COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

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

REPORT OF EVERSOURCE ENERGY ON ENERGY BILL AFFORDABILITY

Dated: February 13, 2026

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I. Statement on Perspective

On December 15, 2025, the Department of Public Utilities ("Department") opened an investigation for the stated purpose of conducting "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." Vote and Order Opening Inquiry, D.P.U. 25-200, at 1 ("Notice of Inquiry" or "NOI"). The Department acknowledged that policy initiatives and discussion outside of the Department "have advanced the conversation regarding redesigning rates" and that several ongoing working-group initiatives, as well as the Governor's pending energy affordability legislation, H. 4144, each contemplate numerous actions, including Department investigations into alternative rate designs "to promote affordability and electrification" (id. at 3).

However, the Department's NOI indicates that the Department's investigation is somewhat narrowly conceived to address the Governor's request for the Department to "review each and every charge that customers are currently paying to determine whether the charge can be eliminated, reduced, or its impact mitigated (id.)." For example, the Department's NOI states that, with deference to any statutory directives that the Legislature may adopt, the Department is "initiating a review of these matters now," using its existing authority, "to provide relief to ratepayers as promptly as possible" (id.).

From the perspective of Eversource, the Department is positioned in this inquiry to establish a framework for "affordability" that is thoroughly welcomed and long overdue. Among other statutory responsibilities, the Department is charged by statute as the economic regulator of public utility companies, with the fundamental obligation to provide "a necessary energy supply for the commonwealth with a minimum impact on the environment at the lowest possible cost." In fact, the Department is the only agency in the Commonwealth charged with this vital, complex mission. This mission recognizes the interlocking (and sometimes, conflicting) goals associated with the provision of essential services to customers, environmental impact and cost. G.L. c. 164, § 69*I*.

In today's operating environment, examining the issue of "affordability" in customer utility bills fits within the heart of the Department's statutory mission and, if done meaningfully, will require the Department to consider a wide range of considerations, well beyond the Department's stated focus of reviewing "each and every charge that customers are currently paying to determine whether the charge can be eliminated, reduced, or its impact mitigated." The Department should take this opportunity – and use this forum – to create a constructive regulatory framework that can and should apply over time to protect the interests of customers, along with the delivery of essential utility services on a safe and reliable basis.

For example, achieving a meaningful gain for customers in terms of "energy affordability" will require the Department to articulate a definition for "affordability" that reflects a balance of cost responsibility and customer bill impacts, along with recognition of what it takes for a utility to provide electric and/or natural gas service to the customers that rely on these essential services, with a high degree of safety and reliability. All of the Massachusetts utilities serve a broad spectrum of "customers," coming to the system with differing needs and capabilities, reflecting economic circumstances, educational levels, socio-economic backgrounds, and numerous other characteristics. At the same time, the interests of customers are common, in that every customer seeks to obtain an essential service that is of critical value to them, at a cost that has a degree of correlation to that value, and at a cost that they can reasonably pay.

For that reason, the Department's investigation will need to dig deep into the perspective of customers to understand the individual circumstances of various customer segments and to work toward an integrated solution set that includes outcomes tailored to the different needs and capabilities of individual customer segments, while maintaining the utility's overall ability to meet its fundamental obligation to provide essential services to all customers seeking to rely on those services. In this regard, it will be necessary for the Department to reach beyond the targeted scope that it has set for itself, which has the appearance of being limited to a "weeding out" of anticipated unnecessary charges on the bill, which may or may not be a reality, along with the alleged elimination of rate factors, although there may be no opportunity to eliminate, control or mitigate the costs recovered through those factors, which is a fundamental prerequisite for "fixed" rate recovery.

In fact, to achieve a meaningful gain for customers on "energy affordability," the Department will need to assume a broader perspective for this critical inquiry, that will enable consideration of the total customer picture, including distribution, supply, and public-policy cost components and to assess "affordability" impacts over time, rather than as isolated lines on the current customer bill. Within this context, areas for investigation by the Department should include:

→ Development of ratemaking models and analytical constructs to promote energy cost containment and customer-segment cost responsibility,

→ Development of balanced and transparent rate designs and cost-allocation strategies,[1] and

→ Development of strategies that promote customer bill stability, aided by education, outreach and inclusion, aimed at both customers and utility stakeholders.

Reaching an outcome in this proceeding that would establish a comprehensive energy affordability framework to apply to the Department's regulatory proceedings on a consistent basis would be a hugely beneficial outcome for all stakeholders, but most importantly for Massachusetts energy customers. A regulatory affordability rubric that can be consistently applied across electric and gas proceedings could encompass strategies to evaluate electric and gas bills and energy-cost responsibility outcomes, while assuring that those outcomes remain reasonable over time, by customer class and by income level. A regulatory affordability rubric could also involve the evaluation of whether specific customers or customer segments bear a disproportionate share of costs due to rate design, general cost allocation principles, or cost allocations associated with public-policy costs.

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[1] In terms of the development of customer transparency initiatives, the Department has promoted work on bill re-design concepts and Eversource appreciates those efforts. However, in addition, there are other meaningful ways for the Department and Eversource to provide transparency on rates and policy changes, which the Company looks forward to raising for discussion in this docket.

Together, these types of strategies would provide the Department with a clear, repeatable lens to: (1) manage affordability impacts across regulatory filings; (2) identify when affordability concerns require deeper scrutiny; and (3) distinguish between broad system pressures and targeted issues. Eversource supports this type of outcome for this proceeding. In addition, Eversource is committed to working with the Department in this proceeding on shorter-term solutions that could provide relief in the near term while efforts are made to pursue the longer term affordability framework.

There is no party coming to the Department's inquiry that has all the answers. The questions that are inherent in establishing an energy affordability framework to apply broadly to the Department's regulatory proceedings are numerous and without easy answers. As a result, Eversource and the other electric distribution companies and natural gas local distribution companies envision that this type of effort will require iterative rounds of input and feedback, conducted by the Department in sequential series of comments, reply comments, technical hearings and other input opportunities. Changes to legislation may be necessary to implement ideas arising in this inquiry. However, through this process, good ideas will emerge and the Department should seek that result.

Eversource looks forward to participating in that type of inquiry and has developed the information requested by the Department for this first report to provide the compiled data and analysis to serve as a first step.

II. Introduction

On December 15, 2025, the Department of Public Utilities ("Department") opened an investigation 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. Vote and Order Opening Inquiry, D.P.U. 25-200, at 1 ("Notice of Inquiry" or "NOI"). Motivated by a recent pronouncement by Governor Healey, calling on the Department to "review each and every charge that customers are currently paying to determine whether that charge can be eliminated, reduced, or its impact mitigated," the Department has initiated the inquiry to examine whether the current structure of rates and charges aligns with the needs of the Commonwealth's residents and businesses. Id. at 1, 3 (footnote omitted). In its NOI, the Department noted that, in Massachusetts, electricity and natural gas costs have risen more rapidly than inflation, resulting in economic hardship for many customers. Id.

