rate change will affect customer bills throughout the calendar year. Once the Department approves the reporting template, each utility will need to file the report with every proposed rate change and include a rolling 5-year historical rate lookback.

These decisions will result in the following benefits to ratepayers: (1) encourage utilities to control costs by reducing the bias for the utility to invest in capital projects where they earn a profit for investors; (2) reduce the risk that a utility will seek to recover a cost twice through different charges; and (3) require utilities to file proposals that consider opportunities to lower carrying charges. The impact of these decisions will occur over time, but, once implemented, customers will experience reduced bill volatility and utilities will have stronger incentives to contain costs. The next phase of this investigation will focus on additional opportunities to contain costs and increase transparency of costs on bills.

I. INTRODUCTION

The Department of Public Utilities ("Department") opened this inquiry to conduct a comprehensive review of gas and electric delivery rates and charges with the aims of containing customer costs, reducing utility bill volatility, and increasing utility bill transparency and accessibility. Investigation by the Department of Public Utilities on Its Own Motion into Gas and Electric Delivery Charges and Bill Redesign, D.P.U. 25-200, Vote and Order Opening Investigation (2025) ("Vote and Order"). In particular, the Department sought to examine whether changes to the current design and composition of electric and gas delivery rates can mitigate and manage recent cost trends and to enable a transparent and holistic review of the annual reconciling rate changes for each of the electric distribution companies ("EDCs") and gas local distribution companies ("LDCs") (together, "Distribution Companies").[1]

The Department set forth the following objectives for the first phase of its investigation: (1) identify which reconciling charges can be eliminated or included in base distribution rates going forward; (2) determine whether certain electric and gas reconciling mechanism costs should be collected from customers through fixed charges rather than volumetric charges; (3) determine whether certain electric reconciling mechanisms should be included in the EDCs'

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[1] The Distribution Companies include: The Berkshire Gas Company ("Berkshire Gas"); Boston Gas Company ("National Grid (gas)"), Massachusetts Electric Company, and Nantucket Electric Company ("National Grid (electric)"), each d/b/a National Grid (together, "National Grid"); NSTAR Electric Company ("NSTAR Electric"), NSTAR Gas Company ("NSTAR Gas"), and Eversource Gas Company of Massachusetts ("EGMA"), each d/b/a Eversource Energy (together, "Eversource"); Fitchburg Gas and Electric Light Company (Electric Division) ("Unitil (electric)"), and Fitchburg Gas and Electric Light Company (Gas Division) ("Unitil (gas)"), each d/b/a Unitil (together, "Unitil"); and Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty ("Liberty").

annual retail rate filings for review and approval rather than filed in separate dockets at different times of the year; (4) determine how the value of net metering credits and the associated bill impacts to electric customers in Massachusetts compare to similar programs in other jurisdictions and whether the value of the net metering credit should be adjusted; and (5) determine the feasibility of creating a maximum threshold for the amount that charges assessed to customers may change from one month to another. Vote and Order at 12-13. The Department also indicated our intent to investigate, as a subsequent phase of this investigation, how to redesign Massachusetts utility bills to enhance customer knowledge, agency, and responsiveness to price and policy signals. Vote and Order at 20-21.

As part of our review, the Department sought input from the Distribution Companies and all other interested stakeholders. Importantly, the Department received comments from dozens of ratepayers. These ratepayer comments noted a range of concerns about high energy bills, a lack of transparency in charges, and excessive earnings by the Distribution Companies. The Department appreciates the public's concern about these issues, and we see our analysis and decisions in this Order as a significant first step to respond to these concerns, with additional phases of this investigation to follow.

Based on the data collected, comments, responses to requests for information, and discussions at technical conferences, the Department issues this Phase I Order with a focus on reviewing the electric and gas delivery charges and identifying for elimination any unnecessary charges on the bill; announcing a higher standard for adding new charges to the bill going forward; and providing greater transparency regarding rate changes that occur throughout the year. The directives in this Order, taken together, reflect our priority to contain costs for

customers as we oversee Distribution Company investments in electric and gas distribution infrastructure to maintain safe and reliable service and to support the Commonwealth's clean energy transition.

Specifically, this Phase I Order: (1) identifies which reconciling charges can be eliminated and provides directives as to whether the costs currently collected through a reconciling mechanism should instead be collected through base distribution rates following the relevant Distribution Company's next base distribution rate case; (2) establishes standards for continuing or creating new reconciling mechanisms going forward; (3) directs each Distribution Company to submit certain information related to carrying charges used for reconciling mechanisms in its next base rate case; (4) finds that at this time, it is not in the best interest of ratepayers to consolidate electric reconciling mechanisms into one annual retail rate filing; and (5) directs the Distribution Companies to submit reporting templates with each reconciliation filing comparing the proposed rate change to the rates in effect twelve months prior to the effective date of the proposed rate (e.g., rates proposed for effect January 1, 2027 compared with rates effective January 1, 2026) using the parameters outlined below in Section V.

II. PROCEDURAL HISTORY

In its Vote and Order, the Department directed the Distribution Companies to each submit a report with the Department containing information necessary for this investigation ("Report"). Vote and Order at 16-17. The Department also requested written comments from the Distribution Companies and any interested stakeholders responding to certain questions related to the Department's review of gas and electric delivery rates. Vote and Order at 17-20.

In addition, the Department provided an opportunity for reply comments. Vote and Order at 17-20.[2]

On February 13, 2026, the Distribution Companies filed their Reports with the Department. The Department also received comments and responses to the questions posed in the Vote and Order from over 50 members of the public and other interested stakeholders, including the following: (1) the Distribution Companies; (2) the Office of the Attorney General ("Attorney General"); (3) Department of Energy Resources ("DOER"); (4) Massachusetts Coalition for Sustainable Energy ("MCSE"); (5) Feeney Brothers Utility Services; (6) the Low-Income Weatherization and Fuel Assistance Program Network, the Low-Income Energy Affordability Network, and the Massachusetts Energy Directors Association (MEDA) (collectively, "LEAN"); (7) Black Swan Lab; (8) a coalition of clean energy advocates ("Clean Energy Parties");[3] (9) National Consumer Law Center ("NCLC"); (10) Cape Light Compact; (11) Green Energy Consumers Alliance ("GECA"); (12) The Energy Consortium ("TEC"); (13) a coalition of climate, energy, and consumer advocates ("Climate Advocates");[4]

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2 On February 10, 2026, the Department sent a letter to the Distribution Companies regarding their efforts to reduce winter electric and gas rates in response to the Governor's call for winter bill relief, wherein we emphasized the need for the Distribution Companies to comprehensively review their rates and charges to offer robust proposals for proactively managing and mitigating costs for their customers for the Department's review in the context of this investigation. Letter from the Department to the Distribution Companies (February 10, 2026).

3 The Clean Energy Parties include representatives of Advanced Energy United, The Alliance for Climate Transition, the Solar Energy Industries Association, Coalition for Community Solar Access, and the Solar Energy Business Association of New England.

4 The Climate Advocates include representatives of the Conservation Law Foundation, Vote Solar, Acadia Center, Sierra Club, LEAN, the Massachusetts Association for

(14) the Environmental Defense Fund ("EDF"); (15) Cashman Preload Cryogenics; (16) the Massachusetts Institute of Technology ("MIT"); (17) Patriot Hydro; (18) PowerOptions; (19) Altus Power Renewable Energy; (20) Senator Mark Montigny; and (21) the City of Boston. The Department appreciates the thorough and thoughtful comments from interested stakeholders and analyzes and responds to these comments as appropriate in the discussion below.

On April 1, 2026, the Department convened a hybrid technical conference for the Distribution Companies to present the recommendations and data contained in their Reports and for the Department and stakeholders to further explore the objectives identified in the Vote and Order. On April 3, 2026, the Department held a virtual technical conference for interested stakeholders to make presentations and engage in discussions. More than 20 stakeholders actively participated in the technical conferences, which drew many more attendees. The Department also issued several rounds of information requests to the Distribution Companies, DOER, and the Attorney General regarding their Reports, comments, and proposals.[5]

On June 26, 2026, the Department issued a Hearing Officer Memorandum setting forth the anticipated scope of the Phase I Order. D.P.U. 25-200, Hearing Officer Memorandum (June 26, 2026) ("June 26 Memo"). In addition, the Department stated its intent to defer certain objectives outlined in the Vote and Order for further investigation, noting that these issues likely

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Community Action, the Environmental Defense Fund, and the Environmental League of Massachusetts.

[5] The Department on its own motion, pursuant to 220 CMR 1.10(3), moves into the evidentiary record of this proceeding the following responses to information requests: DPU-Common 1-1; DPU-Common 2-1 through DPU-Common 2-2; DPU-Common 3-1 through DPU-Common 3-19; DPU-Common 4-1 through DPU-Common 4-12; DPU-AG 1-1 through DPU-AG 1-3; and DPU-DOER 1-1 through DPU-DOER 1-4.

require further consideration and process.[6] June 26 Memo at 2-3. Finally, the Department indicated that as part of its investigation into promoting more manageable, stable electric and gas bills, the Department will evaluate potential changes to existing processes to enable a transparent and holistic understanding of changes to each utility's annual reconciling rates, supply rates, and distribution rates, including cumulative bill impacts and cost trends. June 26 Memo at 3-4; Vote and Order at 2. To this end, the Department requested that the EDCs, jointly, and the LDCs, jointly, submit proposals for an annual (electric) or bi-annual (gas) reporting template to show each rate change scheduled to take effect in the calendar year (electric) or by season (gas). June 26 Memo at 3-7. We further requested that the Distribution Companies address certain considerations as part of the reporting template proposals, discussed further below. June 26 Memo at 7-8. The Department also provided an opportunity for stakeholders to comment on the Distribution Companies' reporting template proposals. June 26 Memo at 8.

On July 31, 2026, the Distribution Companies submitted proposed reporting templates along with associated comments to the Department, discussed further below in Section V. The Department subsequently received comments on the Distribution Companies' reporting template proposals from the Attorney General, DOER, and the City of Boston, addressed below.

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[6] These deferred issues include the following: (1) whether certain electric and gas reconciling mechanism costs should be recovered from customers through fixed charges rather than volumetric charges; (2) how the value of net metering credits and the associated bill impacts to electric customers in Massachusetts compare to similar programs in other jurisdictions and whether the value of the net metering credit should be adjusted, to the extent possible under the Department's existing authority; and (3) the feasibility of creating a maximum threshold for the amount that charges assessed to customers may change from one month to another.

III. REVIEW OF ALL DELIVERY CHARGES ON ELECTRIC AND GAS BILLS

A. Introduction

We begin with a review of all the delivery charges on electric and gas bills for the investor-owned utilities regulated by the Department.[7] Base distribution rates and customer charges (often referred to collectively as "base rates") are designed to recover the utility's cost to operate and maintain its distribution system and are reviewed and approved in a base distribution rate proceeding. Reconciling rates—which recover costs that are incremental to those recovered in base rates—are recovered on an annual, fully reconciling basis. Unlike base rates, the Department reviews and approves reconciling rates annually—and in the case of some LDC reconciling mechanisms, semi-annually—to confirm that the costs are consistent with a Distribution Company's tariff and applicable Department precedent, and to determine whether the costs are prudent and result in just and reasonable rates. See, e.g., Liberty Utilities (New England Natural Gas Company) Corp., D.P.U. 26-24, at 3-4 (2026) (reviewing and approving Liberty's off-peak period revenue decoupling adjustment factors). Whether recovered through base distribution charges or through a reconciling mechanism, all costs must be prudently incurred, and all distribution company rates must be just and reasonable.

The Department conducts several dozen proceedings each year to review and approve the proposed rates for reconciling mechanisms. Each EDC consolidates a subset of their reconciling adjustments in an annual retail rate filing. See, e.g., NSTAR Electric Company, D.P.U. 25-158; Fitchburg Gas and Electric Light Company, D.P.U. 25-168; Massachusetts Electric Company

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[7] This Order does not address electric or gas supply charges, as the Department's jurisdiction over supply charges is limited.

and Nantucket Electric Company, D.P.U. 26-02. The LDCs consolidate their requests for reconciling mechanism adjustments in their local distribution adjustment factor ("LDAF") filings in the peak (November through April) and, as necessary, in the off-peak (May through October) seasons.[8] See, e.g., NSTAR Gas Company, D.P.U. 25-PGAF-NSTAR at 2 (2025); see also Boston Gas Company, D.P.U. 26-OGAF-GRID at 2 (2026). Some of the LDC reconciling mechanisms, however, are also investigated in their own individual proceedings each year. See, e.g., Eversource Gas Company, D.P.U. 25-GREC-05 (2025) (investigating the LDC's proposed gas system enhancement reconciliation adjustment factors ("GSERAFs")); NSTAR Gas Company, D.P.U. 23-86/24-114 (2026) (investigating the LDC's proposed geothermal energy provision factors).

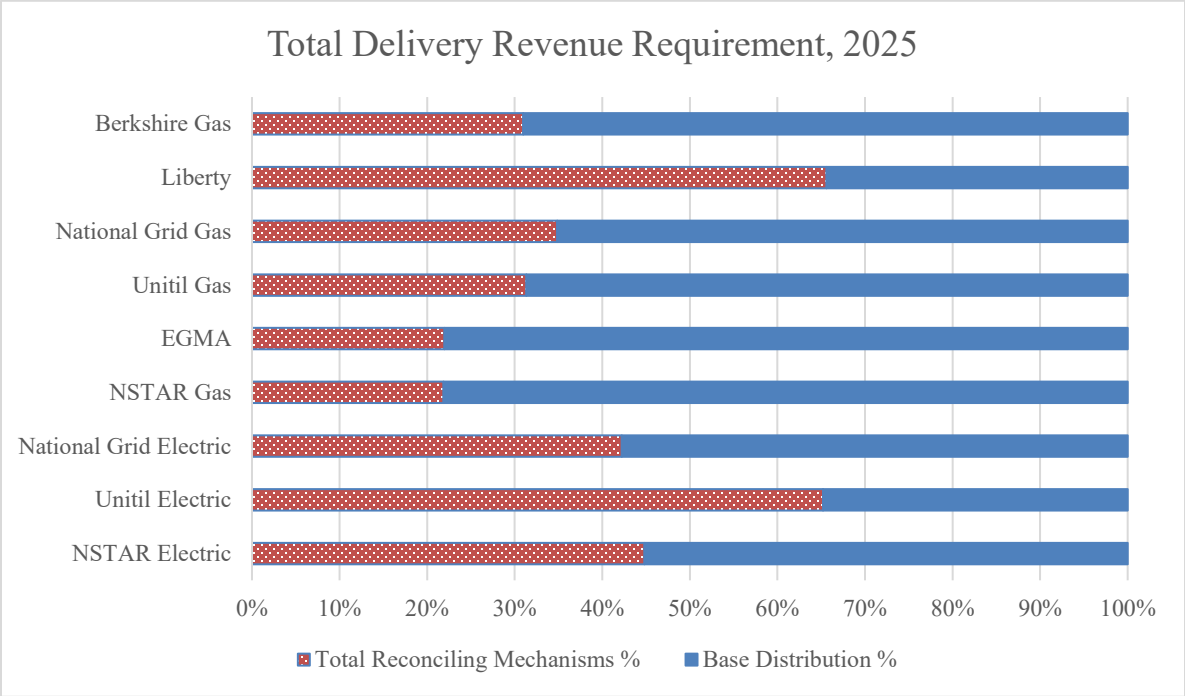
The percentage of each Distribution Company's delivery costs recovered through reconciling mechanisms fluctuates widely based on various factors, including the timing of base rate cases. Using the data provided in the Reports filed by the Distribution Companies, a snapshot from 2025 shows that the EDCs recover between 42 percent and 65 percent of their delivery costs through fully funded reconciling mechanisms, while the LDCs recover between

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[8] Each LDC implements its LDAFs pursuant to its Local Distribution Adjustment Clause ("LDAC") tariff. The LDAC is a mechanism that allows an LDC to recover, or credit, on a fully reconciling basis, costs that have been determined to be distribution-related costs but are not included in base distribution rates. Such costs include energy efficiency costs, environmental response costs associated with manufactured gas plants, and Federal Energy Regulatory Commission Order 636 transition costs. The LDAC is applicable to all firm customers (both sales and transportation). Colonial Gas Company, D.P.U. 98-128, at 54, n. 35 (1999); Bay State Gas Company, D.P.U. 98-31, at 12, n.16 (1998); Eastern-Essex Merger, D.P.U. 98-27, at 6, n.9 (1998).

22 percent and 66 percent[9] of their delivery costs through fully funded reconciling mechanisms (see Chart 1 below).[10]

Chart 1



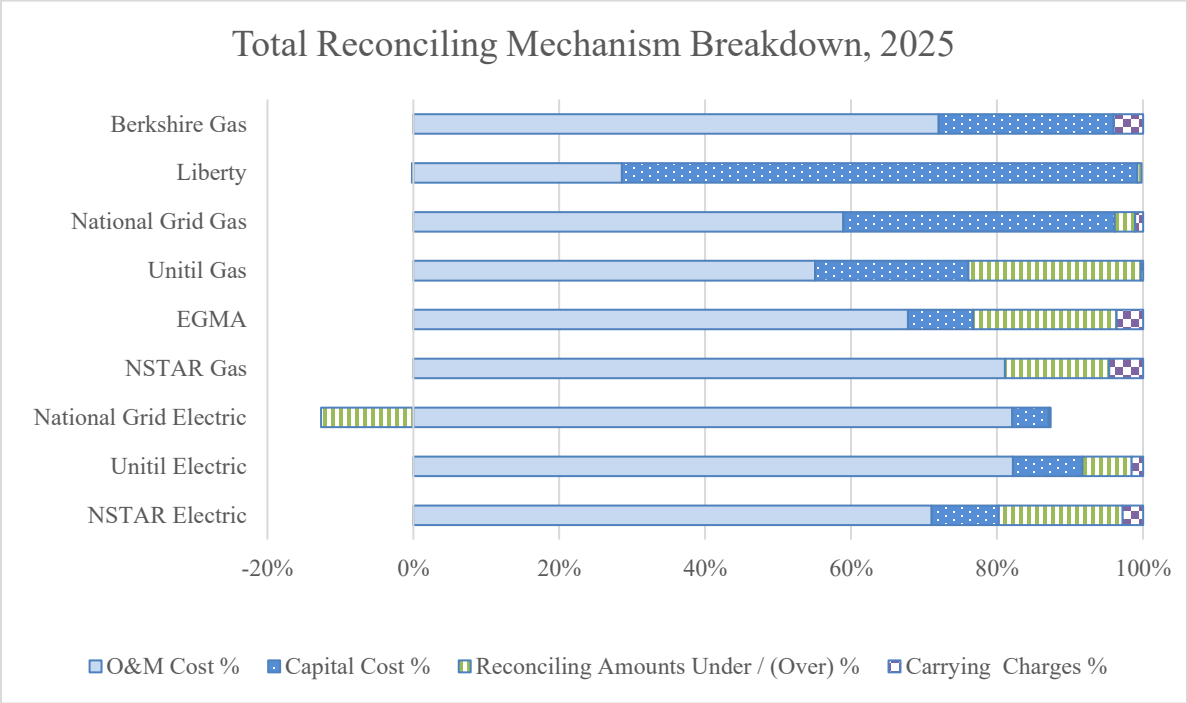
The 2025 snapshot also reveals that operations and maintenance ("O&M") costs make up a significant portion of the costs that are recovered through reconciling mechanisms (see Chart 2 below).