The Department further noted in the NOI that one of the primary drivers of these cost increases is the aging infrastructure of the electric and gas distribution systems throughout the state and the New England region, which require significant investment in the near term to maintain safe and reliable service.[2] Id. at 1-2. The Department also noted: "[a]t the same time, the implementation of the Commonwealth's clean energy transition requires investments to support an upgraded, modern electric grid; the deployment and interconnection of clean, renewable energy sources, and the decarbonization of the building and transportation sectors. These investments provide customers with meaningful, long-term benefits, but they come with significant up-front costs, many of which are charged to ratepayers on their monthly utility bills." Id at 2 (footnotes omitted). In the context of these cost drivers, the Department stated that it "has a responsibility to investigate whether

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2 Although not expressly noted in the Department's NOI, these near-term infrastructure investments are necessary not only to provide long-term safety and reliability benefits to customers but also to facilitate the achievement of other benefits, including the important benefits that are the focus of clean-energy policies.

changes to current design and composition of electric and gas delivery rates can mitigate and manage recent cost trends. Moreover, to further promote more manageable, stable electric and gas bills, the Department will also investigate changes to existing processes to enable a more transparent and holistic review of each utility's annual reconciling rate changes." Id.

In this report, NSTAR Electric Company ("NSTAR Electric"), NSTAR Gas Company ("NSTAR Gas") and Eversource Gas Company of Massachusetts ("EGMA") each d/b/a Eversource Energy (collectively, "Eversource" or the "Companies") support the Department's action to commence this important inquiry. This past year, an inflection point has occurred in terms of customer perceptions of energy affordability. All interested stakeholders will benefit from a holistic, thoughtful, transparent analysis of the costs and cost drivers embedded on utility bills, as well as gaining an understanding of the purposes served, the benefits accrued and the burden that customers bear to support these costs, notwithstanding the fact that customers depend upon the essential service that public utilities provide or that public-policy objectives associated with the provision of gas and electricity have important benefits to all stakeholders. The information provided herein is reported consistent with the Department's requests in commencing its inquiry and associated investigation.

III. Scope of Investigation

The NOI identified the objectives of the Department's investigation as follows:

1. Identify electric and gas reconciling mechanisms that can be eliminated or included in base distribution rates going forward, with a goal to contain costs, reduce bill volatility, limit administrative burden, and reduce barriers to stakeholder participation in Department proceedings;[3]

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[3] As discussed in this report, although the Department appropriately identifies this objective as a focus of its inquiry in this proceeding, transferring cost recovery from annually adjusted reconciling factors to base rates is unlikely to achieve "affordability" for customers because it has a strong potential to exacerbate the very concerns that the Department is trying to address in this docket. "Affordability" is inextricably linked to rate "stability" and the special-purpose reconciling factors are critical to avoid frequent base-rate cases that will update *all* utility cost components, potentially on an annual basis if reconciling factors are "eliminated."

2. Determine whether certain electric and gas reconciling mechanism costs should be collected from customers through fixed charges rather than volumetric charges, with a goal of more cost-reflective rates and to reduce bill volatility;

3. Determine whether certain electric reconciling mechanisms should be included in the electric distribution companies' annual retail rate filings for review and approval rather than filed in separate dockets at different times of the year, with a goal of reducing administrative burden and cost and promoting greater transparency;

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, with a goal to reduce costs associated with net metering; 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.

NOI at 12-13.

IV. Overview of Rate Structures

As part of their base distribution rate proceedings, the Electric Distribution Companies ("EDCs")[4] and Local Distribution Companies ("LDCs")[5] typically propose rate designs that align with the Department's rate-structure goals. As noted in the Department's NOI, these rate structure goals are: (1) efficiency; (2) simplicity; (3) continuity; (4) fairness among rate classes; and (5) earnings stability (NOI at 11). Rate structures are established in a two-step process of cost allocation and rate design. Cost allocation is performed through an allocated cost of service study that assigns the costs of providing service and the associated revenue

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Reconciling factors also are useful to reduce carrying costs, which increase costs for customers. Thus, the tradeoffs between reconciling rate recovery and base-rate recovery are appropriately evaluated by the Department in this inquiry.

[4] The EDCs include NSTAR Electric, Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid ("National Grid") and Fitchburg Gas and Electric Light Company d/b/a Unitil.

[5] The LDCs include NSTAR Gas, EGMA, Unitil, The Berkshire Gas Company ("Berkshire"), Boston Gas Company and the former Colonial Gas Company d/b/a National Grid ("National Grid"), and Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty Utilities ("Liberty").

requirements to each rate class, in accordance with cost causation. This initial step establishes revenue targets for each rate class on which rates are designed.

Establishing rates on a pure cost-causation basis, however, has always been a challenge and is sometimes impractical for rate-continuity reasons, as well as resulting customer bill impacts. In those circumstances, designing rates purely on cost causation principles is realistic only if customer impacts are to be disregarded. The principles of continuity and fairness drive this balance. If the cost responsibility for one particular class is so large that it results in undue impact to customers, the EDCs/LDCs seek to re-allocate costs to other rate classes to better balance cost impacts across all customers.

Once that balance of rate-class cost-causation is established, rates are then designed to address fairness within a rate class. In other words, rates are designed to minimize impacts across a range of usage and demand in a rate class. Conceptually, all delivery rates should be based on a customer charge and demand charge. Customer charges are fixed charges that reflect costs unrelated to customer demand such as metering. A demand charge reflects the amount of capacity required to serve a customer.

Rates, however, have been in place for customers over decades with consistent rate structures. For residential customers, this design is a simple customer charge and energy charge. Part of this was born out of metering limitations where the cost of metering demand for relatively small loads outstripped the benefits that would accrue to customers. Larger customers were given interval meters that are capable of capturing demand and intervals of energy consumption. Such customers faced larger bills and could accept the cost of more sophisticated meters. Larger customers are also more likely to benefit from demand due to their high-volume consumption.

In D.P.U. 12-126, the Department opened in investigation into cost-based rate design for reconciling charges per Section 51 of An Act Relative to Competitively Priced Electricity in the Commonwealth, St. 2012, c. 209 ("Section 51). Specifically, Section 51 stated the following:

> *The department shall reset reconciliation factors to recover such costs from each rate class under cost-based criteria. In the absence of clear cost causation, volumetric charges shall be employed in a uniform manner in direct proportion to the contribution of base distribution revenues from each class.*

Ultimately, the Department approved utility proposals to allocate costs using a specific allocator (e.g. labor allocator for pension costs) or the base distribution allocator where there was no clear basis in cost causation. This was typical of public policy-oriented programs where the costs arose out of statue, such as net metering. Rate design did not play a role in this review because the statue mandated volumetric charges where cost causation was not clear.

V. <u>Guiding Principles</u>

In this report, Eversource is submitting data in response to five questions set forth by the Department, which are addressed in further detail below. These five questions revolve around the first two objectives of the Department's scope of investigation as presented in Section II of this report. The first objective is regarding the transfer of costs for recovery from reconciling rates to base distribution rates and the second objective is regarding rate design and the appropriateness of fixed charges versus volumetric charges. The establishment of guiding principles will assist in the discussion and evaluation of the complexity of the two objectives outlined by the Department.

Regarding the first objective on the potential transfer of cost recovery from reconciling rates to base rates, Eversource recommends that the guiding principles listed should be used when considering whether a cost item could potentially be transferred to base distribution rates. Costs could be included in base distribution rates if the costs meet the following criteria:

1) Enable the provision of distribution service to customers;
2) Are within the control of management; and
3) Are stable and predictable

Regarding the second objective on the recovery of reconciling costs through a fixed or volumetric rate design, Eversource recommends that traditional ratemaking principles be used when considering the type of charge:

1) If the cost is a capital investment in support of distribution system capacity, a demand charge is the most cost reflective.
2) If the cost is driven by the quantity of customers (e.g. meters), then a fixed charge is most cost reflective.
3) If the cost is a public policy item that cannot be associated with customer usage or demand, a fixed charge may be appropriate.

Within Attachment 2 of this report, the Company presents a table illustrating cost components that could potentially be included in base distribution rates, when evaluated by applying the guiding principles, but also notes the consequences that could arise from such a transfer depending on the particular circumstances of the cost under consideration. Attachment 3 is a table illustrating cost-reflective rate design for each reconciling rate. However, there are also consequences for drastic changes in rate design, which are addressed below.

A. Transferring Cost Recovery from Reconciling Mechanisms to Base Rates

Recovery of costs through base distribution rates that are currently recovered through a reconciling mechanism is feasible only where the costs are reasonably stable and predictable; are within the utility's control; and are necessary to provide distribution service to customers. This is the ratemaking foundation that applies to the rate structure of base distribution rates using a historic test year. For example, a primary reconciling factor that recovers costs associated with distribution service is the pension and post-retirement benefits other than pensions ("PBOP"), which the Department first approved in D.T.E. 03-47, for the Eversource companies (at the time Boston Edison Company, Commonwealth Electric Company, Cambridge Electric Light Company, and NSTAR Gas Company) (the "P/PBOP Mechanism"). The P/PBOP Mechanism was approved by the Department due to its recognition of the volatile nature of pension-related costs and its lack of nexus to cost areas under the control of the utility. In the Department's D.T.E. 03-47-A Order at 26, the Department stated that *"In evidence and argument, the Companies have convincingly shown the risk of serious volatility in pension and PBOP expense."* Similarly, in D.T.E. 01-106, the Department approved the establishment of a reconciling mechanism to recover revenue shortfalls as a result of increased enrollment in the low-income discount rate resulting from a computer matching program that would determine eligibility through means tested benefits. This reconciling rate was necessitated due to the uncertain nature of discount costs that could not be reliably established on a test-year basis.

These two reconciling mechanisms remained as the only reconciling charges beyond the standard transmission, transition and supply costs on customer bills until the introduction of the Green Communities Act of 2008, which dramatically altered the energy landscape in the Commonwealth. This statute led to the expansion of energy efficiency budgets, the introduction of net metering, and revenue decoupling. These three components required reconciling rates because the cost components were outside of utility control, volatile, significant in amount, and did not directly fund the safety and reliability of the distribution system. Energy efficiency funding was based on budgets and goals that could not be injected into a rate case as a fixed amount, which is necessary to set base rates. Net metering was largely unknown in 2008 and grew rapidly, outside of the EDCs' authority to manage, predict or limit that growth. Revenue decoupling is highly influenced by weather and was also necessitated by the initiatives coming out of the Green Communities Act, as without it, Eversource's financial integrity was tied to sales growth, creating an obstacle to the EDCs' proactive pursuit of energy efficiency opportunities with customers, such as facilitating the installation of distributed generation.

Related reconciling rate items emerged in subsequent years to meet public policy initiatives. Long-term renewable contracts served to bring wind and cleaner energy to the Commonwealth and augment the state's existing Renewable Portfolio Standard ("RPS"). In 2012, the Department launched the Grid Modernization initiative to transform the distribution system to better enable economic growth, environmental sustainability, and consumer satisfaction. In 2014, the Gas System Enhancement Program ("GSEP") was enacted in statute to accelerate the replacement of leak prone gas pipe and infrastructure. GSEP introduced costs that could not be contemplated in a base-rate structure due to the acceleration of replacement of leak-prone infrastructure, which required more timely recovery outside of the base-rate structure. Supplemental storm cost recovery was necessitated to address the increasing volatility of storms and the need to restore the system quickly and safely to satisfy the growing "zero tolerance" of customers for service outages. In 2018, the SMART program was introduced by the DOER, which was layered onto the net metering program and increased costs to incentivize solar development further outside of utility control.

A review of the various reconciling costs shows that these rates were born out of necessity to support public-policy initiatives and assist customers without sparking the need for more frequent base-rate filings, which is the exact outcome that will occur if volatile costs of a magnitude outside the utility's control are baked into base rates. Although reconciling rates adjust more frequently than base rates, the rate changes that do occur typically do not upset the *stability* of rates for customers – except for the commodity-based energy costs.

For example, based on information reported by the U.S. Energy Information Administration (www.eia.gov), solar energy accounted for about 25% of Massachusetts's total in-state electricity net generation in 2024.[6] The state ranked 12th in the nation in net generation from all solar. At the end of 2025, Massachusetts had 3,936 public electric vehicle charging locations, the most in New England and third-most in the nation. It is clear that the Commonwealth and the EDCs have worked effectively to make the Commonwealth a leader in clean energy and the availability of reconciling rate factors has enabled that outcome.

As a result, embedding costs that are currently recovered through reconciling factors into base distribution rates means turning back the clock to a time when rate structures may have been more streamlined and simple, but also a time when the EDCs and LDCs were not supporting over-arching policy objectives that do not directly contribute to the operation and sustainability of the system.

B. Moving from Reconciling Volumetric Charges to Fixed Charges

In its request for information from the Distribution Companies, the Department states that the EDCs and LDCs should identify any volumetric reconciling charges it agrees should be eliminated, and proposals for recovering such costs through: (1) fixed reconciling charges; (2) base distribution rates (volumetric or customer charge); or (3) an alternative.[7] The NOI

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6 https://www.eia.gov/electricity/state/massachusetts/
7 D.P.U. 25-200 Vote and Order Opening Inquiry, at 16

also states that each Distribution Company should explain how current reconciling charges and any proposed changes advance cost-reflective rate design.[8] It is premature for Eversource to make proposals regarding rate elimination or conversion to fixed charges without further discussion regarding circumstances, impacts to existing programs, and customer bill impacts. However, as noted above, cost-reflective rate design is best determined by how a cost item serves the distribution system and the customer. Attachment 3 shows how current reconciling costs might be collected through a more cost-reflective rate design.

There are advantages, however, to the use of energy rates for reconciling purposes over a fixed charge. Energy charges scale based on actual customer use; therefore, energy charges minimize the impact on smaller users and allow cost recovery to more accurately reflect the scale of service provided to each individual customer. Energy charges are also better suited for reconciliations because they are variable and align with the variability of both the underlying costs (e.g. supply costs, etc.) and the reconciliation itself. Fixed charges that move up and down can have a greater impact on customers and lead to customer dissatisfaction because customers expect fixed charges to be held constant.