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9 Liberty is the only LDC that recovers 66 percent of its delivery costs through reconciling mechanisms as of 2025; the other LDCs recover between 22 and 35 percent of their delivery costs through reconciling mechanisms. The Department recently approved a settlement agreement in Liberty's base rate proceeding, which included moving some costs from reconciling mechanisms to base rates. Liberty Utilities (New England Natural Gas Corp.), D.P.U. 25-85 (March 27, 2026).

10 A fully funded reconciling mechanism allows for dollar-for-dollar recovery of approved costs from ratepayers, subject to Department oversight. 2022-2024 Three-Year Energy Efficiency Plans, D.P.U. 21-120 through D.P.U. 21-129, at 285 (2022).

Chart 2[11]



Each Distribution Company filed a list of delivery charges in its Report. Before discussing whether any of those charges should be eliminated, we first summarize each delivery charge, the costs it recovers, and the basis for its origination. While there are dozens of delivery charges summarized below, the specific delivery charges that show up as separate line items on the bill vary by Distribution Company. Many of the delivery charges listed below do not show up as separate line items on the bill – instead, they are typically included in line items such as "Distribution Charge" or "Distribution Adjustment Charge." The Department intends to further

11 At the time of this snapshot in 2025, National Grid (electric) shows a credit for reconciling amounts because the prior recovery period resulted in an overcollection, and National Grid (electric) is now returning those over collected costs to customers.

investigate utility bill design, and how to effectively and transparently communicate to customers what charges are included in their utility bill, in a subsequent phase of this proceeding.

B. Summary of all Delivery Charges

1. Delivery Charges for Both Electric Distribution Companies and Gas Local Distribution Companies

Table 1 below lists the charges applicable to both the EDCs and the LDCs and indicates whether they apply to each Distribution Company.

Table 1: Electric and Gas Distribution Company Delivery Charges

Mechanism	Electric Distribution Companies			Local Distribution Companies					
	NSTAR Electric	**National Grid (electric)**	**Unitil (electric)**	**National Grid (gas)**	**EGMA**	**NSTAR Gas**	**Liberty**	**Berkshire Gas**	**Unitil (gas)**
Base Distribution Charge	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Customer Charge	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Revenue Decoupling	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Pension Adjustment Factor	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Residential Assistance Adjustment Factor	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Attorney General Consultant Expense	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
Electronic Payment Recovery Factor	**X**	**X**		**X**	**X**	**X**			
Tax Act Credit Factor	**X**	**X**			**X**	**X**	**X**		
Service Quality	**X**	**X**		**X**		**X**		**X**	
Exogenous Cost	**X**			**X**	**X**	**X**			**X**

Base Distribution Rates (All Distribution Companies). Base distribution rates allow a company to recover both a return *of* (i.e., depreciation) and a return *on* (i.e., profit)[12] its capital expenditures as well as a representative level of O&M expenses, taxes, and amortization expenses, necessary to own and operate the company's distribution system. Base distribution rates include a base distribution charge and a customer charge. Under traditional cost-of-service ratemaking, the base distribution rates remain the same between base distribution rate cases. Most of the Distribution Companies, however, currently operate under an alternative ratemaking framework referred to as a performance-based ratemaking ("PBR") plan. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 23-150, at 78 (2024); Fitchburg Gas and Electric Light Company, D.P.U. 23-80/D.P.U. 23-81, at 34 (2024); NSTAR Electric Company, D.P.U. 22-22, at 51 (2022); Boston Gas Company, D.P.U. 20-120, at 68-69 (2021); NSTAR Gas Company, D.P.U. 19-120, at 60 (2020). These PBR plans contain annual formula adjustments to base distribution rates between base distribution rate cases. See, generally, Incentive Regulation, D.P.U. 94-158 (1995); NSTAR Electric Company, D.P.U. 26-124 (requesting an increase in base rates pursuant to the approved PBR formula). For each current PBR plan, the Department determined that the PBR plan was necessary to enable the EDC or LDC to adapt to policy-driven market developments, including legislative and regulatory initiatives "designed to address

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12 The United States Supreme Court has held that, to avoid confiscation of regulated utilities' property in violation of the United States Constitution, regulated utilities are entitled to collect reasonable operating costs and must be provided an opportunity to earn a just and reasonable return on investment. Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679, 690 (1923); Cambridge Electric Light Company, Commonwealth Electric Company, and Canal Electric Company, D.P.U./D.T.E. 97-111, at 37 (1998).

climate change and to foster a clean energy economy." D.P.U. 23-150, at 76-77; D.P.U. 23-80/D.P.U. 23-81, at 32-33; D.P.U. 22-22, at 48-49; D.P.U. 20-120, at 66-67; D.P.U. 19-120, at 60-61.

Base Distribution Charge (All Distribution Companies). This charge is a component of base distribution rates and typically constitutes the largest portion of the delivery charge on each bill. The Department sets base distribution charges through a base distribution rate case pursuant to G.L. c. 164, § 94.

Customer Charge (All Distribution Companies). The customer charge is a component of base distribution rates. It is a fixed charge that does not change based on a customer's usage. The customer charge recovers some of the fixed costs to serve each customer, such as meter reading, billing, and customer service. Like the base distribution charge, the Department sets the customer charge during a base distribution rate case pursuant to G.L. c. 164, § 94.

Revenue Decoupling (All Distribution Companies). Revenue decoupling is a mechanism that "decouples" the utility's sales volumes from the base distribution revenues that it charges each year to eliminate the financial barriers to the full engagement and participation by the utility in demand-reducing efforts such as energy efficiency. It does this by reconciling the Department-approved distribution revenues with the actual distribution revenues billed by the company. This reconciling mechanism was created pursuant to Department policy directives in Revenue Decoupling, D.P.U. 07-50-A (2008), where the Department found that revenue decoupling provides the Distribution Companies with better financial incentives to pursue a cleaner, more efficient energy future consistent with enacted legislation (i.e., An Act Relative to Green Communities, St. 2008, c. 169). The EDCs refer to this mechanism as the revenue

decoupling mechanism, or "RDM." The LDCs refer to this mechanism as the revenue decoupling adjustment factor, or "RDAF." The Department adjusts each company's Department-approved distribution revenues during its base distribution rate case.

Pension Adjustment Factor ("PAF") (All Distribution Companies). This mechanism recovers costs associated with the Distribution Companies' employee retirement pension and post-retirement benefits other than pension ("PBOP") programs. The PAF mechanism was first established to address the effects of a declining stock market and steeply falling interest rates on the value of the Companies' pension and PBOP plans. Boston Gas Company, D.T.E. 03-40, at 309-310 (2003); Commonwealth Electric Company, Cambridge Electric Light Company, and Boston Edison Company, D.T.E. 03-47-A at 19-20 (2003).

Residential Assistance Adjustment Factor ("RAAF") (All Distribution Companies). This charge recovers the costs (or revenue shortfalls) associated with the income-eligible discount rate program and the arrearage management programs designed to help income-eligible customers get a bill discount or eliminate past-due debt. Distribution Companies are required to provide discount rates to income-eligible customers pursuant to G.L. c. 164, § 1F(4)(i) and are required to offer arrearage management programs pursuant to An Act Relative to Heating Energy Assistance and Tax Relief, St. 2005, c. 140, § 17. Cost recovery for the discount rates and arrearage management programs through the RAAF was established in Low-Income Discount Participation Rate, D.T.E. 01-106-B (2004), where the Department found that G.L. c. 164, § 1F(4)(i) requires that costs of the low-income discount program must be included in the rates charged to Distribution Company customers. To effectuate the intent of the statute, the Department authorized a departure from its typical practice to direct recovery of revenue

shortfalls to base rate cases, and found, instead, that it was appropriate to allow for cost recovery through a reconciling mechanism. D.T.E. 01-106-B at 8-9. See also Low-Income Discount Participation Rate, D.T.E. 01-106-C/D.T.E. 05-55/D.T.E. 05-56 (2005) (approval of tariffs for discount rates) and Standards for Arrearage Management Programs, D.T.E. 05-86 (2006) (directing cost recovery through the RAAF for arrearage management programs).

Attorney General Consultant Expense Factor ("AGCEF") (All Distribution Companies). An Act Relative to Green Communities, St. 2008, c. 169, created a new statute, G.L. c. 12, § 11E(b), whereby the Attorney General, as the ratepayer advocate, is authorized to collect the costs incurred to retain experts to assist in Department proceedings involving the Distribution Companies, who then pass this expense on to ratepayers annually through the AGCEF. In several proceedings following the passage of An Act Relative to Green Communities, in 2008, the Department approved reconciling mechanisms for the recovery of these costs. E.g., Fitchburg Gas and Electric Light Company, D.P.U. 11-01/11-02, at 277-278 (2011). The Department found that a reconciling mechanism would ensure that ratepayers only pay for costs that are actually incurred but noted that "[a]s we gain more experience with these types of expenses, we may consider whether these expenses are better recovered through base rates instead of in a reconciling mechanism." D.P.U. 11-01/11-02, at 277 n.172.

Electronic Payment Recovery Factor ("EPRF") (NSTAR Electric; National Grid (electric); National Grid (gas); EGMA; and NSTAR Gas). This charge recovers costs associated with the Distribution Companies' "Fee-Free" programs, which allow their residential customers to pay their utility bills using a credit or debit card without incurring a transaction fee. Instead, the transaction fee costs are passed along to all the Distribution Companies' residential

ratepayers through this factor as approved by the Department in Alternative Bill Payment Options for Customers, D.P.U. 20-91-A (2022). In that proceeding, the Department found a reconciling mechanism appropriate to facilitate the implementation of the proposed fee-free debit/credit card payment programs. D.P.U. 20-91-A at 43, 48-49. The Department explained that, as compared to base distribution rate recovery, an annual reconciling mechanism limits the recovery of costs to the actual expenses incurred during a time when such expenditures are expected to vary from year-to-year. D.P.U. 20-91-A at 43. Finally, the Department noted that recovery through a reconciling mechanism during the initial years of program implementation will facilitate timely Department and stakeholder review of program costs, benefits, and savings to ensure the program is working as intended. D.P.U. 20-91-A at 43.

Tax Act Credit Factor ("TACF")[13] (NSTAR Electric; National Grid (electric); EGMA; NSTAR Gas; and Liberty). This mechanism was created in Effect of the Reduction in Federal Income Tax Rates on the Rates Charged by Electric, Gas, and Water Companies, D.P.U. 18-15-E (2018). The purpose of the mechanism is to pass back to customers the cost savings the Distribution Companies received on costs previously paid by their customers, as a result of the Tax Cuts and Jobs Act of 2017, Pub. L. No. 115-97, 131 Stat. 2054, which reduced the federal income tax rate from 35 percent to 21 percent. The Department found that creating a new reconciling mechanism to effectuate the return of costs to customers was administratively efficient because it would obviate the need for annual base distribution credit tariff filings, and

[13] Liberty refers to this mechanism as the "2017 Tax Act Excess Accumulated Deferred Income Tax Factor" or "TAEDIT" (Exh. LU-1 Bill Summary).

because it was sufficiently transparent, as the amounts of credit/recovery would be readily identifiable, understandable, and easy to track. D.P.U. 18-15-E at 35.

Service Quality mechanism (NSTAR Electric; National Grid (electric); National Grid (gas); NSTAR Gas; and Berkshire Gas)**.** Each company is required to develop and implement a Service Quality Plan pursuant to G.L. c. 164, § 1F(7) and Order Adopting Revised Service Quality Guidelines, D.P.U. 12-120-D (2015). When a Distribution Company fails to meet its service quality standards, the Department assesses a penalty, which is then credited to the distribution company's customers via the Service Quality credit factors.[14] Each Distribution Company with this reconciling mechanism has a slightly different name for the factor: National Grid (electric) terms it "Service Quality Penalty"; National Grid (gas) terms it "Service Quality Index"; NSTAR Electric terms it "Service Quality Performance Adjustment"; NSTAR Gas terms it "Service Quality Penalty Factor"; and Berkshire Gas terms it "Service Quality Measurement Penalty Factor." EGMA, Liberty, Unitil (electric), and Unitil (gas) do not have this reconciling mechanism.[15]

Exogenous Cost mechanism (NSTAR Electric; National Grid (gas); EGMA; NSTAR Gas; and Unitil (gas)).[16] This reconciling mechanism exists to recover (or return) any costs that

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14 Because the Service Quality factor is a reconciling mechanism, a small charge (rather than a credit) may appear from time to time to reconcile any over-crediting that may have occurred in a prior reconciliation period.

15 On the occasion that these companies incur a service quality penalty, they credit customers through another already existing mechanism.

16 Although National Grid (electric) and Unitil (electric) do not currently have an exogenous cost mechanism in effect, they each have PBR plans that allow them to

meet a significance threshold, are beyond the control of the company, and are not otherwise accounted for in base rates or other reconciling mechanisms. D.P.U. 23-80/23-81, at 52. Exogenous cost recovery is typically allowed when the Distribution Company is subject to a stay-out provision as part of a PBR plan or a base distribution rate freeze as part of an approved settlement agreement. Because the Distribution Company cannot file a new base distribution rate case during the term of the PBR plan or the settlement agreement without incurring a penalty, exogenous cost recovery provides an avenue for recovery of costs that meet specific requirements. Eversource Gas Company of Massachusetts, D.P.U. 22-122, at 6 (2022), citing Boston Gas Company, D.P.U. 96-50, at 291 (1996). The Distribution Companies have recovered property tax expenses through the Exogenous Cost mechanism. See, e.g., Boston Gas Company, D.P.U. 23-56, at 16-17 (2023) (approving National Grid (gas)'s proposal to recover incremental property tax expenses as an exogenous cost in a separate factor over a three-year term). NSTAR Electric, EGMA, and Unitil (gas) all refer to this mechanism as the "Exogenous Cost Adjustment Factor" ("ECAF") (NSTAR Electric Report, Att. 1a NSTAR Electric; EGMA Report, Att. 1c EGMA; Unitil (gas) Report, Att. 1 Gas). National Grid (gas) refers to it as "Exogenous Cost Factor," and NSTAR Gas refers to it as "Exogenous Events" (National Grid (gas) Report, Att. NG-Gas-1; NSTAR Gas Report, Att. 1b NSTAR Gas).

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request separate cost recovery for non-recurring exogenous costs during the term of their PBR plans.

2. Gas Local Distribution Company Delivery Charges

Table 2 below lists the charges specific to LDCs and indicates whether they apply to each LDC.

Table 2: Gas Local Distribution Company Delivery Charges

Mechanism	Local Distribution Companies					
	National Grid (gas)	**EGMA**	**NSTAR Gas**	**Liberty**	**Berkshire Gas**	**Unitil (gas)**
Energy Efficiency Surcharge	**X**	**X**	**X**	**X**	**X**	**X**
Gas System Enhancement Adjustment Factor	**X**	**X**	**X**	**X**	**X**	**X**
Balancing Penalty Credit	**X**		**X**	**X**	**X**	**X**
Environmental Remediation Adjustment Factor	**X**	**X**	**X**	**X**	**X**	**X**
System Supply Factor	**X**	**X**	**X**	**X**	**X**	**X**
Margin Credits	**X**		**X**	**X**		**X**
Geothermal Energy Provision Factor	**X**		**X**			
Base Distribution Reconciliation Factor		**X**				
Gas Business Enablement Factor	**X**					

Energy Efficiency Surcharge ("EES") (All LDCs). Pursuant to An Act Relative to Green Communities, St. 2008, c. 169, each LDC must prepare a three-year energy efficiency plan, and each plan must include a fully reconciling funding mechanism to recover costs associated with the approved three-year plan budgets. G.L. c. 25, § 19(b); G.L. c. 21(b)(2)(vii); see also G.L. c. 25, § 21(d)(2). Gas Three-Year Energy Efficiency Plans Order, D.P.U. 09-121 through D.P.U. 09-128 (2010). The Department's Energy Efficiency Guidelines specify the

manner in which revenue from an EES may be collected from ratepayers. Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines, D.P.U. 20-150-A, App. A at § 3.2.2 (2021).

Gas System Enhancement Adjustment Factor ("GSEAF") and GSERAFs (All LDCs). In 2014, the Legislature passed An Act Relative to Natural Gas Leaks, St. 2014, c. 149 (the "Gas Leaks Act"). The Gas Leaks Act, as codified at G.L. c. 164, § 145, required LDCs to submit to the Department, on an annual basis, plans to repair or replace aged natural gas infrastructure in the interest of public safety and to reduce lost and unaccounted for gas. These plans are referred to as the Gas System Enhancement Plans ("GSEPs"). G.L. c. 164, § 145 also directed the Department to establish a fully reconciling mechanism to recover GSEP costs on an annual basis. Accordingly, the GSEAF recovers eligible GSEP costs, and the GSERAF reconciles any over or under recovery of those costs. The Department first implemented the statute in 2015. See, e.g., NSTAR Gas Company, D.P.U. 14-135 (2015).

Balancing Penalty Credit (National Grid (gas); NSTAR Gas; Berkshire Gas; Liberty; and Unitil (gas) [17]). This mechanism credits all customers with balancing penalty revenues that the LDCs charge to third-party suppliers for over or under deliveries on the company's gas system as determined by the LDC's Distribution Terms and Conditions Tariff. See, e.g., Boston Gas Company, Distribution Service Terms and Conditions Tariff, M.D.P.U. No. 61.3. The

[17] Unitil (gas) refers to this mechanism as the "Broker Imbalance Penalty Credit" (Unitil Report, Att. 1 Gas).

mechanism was implemented following the unbundling of the gas industry in the late 1990s[18] and is in each LDC's Distribution Service Terms and Conditions Tariff.

Environmental Remediation Adjustment Factor (All LDCs). Pursuant to a settlement agreement approved by the Department in Manufactured Gas Plants, D.P.U. 89-161, at 30, 56 (1990), the LDCs recover costs for remediating manufactured gas plant sites, disposal sites, or other sites onto which hazardous material may have migrated, as a result of the operating or decommissioning of Massachusetts manufactured gas facilities. The Distribution Company may recover up to five percent of its environmental remediation costs annually through its LDAF. D.P.U. 89-161, at 34.

System Supply Factor (All LDCs). This mechanism recovers the cost of gas used to maintain pressures on the system. These costs were previously collected as part of the Cost of Gas Adjustment Factor ("GAF"), the charge for gas supply. Certain large customers, however, do not pay the GAF and thus do not pay these costs, even though they benefit from them. To eliminate this subsidy, the Department directed the LDCs to create a component of the LDAF in their LDAC tariffs in Gas Distribution Companies Revised Tariffs, D.P.U. 23-122 (2024), termed the "System Supply Factor," into which large customers also contribute.

Margin Credits (National Grid (gas); NSTAR Gas; Liberty; and Unitil (gas)). Margins earned as a result of interruptible transportation, capacity release, off-system sales, interruptible sales, portfolio management and optimization agreements, and related transactions are credited to all gas customers and the gas company under a 90/10 percent margin-sharing allocation

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[18] See, e.g., Natural Gas Unbundling, D.T.E. 98-32-A (1998) (overseeing and implementing the initial steps in restructuring of the natural gas market).

through either the LDAC or the cost of gas adjustment clause. See Investigation into Margin Sharing, D.P.U. 10-62-A at 36 (2013); see also Interruptible Transportation, D.P.U. 93-141-A (1996).