Reconciling charges encompass a number of public policy related programs. Programs like net metering or low-income discounts are not directly related to the cost to serve a customer. This means that there is no basis for cost-reflective rate design in relation to distribution service. In such circumstances, it may be appropriate to utilize a fixed charge rate design. Such application, however, is not necessarily universal. The Energy Efficiency Charge is an interesting exception. As a public policy initiative and not a cost of the distribution

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8 D.P.U. 25-200 Vote and Order Opening Inquiry, at 17

system, a fixed charge would appear to be the natural cost-reflective rate design. However, the customers who have the potential to take the most advantage of MassSave Programs are *large users*. This makes a volumetric design appropriate because it scales with the size of the customer. Large customers should contribute more to the MassSave fund because they are likely to take a greater share of that funding. On the other hand, larger customers are also more likely to install solar and reduce their usage resulting in little contribution to MassSave. Yet, these customers may still access these funds for improvements to their home or business.

Where costs are related to distribution service, a demand charge is the most cost-reflective design if possible. This may not be the best option for customers depending on customer size and concerns over rate continuity. Residential customers do not have demand charges due to metering limitations and the small size of their demand. As residential customer load profiles change, there may be an opportunity to utilize demand charges, but more granular customer usage information is required, which the utilities will gain as AMI is deployed.

Eversource recommends that consideration of moving costs from reconciling volumetric charges to fixed charges should focus on the potential customer class bill impacts that may result from such a change and that each rate be evaluated on an individual facts and circumstances basis. To the extent that the Department elects to transition costs from being recovered from volumetric charges to fixed charges, the Department should explore options to do so gradually, in order to minimize rate shock and promote rate continuity.

VI. Achieving More Affordable Bills for Customers

The considerations noted above for potentially moving cost recovery from a reconciling, volumetric factor to an alternative such as base rates are relevant, but not determinative, of whether more "affordable" customer bills will be achieved. For example, structuring cost recovery in a manner to smooth out bills for customers during peak periods is a fundamental strategy in terms of making bills more "affordable" for customers. Recently, this smoothing has been accomplished through bill credits issued during high energy use periods (i.e. fixed winter bill stabilization credits for NSTAR Gas and EGMA).

In addition, this proceeding is appropriately focused on identifying additional means of mitigating the volatility of volumetric charges, by considering the pros and costs of recovering some costs through fixed charges. However, although moving costs from a reconciling volumetric factor to a fixed charge may reduce some bill volatility based on usage, it may not result in more affordable bills for customers on an annual basis. Each individual customer consumes different amounts of energy, therefore, transitioning to more fixed charges could significantly alter the utility bills that customers experience each month – throughout the entire year. For example, a low-use customer may see an increase to their utility bill under a fixed charge whereas a high-use customer may see a decrease in their monthly bill. Additionally, if the costs of an identified rate component tend to be more variable in nature, the use of a fixed charge will not likely eliminate bill volatility, as any over- or under-collection would need to be adjusted via an updated fixed charge in a subsequent billing period.

The transfer of cost recovery from reconciling rates to base distribution rates will also not likely result in a more "affordable" cost for customers. Eliminating the recovery mechanism does not eliminate the cost incurrence and sticking volatile, large magnitude costs that are not susceptible to reasonable forecasting or "normalization" will simply drive the need for more frequent rate cases, in which all utility costs are updated and the impact to customers is much larger, unexpected and more difficult to adapt to. For this reason, the Department needs to maintain a holistic customer focus in this proceeding, taking time and resources to gather data and information on the *customer experience* and the *customer impact* of changing rate-recovery structures beyond the issue of dealing with high bills in high consumption months. The application of relevant and reasonable guiding principles will assist in the Department's evaluation of the facts and circumstances surrounding each objective identified in the NOI. Even in the best of circumstances, utility rate-setting is a nuanced and complex exercise with "winners and losers" in every corner and a meaningful, constructive change can only arise where the Department takes the time and initiative to consider the long-term outlook and account for all reasonably identifiable ramifications because there is a lot more under the surface than may appear. Changes in rate structures that may be attractive for simplicity could increase the likelihood of a customer over or under paying for a specific cost or service each year, while actually making it more difficult for the customer to manage their energy costs. At the same time, there is significant room for improvement in terms of customer awareness of what they are paying for; how customer needs may be better served through different billing structures and how the overall customer bill fits within the definition of "affordability."

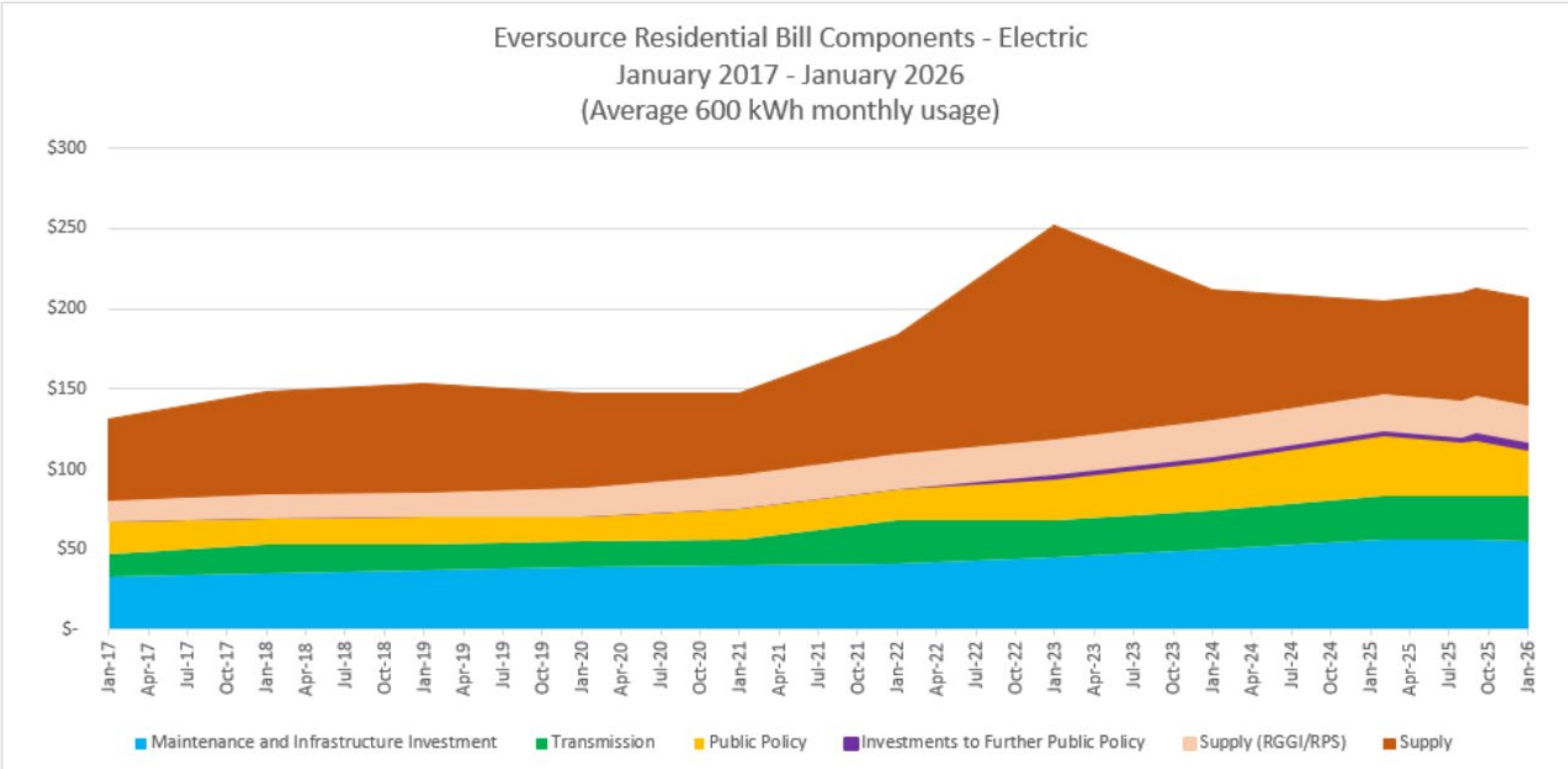
VII. Current Customer Bill Components.