Geothermal Energy Provision Factor ("GEP") (National Grid (gas) and NSTAR Gas). This mechanism recovers costs associated with the geothermal network pilot projects in Framingham, MA (NSTAR Gas) and Boston, MA (National Grid (gas)). As part of NSTAR Gas's last base distribution rate case in NSTAR Gas Company, D.P.U. 19-120 (2020) and National Grid (gas)'s geothermal pilot proposal reviewed in Boston Gas Company, D.P.U. 21-24 (2021), the Department authorized the pilot projects, and established this mechanism, to explore the feasibility of converting natural gas customers to geothermal heat. In D.P.U. 19-120, the Department found that the intent of the geothermal pilot project was consistent with An Act Establishing the Global Warming Solutions Act, St. 2008, c. 298 ("Global Warming Solutions Act"), and the Commonwealth's energy and climate policies. D.P.U. 19-120, at 139-140.

Base Distribution Reconciliation Factor ("BDRF")[19] (EGMA). This mechanism was implemented pursuant to EGMA's rate plan in the settlement agreement approved by the Department in 2020 ("EGMA Rate Plan Settlement"). Eversource Energy/Bay State Gas Company, D.P.U. 20-59/19-140/19-141 (2020) (approving settlement agreement and rate plan). According to the rate plan, the Company is eligible for two rate base resets (i.e., an increase in

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19 In addition, NSTAR Gas recovers a BDRF from G-53 customers for those distribution costs in excess of the rate base reset that were not included in base distribution rates for effect January 16, 2026, as allowed by the company's Local Distribution Adjustment Clause tariff, M.D.P.U. No. 402AF, § 14.1. NSTAR Gas Company, D.P.U. 24-134-B/D.P.U. 25-53-A at 13-14 (January 16, 2026).

base rates) during the eight-year term of the rate plan, each subject to a seven percent cap. If costs exceed the rate base reset cap, then EGMA may recover, through a reconciling mechanism, base distribution costs in excess of the cap that were deferred for collection and implement the remaining revenue requirement in the following year through a base distribution rate increase. D.P.U. 20-59/19-140/19-141, at 20; EGMA Rate Plan Settlement §§ 2.6.1, 2.6.1.8, 2.6.2. The initial BDRF was approved for an 18-month term effective May 1, 2025, to October 31, 2026. EGMA, however, may request recovery through the BDRF following its second rate base reset on November 1, 2027, if its costs exceed the rate base reset cap.

Gas Business Enablement Factor ("GBEF") (National Grid (gas)). This mechanism was used to recover costs related to investments in National Grid's Gas Business Enablement program, an enterprise-wide information technology initiative. The Department originally approved the mechanism in Boston Gas Company and Colonial Gas Company, D.P.U. 17-170, at 235-248 (2018). On October 13, 2023, the Department suspended further cost recovery through the GBEF and ordered National Grid (gas) to issue refunds to its customers of all the money collected through the mechanism to date. Boston Gas Company, D.P.U. 22-93-A (2023). In 2024, National Grid (gas) provided its customers a credit in the amount of $29,091,621 (National Grid (gas) Report, Att. NG-Gas-4, at 8).[20]

[20] National Grid (gas) also lists an "Earnings Sharing Mechanism" as a separate reconciling mechanism in its Report. Because that mechanism is an integral part of the PBR plan approved by the Department in National Grid (gas)'s last rate case, D.P.U. 20-120, we do not address it separately here.

3. Electric Distribution Company Delivery Charges

Table 3 below lists the charges specific to the EDCs and indicates whether they apply to each EDC.

Table 3: Electric Distribution Company Delivery Charges

Mechanism	Electric Distribution Companies		
	NSTAR Electric	**National Grid (electric)**	**Unitil (electric)**
Transmission Charge	**X**	**X**	**X**
Transition Charge	**X**	**X**	
Basic Service Adjustment or True Up Factor	**X**	**X**	**X**
Energy Efficiency Reconciling Factor	**X**	**X**	**X**
System Benefits Charge	**X**	**X**	**X**
Electric Sector Modernization Plan Factor	**X**	**X**	**X**
Grid Modernization Factor	**X**	**X**	**X**
Long Term Renewable Contract Adjustment	**X**	**X**	**X**
Net Metering Recovery Surcharge	**X**	**X**	**X**
Distributed Solar Charge	**X**	**X**	**X**
Renewables Charge	**X**	**X**	**X**
Storm Costs	**X**	**X**	**X**
Storm Performance Adjustment Factor		**X**	
Advanced Metering Infrastructure Factor	**X**	**X**	
Vegetation Management Factor	**X**	**X**	
Electric Vehicles Program Charge	**X**	**X**	
Provisional System Planning Factor	**X**	**X**	
Smart Grid Distribution Adjustment Factor		**X**	
Solar Program Cost Adjustment Factor	**X**	**X**	
Solar Expansion Cost Recovery Factor	**X**		
Capital Cost Adjustment			**X**
ISRE Factor		**X**	
Cable Facilities Surcharge		**X***	

**Nantucket Electric customers only*.

Transmission Charge (All EDCs). This charge collects the costs to build, maintain, and operate the transmission grid, which carries electricity at higher voltages over long distances.[21] Transmission costs are regulated by the Federal Energy Regulatory Commission pursuant to the Federal Power Act, 16 U.S.C. §§ 791 *et seq*. While transmission costs are not subject to the Department's jurisdiction, the Department regulates the delivery rates through which retail customers pay for transmission costs.

Transition Charge (NSTAR Electric and National Grid (electric)). In 1997, An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, St. 1997, c. 164 ("Restructuring Act") directed the deregulation of the generation and supply sector of the utility industry, transforming the vertically integrated electric utilities into EDCs, responsible for only the delivery of electricity. As a result, the EDCs sold off their generation assets. The transition charge was established to recover each EDC's non-mitigatable stranded investment costs in generation. G.L. c. 164, §§ 1A(a), 1G(b); see, e.g., Cambridge Electric Light Company, Commonwealth Electric Company, and Canal Electric Company, D.P.U./D.T.E. 97-111, at 40, 54-55 (1998) (directing the EDCs to list the transition charge as a separate line item on bills as of March 1, 1998).

Basic Service Adjustment or True Up Factor (All EDCs)**.** The Restructuring Act created a statutory requirement for the EDCs to provide basic service electric supply for their customers. G.L. c. 164, § 1B(d). This basic service adjustment or true up mechanism is used to

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21 U.S. Energy Information Administration, *Electricity Explained: How electricity is delivered to consumers*, https://www.eia.gov/energyexplained/electricity/delivery-to-consumers.php (last visited September 2, 2026).

recover or credit the difference between the EDCs' costs to provide basic service for the year and the revenues billed to customers receiving basic service over the same year. See, e.g., Cost Based Reconciling Mechanisms, D.P.U. 12-126-A at 8 (2013). The mechanism was established in Order Addressing Recommendation of the Working Group on Default Service Issues, D.T.E. 99-60-C (2000). In that proceeding, the Department determined that basic service (also referred to as "default service") benefited all customers because it acts as a safety net, even for those customers who do not currently receive basic service. D.T.E. 99-60-C at 13. The Department also found that, because customers on basic service frequently change, collecting or refunding basic service reconciliation costs from or to basic service customers may not collect or refund the costs from the actual customers that caused the costs. D.T.E. 99-60-C at 13. Accordingly, the Department found a reconciling mechanism collecting (or returning) these reconciliation costs from all customers was appropriate. D.T.E. 99-60-C at 13. National Grid (electric) and Unitil (electric) term this mechanism the "Basic Service Adjustment Factor" (National Grid (electric) Report, Att. NG-Electric-1; Unitil (electric) Report, Att. 1 Electric). NSTAR Electric terms it the "Basic Service Cost True Up Factor" (NSTAR Electric Report, Att. 1a NSTAR Electric).

Energy Efficiency Reconciling Factor ("EERF") (All EDCs). Pursuant to An Act Relative to Green Communities, St. 2008, c. 169, each EDC must prepare a three-year energy efficiency plan, and each plan must include a fully reconciling funding mechanism to recover costs associated with the approved three-year plan budgets. G.L. c. 25, § 19(a); G.L. c.21(b)(2)(vii); see also G.L. c. 25, § 21(d)(2). The Department first implemented this statutory requirement in the 2010-2012 three-year plans approved in Electric Three-Year Energy

Efficiency Plans Order, D.P.U. 09-116 through D.P.U. 09-120 (2010). The Department's Energy Efficiency Guidelines specify how revenue from an EERF may be collected from ratepayers. D.P.U. 20-150-A, App. A at § 3.2.1.4. The EERF is one of five statutorily identified funding sources for the electric three-year energy efficiency plans. D.P.U. 20-150-A, App. A at § 3.2.1; G.L. c. 25, § 19(a).

System Benefits Charge ("SBC") (All EDCs). G.L. c. 25, § 19(a) requires a mandatory charge of 2.5 mills (or 0.25 cents) per kilowatt-hour for all electric company customers to fund energy-efficiency programs. The System Benefits Charge is one of five funding sources for the electric three-year energy efficiency plans. D.P.U. 20-150-A, App. A at § 3.2.1; G.L. c. 25, § 19(a).[22] The System Benefits Charge was first established by the Restructuring Act and was modified by An Act Relative to Green Communities. St. 1997, c. 164, § 37; St. 2008, c. 169, § 11. The current iteration of the SBC was first implemented as part of Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines Consistent with An Act Relative to Green Communities, D.P.U. 08-50, at 10-12 (2008) (discussing program funding sources).

Electric Sector Modernization Plan ("ESMP") Factor (All EDCs)**.** Established in Electric Sector Modernization Plans Phase II Order, D.P.U. 24-10-A/D.P.U. 24-11-A/D.P.U. 24-12-A (2025) pursuant to G.L. c. 164, § 92B, this

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[22] In addition to the EERF and System Benefits Charge, the following funding sources for energy efficiency three-year plans are specified in the statute: revenues from the Forward Capacity Market; revenues from cap and trade pollution control programs; and other funding approved by the Department. G.L. c. 25, § 19(a); D.P.U. 20-150-A, App. A at § 3.2.1.

mechanism recovers incremental costs associated with implementing and deploying ESMP-related capital investments and incremental O&M expense. The ESMPs are a strategic roadmap to the EDCs' investments in their electric distribution and transmission systems to enable an affordable, equitable clean energy transition. The Legislature directed the ESMP process in Section 53 of An Act Driving Clean Energy and Offshore Wind, St. 2022, c. 179. The Department determined that a short-term reconciling mechanism was necessary to provide sufficient revenues to support the step change needed to achieve the Commonwealth's greenhouse gas emissions reduction targets in the current operating environment. Electric Sector Modernization Plans Phase I Order, D.P.U. 24-10/ D.P.U. 24-11/ D.P.U. 24-12, at 443 (2024).

Grid Modernization Factor ("GMF") (All EDCs). This mechanism recovers incremental capital and O&M costs associated with the EDCs' Grid Modernization Plans, originally established in Modernization of the Electric Grid, D.P.U. 12-76-B (2014), and later modified in Grid Modernization, D.P.U. 15-120/ D.P.U. 15-121/ D.P.U. 15-122 (2018), D.P.U. 15-120-E/D.P.U. 15-121-E/D.P.U. 15-122-E, at 25-41, and New Technologies and Advanced Metering Infrastructure Proposals, D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B at 159-162, 175-176, 190 (2022). In D.P.U. 12-76-B, the Department determined that grid modernization is an important tool to advance the statutory requirements and policy goals for the continued development of energy efficiency, renewable energy resources, demand response, energy storage, microgrids, and electric vehicles. D.P.U. 12-76-B at 8-9 & n.7 (citing to statutes including An Act Relative to Green Communities, St. 2008, c. 169 and the Global Warming Solutions Act, St. 2008, c. 298). The Department initiated Massachusetts's grid modernization plan framework to encourage the EDCs to make investments and implement practices that would

improve the performance of the distribution system while enabling customers to participate in and benefit from a modern electric grid. The Department's framework aimed principally to enhance reliability, reduce electricity costs, and empower customers to accept new technologies and better manage their electricity use. D.P.U. 12-76-B at 2, 9. The Department found that a short-term, targeted cost recovery mechanism was necessary to facilitate the Department's grid modernization objectives by reducing the financial risk associated with the grid modernization investments, while preserving important ratepayer protections.

D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, at 216, citing D.P.U. 12-76-B at 4.[23]

Long Term Renewable Contract Adjustment ("LTRCA") Factor (All EDCs). This mechanism reconciles the expenses,[24] revenues, and interest for the forecast year for the long-term contracts for renewable energy and energy storage entered into by the EDCs pursuant to An Act Relative to Green Communities, St. 2008, c. 169, § 83 ("Section 83"). Section 83 was further amended by An Act Relative to Competitively Priced Electricity, St. 2012, c. 209 (adding Section 83A); An Act to Promote Energy Diversity, St. 2016, c. 188, § 12 (adding Sections 83B, 83C, and 83D); and An Act Promoting a Clean Energy Grid, Advancing Equity and Protecting

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[23] Unitil also recovers electric vehicle ("EV") program costs and Advanced Metering Infrastructure ("AMI") implementation costs through its GMF. D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B at 275; Electric Vehicles, D.P.U 21-90/D.P.U. 21-91/D.P.U. 21-92, at 196 (2022). The Department directed Unitil to petition the Department for a stand-alone EV program cost recovery mechanism in D.P.U. 24-12 (2024). The Department approved Unitil's EV program tariff on September 17, 2025 in D.P.U. 25-89. The Department expects Unitil to submit its first annual EV program cost recovery filing on or before April 15, 2027 for the 2026 Investment Year.

[24] Such expenses include remuneration paid to the EDCs as required by An Act Relative to Green Communities, St. 2008, c. 169, § 83.

Ratepayers, St. 2024, c. 239 (adding Section 83E).[25] These legislative provisions require cost recovery through a fully reconciling mechanism to ensure that the EDCs recover all costs they incur due to such contracts. Long-term renewable energy contracts whose costs are collected under this mechanism include contracts for offshore wind pursuant to Section 83C, approved in Long-Term Contracts for Offshore Wind Energy Generation, D.P.U. 18-76/D.P.U. 18-77/D.P.U. 18-78 (2019)[26] and contracts for hydroelectric energy generation pursuant to Section 83D, originally approved in Long-Term Contracts for Renewable Energy, D.P.U. 18-64/D.P.U. 18-65/D.P.U. 18-66 (2019), and as amended by settlement agreement and approved in Amendment of Transmission Service Agreements, D.P.U. 24-160 (2025).[27]

Net Metering Recovery Surcharge ("NMRS") (All EDCs). This mechanism recovers: (1) net metering credits[28] paid to net metering customers, net of revenues received from the settlement of energy at ISO New England Inc.; (2) the non-reconciling distribution portion of

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25 The Department's website summarizes and details the laws governing long-term contracts for renewable energy and energy storage: https://www.mass.gov/info-details/laws-governing-long-term-contracts-for-renewable-energy-and-energy-storage (last visited September 13, 2026).

26 These contracts pay for power generation by the offshore wind project known as Vineyard Wind. D.P.U. 18-76/D.P.U. 18-77/D.P.U. 18-78, at 3-5.

27 These contracts pay for hydroelectric generation supplied by H.Q. Energy Services (U.S.) Inc. and delivered by Central Maine Power Company over the New England Clean Energy Connect transmission line. D.P.U. 24-160, at 1.

28 A net metering credit is defined as the monetary value of the net "excess electricity generated" by a Net Metering facility and fed back to the EDC, which is calculated pursuant to Section 1.06 in each EDC's net metering tariff. Net Metering Model Tariff, D.P.U. 09-03-A at 5 n. 7 (2009); see also 220 CMR 18.02.

revenue displaced by customers who have installed on-site net metering generation facilities; and (3) prior period reconciliation adjustments. This mechanism was created in Net Metering Model Tariff, D.P.U. 09-03-A (2009), pursuant to An Act Relative to Green Communities, St. 2008, c. 169, § 78.[29]

Distributed Solar Charge (All EDCs). As required by An Act Relative to Solar Energy, St. 2016, c. 75, § 11(b), the EDCs recover costs associated with implementing and operating the Solar Massachusetts Renewable Target ("SMART") Program. These SMART costs include solar incentive payments, alternative on-bill credits, and incremental administrative costs. This mechanism was initially established in Model SMART Provision, D.P.U. 17-140-A (2018).

Renewables Charge (All EDCs). Pursuant to G.L. c. 25, § 20, this statutorily mandated charge of 0.5 mill (or 0.05 cents) per kilowatt-hour provides funding to the Massachusetts

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[29] Net metering existed in a different form prior to 2009; beginning in 1981, to implement the federal law known as the Public Utility Regulatory Policies Act, Pub. L. No. 95-617, 92. Stat. 3117 (1978), customers with generating facilities less than 30 kilowatts ("kW") were permitted to run their meter "backwards." In Electric Industry Restructuring, D.P.U./D.T.E. 96-100, at 22-23 (1998), eligibility for net metering increased from 30 kW to 60 kW. Since An Act Relative to Green Communities, St. 2008, c. 169, updates, revisions, and additions to net metering have been passed by the Legislature as part of the following session laws: An Act Making Appropriations for the Fiscal Years 2010 And 2011 to Provide for Supplementing Certain Existing Appropriations and for Certain Other Activities and Projects, St. 2010, c. 359; An Act Relative to Competitively Priced Electricity in the Commonwealth, St. 2012, c. 209; An Act Relative to Credit for Thermal Energy Generated with Renewable Fuels, St. 2014, c. 251; An Act Relative to Solar Energy, St. 2016, c. 75; An Act to Promote Energy Diversity, St. 2016, c. 188; An Act to Advance Clean Energy, St. 2018, c. 227; An Act Creating a Next-Generation Roadmap for Climate Policy, St. 2021, c. 8; An Act Driving Clean Energy and Offshore Wind, St. 2022, c. 179; and An Act Promoting a Clean Energy Grid, Advancing Equity and Protecting Ratepayers, St. 2024, c. 239. The net metering laws and regulations page on the Department's website provides additional detail on this legislative history: https://www.mass.gov/info-details/net-metering-laws-and-regulations (last visited September 2, 2026).

Renewable Energy Trust Fund to support the development and promotion of renewable energy projects. The Massachusetts Renewable Energy Trust Fund is administered by the Massachusetts Clean Energy Center. G.L. c. 23J, § 9. This charge was originally implemented as part of electric industry restructuring. See Electric Industry Restructuring, D.P.U./D.T.E. 96-100 (1998), Att. A at A-14; 220 CMR 11.04(7). NSTAR Electric terms this the "Renewable Energy" mechanism, National Grid (electric) terms it the "Renewables Charge," and Unitil (electric) terms it the "Renewables Resource Charge" (NSTAR Electric Report, Att. 1a NSTAR Electric; National Grid (electric) Report, Att. NG-Electric-1; Unitil (electric) Report, Att. 1 Electric).

Storm Costs (All EDCs). NSTAR Electric has a "Storm Adjustment Factor," Unitil (electric) has a "Storm Reserve Adjustment Factor," and National Grid (electric) has an "Exogenous Storm Factor" and a "Storm Fund Replenishment Factor" (NSTAR Electric Report, Att. 1a NSTAR Electric; Unitil (electric) Report, Att. 1 Electric; National Grid (electric) Report, Att. NG-Electric-1). These mechanisms collect costs associated with the EDCs' restoration and recovery efforts following major storm events. Each EDC has a storm fund, and a set amount of costs collected through base distribution rates are credited annually to the storm fund. See D.P.U. 23-80/ D.P.U. 23-81, at 284-294; D.P.U. 22-22, at 271-284; D.P.U. 23-150, at 376-388. When an extraordinary storm event occurs, the EDC recovers the incremental O&M costs through the storm fund.[30] If the storm fund runs a deficit because the EDC incurs a significant

[30] The EDC may not recover costs through the storm fund until the costs are reviewed and approved by the Department in a separate investigation. See, e.g., Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 20-51/D.P.U. 21-03, at 1 (2026)

amount of extraordinary storm costs, then the EDC may petition the Department to recover costs through a storm factor to replenish and increase funding to the storm fund. The EDCs' storm funds and storm factors were created to smooth out the recovery from ratepayers of the significant costs associated with the repair and restoration of power from major storm events. See Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 09-39, at 205-209 (2009).

Storm Performance Adjustment Factor (National Grid (electric)). This mechanism was created per the directives of Investigation by the Department of Public Utilities on its Own Motion into the Preparation and Response of Massachusetts Electric Company and Nantucket Electric Company to Tropical Storm Irene, D.P.U. 11-85-A/D.P.U. 11-119-A (2012) (National Grid (electric) Report, Att. NG-Electric-1). In that proceeding, the Department levied penalties against National Grid (electric) for failure to restore service in a safe and reasonably prompt manner and directed the Company to credit the penalty amounts to its customers. D.P.U 11-85-A/D.P.U. 11-119-A at 153-156.

Advanced Metering Infrastructure ("AMI") Factor (NSTAR Electric and National Grid (electric)). The AMI factor recovers legacy meter and information technology costs, as well as incremental costs associated with the company's implementation and deployment of AMI. This factor was first established in 2022, when the Department approved full AMI deployment in support of the Commonwealth's long-term energy policies. D.P.U. 21-80-B/ D.P.U. 21-81-B/D.P.U. 21-82-B at 192-193 (describing "a fundamental evolution taking place in

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(finding that costs are storm-related, incremental, and prudently incurred and permitting recovery through the storm fund and associated storm replenishment factors).

the way electricity is produced and consumed in Massachusetts," and listing numerous recently passed energy laws for support, including Act Driving Clean Energy and Offshore Wind, St. 2022, c. 179; An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, St. 2021, c. 8; the Green Communities Act; and the Global Warming Solutions Act). The Department found that a dedicated, short-term reconciling mechanism for these AMI-related costs would facilitate the necessary Department oversight and stakeholder input regarding these investments. D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B at 285-286.[31]

Vegetation Management Factor (NSTAR Electric and National Grid (electric)). This mechanism recovers incremental costs for enhanced vegetation-management pilot programs meant to benefit ratepayers by improving the reliability and resiliency of the distribution systems. NSTAR Electric Company, D.P.U. 17-05, at 580 (2017). The Department found that a separate cost recovery mechanism was appropriate because the costs and programmatic effectiveness of the programs were largely unknown because no historical data yet existed. D.P.U. 17-05, at 583.[32]

Electric Vehicles ("EV") Program Charge (NSTAR Electric and National Grid (electric)). This charge recovers costs related to NSTAR Electric's and National Grid (electric)'s respective EV programs, including make-ready infrastructure, EV supply equipment for certain types of charging stations (e.g., public, multifamily buildings, workplaces, fleets, and for

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31 Unitil recovers its AMI implementation costs through the GMF reconciling mechanism. D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B at 283.

32 National Grid's enhanced vegetation management program costs were transferred to base distribution rates effective October 1, 2024, following its last base rate case, D.P.U. 23-150.

income-eligible customers), and managed charging incentives. The EDCs first proposed EV programs in 2017, as encouraged by an Act Promoting Zero Emission Vehicle Adoption, St. 2016, c. 448. D.P.U. 17-05, at 471-501; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 17-13, at 56 (2018). The Department determined that a separate cost recovery mechanism was necessary to allow for increased transparency and a focused review of the investments. Electric Vehicles, D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, at 194.[33]

Provisional System Planning ("PSP") Factor (NSTAR Electric and National Grid (electric))**.** This factor recovers costs that support the interconnection of distributed energy resources ("DER") (e.g., solar facilities and energy storage facilities) in approved areas of the EDC's service territory. The PSP factor is a component of the PSP framework approved by the Department in Provisional System Planning Program, D.P.U. 20-75-B (2021) to improve DER planning and interconnection, thereby advancing towards the Commonwealth's greenhouse gas emissions reductions targets codified in An Act Creating a Next-Generation Roadmap for Climate Policy, St. 2021, c. 8. The PSP framework facilitates the planning and funding of essential upgrades to the electric distribution system to allow for the timely and cost-effective development and interconnection of DERs. D.P.U. 20-75-B at 1. The costs recovered under this mechanism should be partially offset by fees paid by interconnecting DER customers over time. D.P.U. 20-75-B at 8. The first project approved under this framework was the Marion-Fairhaven Capital Investment Project in NSTAR Electric Company, D.P.U. 22-47 (2022).

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[33] Unitil currently recovers its EV program costs through the GMF reconciling mechanism. D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, at 196. The Department directed Unitil to petition the Department for a stand-alone EV program cost recovery mechanism, to be filed on or before April 15, 2027 for the 2026 Investment Year. See supra n.22.

Smart Grid Distribution Adjustment Factor (National Grid (electric)). This mechanism was used to recover incremental costs related to NSTAR Electric's and National Grid (electric)'s smart grid pilot programs, which these EDCs were required to undertake pursuant to An Act Relative to Green Communities, St. 2008, c. 169, § 85 ("Section 85"). Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 09-32 (2010); NSTAR Electric Company, D.P.U. 09-33 (2010). Section 85 further authorized rate recovery for the incremental costs associated with these pilot programs. National Grid (electric)'s pilot concluded on December 31, 2018, and in Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 22-24-A at 4 (2022), the costs recovered through this mechanism were set to zero pending final reconciliation.[34]

Solar Program Cost Adjustment Factor (NSTAR Electric and National Grid (electric))**.** An Act Relative to Green Communities, St. 2008, c. 169, § 58 added G.L. c. 164, §1A(f), which allows the EDCs to construct, own, and operate generation facilities that produce solar energy. Each EDC's costs for these solar facilities that are not otherwise recovered through base distribution rates are recovered through this reconciling mechanism. Costs recovered through the mechanism are offset by net proceeds and market credits associated with the operation of the facilities. NSTAR Electric Company, D.P.U. 24-172-A at 3 (2026). The Department initially determined that cost recovery through a reconciling mechanism, at least until the time of the EDC's next base rate case, was consistent with the intent of An Act Relative

[34] NSTAR Electric included this mechanism in its Report. The pilot program concluded in December 2015, and the factor was canceled on February 1, 2018 in NSTAR Electric's base rate case, D.P.U. 17-05 (NSTAR Electric Report, Att. 1 (a)).

to Green Communities, St. 2008, c. 169 and a reasonable means of cost recovery. Massachusetts Electric Company, Nantucket Electric Company, Boston Gas Company and Essex Gas Company, D.P.U. 09-38, at 23 (2009). The costs for all but one of National Grid (electric)'s solar facilities are now recovered through the Distribution Company's base distribution rates. See, e.g., D.P.U. 23-150, at 612-613; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 18-150, at 203-206 (2019).

Solar Expansion Cost Recovery Factor (NSTAR Electric)**.** An Act Relative to Solar Energy, St. 2016, c. 75, §§ 1, 2, expanded the amount of solar generation that EDCs were permitted to construct, own, and operate pursuant to G.L. c. 164, § 1A(f). This mechanism was established to recover costs associated with the expansion of NSTAR Electric's solar program. NSTAR Electric Company, D.P.U. 16-105, at 34 (2016). As of January 1, 2023, however, the costs for these solar facilities were transferred to NSTAR Electric's base distribution rates. D.P.U. 22-22, at 2 n.6 & 337-339. This mechanism remains in effect to return to customers the net proceeds and market credits associated with the operation of the solar facilities. NSTAR Electric Company, D.P.U. 24-173-A at 3 (2026).

Capital Cost Adjustment (Unitil (electric)). This mechanism recovers costs associated with Unitil (electric)'s capital investments. Capital cost recovery mechanisms for EDCs, like this one and National Grid (electric)'s Infrastructure Safety, Reliability, and Electrification ("ISRE") mechanism described below, are meant to provide the EDC with rate relief in between base distribution rate cases to account for the potential of a lost increase in revenues caused by revenue decoupling. Fitchburg Gas and Electric Light Company, D.P.U. 15-80/D.P.U. 15-81, at 54 (2016), citing Revenue Decoupling, D.P.U. 07-50-A, at 48 (2008). This capital cost

adjustment mechanism has been phased out following Unitil (electric)'s last base rate case in 2024, where the Department approved the EDC's request to transition recovery of capital costs through a component of the PBR plan.[35] D.P.U. 23-80/D.P.U. 23-81, at 469 (2024).

ISRE Factor (National Grid (electric)). This is a mechanism that recovers incremental costs associated with the Distribution Company's "core" capital investments in connection with its Comprehensive Performance and Investment Plan, as approved by the Department in National Grid (electric)'s last base rate case, D.P.U. 23-150. In that proceeding, the Department found that National Grid (electric) demonstrated a need to recover incremental "core" capital investment costs through this mechanism for the Company to meet its public service obligations and obtain long-term debt and equity financing at a reasonable cost. D.P.U. 23-150, at 44-45.

Cable Facilities Surcharge (Nantucket Electric Company). This charge recovers the costs associated with two undersea distribution cables and related investments necessary to connect the electric distribution infrastructure on the island of Nantucket to the mainland. The charge was first implemented following the Department's approval of a settlement agreement related to the merger of Nantucket Electric Company into the New England Electric System, a predecessor of National Grid (electric). Nantucket Electric Company, D.P.U. 95-67, at 18-20 (1995).[36]

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[35] For the purposes of this Order, a "phase out" or "sunsetting" of a reconciling mechanism means that the mechanism will remain in place only to recover any over- or under-recovery of costs prudently incurred prior to the date the mechanism was terminated. Any costs incurred after the date of termination are not eligible for recovery through the reconciling mechanism. See D.P.U. 23-150, at 371.

[36] National Grid (electric) also lists a "Performance Incentive Factor" as a separate reconciling mechanism in its report. Because this mechanism is an integral part of the

C. Summary of Comments

Many commenters expressed support for moving certain costs currently recovered through reconciling mechanisms to base distribution rates (see, e.g., Attorney General Comments at 1-2; Unitil Comments at 2-3, 9; National Grid Comments at 11-16; DOER Comments at 2-8; Climate Advocates Comments at 8-9; EDF Comments at 1; City of Boston Comments at 10). Several commenters agree that while reconciling charges may serve legitimate purposes under certain circumstances, their expansion over time has generally served utility interests, rather than ratepayer interests, by undercutting the positive effects of regulatory lag and shifting risk from shareholders to ratepayers (see, e.g., Attorney General Comments at 1; Climate Advocates Comments at 8-9; DOER Comments at 2-3). Further, various commenters state the benefits of shifting the costs of certain reconciling mechanisms to base rates including simplifying utility bills, reducing bill volatility and rate shock, increasing administrative efficiency and transparency, and strengthening utility incentives for efficiency and cost control (see, e.g., Attorney General Comments at 1-2; Attorney General Reply Comments at 1; DOER Comments at 2-3; DOER Reply Comments at 4-5, 10; TEC Comments at 3, 7, 9, 11). Some Distribution Companies also acknowledge the merits of moving certain volumetric reconciling charges into base rates, including administrative efficiency and rate stability (see, e.g., Unitil Comments at 9; National Grid Comments at 27).

Commenters propose various tests for the Department's review and approval of reconciling mechanisms going forward. The Attorney General recommends that the Department

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PBR plan approved by the Department in National Grid (electric)'s last rate case, D.P.U. 23-150, we do not address it separately here.

replace its existing approach with a test under which any costs related to the core business of providing distribution service be included in the cost of service used to set distribution rates in a base rate case (Attorney General Comments at 1-2). The Attorney General contends that under her proposed test, the expenses unrelated to the provision of core distribution service, such as energy supply, energy efficiency programs, income-eligible programs, and pass-through costs mandated by law, as well as transmission and generation-related capital trackers, would continue to be recovered through separate mechanisms outside base distribution rates (Attorney General Comments at 2). For the EDCs, the Attorney General identifies all distribution-related capital investment trackers and O&M expense trackers, including mechanisms for pension and post-retirement benefits other than pensions, vegetation management, and storm expenses, for elimination and transfer to base distribution rates (Attorney General Comments at 1-2). For the LDCs, the Attorney General similarly recommends moving all capital investment and O&M costs associated with core gas distribution service into base distribution rates, including the transfer of the GSEP costs subject to a statutory amendment (Attorney General Comments at 2-3).

TEC suggests that any reasonably controllable, distribution-related costs be included in base distribution rates (see, e.g., TEC Comments at 3, 7). TEC agrees with the Attorney General that all distribution-related O&M expenses and capital investment costs recovered through reconciling mechanisms should be included in base distribution rates (TEC Reply Comments at 1). The Climate Advocates agree with the Attorney General's recommendation with respect to phasing out the GSEP program and its corresponding reconciling mechanisms (Climate Advocates Reply Comments at 3, 12-13). The Climate Advocates also suggest that reconciling

charges may be appropriate only in circumstances involving very high costs with high variability that the utility's management cannot control, and they propose that costs utilities can manage should be recovered through base rates, providing utilities a clear financial incentive to manage these costs downward (Climate Advocates Comments at 9). Green Energy Consumers Alliance suggests that those reconciling mechanisms with costs that are predictable, even if outside the Company's control, should be moved to distribution rates (Green Energy Consumers Alliance Comments at 3). PowerOptions recommends moving any policy-driven reconciling mechanisms related to distribution to base rates (PowerOptions Comments at 2). The Clean Energy Parties assert that the Department should review reconciling mechanisms that are not reserved for electric service components, extraordinary cost categories, or clean energy and public benefits programs (Clean Energy Parties Comments at 5). Finally, the City of Boston recommends that the Department prioritize moving reconciling charges into base distribution rates when the underlying investments or spending have become routine, have a minimal bill impact, are not sufficiently volatile to require more frequent base distribution rate cases, and/or no longer satisfy the original basis for separate reconciling mechanism treatment (City of Boston Comments at 4, 10).

DOER suggests that costs that are routine, relatively limited or non-variable, or attributable to investments that should be completed and incorporated into base rates by the EDCs' next rate cases as candidates for base rate cost recovery (DOER Comments at 3-4). Specifically, DOER recommends moving cost recovery for the following reconciling mechanisms to base distribution rates: (1) pension adjustment factor; (2) vegetation management; (3) electronic payment recovery; (4) Attorney General Consulting Expense;

(5) Tax Cuts and Jobs Act of 2017; (6) Smart Grid; (7) Grid Modernization; (8) Advanced Metering Infrastructure; and (9) utility owned solar programs (DOER Comments at 3-4).

DOER also identifies mechanisms for eventual elimination or transfer to base distribution rates following related programmatic, regulatory, or ratemaking changes, while acknowledging that they should continue in the short-to-medium term (DOER Comments at 4-5). These mechanisms include: (1) revenue decoupling; (2) EV program factors; (3) the electric sector modernization plan factor; (4) provisional system planning factors; (5) Massachusetts Electric Company's and Nantucket Electric Company's infrastructure, safety, reliability, and electrification factor; and (6) exogenous cost adjustments (DOER Comments at 5-6). The Climate Advocates agree with DOER's proposed list of reconciling mechanisms to move to base rates presented in DOER's Comments at Table 1 (i.e., pension adjustments, vegetation management, electronic payment recovery, and the remaining smart grid and advanced metering infrastructure investments) as they are costs utilities can and should be able to manage (Climate Advocates Reply Comments at 3-4).

The Distribution Companies argue that movement of reconciling mechanisms to base rates should be limited to those costs which meet certain criteria, namely, that they be: (1) stable and predictable; (2) within the utility's control; and (3) enable distribution service (see, e.g., Eversource Comments at 10-11; National Grid Comments at 11, 13-16). Eversource lists the following reconciling mechanisms as potential candidates to move to base distribution rates on the basis that they are predictable, recurring, and distribution-related: Vegetation Management Factor; Grid Modernization Factor; and historical capital vintage investments (Eversource Comments at 10-11). National Grid lists the following candidates: Electronic Payment

Recovery; AGCEF; Grid Modernization/AMI costs (after program completion); and ISRE (National Grid Comments at 13-16). National Grid emphasizes that movement to base rates should be narrowly tailored, supported by clear benefit-cost justification, and timed to coincide with comprehensive base rate proceedings (National Grid Comments at 27). Unitil, Berkshire Gas, and Liberty emphasize very limited movement and primarily propose only the AGCEF be transferred to base distribution rates on the basis that it is a small, manageable cost (Unitil Comments at 2; Berkshire Gas Comments at 6; Liberty Comments at 6). Several Distribution Companies caution against shifting all reconciling mechanisms to base distribution rates as it could constrain the company's ability to make necessary investments by increasing exposure to cost volatility, leading to more frequent rate cases, and ultimately will not serve to reduce bills (see, e.g., National Grid Comments at 26-27; Berkshire Gas Comments at 9). The Feeney Brothers agrees with Eversource that the Department should continue to include historical-vintage GSEP investments in base distribution rates while continuing the GSEP mechanism for new investments (Feeney Brother Reply Comments at 6).

D. Conclusions

1. Reconciling Mechanisms Coming Off the Bill

While we recognize that there are justifiable reasons behind the establishment of each reconciling mechanism now in operation, the Department must also assess the overall impact of the totality of mechanisms on customers. In short, we must achieve a proper, holistic balance that prioritizes cost recovery through base distribution rates. Based on the review of the reconciling mechanisms listed above and the comments received from the Distribution Companies and other interested stakeholders, the Department identifies the following 15

reconciling mechanisms that should be eliminated or will expire in the near term as shown in Table 4 below: (1) Revenue Decoupling; (2) PAF; (3) AGCEF; (4) EPRF; (5) TACF; (6) Exogenous Cost mechanism; (7) BDRF; (8) GMF; (9) Storm Performance Adjustment Factor; (10) AMI Factor; (11) Vegetation Management Factor; (12) Smart Grid Distribution Adjustment Factor; (13) Solar Program Cost Adjustment Factor; (14) Solar Expansion Cost Adjustment Factor; and (15) Capital Cost Adjustment. Further, we identify any costs that the Distribution Companies should propose for recovery through base rates in their next base distribution rate case.