Included within Attachment 5, and outlined in more detail in the charts below, the Company highlights the current and historical bill impacts for NSTAR Electric, NSTAR Gas and EGMA. The Company used detailed historical rate information to summarize current rates into various rate components including: (1) electric and gas distribution service (maintenance

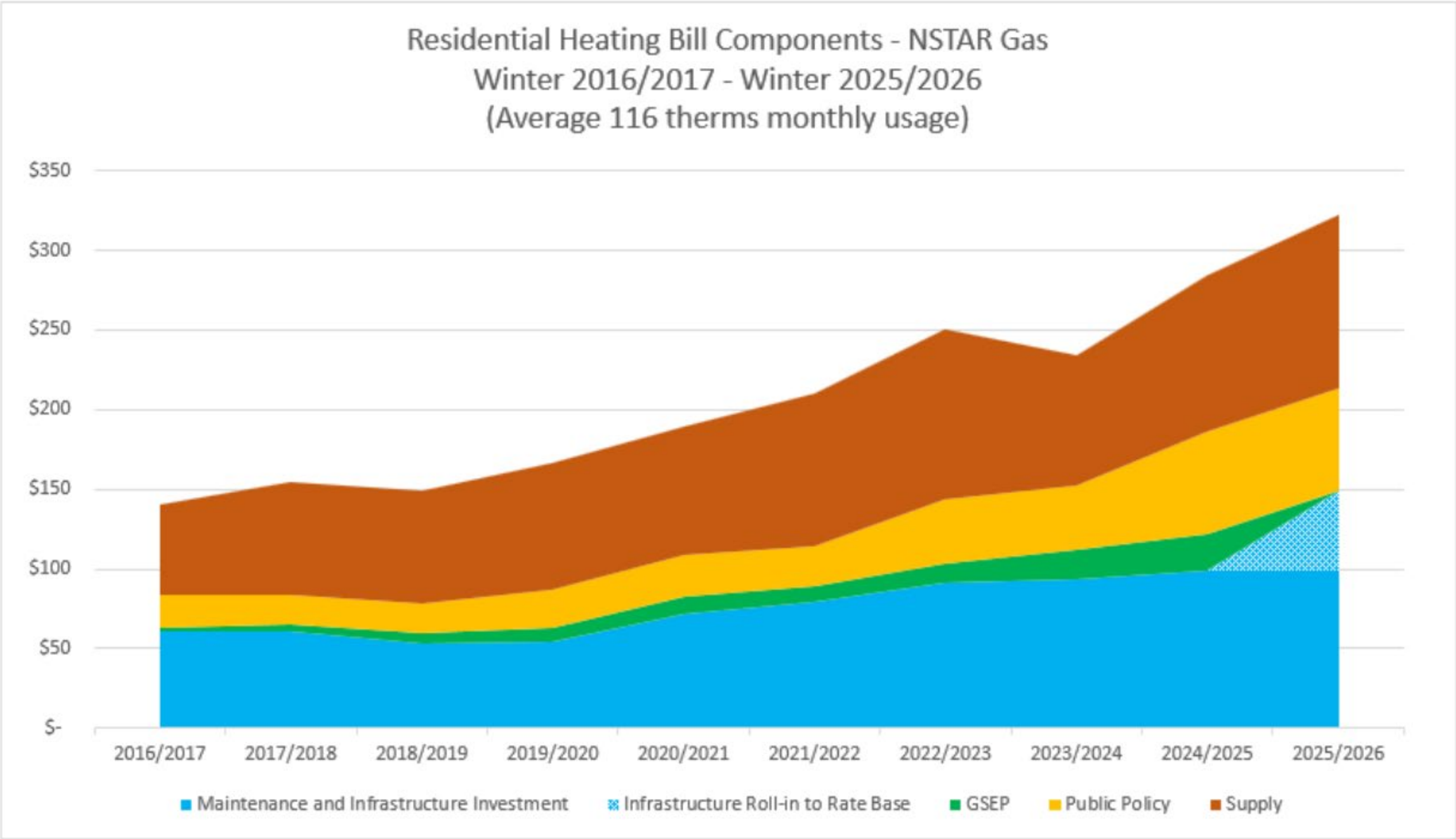
& infrastructure); (2) public policy[9]; (3) investments to further public policy (electric only); (4) gas system enhancement program ("GSEP") (gas only); (5) supply; and (6) transmission (electric only). The graphs shown below portray the bill impact for each rate component over the past ten years.

[9] Through Eversource's new gas bill design all "public policy" related charges are outlined on the gas bill under the "public benefits" section.

NSTAR Electric:

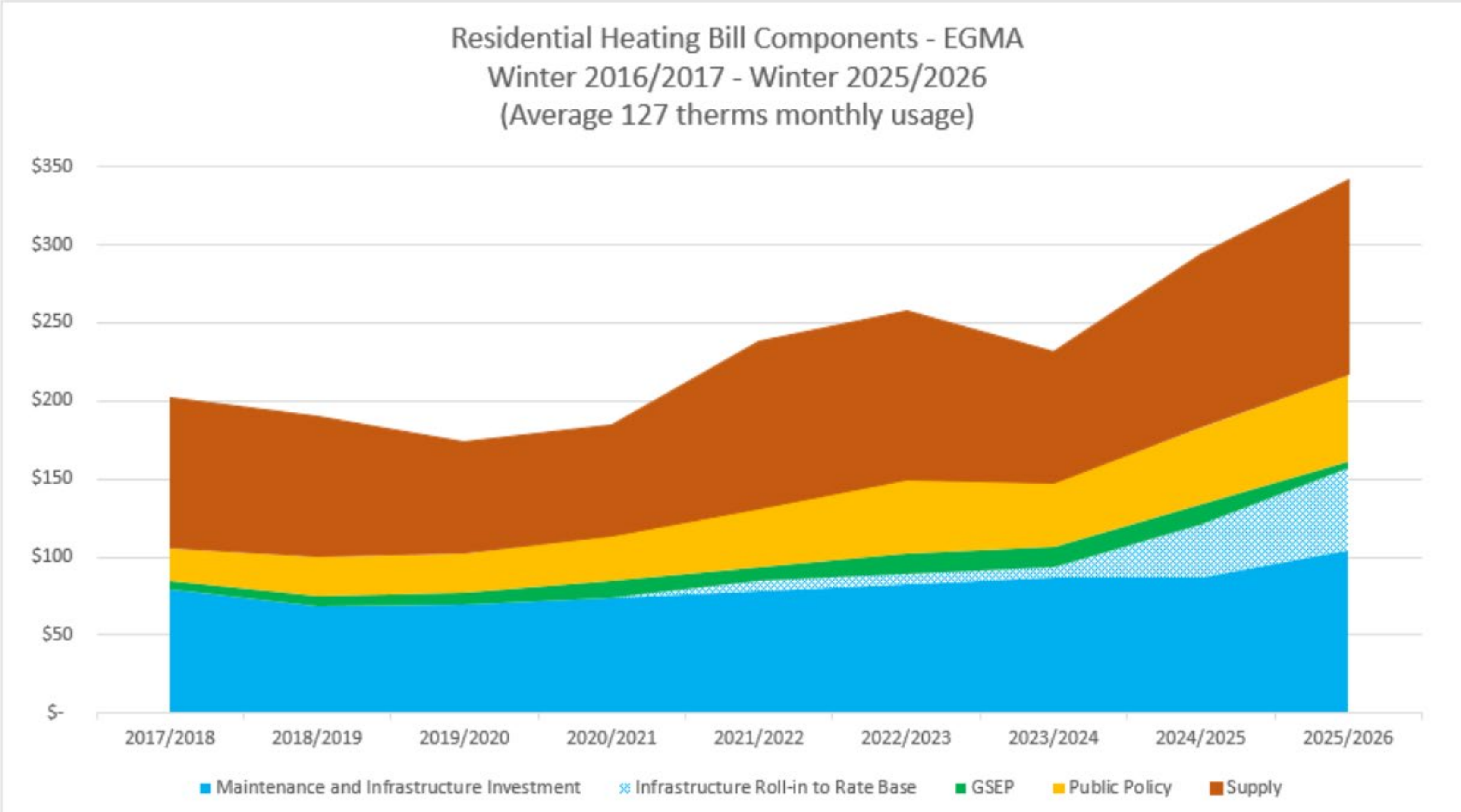


NSTAR Gas:



NOTE: The "Infrastructure Roll-in to Rate Base" section identified in patterned blue primarily consists of the roll-in of GSEP investments (fiscal years 2021 – 2024) in November 2025. As outlined in more detail below, these critical safety investments are focused on the replacement of leak-prone pipe and aging infrastructure for fiscal years 2021 – 2024.

EGMA:



NOTE: The “Infrastructure Roll-in to Rate Base” section identified in patterned blue is specific to rate base updates that were agreed to within the EGMA Settlement within D.P.U. 20-59. The primary increase is associated with capital additions completed from 2018 – 2023, including all GSEP related safety investments. In 2025 and 2026, this amount also includes the recovery of a rate mitigation amount identified in the final order at D.P.U. 24-50, which will subside after April 30, 2026.

A. Delivering Essential Services to Customers

The electric and gas distribution service charges (maintenance and infrastructure components in charts above) are assessed to recover reasonable and prudent costs associated with constructing, owning, operating and maintaining a complex network of electric and natural gas distribution systems that provide essential utility service to homes and businesses across the Commonwealth. This distribution infrastructure includes the poles, wires, substations, mains, services, meters, and other essential equipment required to deliver safe and reliable electric and natural gas service to customers.

These rates include the recovery of capital investments necessary to ensure system safety, reliability, and resiliency, including investments to replace aging infrastructure, comply with regulatory and safety requirements, and support continued service to growing and evolving customer needs and public policies. These capital investments are incorporated into rate base and are recovered over time through depreciation expense with a return, which is approved by the Department.

Additionally, this portion of the bill is designed to recover the ongoing operating, maintenance and administrative costs required to provide day-to-day utility service to our customers. These costs include, but are not limited to, employee labor and benefits, materials and supplies, fleet and equipment, customer service and billing functions, payroll and property taxes, etc. Collectively these costs reflect the recurring expenses that are necessary to operate and support a safe, reliable and resilient distribution system for all customers.

As shown in the charts above and described in detail below, the rates specific to electric and gas distribution service is just one portion of the total electric and natural gas bill. On average over the past 10 years this portion of the bill has represented approximately 25 percent of the bill for NSTAR Electric, 38 percent for NSTAR Gas and 40 percent for EGMA.

The increased average percentage for the two gas distribution companies is primarily due to the significant capital investments to the gas distribution system through the GSEP program (see below). Unrecovered capital investment is a major driver of the need for new base distribution rates. For both NSTAR Gas and EGMA, historical capital investments were recently "rolled into" base distribution rates without a full base-rate filing, avoiding any rate increases to account for changes in operating expense since the last base distribution rate case.

Capital investments are the only component of distribution rates that are eligible to earn a "return" on investment – other costs included in rates do not earn any return. This is because capital resources have to be raised from the marketplace to fund infrastructure projects since customer rates do not yield sufficient revenue within an annual period to fund capital investment. Customers pay back the cost of capital investment over extended timelines -- counted in decades for most categories of work projects. This recovery period is designed to directly align to customer's expected use of the identified capital investments. Therefore, capital funding must be obtained from the marketplace and then is paid back over time with a rate of return for the use of those funds, similar to a home mortgage.

The rate of return for both electric and gas distribution companies accounts for between four and ten percent of total customer bills, which will vary year-to-year based on the composition of all other reconciling rate components. Moreover, the rate of return authorized by the Department is not a guaranteed return and utilities most often do not earn their actual authorized return in a given year (see Table 1 below, which compares the current authorized ROE to the average three and five-year average actual ROE). In addition, the amount of earnings that may be retained by each Eversource company is capped by earnings-sharing mechanisms that require any earnings obtained above the cap to be shared directly with customers, with customers retaining the lion's share.

Table 1: ROE History

	Current Authorized ROE	Three-Year Average (2022-2024)		Five-Year Average (2020 - 2024)	
		Actual	% of Authorized	Actual	% of Authorized
NSTAR Electric	9.80%	7.88%	80%	8.43%	86%
NSTAR Gas	9.90%	8.71%	88%	8.93%	90%
EGMA (1)	9.70%	5.59%	58%	5.65%	58%

(1) EGMA average ROE only includes four years given the acquisition was finalized toward the end of fiscal year 2020.

Lastly, a substantial portion of earnings that are obtained by utility companies, including the Eversource companies, are reinvested into the business to offset the amount of capital that is necessary to be externally sourced from the marketplace. In that regard, utility earnings are not only a necessary part of the equation to maintain access to capital resources needed to support the infrastructure that is used to deliver essential services to customers, that component of the bill charges that customers see is not a driver of "affordability" concerns. Out of all components on the bill, utility earnings are likely one of the smallest and most stable components, while vital to the overall public-service obligation.