Table 4: Reconciling Charges to Eliminate

Mechanism	Electric Distribution Companies			Gas Local Distribution Companies					
	NSTAR Electric	National Grid (electric)	Unitil (electric)	National Grid (gas)	EGMA	NSTAR Gas	Liberty	Berkshire Gas	Unitil (gas)
Electric and Gas Local Distribution Delivery Charges									
Revenue Decoupling	X	X	X						
Pension Adjustment Factor	X	X	X	X	X	X	X	X	X
Attorney General Consultant Expense	X	X	X	X	X	X	X	X	X
Electronic Payment Recovery Factor	X	X		X	X	X			
Tax Act Credit Factor	X	X			X	X	X		
Exogenous Cost	X			X	X	X			X
Gas Local Distribution Company Delivery Charges									
Base Distribution Reconciliation Factor					X				
Electric Distribution Company Delivery Charges									
Grid Modernization Factor	X	X	X						
Storm Performance Adjustment Factor		X							
Advanced Metering Infrastructure Factor	X	X							
Vegetation Management Factor	X	X							
Smart Grid Distribution Adjustment Factor	X	X							
Solar Program Cost Adjustment Factor	X	X							
Solar Expansion Cost Recovery Factor	X								
Capital Cost Adjustment			X						

a. Reconciling Mechanism Screening Criteria

The Department launched this investigation to conduct a comprehensive review of gas and electric delivery rates and charges to identify, in part, whether any reconciling mechanisms can be eliminated and/or included in base rates going forward. The reasons for each mechanism's existence are varied and nuanced—for example, some mechanisms flow credits back to customers; some are required, supported, or otherwise encouraged by the laws and policies of the Commonwealth; and, because costs flowing through reconciling mechanisms require review and approval on an annual or semi-annual basis, some were created to provide additional assurances of transparency and accountability for the Department and stakeholders with respect to the investments made by the Distribution Companies. Most relevant to our purposes here, several mechanisms were created as an interim measure or in response to circumstances or uncertainties that no longer exist, and they are ripe for elimination or expiration in the near term. With these criteria in mind, the Department determines that the 15 reconciling mechanisms noted below are appropriate for elimination or expiration.

b. Reconciling Mechanisms to Eliminate

Revenue Decoupling (All EDCs). This mechanism was created to eliminate financial barriers to the full engagement and participation by the EDCs in demand-reducing efforts, such as energy efficiency. In 2022, the Department announced its intent to re-evaluate the use of full revenue decoupling for the EDCs in light of the increased focus on strategic electrification—which would increase, rather than decrease, electric demand—in the 2022-2024 three-year energy efficiency plans. 2022-2024 Three-Year Energy Efficiency Plans Order, D.P.U. 21-120 through D.P.U. 21-129, at 227-235 (2022) ("2022-2024 Three-Year Plans Order"). The

Department directed each EDC to include in its next base distribution rate proceeding a rate proposal for the discontinuance of full revenue decoupling. The Department also stated that it would consider implementing a targeted decoupling mechanism in lieu of full revenue decoupling. 2022-2024 Three-Year Plans Order, at 234 n.145. Subsequently, in Unitil (electric)'s base rate case, D.P.U. 23-80/D.P.U. 23-81, and National Grid (electric)'s base rate case, D.P.U. 23-150, the Department found that it was reasonable to continue full revenue decoupling given some of the complexities associated with evaluating the continuing role of a full revenue decoupling mechanism at the time of the proceedings. These complexities included uncertainty about the pace of building and transportation electrification in each Distribution Company's service territory. D.P.U. 23-80/D.P.U. 23-81, at 418-419; D.P.U. 23-150, at 554-555. The Department reiterated, however, that it would continue to assess in each electric base distribution rate case whether full or targeted revenue decoupling is warranted. D.P.U. 23-80/D.P.U. 23-81, at 419; D.P.U. 23-150, at 555. Thus, each of the EDCs shall include a proposal for (1) full elimination and (2) targeted elimination of revenue decoupling in its next base rate case.

PAF (All Distribution Companies). The PAF was created in response to specific circumstances in the early 2000s—a declining stock market and steeply falling interest rates—that no longer exist. In D.P.U. 23-150, the Department conducted a robust analysis of National Grid (electric)'s PAF and found, *inter alia*, that National Grid (electric)'s PAF revenues and expenses were low in comparison to National Grid (electric)'s total revenues and expenses, and relatively stable. D.P.U. 23-150, at 313. The Department concluded that continuation of National Grid (electric)'s PAF was no longer warranted and ordered the Company to begin

phasing out the use of its PAF. D.P.U. 23-150, at 302, 320. In D.P.U. 23-80/D.P.U. 23-81, the Department made similar findings and directives regarding Unitil (gas) and Unitil (electric)'s PAF mechanisms. D.P.U. 23-80/D.P.U. 23-81, at 264-265. The PAF mechanisms for National Grid (electric), Unitil (gas), and Unitil (electric) are thus in the process of sunsetting and will be eliminated in the near future. Liberty's PAF also is in the process of being phased out pursuant to the settlement agreement approved by the Department in Liberty's recent base rate proceeding. Liberty Utilities (New England Natural Gas Company) Corp., D.P.U. 25-85 (2026); Settlement Agreement, § 2.2.1.1. As previewed in the Unitil Order, the Department has continued to conduct a robust investigation of PAF mechanisms and Pension/PBOP costs in rate cases, including the pending National Grid (gas) rate case in D.P.U. 26-50, and intends to do so in future rate cases. D.P.U. 23-80/D.P.U. 23-81, at 264. Accordingly, each remaining Distribution Company with a PAF (i.e., NSTAR Electric, EGMA, NSTAR Gas, and Berkshire Gas) shall include a proposal in their next base rate case to eliminate their PAF in favor of including pension and PBOP costs in base rates.

AGCEF (All Distribution Companies). The Department created this mechanism because the cost of the Attorney General's experts was unknown at the time and thus it would be difficult to include a representative amount in base rates. At least 15 years have passed since the Distribution Companies were first directed to pay these costs, and they are no longer unknown or unpredictable. Accordingly, the Department directs all Distribution Companies to include in base distribution rates a five-year average of costs associated with the AGCEF as part of their next base distribution rate proceeding. A five-year average should account for costs associated

with larger, more complex proceedings (such as policy investigations and rate cases), as well as smaller, routine proceedings.

EPRF (NSTAR Electric; National Grid (electric); National Grid (gas); EGMA; and NSTAR Gas). The Department envisioned utilizing this separate cost recovery mechanism only for the fee-free program's initial implementation period of two years. D.P.U. 20-91-A at 45. That period is over. In each Distribution Company's next base distribution rate case, the Distribution Company shall include a proposal to transition recovery of fee-free costs to base distribution rates, to the extent the Distribution Company continues to incur these costs and can provide evidence to support base rate recovery.

TACF (NSTAR Electric; National Grid (electric); EGMA; NSTAR Gas; and Liberty). When this factor was established, the Department determined that it would remain in effect until the Distribution Company's excess accumulated deferred income tax ("ADIT") balance is transferred to new base distribution rates. D.P.U. 18-15-E at 36 n.31; 39 n.34 (National Grid (electric)), (NSTAR Electric)); see also EGMA LDAC tariff, M.D.P.U. No. 4L at Section 13.4; NSTAR Gas LDAC tariff, M.D.P.U. No. 402AF at Section 10.3. In D.P.U. 23-150, National Grid (electric) transferred the excess ADIT balance to base rates, and the reconciling mechanism is currently being phased out (National Grid (electric) Report, Att. NG-Electric-2). In D.P.U. 25-85, Liberty's last base rate case, the Department approved a settlement agreement, which included a provision to eliminate this factor and transfer the excess ADIT balance to base rates. D.P.U. 25-85, Settlement Agreement § 2.2.2.1. The Department expects that the TACF for NSTAR Electric, NSTAR Gas, and EGMA will soon terminate once all credits are

processed,[37] or following each Distribution Company's next base rate distribution case, when any remaining excess ADIT balance will be transferred to base rates.

Storm Performance Adjustment Factor (National Grid (electric)). National Grid (electric)'s Storm Performance Adjustment Factor was created to credit customers the penalty amounts related to storm response in 2013. D.P.U. 11-85-A/11-119-A. National Grid (electric)'s Report shows that it has not utilized this factor since 2019 (National Grid (electric) Report, Att. NG-Electric-1). National Grid (electric) should file, either in its next annual retail rate filing or as part of its next base distribution rate case, a proposal to eliminate this tariff.

Vegetation Management Factor (NSTAR Electric and National Grid (electric)). This mechanism was created, in part, because the enhanced vegetation pilot programs were new programs and no historical cost data existed, thus making it difficult to include a representative level in base rates. National Grid (electric)'s enhanced vegetation management pilot program costs were transferred to base distribution rates effective October 1, 2024, following its last base rate case, and the factor is currently being phased out. D.P.U. 23-150, at 369. In that proceeding, the Department directed the elimination of this reconciling mechanism for National Grid (electric) because it found that: (1) the annual costs of the program were relatively stable; (2) including a representative level of costs in base rates will incentivize greater cost-control measures; and (3) its elimination would avoid the administrative burden of an annual reconciling

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[37] In NSTAR Electric's last base rate case, the Department found that it would be inappropriate to include the excess ADIT balance in NSTAR Electric's base rates, and thus terminate this TACF, because there was a potential need for a further adjustment to the excess ADIT balance due to a proposal by the Biden Administration to adjust the federal corporate income tax rate from 21 percent to 28 percent. D.P.U. 22-22, at 253-254.

filing. D.P.U. 23-150, at 369. For NSTAR Electric, its recovery of enhanced vegetation management pilot program costs through this reconciling mechanism will continue through the end of its current PBR term, as established in its most recent base rate case. D.P.U. 22-22, at 297-298. Accordingly, at the end of the current PBR term, NSTAR Electric should make a proposal to include enhanced vegetation management costs in base rates, to the extent that NSTAR Electric continues to make these investments and can provide evidence to support base rate recovery.

Smart Grid Distribution Adjustment Factor (National Grid (electric)). National Grid (electric)'s smart grid pilot program concluded on December 31, 2018, and in Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 22-24-A at 4 (2022), the costs recovered through this mechanism were set to zero pending final reconciliation of disputed costs under review in several outstanding proceedings. See Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 21-33; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 17-53/D.P.U. 18-28/D.P.U. 18-29/D.P.U. 19-35/D.P.U. 20-30; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 16-28; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 14-109/D.P.U. 15-21.[38] The Department anticipates issuing Orders to resolve these dockets, which should facilitate elimination of this reconciling mechanism for National Grid (electric).

[38] As noted in Section III(B) above, NSTAR Electric included this mechanism in its Report, but after the pilot program concluded in December 2015, the factor was canceled on February 1, 2018 in NSTAR Electric's base rate case, D.P.U. 17-05 (NSTAR Electric Report, Att. 1 (a)).

Solar Program Cost Adjustment Factor (NSTAR Electric and National Grid (electric)). The Department initially determined that cost recovery through a reconciling mechanism was consistent with the intent of An Act Relative to Green Communities, St. 2008, c. 169 and a reasonable means of cost recovery, at least until the time of the EDC's next base rate case. Massachusetts Electric Company, Nantucket Electric Company, Boston Gas Company and Essex Gas Company, D.P.U. 09-38, at 23 (2009). The costs for all but one of National Grid (electric)'s solar facilities are now recovered through its base distribution rates. See, e.g., D.P.U. 23-150, at 612-613; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 18-150, at 203-206 (2019). In its next base rate proceeding, National Grid (electric) should include a proposal to move into overall rate base and recover through base rates the costs for the remaining facility, as well as a proposal for how it will pass back to customers the net proceeds and market credits associated with the operation of the facilities through another, already-existing reconciling mechanism, such as the LTRCA.

NSTAR Electric's solar program costs have not been moved into rate base and thus recovered through base rates in part due to a stipulation agreement with the Attorney General approved by the Department in Western Massachusetts Electric Company, D.P.U. 09-05, at 19 (2009) ("Despite our approval of this Agreement, we encourage the Stipulating Parties to explore reaching an agreement that would roll the Solar Program rate base into the Company's overall rate base in a future base rate filing made pursuant to G.L. c. 164, § 94."). NSTAR Electric proposed to include these costs in rate base in its last base rate case but withdrew its proposal because it had failed to confer with the Attorney General, as required by D.P.U. 09-05.

D.P.U. 22-22, at 335 n. 165. The Department, therefore, directs NSTAR Electric, prior to its next base rate proceeding, to confer with the Attorney General to eliminate this tariff provision.

Solar Expansion Cost Adjustment Factor (NSTAR Electric). As of January 1, 2023, the costs for these solar facilities were transferred to NSTAR Electric's base rates. D.P.U. 22-22, at 2 n.6 & 337-339. This mechanism remains in effect to return to customers the net proceeds and market credits associated with the operation of the solar facilities. NSTAR Electric Company, D.P.U. 24-173-A at 3. NSTAR Electric should file with the Department, either as part of its next annual solar expansion cost recovery filing or in its next base rate case proceeding, a proposal to eliminate this tariff provision and pass back the net proceeds and market credits through another, already-existing reconciling mechanism, such as the LTRCA.

Capital Cost Adjustment (Unitil (electric)). On March 6, 2026, the Department approved Unitil (electric)'s proposal to eliminate this mechanism, and it is being phased out. Fitchburg Gas and Electric Light Company, D.P.U. 25-88-A, at 5-6 (2026).

c. Reconciling Mechanisms Set to Expire

Exogenous Cost mechanism (NSTAR Electric; National Grid (gas); EGMA; NSTAR Gas; and Unitil (gas)). The Department approved Unitil (gas)'s request to terminate its ECAF as of March 1, 2025. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 24-201, at 5 (2025). EGMA's eligibility for exogenous cost recovery through the ECAF will expire at the end of the term of its approved settlement agreement and corresponding base rate distribution freeze, on October 31, 2028. D.P.U. 20-59/D.P.U. 19-140/D.P.U. 19-141,

at 22-23; Settlement § 2.7. For National Grid (gas), the Exogenous Cost Factor[39] can terminate following the final reconciliation of the amount approved in D.P.U. 23-56 for collection over a three-year term, from November 1, 2023 through October 31, 2026. D.P.U. 23-56, at 16-17. NSTAR Gas's eligibility for exogenous cost recovery for exogenous events through its mechanism will expire at the end of its PBR term on November 1, 2030. NSTAR Gas Company, D.P.U. 24-134-B/D.P.U. 25-53-A at 6 (2025); Settlement § 2.4. NSTAR Electric reports that although it has an ECAF, it has not used the ECAF to recover or return costs to customers for the last ten years (NSTAR Electric Report, Att. 1a). Thus, NSTAR Electric shall file a proposal to terminate its ECAF at the time of its next base rate case proceeding.

BDRF (EGMA).[40] Recovery of costs through this mechanism are limited to the specific circumstances laid out in D.P.U. 20-59/D.P.U. 19-140/D.P.U. 19-141, Settlement §§ 2.6.1, 2.6.2. The reconciling mechanism will expire following the recovery and final reconciliation of any costs deemed eligible in the rate base reset proceedings. Eversource Gas Company of Massachusetts, D.P.U. 24-50, at 24 (2024); Eversource Gas Company of Massachusetts, D.P.U. 25-108, at 12 (2025).

AMI Factor (NSTAR Electric and National Grid (electric)). The Department explicitly limited the term of accelerated cost recovery through this mechanism to coincide with each

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39 As noted above, Unitil (gas), EGMA, and NSTAR Electric term this mechanism the ECAF, while National Grid (gas) terms it the "Exogenous Cost Factor" and NSTAR Gas uses "Exogenous Events."

40 For NSTAR Gas, recovery of the BDRF is limited to G-53 customers and the mechanism shall remain in effect until the reconciliation balance reaches zero. NSTAR Gas Company, M.D.P.U. No. 402AF, § 14.1.

company's AMI deployment schedule (i.e., a seven-year term dating from 2022 through 2028 for NSTAR Electric, and a five-year term dating from 2023 through 2027 for National Grid (electric)). D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B at 291-292. The Department also conditioned eligibility for accelerated cost recovery on each Distribution Company meeting its anticipated AMI investment implementation timelines. D.P.U. 21-80-B/D.P.U. 21-81-B/ D.P.U. 21-82-B at 291-292. Finally, the Department reiterated its expectation that the Distribution Companies include grid modernization and AMI-related investments in their normal course of business over time. D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B at 290. Thus, any AMI-related investments placed into service after the terms expire will not be eligible for accelerated cost recovery through the AMI factor and instead must be recovered through traditional ratemaking, i.e., a base distribution rate case. D.P.U. 21-80-B/D.P.U. 21-81-B/ D.P.U. 21-82-B at 292 n.121. Costs for investments placed into service during the approved terms will continue to be recovered through the AMI factor until each Distribution Company's next base rate case, where the costs can be moved into base rates if deemed eligible following a prudency review.

GMF (All EDCs). The Department limited the term of accelerated cost recovery through this mechanism to two terms of three years each (i.e., 2018 through 2021 and 2022 through 2025). D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B at 289. The Department reiterated its expectation that the Distribution Companies include grid modernization and AMI-related investments in their normal course of business over time.
D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B at 290. Thus, any grid modernization investments placed into service after the end of the second term (December 31, 2025), with the

exception of eligible carry-over costs and program termination expenses, will not be eligible for accelerated cost recovery through the GMF and instead must be recovered through traditional ratemaking, i.e., a base rate distribution case. D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B at 289; D.P.U. 21-80-C/D.P.U. 21-81-C/D.P.U. 21-82-D at 8-9. Costs for investments placed into service during the approved terms will continue to be recovered through the GMF until each Distribution Company's next base rate case, where the costs can be moved into base rates if deemed eligible following a prudency review. D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B at 289.

2. Standards for Future Reconciling Mechanisms

As outlined in the Vote and Order, the Department is charged with implementing an equitable clean energy transition during a time of increasing energy costs, attributable in part to aging infrastructure and in part to geopolitical upheaval and upward pressure on fossil fuel prices and supply chain and labor costs. Vote and Order at 1-2, 6-7. These external cost pressures lead us to evaluate all possible options within our authority to keep energy bills manageable and affordable for Commonwealth residents. In particular, this includes our general supervisory authority pursuant to G.L. c. 164, § 76 and our ratemaking authority under G.L. c. 164, § 94, which we can use to direct methods of cost recovery (and corresponding ratemaking) that incentivize utilities to control and minimize costs wherever possible.[41] In the context of this

[41] In setting rates, the Department's scope of decision is not bound by a single method. D.T.E. 03-47-A at 16 (2004), citing Massachusetts Electric Company v. Department of Public Utilities, 376 Mass. 294, 302 (1978); Verizon Massachusetts, D.T.E. 01-31 (Phase II) at 72 (2003), citing American Hoechest Corporation v. Department of Public Utilities, 379 Mass. 408, 413 (1980), and New England Telephone & Telegraph Company v. Department of Public Utilities, 371 Mass. 67, 71 (1976).

investigation, we determine that it is necessary to reinforce a preference for cost recovery through base distribution rates rather than through reconciling mechanisms.

As many commenters recognized, costs recovered through base distribution rates are subject to regulatory lag—the delay in recovery between when a company incurs capital expenditures and when it recovers a return of and on such expenditures in base rates. D.P.U. 09-39, at 80. Absent sufficient regulatory lag, utilities have a greater bias to make investments in capital projects instead of O&M expenses because capital investments provide a return to utility shareholders.[42] Regulatory lag thus incentivizes utilities to control costs by pursuing a more balanced strategy between capital expenditures and O&M expenses in their provision of safe and reliable service to their ratepayers. D.P.U. 09-39, at 80-81. Reconciling mechanisms, which have proliferated in recent years for myriad reasons as explained above, can significantly reduce regulatory lag because they allow for dollar-for-dollar cost recovery on an annual basis.

Moreover, when a reconciling mechanism recovers incremental O&M costs in addition to capital costs—and many of them do—there is an increased risk that a utility could recover a portion of those O&M costs more than once, also referred to as "double recovery." D.P.U. 17-13, at 57, citing D.P.U. 12-76-B at 23; D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, at 218. We have previously explained this risk of double recovery of O&M costs in detail:

> It is well-established Department precedent that base rate filings are based on an historic[al] test year. See, e.g., Eastern Edison Company, D.P.U. 1580, at 13-17, 19 (1984); Massachusetts Electric Company. D.P.U. 136, at 3 (1980). This approach is based on the theory that the revenues, expenses, and rate base amounts during a recent year, adjusted

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42 This tendency is referred to as the Averch Johnson effect. D.P.U. 09-39, at 80-81.

> for known and measurable changes, provides the most reasonable representation of a distribution company's present financial situation and fairly represent its cost to provide service. Modernization of the Electric Grid, D.P.U. 12-76-B at 20-21 (2012). Because a representative level of O&M expense is recovered through base distribution rates, allowing recovery of O&M expense, including labor and overheads and burdens expense, through a targeted cost recovery mechanism increases the risk that a company could recover a portion of these costs from ratepayers more than once. Grid Modernization Order at 218. To minimize the possibility of double recovery, the Department has found that cost categories should typically be recovered through only one cost recovery mechanism at a time.
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> Grid Modernization, D.P.U. 15-120-E/D.P.U. 15-121-E/D.P.U. 15-122-E at 22-23 (2022) (footnote omitted).

The Department has long held that a company cannot charge customers the same costs twice (i.e., double recovering the cost to serve its customers in violation of ratemaking principles). D.P.U. 15-120-E/D.P.U. 15-121-E/D.P.U. 15-122-E at 22 n.18, citing Fitchburg Gas and Electric Light Company, D.T.E. 99-66-A at 21-22 (2001); Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company, D.T.E./D.P.U. 06-82-A at 39-40 (2010); NSTAR Electric Company, D.P.U. 09-33, at 66 (2010). The Department's obligation to protect the public interest requires that ratepayers be made whole for any double recovery should it occur. D.P.U. 15-120-E/D.P.U. 15-121-E/D.P.U. 15-122-E at 22-23 n.18, citing D.T.E. 99-66-A at 24.

Accordingly, when costs are recovered via reconciling mechanisms, the utility's incentive to control and/or minimize capital costs to ratepayers is weaker, and the risk of duplicative O&M charges is higher. We recognize that sending the appropriate regulatory signals to the utilities to keep costs under control is critically important. At various times in the past, the Department has articulated criteria to guide our analysis of whether recovery through a reconciling mechanism is

appropriate, including whether the costs are (1) volatile in nature;[43] (2) large in magnitude; and (3) beyond the company's control.[44] We find that the consistent application of these criteria will limit the creation of new reconciling mechanisms. Going forward, the Department expects cost recovery to occur through base distribution rates unless the cost in question meets all the following criteria: (1) volatile in nature; (2) large in magnitude; and (3) beyond the company's control. D.P.U. 11-01/D.P.U. 11-02, at 364-365.

This standard will apply to all costs, including those costs incurred to make investments required to implement the Commonwealth's clean energy transition.[45] Although the Department acknowledges that base distribution rates typically recover costs associated with "business as usual" capital expenditures and O&M expenses, we also recognize that "business as usual" for the Distribution Companies, and across the regulated utilities industry,[46] has fundamentally

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43 A volatile expense is one that varies significantly based on economic circumstances beyond a company's control. D.P.U. 11-01/D.P.U. 11-02, at 364, citing D.T.E. 03-47-A at 19-20.

44 When a distribution company has the discretion to establish goals and a budget for a program and subsequently is afforded the leeway to manage the expenditures in the program, the costs are well within the company's control. D.P.U. 11-01/D.P.U. 11-02, at 364-365.

45 The standard will not apply to legislatively mandated reconciling mechanisms.

46 See, e.g., *Enhancing Critical Energy Infrastructure is Crucial for a Resilient Clean Energy Future*, Edison Electric Institute (May 2024), https://www.eei.org/en/news/news/all/enhancing-critical-energy-infrastructure-is-crucial-for-a-resilient-clean-energy-future ("As data centers, artificial intelligence, and an increasingly electrified economy spur demand for electricity in the years ahead, we will need new energy infrastructure investments of all kinds. These efforts will be vital to electric companies' mission of delivering resilient clean energy to the customers and communities they serve, without sacrificing reliability or affordability.") (last visited September 28, 2026).

changed in recent years. In Massachusetts, numerous climate and clean energy bills have been enacted since 2008.[47] In 2021, the Department's enabling statute, General Laws Chapter 25, was amended to add Section 1A, listing the six priorities the Department must consider in carrying out its responsibilities under Chapters 25 and 164. St. 2021, c. 8, § 15. These priorities are: (1) safety; (2) security; (3) reliability; (4) affordability; (5) equity; and (6) greenhouse gas emissions reductions. This statutory change reflects the shift in the larger energy policy landscape in the Commonwealth by requiring the Department to prioritize affordability, equity, and reductions in greenhouse gas emissions in addition to its traditional role in ensuring that utilities provide safe, secure, and reliable service at the least cost. The Distribution Companies' priorities and "business as usual" approach must also shift to reflect the current regulatory landscape and encompass the investments that the Distribution Companies need to make to comply with the laws and policies of the Commonwealth. Accordingly, the Department expects Distribution Companies to build most of their distribution-related capital and O&M costs into base distribution rates, as litigated in base rate case proceedings.

An additional benefit of enforcing this stricter standard for reconciling mechanism eligibility going forward is that it should serve to meaningfully reduce the number of these requests and filings, with a corresponding reduction in administrative burden. Although one

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47 See, e.g., An Act Promoting a Clean Energy Grid, Advancing Equity and Protecting Ratepayers, St. 2024, c. 239; An Act Driving Clean Energy and Offshore Wind, St. 2022, c. 179; An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, St. 2021, c. 8; see also An Act to Advance Clean Energy, St. 2018, c. 227; An Act to Promote Energy Diversity, St. 2016, c. 188; An Act Relative to Solar Energy, St. 2016, c. 75; An Act Relative to Green Communities, St. 2008, c. 169; Global Warming Solutions Act, St. 2008, c. 298.

justification for reconciling mechanisms is that they allow for less frequent rate cases, any reduction in rate case frequency is met with increased reconciling mechanism proceedings; indeed, the Department adjudicates several dozens of these proceedings every year. Rather than meaningfully reducing administrative burden, the burden is simply shifted from a larger, overarching rate case with increased public scrutiny to dozens of siloed reconciling mechanism proceedings with reduced public interest and stakeholder engagement.

In addition to the standard articulated above, the Department establishes a presumption that all reconciling mechanism will be time-limited absent statutory requirements. Therefore, in future proceedings, if a distribution company argues that a new reconciling mechanism is necessary and the costs meet the standard announced above, or if a distribution company seeks to alter or revise the terms of an existing reconciling mechanism or proposes to continue an existing reconciling mechanism in the context of a company's rate case proceeding, the Department directs such proposals to include:

1. The term of the program or effort requiring accelerated cost recovery;
2. The indicators and steps that must be taken to sunset the mechanism; and
3. The appropriate rate class allocator and why it is the most cost reflective.

The Department also reminds the Distribution Companies of our directive in Bay State Gas Company, D.P.U. 09-30 (2009):

> [T]he Department places all companies on notice that we will continue to explore on a case-by-case basis which… mechanism currently in place should continue … or whether a representative level of the applicable costs should be recovered through base rates. D.P.U. 07-50-A at 50. Any distribution company seeking to retain a current reconciling mechanism, or add a new reconciling mechanism, must continue to demonstrate that recovery in a separate mechanism is warranted.

D.P.U. 09-30, at 215; see also D.P.U. 12-126-A at 23-24 (reminding each gas and electric distribution company that at the time of its next base rate proceeding, it must be prepared to demonstrate the continued recovery of costs in a reconciling mechanism is warranted).

The Distribution Companies shall comply with their obligation to justify the continued operation of existing reconciling mechanisms in their rate case proceedings, including whether any carrying charges assessed remain reasonable (discussed further below). For those reconciling mechanisms that are not currently term limited, in each rate case proceeding, the Distribution Company shall demonstrate that the costs meet all of the criteria of the Department's standard for reconciling mechanisms and shall propose a sunset date for the mechanism or demonstrate why a sunset date is inapt—i.e., the costs are related to a legislative directive (e.g., EES and EERF) or a Department priority to encourage certain policy objectives (e.g., RAAF). Reconciling mechanisms that are term limited will sunset at the end of the prescribed term and after a final reconciliation of costs and prudency review are completed.

3. Review of Carrying Charges

In furtherance of the principle of cost containment, we also reviewed the use of carrying charges associated with the various reconciling mechanisms discussed above. The Department recognizes that, currently, there is no consistent approach to the application of carrying charges, with different interest rates used across and within the Distribution Companies. Namely, some reconciling mechanisms accrue interest at the customer deposit rate, some accrue at the prime rate, and others at a tax-adjusted prime rate[48] (National Grid (Electric),

[48] There can be significant differences between the customer deposit rate, the prime rate, and tax-adjusted prime rate. The customer deposit rate is the interest a financial institution pays consumers for holding their money in savings, checking, or certificate accounts. In contrast, the prime rate is a benchmark interest rate that commercial banks charge corporate clients for short-term corporate loans. A tax-adjusted prime rate alters

Exh. DPU-Common 1-1-ELEC, Att.; National Grid (Gas), Exh. DPU-Common 1-1-GAS, Att.; Liberty, Exh. DPU-Common 1-1, Att.; Berkshire Gas, Exh. DPU-Common 1-1, Att.; Unitil (gas), Exh. DPU-Common 1-1, Att. 1 Gas; Unitil (electric), Exh. DPU-Common 1-1, Att. 1 Electric; NSTAR Electric, Exh. DPU-Common 1-1(a), Att.; EGMA, Exh. DPU-Common 1-1(b), Att.; NSTAR Gas, Exh. DPU-Common 1-1(c), Att.). For example, National Grid (electric)'s vegetation management factor uses the customer deposit rate, while NSTAR Electric uses the prime rate for the same factor. Further, each Distribution Company uses different rates for different factors. For example, NSTAR Electric uses the customer deposit rate for the ESMP factor, EERF, and NMRS, while using the prime rate for other factors such as the SMART factor, RAAF, and Storm costs (NSTAR Electric, Exh. DPU-Common 1-1(a), Att.). There are also certain reconciling mechanisms that do not accrue any interest at all (see, e.g., NSTAR Electric's AGCEF).

In light of the inconsistencies described above, we discuss the principles underlying the selection of carrying charges, remaining focused on achieving optimal outcomes for ratepayers. Carrying charge rates should be designed to reflect a company's actual cost to finance over- and under-recoveries of its required revenues to replace only the time value of money not recovered in the mechanism, whether owed to the Distribution Company or the customer. See, e.g., Fitchburg Gas and Electric Light Company, D.P.U. 15-80/D.P.U. 15-81, at 239 & n.123 (2016); Fitchburg Gas and Electric Light Company, D.P.U. 12-13-A at 8 (2013). Carrying charges

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the standard prime rate to reflect financial reality after accounting for fiscal policies. Currently, the prime rate is higher than the customer deposit rate and the tax-adjusted prime rate.

should also incent an accurate forecast for recovery of reconciling costs while not unduly penalizing (or rewarding) the Distribution Company or ratepayers for large, deferred reconciling balances. See, e.g., Western Massachusetts Electric Company, D.P.U. 10-70, at 205-206 (2011). Further, in some instances, it may be appropriate to set the carrying cost rate below the actual financing cost, meaning the Distribution Company bears more of the financial risk of deferred recovery and therefore has a greater incentive to control costs. With these objectives in mind, we intend to investigate the appropriateness of carrying charges and their associated interest rates for all reconciling mechanisms in each Distribution Company's next base distribution rate proceeding.

Accordingly, the Department directs that each Distribution Company provide the following information and supporting documentation in its next base distribution rate filing for each reconciling mechanism it proposes to continue:[49] (1) whether the reconciling mechanism should have associated carrying charges on over-/under- recovery balances, and why; (2) the implications of using the various interest rate options; (3) what interest rate the Distribution Company proposes to use for the reconciling mechanism's associated carrying charges, and why; and (4) how the proposed carrying charge rate is an accurate reflection of the actual cost to finance over- and under-recoveries. Each Distribution Company shall also address the items listed above for any new reconciling mechanism it proposes going forward.

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[49] The Distribution Companies should provide the listed information irrespective of their tariffs in place at the time of filing.

IV. REVIEW OF THE TIMING AND COMPOSITION OF RECONCILING MECHANISM FILINGS

A. Introduction

In the Department's Vote and Order, we stated our intent to examine the timing and composition of the current electric annual reconciling mechanism petitions filed with the Department to determine whether certain electric reconciling mechanism filings should be included with the EDCs' annual retail rate filings for review and approval rather than filed in separate dockets at different times of the year. Vote and Order at 13-14.[50] We noted that each EDC has dozens of reconciling mechanisms, a minority of which are consolidated as part of the annual retail rate filings, with the remaining reconciling mechanisms filed individually and on different dates. Vote and Order at 14. The EDCs adjust these rates throughout the year in an uncoordinated fashion.[51] Vote and Order at 14. These individual filings for electric reconciling mechanisms trigger separate administrative proceedings, which can make it challenging for interested stakeholders to understand the collective bill impacts associated with a distribution

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50 Each EDC files a single proposal to update multiple reconciling rates at one time annually. These rates include the Transmission charge, Transition charge, AGCEF, NMRS, Long Term Renewable Contract Adjustment, and the RAAF, among others. See, e.g., NSTAR Electric Company, D.P.U. 25-158; Fitchburg Gas and Electric Light Company, D.P.U. 25-168; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 26-02.

51 For example, National Grid (electric)'s delivery rates change on January 1, March 1, May 1, July 1, and October 1 due to adjustments to different rate factors. For customers taking fixed basic service, supply rates change on February 1 and August 1 for residential and small commercial and industrial customers, and February 1, May 1, August 1, and November 1 for large commercial and industrial customers. In other words, residential customers of National Grid (electric) may face rate changes at the outset of seven out of twelve months of the year.

company's proposed rates and to participate in the Department's proceedings. Vote and Order at 14.

Two Department goals in conducting this comprehensive review of all reconciling mechanisms are (1) to reduce administrative burden and cost and (2) to achieve greater transparency and certainty regarding rate changes. Vote and Order at 14. Additional transparency should enable customers and interest groups to have a more holistic understanding of cumulative bill impacts and cost trends and should facilitate more informed participation in Department proceedings. Vote and Order at 14.

To this end, as part of its Vote and Order, the Department requested certain information from the Distribution Companies regarding the cadence of the various reconciling mechanism filings, as well as their respective filing and effective dates. Vote and Order at 16. The Department also sought input from the Distribution Companies as well as interested stakeholders on the question of whether the Department should modify the timing of bill changes to reduce volatility or to serve other policy objectives. Vote and Order at 19. In addition, as part of our investigation into existing processes to enable a transparent and holistic review of each utility's annual reconciling rate changes, on June 26, 2026, the Department issued a Hearing Officer Memorandum requesting that the Distribution Companies submit proposals for an annual reporting template showing each rate change scheduled to take effect in the calendar year (electric) or by season (gas) (June 26 Memorandum at 3-4). The Department outlined certain parameters to be used in developing this requested template and sought input from the Distribution Companies and stakeholders. June 26 Memorandum at 4-8.

B. Summary of Comments

Several commenters support modifying the timing of bill changes to reduce volatility (see, e.g., TEC Comments at 11; Climate Advocates Comments at 12). Some commenters express concerns with difficulty tracking the various dockets that lead to rate increases in a given year and suggested that the Department consolidate its review of the electric reconciling mechanisms to reduce administrative burden, enable stakeholder participation, and promote the predictability of bill changes (see, e.g., EDF Comments at 1; City of Boston Public Comments at 4; PowerOptions Comments at 6; GECA Comments at 3; The Feeney Brothers Comments at 6).

TEC recommends mid-year adjustments to reconciling rates to help reduce volatility by avoiding large variances at annual updates (TEC Comments at 11). TEC further suggests the Department define volatility as a rate change that has the potential to result in a total bill variance of greater than three percent for customers (TEC Comments at 11).

The Climate Advocates argue that rate changes that are implemented abruptly or during periods of high energy usage unnecessarily drive bill volatility and create avoidable bill shocks (Climate Advocates Comments at 12). In addition, the Climate Advocates contend that the Department has broad authority to regulate the timing of bill changes to smooth bill impacts, reduce bill volatility, and align utility rates with state clean energy policy objectives (Climate Advocates Comments at 12). The Climate Advocates therefore recommend phasing in rate increases over time to give customers an opportunity to adjust household budgets, access assistance programs, and take advantage of energy efficiency and electrification opportunities that can reduce long-term energy costs (Climate, Energy Efficiency, and Consumer Advocates

Comments at 12). In addition, the Climate Advocates suggest that the Department can further mitigate bill volatility by delaying the effective dates of rate changes to the shoulder seasons, which would materially reduce volatility and improve bill predictability for ratepayers (Climate Advocates Comments at 12-13). The Climate Advocates note, however, that this approach should not result in collection of carrying charges by the Distribution Companies (Climate Advocates Comments at 13).

The Attorney General suggests the Department focus on the customer experience of bill changes as it considers the frequency, timing, and threshold for bill increases (Attorney General Comments at 20-21). The Attorney General notes that frequent rate changes result in greater volatility and lack of predictability, and thus are likely to cause customer confusion and frustration (Attorney General Comments at 20). To this end, the Attorney General states that the customer experience can be improved through greater utility coordination (i.e., rate changes should be implemented in a coordinated fashion across overlapping gas and electric company service territories) as well as targeted education and notification efforts, such as notifying customers through multiple channels ahead of changes to make bills more predictable (Attorney General Comments at 21). In addition, the Attorney General suggests that significant increases should be phased in rather than implemented on a single date (Attorney General Comments at 21). The Attorney General therefore recommends the Department: (1) reduce the number of times a year that volumetric charges change to promote greater transparency and predictability and to reduce administrative costs and burdens relating to the review of reconciling charge petitions; (2) carefully consider when increases go into effect to avoid significant increases during the peak season; and (3) consider phasing in rate increases over time to mitigate rate

shock, but noting this must be balanced against the increased overall costs due to carrying charges; and (4) carefully review bill impacts for the peak season alongside average bill impacts, noting that customer's experience viewing and paying their winter gas bill is different than a customer's experience adding up their total bills over twelve months to determine their average monthly bill (Attorney General Comments at 21).