B. Public-Policy Charges

Public-policy charges include costs required by the government for public policies such as financial payment assistance programs, efficiency programs, purchasing renewable and carbon-free electricity, and funding solar and electric vehicle incentives to make it easier to take advantage of clean energy options. These costs provide value to customers and the Commonwealth by helping reduce energy usage and enabling customers to better manage their monthly bills.

Eversource has partnered for many years with the Commonwealth to implement important public policies focused on reducing greenhouse gas emissions, in furtherance of G.L. c. 21N. The costs of these policies are included in customer bills in the form of various charges, recoverable through reconciling factors as well as within supply charges. Many of the charges, however, are the result of extensive and proscriptive statutory provisions enacted by the legislature since 2008 that were not clearly incremental or distinct from previous laws enacted to meet the same goals. In many instances, new programs have been layered on top of existing programs after it had been determined that the animating thesis behind the original program was incorrect. As a result, the Commonwealth has required customers to pay energy costs that are aimed at the important goal of reducing greenhouse gas emissions, but without a comprehensive examination as to whether the portfolio of policies billed to customers through their energy bills has been optimized to meet climate goals at the least possible cost. The Company acknowledges that many of these customer costs are outside the jurisdiction of the Department, with the legislature or other state agencies frequently determining specific program designs, incentive levels and customer costs. And, as a result, because these programs are not under Department jurisdiction, the programs are not designed and evaluated based on the same level of scrutiny as distribution maintenance and infrastructure costs on whether the programs will result in "just and reasonable" utility rates on a holistic basis. Consequently, it is critical that any affordability discussion in the Commonwealth include detailed analysis of the impact of these programs on customers, both from a benefit and cost perspective.

Lastly, the focus on charging these public-policy costs only to customers of regulated utilities is fundamentally unreasonable, unfair and exacerbates unaffordability for our customers. Specifically, the Commonwealth has repeatedly recognized the societal benefits of greenhouse gas reduction programs yet does not impose the costs to support such benefits on municipal light department customers in over 40 cities and towns. This equates to almost

15% of Massachusetts energy customers[10] who are benefitting from GHG reductions that are being paid for by all other utility customers in the state. This skews the burden of supporting climate policies that have vastly increased since 2008, to the customers of regulated utilities.

As shown in the chart above, the public-policy portion of the bill has grown over the past ten years, as policy goals and initiatives have expanded. Today, public-policy charges account for approximately 25 percent of the bill for NSTAR Electric (14% in the public policy section and 11% within supply for RGGI and RPS – as outlined in the chart above); 20 percent for NSTAR Gas; and 16 percent for EGMA. Eversource shares the Governor's view that it is important to ensure that only programs that are essential and effective are funded through customer bills, and a review within this docket is appropriate to determine whether certain charges, or the level of such charges, continue to advance the Commonwealth's goals and objectives at rates that are affordable to customers. Applying consistent and thoughtful review to the affordability of public-policy charges can help ensure these programs remain aligned with policy goals at a manageable cost for customers. Eversource looks forward to engaging constructively in these discussions as part of this docket.

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10 https://www.massclimateaction.org/municipal_light_plants#:~:text=Fifty%2Dtwo%20towns%20in%20Massachusetts%20are,in%20the%20Commonwealth%20of%20Massachusetts.

C. Investments to Further Public Policy Charges (Electric Only)

The EDCs maintain certain capital-recovery mechanisms designed to recover investments made in the electric distribution system to advance the Commonwealth's public policy objectives. Currently, these rate components currently represent approximately 2% of the overall electric bill and include the following:

Grid Modernization: Grid Modernization rates recover the cost of work projects that support the Commonwealth's energy and climate policy goals by improving electric system reliability and resiliency while enabling the clean energy transition. These investments are undertaken pursuant to Department directives and established planning frameworks, including the grid modernization policies initiated in D.P.U. 12-76.

In that proceeding, the Department established policies to encourage electric companies to deploy grid modernization technologies that enhance service reliability and empower customers to better manage their energy usage. To date, the Department has approved two Grid Modernization Plans for NSTAR Electric, with the first covering fiscal years 2018–2021 and the second covering 2022–2025. Collectively, these investments are intended to prepare the electric distribution system to accommodate increased electrification, integrate distributed energy resources, and support the Commonwealth's long-term emissions reduction and net-zero objectives, while continuing to provide safe and reliable service to customers.

Advanced Metering Infrastructure ("AMI"): AMI rates recover the costs associated with the deployment, operation and maintenance of advanced electric meters and the supporting communications infrastructure. These investments provide customers with enhanced access to usage data and billing information, improve outage detection and restoration capabilities, and enable the future adoption of time-varying rates, among other benefits. AMI investments further support the Department's broader grid modernization policies and the Commonwealth's clean energy goals. The Department approved NSTAR Electric's AMI plan in D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B in November 2022 and subsequently approved a dedicated recovery mechanism for AMI-related costs in NSTAR Electric's most recent rate case in D.P.U. 22-22. These rates recover both ongoing AMI investments and operating costs, as well as all meter-related capital costs, in accordance with the Department's final decision in D.P.U. 22-22 which became effective January 1, 2023.

Other Future Recovery Mechanisms: In addition to Grid Modernization and AMI rates currently in effect, this category of rates includes future rate components designed to recover costs associated with NSTAR Electric's Capital Investment Projects ("CIPs") to facilitate distributed generation development, and its Electric System Modernization Plan ("ESMP"), which funds proactive electrification investments. Several CIP projects are currently underway to promote the timely and cost-effective interconnection of distributed generation across various regions of the commonwealth. In addition, NSTAR Electric's ESMP serves as a long-term strategic planning framework outlining how the Company will modernize its electric distribution system to support the Commonwealth's clean energy transition. While neither CIP nor ESMP investments are currently reflected in rates, these initiatives are expected to be incorporated into rates in the near future.

D. Gas System Enhancement Program ("GSEP") (Gas Only)

The GSEP costs apply exclusively to natural gas customers. By statute, these rates are designed to recover the costs of safety and reliability investments made by LDCs in Massachusetts to replace or improve aging and leak-prone natural gas infrastructure, including cast iron and unprotected steel mains and services that are more susceptible to leaks or failures. The GSEP rates implement the provisions of G.L. c. 164, § 145, which authorize both NSTAR Gas and EGMA to recover eligible costs associated with the replacement, retirement, or improvement of existing natural gas distribution infrastructure. By prioritizing the replacement and improvement of aging and leak-prone facilities, these investments reduce safety risks, lower methane emissions, and help ensure reliable service for customers. All GSEP investments are subject to regulatory oversight and approval by the Department and are structured to address critical system needs while aligning with the Commonwealth's broader energy, environmental and affordability objectives.