DOER supports reducing the frequency and volume of reconciling mechanism filings to promote efficiency and oversight (DOER Reply Comments at 4). DOER notes that the high frequency and volume of rate changes is confusing for customers and can lead to significant month-to-month bill volatility (DOER Reply Comments at 4). In addition, DOER remarks that the various reconciling tariff filings add administrative burden and make it challenging for intervenors, the Department, and the public to examine and engage with proceedings regarding the various cost components of customer bills (DOER Reply Comments at 4). DOER agrees with other commenters that limiting the number of times rates can change in a year and scheduling rate increases for non-supply reconciling mechanisms during lower-usage shoulder seasons would improve predictability for customers as well as administrative efficiency (DOER Reply Comments at 4, citing Attorney General Comments at 21; Climate Advocates Comments at 12-13). DOER therefore recommends that the Department consider reforms to streamline rate filings to limit month-to month volatility, reduce administrative costs, and improve transparency (DOER Reply Comments at 4, citing Attorney General Comments at 1-2; EDF Comments at 1; GECA Comments at 3; TEC Comments at 11).

Several of the Distribution Companies maintain that modifying the timing of bill changes will not necessarily lead to increased bill stability (see, e.g., Eversource Comments at 49-50;

Liberty Comments at 13). In addition, several of the Distribution Companies argue that limiting the timing of rate changes to one or two times per year could also increase the risk of bill shock by concentrating multiple adjustments into fewer, larger rate changes (see, e.g., National Grid Comments at 34; Berkshire Gas Comments at 10-11; Unitil Comments at 15).

According to National Grid and Berkshire Gas, setting limits on when rates may be adjusted to fixed intervals could lead to higher reconciliation balances and associated carrying costs, by limiting the Company's ability to propose interim revisions to rates when necessary (National Grid Comments at 34; Berkshire Gas Comments at 10-11). Therefore, National Grid and Berkshire Gas support maintaining flexibility in the timing of bill changes to preserve cost reflective rates and timely recovery (National Grid Comments at 34; Berkshire Gas Comments at 10). National Grid further states that adjusting different rate mechanisms at different time periods promotes transparency and regulatory efficiency by reviewing specific costs in their own dedicated proceedings, rather than conducting a review of all costs at the same time (National Grid Comments at 34).

Eversource notes that it is challenging to predict the appropriate time for rate changes because the best timing is different for every customer (Eversource Comments at 49). Eversource states that it implements electric rates in January and in July (with some transitioning to September) while gas rates are set in November and May, and Eversource claims that spreading rate changes across the year would result in more frequent rate changes, which is contrary to the desire for greater bill stability (Eversource Comments at 49). Eversource contends that while this would result in smaller incremental price increases, it may not ultimately lower the cost of the total bill (Eversource Comments at 49). Therefore, Eversource maintains

that spreading the impact of a rate change across the year is better accomplished through fixed cost or demand charge recovery (Eversource Comments at 49). Eversource, however, supports a process to enable more frequent rate changes when rates become misaligned with the cost of the programs those rates are set to collect, thereby avoiding the build-up of a large under-recovery balance that will accumulate added carrying charges (Eversource Comments at 49-50). Eversource notes that consistent with these principles, the Company has proposed rate-effective-date changes to better align customer communications and usage patterns (Eversource Comments at 50). For example, Eversource has previously proposed moving the effective dates of certain reconciling mechanisms (e.g., the EERF) from July 1 to September 1 on an annual basis to mitigate the impact of rate changes to customers during periods of historically higher usage (Eversource Comments at 50).

Liberty contends that modifying the timing of bill changes for gas customers will not reduce volatility or serve other policy objectives (Liberty Comments at 13). Liberty notes that the current peak period begins November 1 and the current off-peak period begins May 1, both of which are shoulder months and allow time for customers to adjust their consumption based on price signals (Liberty Comments at 13).

While Unitil agrees that reducing the number of rate changes throughout the year may increase administrative efficiency, it could lead to larger volatility in rates when rates do change (Unitil Comments at 15). Unitil notes that consolidating its January 1, June 1, and July 1 adjustments to a single date would reduce the number of rate changes per year, which may be less confusing for customers, and is therefore prepared to evaluate this possibility (Unitil Comments at 15).

The City of Boston emphasizes that multiple capital investment filings, recovered in either base rates or reconciling charges, increase administrative burden for the Department, stakeholders, and the utilities (City of Boston Public Comments at 6). The City of Boston therefore recommends the Department explore an annual capital investment filing for informational purposes only (e.g., as a measure included in future annual PBR reporting) that: (1) tracks the past year's capital investments (either completed or ongoing); (2) cites the proceeding in which the investments were approved for cost recovery; and (3) identifies the associated cost recovery mechanism (City of Boston Public Comments at 6). The City of Boston further states that consolidating review of capital investments presents an opportunity to drive optimization and prioritize affordability in capital planning (City of Boston Public Comments at 9).

PowerOptions supports consolidating the timing of rate adjustments so that customers experience fewer, more predictable bill change events per year, which would improve their ability to plan and budget (PowerOptions Comments at 6). Where reconciling mechanisms are retained, PowerOptions suggests the Department consider establishing uniform adjustment dates for any rate change that has the potential to produce a significant total bill impact (PowerOptions Comments at 6). Other commenters caution that any consolidation of reconciling mechanisms or annual recovery processes should consider the effect on construction work and planning, including permitting cycles, seasons, procurement lead times, municipal permitting calendars, and the availability of trained crews and specialized equipment (Feeney Brothers Utility Services Comments at 6).

C. Conclusions

1. Consolidating Certain Reconciling Mechanisms in the Electric Distribution Companies' Annual Retail Rate Filings

As part of the Department's investigation into promoting more manageable and stable electric and gas bills, we examined whether certain electric reconciling mechanisms should be included in the EDCs' annual retail rate filings for review and approval rather than filed in separate dockets at different times of the year, with the goals of reducing the number of rate changes over the course of a year as well as administrative burden and cost, and promoting greater transparency and certainty regarding rate changes. Vote and Order at 13-14. The Department appreciates the input from the Distribution Companies and stakeholders on this issue. Many stakeholders agreed with the Department's efforts to reduce volatility and administrative burden and to increase transparency. The Distribution Companies, however, cautioned that limiting the timing of rate changes to one or two times per year could also increase the risk of bill shock by concentrating multiple adjustments into fewer, larger rate changes.

We acknowledge that modifying the timing of rate adjustments by consolidating certain reconciling mechanisms could result in fewer and more predictable bill change events per year for customers, as well as potentially reducing barriers for stakeholder participation. The Department, however, is concerned about bill shock for customers when more rates change at the same time, rather than being spread throughout the year (see, e.g., Eversource, DPU-Common 3-17(a); National Grid (electric), DPU-Common 3-17(a); Unitil (electric), DPU-Common 3-17(a)). In addition, the Department agrees with the EDCs that the added complexity resulting from consolidating numerous reconciling mechanisms that may have

different effective dates into the annual retail rate filing could ultimately increase, not reduce, administrative burden (see, e.g., Eversource, DPU-Common 3-17(a); National Grid (electric), DPU-Common 3-17(a); Unitil (electric), DPU-Common 3-17(a)). As noted by the EDCs, the inclusion of additional reconciliation mechanisms within the annual retail rate filing would increase the number of exhibits and overall information presented within the annual retail rate filing (see, e.g., Eversource, DPU-Common 3-17(a); Unitil (electric), DPU-Common 3-17(a)). Moreover, for rates that recover capital investments made in the prior calendar year and previous years, the EDCs require time to compile all supporting capital and project information after the end of the fiscal year to be included within the initial filing, and therefore, the documentation would not be available and complete by the annual retail rate filing deadline (see, e.g., Eversource DPU-Common 3-17(a); National Grid (electric), DPU-Common 3-17(a)). Given that the Department must continue to evaluate each proposed reconciling mechanism charge individually, consolidating the filings will not necessarily promote increased efficiency (see, e.g., National Grid (electric), DPU-Common 3-17(b)).

After review, we find that reducing the number of reconciling mechanisms, rather than consolidating their review and effective dates into the annual retail rate filing, will serve as a more appropriate avenue to reduce the frequency of bill changes and ultimately improve stability, as discussed above in Section III(D). In addition, to improve transparency and facilitate a more holistic understanding of cumulative bill impacts and cost trends, the Department establishes annual reporting requirements regarding rate changes, described below in Section V.

2. Reconciling Mechanism Effective Dates

With respect to modifying the effective dates of certain reconciling mechanisms with the aim of mitigating bill impacts during peak seasons, the Department finds that this issue requires further investigation. While we recognize that there may be certain instances where it is beneficial to modify the effective date for rate changes (e.g., to mitigate bill increases during times of higher customer usage), it is important to understand the full scope and impact on other rate proceedings, as well as on customers, before implementing a comprehensive approach. As noted by Eversource, the best time for rate changes to go in effect may be different for each customer. In addition, where a planned rate adjustment results in a bill decrease instead of a bill increase, a change in the effective date may not be appropriate or warranted. Therefore, the Department intends to continue to carefully evaluate this topic as part of a subsequent phase of this proceeding, where we will investigate utility bill design with the aim of improving the customers' experience and understanding of bill charges. Vote and Order at 4.

V. ANNUAL REPORTING REQUIREMENTS FOR RATE CHANGES

A. Introduction

To further promote more manageable, stable electric and gas bills, the Department investigated changes to existing processes to enable a transparent and holistic review of annual rates, cumulative bill impacts, and cost trends (June 26 Memorandum at 3-4). Vote and Order at 2. To this end, the Department requested that the EDCs, jointly, and the LDCs, jointly, submit proposals for a reporting template that demonstrates the various rate changes scheduled to take effect in the calendar year (electric) or by season (gas) using certain parameters discussed below

(June 26 Memorandum at 3-4). In addition, the Department provided an opportunity for stakeholders to comment on the Distribution Companies' proposals (June 26 Memorandum at 8).

The Department requested that the EDCs jointly submit a proposed template that includes: (1) for each rate class and company total, the change in all costs for the current year compared to the prior year; (2) for each rate class, the change in all rates for the current program year compared to the prior year; (3) monthly bill impacts for each month of the year for each rate class comparing current rates to the proposed and forecasted rates; (4) for each rate class and company total, the performance-based revenue adjustment and any exogenous cost adjustment for the year, so that the year-over-year increase in base rates is also included; (5) the total projected increase in base distribution rates for the year; (6) the full impact and timing of all rate changes for the year, presented by line items as they appear on a customer's bill, with a list of individual rates that constitute each line item; (7) projections of estimated costs presented by line items as they appear on a customer's bill, with a list of individual rates that constitute each line item; and (8) tables and graphs where possible, to include the prior, current, proposed, and forecasted residential rates for each rate grouping, the electricity rates measured in cents per kilowatt-hour ("kWh") for a customer with mean usage, and how much each grouping makes up the total electric bill (June 26 Memorandum at 3-6).

With respect to the LDCs, the Department recognized that GAFs vary seasonally (or monthly) and consequently, annual rate projections may not accurately reflect the variability and timing of GAF rate adjustments (June 26 Memorandum at 5). Accordingly, the Department requested the LDCs jointly submit a proposal for a seasonal report template that is comparable to the parameters described above for the EDCs, to the extent practicable, for inclusion in both peak

and off-peak GAF filings (June 26 Memorandum at 5). We specified that all rate comparisons should be made between corresponding seasonal periods (i.e., peak to peak and off-peak to off-peak) and that for each company and rate class, the proposal should include: (1) the total change in all costs for the current peak or off-peak period compared to the corresponding prior peak or off-peak period; (2) the proposed change in all rates for current peak or off-peak period compared to the corresponding prior peak or off-peak period; (3) monthly bill impacts for each month of the current peak or off-peak period comparing current rates to the proposed rates for the corresponding seasonal period; and (4) tables and graphs where possible, to include the prior, current, proposed, and forecasted residential rates for each rate grouping, the changes in the GAF measured in dollars per therm for the peak and off-peak periods, assuming mean usage, and how much each grouping makes up the total gas bill (June 26 Memorandum at 4, 6-7). The Department also requested that, for each analysis, the LDAF be shown both in aggregate and by individual reconciling charge (June 26 Memorandum at 6).

In addition, the Department requested that all Distribution Companies address certain issues as part of their proposals (June 26 Memorandum at 7). Specifically, we asked the Distribution Companies to discuss: (1) any pros and cons of providing the requested information; (2) any supplemental information that the Distribution Companies deem useful for the Department, stakeholders, and customers to understand how the different rate components affect the total bill and provide more transparency to customers; (3) any recommendations on the report structure and/or content outlined above; (4) what supporting information and documentation the Distribution Companies could provide with these forecasts of rates expected to change but not yet proposed; (5) whether or to what extent bill impact analyses and rate

summaries can be standardized across companies through the use of a common reporting format in electric and gas filings; (6) any Distribution Company-specific differences to incorporate; and (7) how the Companies can make this information accessible to customers (e.g., labeling costs in terms customers could understand and see on their bills) (June 26 Memorandum at 7-8).

On July 31, 2026, the EDCs jointly submitted a reporting template ("EDCs Reporting Template") to be used in the annual electric retail rate reconciliation filings and the LDCs jointly submitted a reporting template ("LDCs Reporting Template") to be used in the seasonal gas filings (together, "Reporting Templates"). The EDCs and LDCs also jointly submitted comments along with their templates ("Distribution Companies' Joint Reporting Comments"), which: (1) summarized the templates and described how the Distribution Companies addressed each of the Department's requests; and (2) responded to the Department's specific issues outlined above (Distribution Companies' Joint Reporting Comments at 1). The Department received comments from DOER on August 10, 2026, and from the Attorney General and the City of Boston on August 13, 2026, regarding the Distribution Companies' proposals.

B. Summary of Comments

1. Distribution Companies

The Distribution Companies indicate their overall support for the Department's efforts to increase transparency into the drivers of energy costs; however, they caution that while the requested information and format may be useful to the Department, it may not be the ideal way to convey cost drivers to customers (Distribution Companies' Joint Reporting Comments at 1). The Distribution Companies suggest that they can provide firsthand operational experience on how to best present information to their customers and indicate they will further discuss the

potential approaches during Phase II of this proceeding (Distribution Companies' Joint Reporting Comments at 1).

The Distribution Companies state that their annual report templates incorporate the specific information requested by the Department (Distribution Companies' Joint Reporting Comments at 1). The Distribution Companies, however, propose several modifications to the information to be included in their respective templates (Distribution Companies' Joint Reporting Comments at 1).

First, the Distribution Companies propose to not forecast rates beyond the proposed rates included with their annual or semi-annual rate filings (Distribution Companies' Joint Reporting Comments at 3, 5-6, 9-10). The Distribution Companies contend it is neither feasible nor beneficial to include forecasted rates as there are too many variables and uncertainties in future costs, including those outside their control, such that providing rate forecasts could mislead customers or other stakeholders (Distribution Companies' Joint Reporting Comments at 3, 5-6, 9-10). The Distribution Companies state that longer-term rate forecasts may represent "false precision" and differ significantly from the eventual approved rates (Distribution Companies' Joint Reporting Comments at 3). The Distribution Companies further state that while they could provide preliminary estimates and assumptions, such estimates would involve considerable uncertainty, making it difficult to draw any conclusions from such an analysis (Distribution Companies' Joint Reporting Comments at 9, citing Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid, D.P.U. 12-76-C at 30 (2014)).

In addition, the LDCs explain that since the majority of the LDCs' LDAF and RDAF costs are often volatile, unpredictable, and/or difficult to measure with precision, they are unable to provide reliable, forecasted rates beyond what is being proposed (Distribution Companies' Joint Reporting Comments at 9, citing Liberty's Initial Report at 17). The EDCs add that including estimates for the reconciling mechanisms used to recover capital investments with annual retail rate filings would not be feasible given that recovery of capital investment costs is based on the prior calendar year's plant-in-service, which would not be available by the filing date (Distribution Companies' Joint Reporting Comments at 9).

The Distribution Companies further argue that forecasting supply rates is challenging because both natural gas and electric supply costs are affected by the sensitivity and volatility of the market price for natural gas on the New York Mercantile Exchange, resulting in fluctuations in underlying commodity prices (Distribution Companies' Joint Reporting Comments at 9-10). According to the Distribution Companies, given the volatility of natural gas prices, any forecasted Basic Service rates or GAFs may change significantly, resulting in limited benefits and potential disadvantages to using forecasted commodity prices to make decisions (Distribution Companies' Joint Reporting Comments at 10). For these reasons, the Distribution Companies propose that the templates include only Department-approved rates as well as rates proposed as part of their annual retail rate filings or seasonal GAF filings (Distribution Companies' Joint Reporting Comments at 10).

Second, with respect to the Department's request to the EDCs for a graph that shows the changes to cents per kWh rates over time, the EDCs suggest that a graph showing historical average monthly bill dollar amounts would be more meaningful to customers (Distribution

Companies' Joint Reporting Comments at 3, 8). The EDCs explain that presenting bill impacts in volumetric terms could be misconstrued given that not all rates are usage-based (e.g., fixed charges such as the Customer Charge can only be expressed as a volumetric rate by assuming a specific level of usage) (Distribution Companies' Joint Reporting Comments at 8). Consequently, the Distribution Companies state they also provide a bill impact graph that shows historical monthly bill amounts in dollars, based on an average residential customer monthly usage (Distribution Companies' Joint Reporting Comments at 8). Ultimately, the Distribution Companies contend that presenting average monthly bill amounts is more meaningful in assessing the overall cost of utility service to a customer (Distribution Companies' Joint Reporting Comments at 8).

As mentioned above, in addition to the proposed templates and explanatory summary, the Distribution Companies responded to specific questions posed by the Department (Distribution Companies' Joint Reporting Comments at 7-15; June 26 Memorandum at 7-8). First, the Distribution Companies described the pros and cons of providing the requested information. The Distribution Companies explained that the main benefit of this type of annual reporting is that it provides an all-in view of utility rates and costs that allows for a comprehensive review of customer impacts (Distribution Companies' Joint Reporting Comments at 7). In addition, the Distribution Companies state that proposed templates enhance transparency by offering a level of detail generally not displayed on customer bills and displays utility rates in a format that aligns with how charges appear on customers' bills to help the Department and stakeholders understand the primary drivers behind the increases in utility bills (Distribution Companies' Joint Reporting Comments at 7). Further, the Distribution Companies state that their templates group rates by

cost category, which they contend makes it easier to distinguish costs driven by delivery, public policy, investments in the Distribution Companies' distribution systems, investments in regional transmission infrastructure, accelerated investments undertaken to support policy objectives, GSEP, and commodity costs (Distribution Companies' Joint Reporting Comments at 7). Finally, the Distribution Companies state that their graphs show rate changes over time, offering a visual presentation that may be more accessible and informative than reviewing data in a spreadsheet format (Distribution Companies' Joint Reporting Comments at 7).

With respect to the potential cons, the Distribution Companies indicate that the main disadvantage of the proposed template is their complexity, as they contain a substantial amount of information and data points that cover an array of rates and costs, as well as their potential to lead to confusion (Distribution Companies' Joint Reporting Comments at 7-8). To this end, the Distribution Companies recommend a bill impact graph that shows historical monthly bill amounts in dollars, based on an average residential customer monthly usage, which will be more meaningful in assessing the overall cost of utility service to a customer (Distribution Companies' Joint Reporting Comments at 8).

Second, the Distribution Companies recommended no further supplemental information for the templates (Distribution Companies' Joint Reporting Comments at 8). The Distribution Companies explain that they already provide supporting information in each rate filing, and that their proposed templates maximize information in a highly dense format (Distribution Companies' Joint Reporting Comments at 8). In addition, the Distribution Companies note that the level of information may be too detailed to enable more transparency to the average customer (Distribution Companies' Joint Reporting Comments at 8).

Third, with respect to recommendations on report structure and content, the Distribution Companies recommend including both a detailed view of the information across multiple tabs as well as a graph to ensure the reports provide value to a broad range of stakeholders and customers (Distribution Companies' Joint Reporting Comments at 8). The Distribution Companies also note that on November 1, 2026, as directed by the Department's orders in D.P.U. 24-15, customer discounts for income-eligible rate classes will include six discount tiers based on the level of their household income (Distribution Companies' Joint Reporting Comments at 8). The Distribution Companies caution that presenting six variations of discount tiers on one tab will make the template more difficult to read and interpret, and therefore the companies propose to include monthly bill impacts for income-eligible discount program Tier 1 and Tier 6 only to demonstrate a range of discounts customers will receive (Distribution Companies' Joint Reporting Comments at 8-9).

In addition, the EDCs indicate that they included only Basic Service rates in this template, not supply costs for customers that receive their electric supply from third parties (competitive suppliers or municipal aggregators), given that the EDCs do not have full insight into supply costs across all customers (Distribution Companies' Joint Reporting Comments at 9). Further, the Distribution Companies state that the Renewable Energy Charge is only presented on the rates tabs, but the costs of total billings through the Renewable Energy Charge are not estimated in the cost tabs because they do not submit proposals for recovery with costs shown (Distribution Companies' Joint Reporting Comments at 9). Additionally, the Companies prefer to present graphs for residential rate classes using monthly bill amounts, rather than in cents-per

kWh (for electric) or dollars-per-therm (for gas) as requested (Distribution Companies' Joint Reporting Comments at 9).

Fourth, as discussed above, the Distribution Companies contend that it is neither feasible nor beneficial to customers for the Distribution Companies to include forecasted rates (beyond proposed rates for effect) in the template, as doing so would be misleading (Distribution Companies' Joint Reporting Comments at 9). Accordingly, the Companies propose that the templates include only Department-approved rates as well as rates proposed as part of their annual retail rate filings or seasonal GAF filings (Distribution Companies' Joint Reporting Comments at 10).

Fifth, with respect to the question of whether or to what extent bill impact analyses and rate summaries can be standardized across companies through the use of a common reporting format in electric and gas filings, the Distribution Companies state they recognize the value of additional information provided by the templates and agree to include the standardized bill impacts in future annual retail rate filings and seasonal GAF filings, along with other required exhibits (Distribution Companies' Joint Reporting Comments at 10). To that end, the Distribution Companies represent that the templates submitted with this filing include standardized bill impact analyses that the Distribution Companies collaboratively developed (Distribution Companies' Joint Reporting Comments at 10).

The Distribution Companies, however, do not recommend that these new templates replace the bill impact templates they currently use in recurring rate adjustment filings, arguing there is already sufficient consistency in the rate summaries such that no further standardization is needed (Distribution Companies' Joint Reporting Comments at 10). The Distribution

Companies further maintain that they use these rate summaries to administer and support internal rate changes within their own billing systems and that changing the formats to standardize them across all the EDCs or LDCs would trigger time-consuming system changes within each Distribution Company's billing systems (Distribution Companies' Joint Reporting Comments at 10).

Sixth, the Distribution Companies indicate their overall support for a standardized reporting framework that provides customers with consistent and comparable information across all utilities; however, they argue that such framework should allow for limited utility-specific modifications to reflect differences in rate structures, reconciling mechanisms, and customer classes (Distribution Companies' Joint Reporting Comments at 11). The Distribution Companies contend this will preserve consistency while ensuring that utility-specific information is presented accurately and in a manner that is meaningful to customers (Distribution Companies' Joint Reporting Comments at 11).

Finally, with respect to suggested approaches to make the reporting information accessible to customers, each Distribution Company presented its feedback on potential enhancements to customer bill presentation going forward, to be evaluated during Phase II of this proceeding (Distribution Companies' Joint Reporting Comments at 12-15). The Distribution Companies suggest that, following the Department's forthcoming Phase II order on bill redesign, any approved changes to rate presentation on customer bills, as well as any other relevant modifications, could be incorporated into the reporting templates (Distribution Companies' Joint Reporting Comments at 12).

2. Attorney General

The Attorney General maintains that while the information in the electric and gas Reporting Templates will support greater transparency for many stakeholders, the Attorney General expects that Phase II of this proceeding will focus on the specific information that will be communicated to customers on their bills, as well as how that information is communicated (Attorney General Reporting Comments at 1). The Attorney General also recommends the following with respect to the Distribution Companies reporting templates: (1) to provide more granularity and transparency with regard to the cost components of Basic Service, the Attorney General requests that the Department direct the EDCs to provide an additional tab in the Electric Report Template that breaks out the Renewable Portfolio Standard ("RPS") and Alternative Portfolio Standard ("APS") compliance costs; (2) to improve the understandability of the variances in the Natural Gas Report Template, the Attorney General requests that the Department direct the LDCs to use the customary formula for Percent Variance (i.e., subtracting the prior value from the new value, and dividing the result by the prior value, rather than by the total bill amount); (3) to facilitate a more detailed and transparent comparison of changes in costs and rates in the Electric Report Template and the Natural Gas Template, the Attorney General recommends that the Department direct the EDCs and LDCs to add two additional columns next to the "Change" columns in each of the "Costs-XX" and "Rates-XX" tabs to include the Percent of Total Change and Percentage Change for each line item for each rate class; and (4) to improve the accessibility of the data in the "Rates-XX" tabs in both the Electric and Natural Gas Report

Template, the total energy unit costs ($/kWh or $/therm) of the respective rates should be prominently listed for all tables (Attorney General Reporting Comments at 1-3).

3. DOER

DOER supports the Department's efforts to give customers greater transparency into electric rates and the timing of rate changes (DOER Reporting Comments at 1). DOER agrees with the Distribution Companies that the level of detail and information in the proposed template reports is not ideal for customer-level communication and believes that the Distribution Companies should provide the critical information offered in these reports to customers in an accessible manner as soon as practicable, prior to the broader investigation of bill redesign in Phase II (DOER Reporting Comments at 3). DOER states that the Distribution Companies' proposed reporting templates provide valuable and detailed information in a consistent format; however, DOER recommends three modifications to increase transparency for both engaged stakeholders and for customers (DOER Reporting Comments at 2-5).

First, DOER recommends the Distribution Companies update the templates to also identify: (1) how long each rate component will be in effect; (2) when the Companies submitted or will submit a filing that would modify each proposed rate component, if known; (3) when the Department approved or the Company expects approval of a new rate; and (4) the docket number where approval was made, or is pending (DOER Reporting Comments at 2-3). DOER contends this will provide fuller picture of the timing of all rate changes for the year (DOER Reporting Comments at 2).

Second, DOER recommends that the Companies develop plain-language summaries of the key information in these reports as an accompaniment to the full, detailed reports each year

to allow a customer to quickly identify how different cost categories contribute to their bill and when their bill is likely to change in the current year (DOER Reporting Comments at 3-4). DOER developed an example summary for electric customers using the EDCs' reporting template, and included a simple figure and table that differentiate between approved and proposed rates, and described when rates change throughout the year (DOER Reporting Comments, Att. A).

Third, while DOER acknowledges the Distribution Companies' proposed templates offer clear and detailed information on all rate components by month and customer class, it notes that the electric and gas templates include data on approved rates dating back only two years, to January 1, 2024, and November 1, 2024, respectively (DOER Reporting Comments at 4). DOER recommends that the Companies update the report templates to provide the same rate data extending back to 2016 to better enable stakeholders to contextualize current bill costs by showing how cost drivers have evolved over time (DOER Reporting Comments at 4-5).

4. City of Boston

The City of Boston makes several suggestions to improve stakeholder understanding of the Distribution Companies' templates. First, the City of Boston recommends the Distribution Companies add a glossary with each template to include: (1) a definition of each charge, its purpose, and most recent docketed proceeding/Order; (2) explanations of certain items that may not be intuitive on first read to all stakeholders (e.g., stating explicitly that PBR adjustments are embedded in the base distribution rate line item, as noted by the utilities in their filings) (City of Boston's Reporting Comments at 1). The City of Boston also indicates support for the approach proposed by DOER in their filed comments (City of Boston's Reporting Comments at 1).

Second, the City of Boston states the Distribution Companies should fix a formula issue in the electric template (City of Boston's Reporting Comments at 1). Namely, on the Bill Impact R-1 tab, the City of Boston indicates that cell O31 ("Total Distribution") appears to sum only cells O16:017 rather than the full distribution components in rows 16:30, and the corresponding monthly totals in C31:N31 sum rows 16:30, as does the proposed-rate annual total in O69 (City of Boston's Reporting Comments at 1).

Third, the City of Boston recommends the Distribution Companies include a narrative around historical rate trends of, for example, the prior five years with year-over-year change in certain cost categories (City of Boston's Reporting Comments at 2). In addition, the City of Boston recommends a discussion of any similarities or differences anticipated in the future such as expected major capital projects coming online or ending in future years (City of Boston's Reporting Comments at 2). The City of Boston acknowledges the complexity and potential for misleading information with respect to providing forecasted rates in the templates and therefore suggests that a qualitative narrative could be useful for certain line items and a topic of future discussion led by the Department in this proceeding (City of Boston's Reporting Comments at 2).

C. Conclusions

The Department appreciates the thoughtful analysis and input from the Distribution Companies and various stakeholders in developing the Reporting Templates. We expect the information contained in these reports will be valuable to the Department and stakeholders in understanding the cumulative impact of each rate change proposed throughout a given year. As noted by the Distribution Companies, as well as stakeholders, while the requested detailed

information and format may be useful to the Department, we recognize it may not be a conducive manner to convey cost drivers to customers (Distribution Companies' Joint Reporting Comments at 1, 15; Attorney General Reporting Comments at 1; DOER Reporting Comments at 3). For this reason, the Department intends to explore approaches concerning how to make this information more accessible to customers in a subsequent phase of this proceeding, which we anticipate will focus on the specific information that will be communicated to customers on their bills, as well as how that information is communicated (Attorney General Comments at 1).

The Distribution Companies' proposals included the information requested by the Department, with a few proposed changes. After review, we find these suggested changes reasonable. Therefore, subject to the modifications discussed below, the Department accepts the Distribution Companies' Reporting Template proposals.

First, the Distribution Companies indicate that providing forecasted rates would not be feasible or beneficial given the likelihood that the estimates and assumptions would be preliminary, uncertain, and subject to change, making it difficult to draw reliable conclusions (Distribution Companies Joint Reporting Comments at 9). For these reasons, the Department recognizes that providing forecasted rates may not necessarily result in the desired intent of increased transparency. We therefore accept the Distribution Companies proposal to include only Department-approved rates as well as proposed rates (Distribution Companies Reporting Comments at 9-10). To ensure, however, that the Department is able to understand the complete picture of rate changes throughout the year to the fullest extent practicable, the Distribution

Companies shall submit updated Reporting Templates with each rate change filing,[52] in addition to their annual retail rate filings or seasonal GAF filings. In addition, in line with the City of Boston's recommendation to provide a narrative on historical rate trends, the Department instead directs the Distribution Companies to submit a rolling 5-year historical rate lookback with each filing.

Next, the Department directs the Distribution Companies to remove the categorization of charges in the Reporting Templates. Specifically, the EDCs shall remove the "Charge Category" column in the EDC reporting template, and the LDCs shall remove the "Charge Type" color-coding in the LDC reporting template. Although we acknowledge that grouping rates by cost category may help to distinguish costs driven by certain categories or types of costs (e.g., delivery, public policy, investments in the Distribution Companies' distribution systems), the Department has not yet defined these categories of costs. The Department's definition of delivery costs, for example, may differ from those costs identified by the Distribution Companies in their templates. Accordingly, the Distribution Companies shall remove reference to specified cost categories until the Department defines these groupings. We intend to define cost categories as part of the bill redesign phase of this investigation.

With respect to the Distribution Companies' recommendation for a bill impact graph that shows historical monthly bill amounts in dollars, based on an average residential customer

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[52] A rate change filing includes all filings in which a Distribution Company proposes a change in rates (i.e., filings related to reconciling mechanisms, basic service, revenue decoupling, PBR, etc.). If there are multiple rate changes effective on the same date and proposed through multiple dockets, the Department expects identical reports to be filed in each separate docket.

monthly usage, the Department accepts this proposal but notes that the graphs must show an effective date and an ending date for each rate adjustment. The Department finds this timeline will better reflect how rates change over the course of the year.

Next, the Distribution Companies shall fix certain errors identified by stakeholders. Specifically, the LDCs shall amend the percent variance formula to subtract the prior value from the proposed value, and divide the result by the prior value (rather than by the total bill amount) (Attorney General Reporting Comments at 2). In addition, the EDCs shall correct the "Bill Impacts R-1" tab, "Total Distribution" cell O31, which appears to sum only cells O16:017 rather than the full distribution components in rows 16:30 (City of Boston Reporting Comments at 1). The Distribution Companies shall further review all calculations in all cells to ensure all components are calculated appropriately and consistently.

In addition, the Department agrees with DOER's recommendation to update the Reporting Templates to identify the docket number where a rate was approved, or is pending, as a column in the relevant tables, though we will not require a separate sheet summarizing the information on regulatory process and timeline for each rate component (DOER Reporting Comments at 3). If the docket number is yet to be determined, the Distribution Company should simply indicate as such. The Department finds adding this docket information will aid in the Department's and stakeholders' review of rate changes.

The Department also agrees with the Attorney General's recommendation for the EDCs to provide an additional tab in the Electric Reporting Template that breaks out the RPS and APS compliance costs for Basic Service in tab "Rates-Res" and in the graph in tab "Rate R1 chart" (Attorney General Reporting Comments at 1-2). In addition, the Department agrees with the

Attorney General's recommendation for both the EDCs and the LDCs to prominently list the total energy unit costs ($/kWh or $/therm) of the respective rates for all rates tables (Attorney General Reporting Comments at 3).

We find the above modifications and additions will not be overly burdensome and will facilitate a more detailed and transparent comparison of changes in costs and rates as well as help improve the accessibility of the data presented. The Distribution Companies shall therefore make these adjustments to their respective templates.

After review, we decline to implement the other recommendations proposed by stakeholders at this time. We find that several of the recommendations, while they may yield beneficial information as a general matter, would on balance be overly burdensome to produce, not necessary for our current purposes in reviewing rate change filings, and/or add to the complexity of these reports which already contain a large volume of information. The Department expects that as we gain experience in reviewing and using these reports in the various rate change filings that come before us, we may refine the format and content of the required reporting, with potential opportunities for further input from the Distribution Companies and stakeholders.

With the above modifications, the Department finds that the proposed Reporting Templates are designed to lead to increased transparency and a holistic view of rate changes, and their cumulative impacts, as well as facilitate more informed participation in the various Department proceedings. We expect that this information will also allow the Department to analyze cost trends and provide context for future decisions. Further, through the improved transparency, the Department, Distribution Companies, and stakeholders will gain greater

awareness of when future cumulative bill increases may be approaching an unreasonable level, allowing for evaluation of appropriate preventative or mitigation measures.

The EDCs and LDCs shall file updated Reporting Templates consistent with the directives outlined above for the Department's review within 15 business days of this Order. The EDCs and LDCs shall submit their respective Reporting Templates with each rate change filing upon Department approval of the updated Reporting Templates.

VI. CONCLUSION

Amidst rapidly rising energy costs, the Department opened this investigation to evaluate electric and gas delivery rates, with the aims of containing customer costs, reducing utility bill volatility, and increasing utility bill transparency and accessibility. We also sought to determine whether changes to existing processes could enable customers to gain a transparent and holistic understanding of each utility's annual reconciling rate changes. Through this Order, we take important steps towards ensuring the Distribution Companies are incentivized to control and minimize costs wherever possible. Thus, of the 40 mechanisms reviewed, the Department identifies 15 reconciling mechanisms for elimination and that certain costs currently collected through these reconciling mechanisms should instead be collected through base distribution rates, which would require the Distribution Companies to better control their costs. These changes will also alleviate the administrative burden on the Department and interested stakeholders by reducing the number of reconciling mechanisms we must adjudicate each year.

In addition, going forward, we reinforce our preference for cost recovery through base distribution rates rather than through reconciling mechanisms by establishing a higher standard for approval of any new reconciling mechanism requests and for requests to continue collecting

costs through existing mechanisms filed as part of a base rate case. To further explore cost containment measures, we also direct the Distribution Companies to submit information on the interest applied to reconciling mechanisms to evaluate the appropriateness of these carrying charges.

Finally, the Distribution Companies will now be subject to reporting requirements for each rate change filing they submit. This will ensure that the Department and stakeholders understand the full cumulative impact of each proposed rate change throughout a given year as well as facilitate more informed stakeholder participation in the various Department proceedings. The Department appreciates the thoughtful input from the Distribution Companies, other stakeholders, and members of the public during the course of this investigation, which helped inform our decisions.

We expect that these decisions will result in the following benefits to ratepayers: (1) encourage utilities to control costs by reducing the bias for the utility to invest in capital projects where they earn a profit for investors; (2) reduce the risk that a utility will seek to recover a cost twice through different charges; and (3) require utilities to file proposals that consider opportunities to lower carrying charges. The impact of these decisions will occur over time, but, once implemented, customers will experience reduced bill volatility and utilities will have stronger incentives to contain costs. Subsequent phase(s) of this investigation will focus on additional opportunities to contain costs and increase transparency of costs on bills, including: the consideration of additional rate design changes; determining the feasibility of creating a maximum threshold for the amount that charges assessed to customers may change from one month to another; and bill redesign.

VII. ORDER

Accordingly, after notice and due consideration, it is

ORDERED: That the Massachusetts electric distribution companies and gas local distribution companies shall propose to eliminate the specified reconciling mechanisms in their next base distribution rate case or in the next applicable reconciling mechanism filing, as delineated in this Order; and it is

ORDERED: That the Massachusetts electric distribution companies and gas local distribution companies shall submit, in their next base distribution rate case, information necessary to make a showing that the remaining reconciling mechanisms meet the higher standard and should continue; and it is

ORDERED: That the Massachusetts electric distribution companies and gas local distribution companies shall submit certain information related to carrying charges used for reconciling mechanisms in their next base distribution rate case; and it is

ORDERED: That the Massachusetts electric distribution companies and gas local distribution companies shall file updated Reporting Templates consistent with the directives outlined above for the Department's review within 15 business days of this Order; and it is

FURTHER ORDERED: That the Massachusetts electric distribution companies and gas local distribution companies shall comply with all other directives contained in this Order.

By Order of the Department,

Jeremy C. McDiarmid, Chair

Staci Rubin, Commissioner

Elizabeth A. Anderson, Commissioner