Currently, the GSEP component of the overall gas customer bill for both NSTAR Gas and EGMA is relatively small (current $0 at NSTAR Gas and one percent at EGMA) due to the recent transfer of GSEP investments into base distribution rates. In D.P.U. 24-50, EGMA transferred all GSEP investments through December 31, 2023 into base distribution rates. Similarly, in D.P.U. 24-134-A/D.P.U. 25-53, NSTAR Gas transferred all GSEP and non-GSEP investments through December 31, 2024 into base distribution rates, in lieu of a full base-rate filing. As a result of these transfers, the GSEP rate now represents a much smaller portion of the overall gas bill, while the base distribution, or maintenance and infrastructure, portion of the bill has correspondingly increased.

E. Supply Charges

Supply charges cover the cost of electricity and natural gas from third-party suppliers that generate electricity at a power plant or generating station or supply the gas commodity itself to the LDC, including any transportation, storage or supply management costs. If a customer receives supply from their distribution company, the price of electricity or natural gas is based on the current market prices and is a pass-through cost to customers with no profit to the distribution company. Some customers may be on municipal aggregation, where their city or town purchases electricity in bulk on their behalf or receive their electric or gas supply directly from a third-party supplier.

Notably, the investigation by the Department in this proceeding does not appear to contemplate consideration of supply charges. Supply charges, however, are a substantial driver of energy costs for customers throughout the Commonwealth and certainly are the most volatile aspect of the total electric and natural gas bill, as outlined within the charts above. Over the past ten years, the supply portion of the total bill has been approximately 48 percent at NSTAR Electric (38 percent related to actual supply costs and 10 percent specific to RGGI and RPS); 42 percent at NSTAR Gas; and 41 percent at EGMA. The majority of supply charges are the costs of procuring wholesale supply to serve end-use customers that choose to purchase supply from their distribution company (i.e., basic service). The basic service costs are passed on to customers without any mark-up by their distribution company, as required by statute and Department precedent. For non-basic service customers, supply costs include the costs to procure energy and markups from competitive suppliers, including municipal aggregations.

Supply charges for electric customers also include various costs associated with furthering the Commonwealth's greenhouse gas reduction policies. The Commonwealth's energy supply policies have focused on two predominant strategies with the goal of reducing the carbon intensity of electricity consistent with the state's climate goals. These strategies are:

i) increasing the cost of electricity from carbon emitting sources through two cap-and-trade programs overseen by the Department of Environmental Protection ("DEP"), namely the Regional Greenhouse Gas Initiative ("RGGI") and the Electricity Generator Emission Limits ("EGEL") under 310 CMR 7.74; and

ii) providing financial incentives to clean energy projects through eight distinct tradable credit markets overseen by either the Department of Energy Resources ("DOER") or DEP.

As noted above, applying consistent and thoughtful review to public-policy related charges, can help ensure these programs remain aligned with policy goals while supporting affordability for customers.

Given customer concerns about the overall costs of electricity service, and the Governor's call for the Department to evaluate whether costs should be removed from customer bills, an in-depth analysis of whether these ten distinct programs meet the Commonwealth's climate goals are appropriate for inclusion on customer bills should be undertaken in this docket. Such an analysis should be accomplished in conjunction with examination of other public-policy charges and could determine whether any of these policies are redundant; whether the costs incurred by ratepayers are warranted; and whether the returns accruing to generators participating in these programs are justifiable.

F. Transmission

Electric transmission charges are designed to recover the costs of building, operating and maintaining the regional high-voltage electric transmission system that delivers electricity from power plants across New England to local distribution networks in order to service homes and businesses throughout the state. This system includes large transmission lines, substations and related equipment that moves electricity over long distances before it reaches the local electric distribution system.

In Massachusetts, transmission service is provided through a regional New England transmission system, which is planned and operated to ensure reliability across the region. Transmission rates are regulated at the federal level by the Federal Energy Regulatory Commission ("FERC"), the independent agency with jurisdiction over the interstate transmission of electricity. As a result, transmission charges are set outside the state rate proceedings and are passed through to customers.

These costs have historically remained relatively steady and consistent as a percentage of the total electric bill for NSTAR Electric customers, as evidenced in by the green section of the graph above. Currently, transmission rates represent approximately 14 percent of the total electric distribution bill and over the past ten years these costs have represented approximately 12 percent of the total bill.

VIII. Responses to Department Questions

1. **For each rate factor upon which it currently relies to collect delivery-related costs from ratepayers, provide:**
   a. **what costs are recovered in each factor,**
   b. **the Department proceedings in which each factor was first established;**
   c. **the cadence of filings, filing date, and effective date;**
   d. **whether and, if so, when the Distribution Company expects to transition cost recovery to base distribution rates, therefore terminating the rate factor;**
   e. **total revenue requirement;**
   f. **total revenue requirement relative to total delivery revenues;**
   g. **total revenue requirement broken down by capital costs, operating and maintenance expenses, and carrying costs; and**
   h. **total revenue requirement broken down by actual capital costs, operating and maintenance expenses, and carrying costs and forecasted capital costs, operating and maintenance expenses, and carrying costs in the revenue requirement.**
   i. **For (e) through (h) above, provide the requested information for the most recent period and the five prior periods.**

The Company has included all relevant data and information delineated in Question 1 within Attachment 1 and 2. Below, the Company specifically references the applicable tab where the information in response to the question is identified within Attachment 1. These references are as follows:

(a) – (c) Attachment 1, Tab 1

(d) Please refer to Attachment 2, where the Company analyzes the guiding principles (outlined above in Section IV) regarding a transition of cost reconciliation mechanisms to base distribution rates. For any cost component identified as a potential candidate to be transferred to base distribution rates, the Company believes such a change would require careful consideration and the only appropriate time to make such a determination is at the time of the EDC or LDC's next base distribution rate case.

(e) – (h) Attachment 1, Tab 2

2. **Identify any volumetric reconciling charges the company agrees should be eliminated, and the Company's proposal for recovering such costs through: (1) fixed reconciling charges; (2) base distribution rates (specify whether cost should be included in volumetric charge or customer charge); or (3) an alternative. For all other reconciling charges, identify the circumstances under which the reconciling charge could be eliminated.**

Please refer to the discussion in Section IV, above, on Guiding Principles. The Company encourages the Department to investigate through this proceeding whether transferring cost recovery from reconciling rates to distribution rates will result in more affordable customer bills. This analysis could be accomplished by establishing affordability pillars for consideration by the Department and stakeholders in this proceeding, which can be used to determine whether the subset of reconciling factors identified by applying the principles above should actually be changed to fixed or base rate charges, based on whether doing so would result in reducing the energy burden on various customer classes.

Please refer to Attachment 2 for more detailed information and conclusions regarding the Company's conclusions regarding rates that could be transferred to base distribution rates and Attachment 3 for more information regarding which costs could be collected as a fixed charge.

3. **For each reconciling charge, identify any cost component of the charge that appropriately could be transferred into base distribution rates (e.g., administrative costs included in the reconciling SMART factor).**

Please refer to Attachment 2 for more detailed information and conclusions regarding any specific cost components the Company believes are candidates to be included in base distribution rates at a later date.

4. As part of its report, each Distribution Company shall explain how current reconciling charges and any proposed changes advance cost–reflective rate design.

Please refer to the discussion in Section IV, above, on Guiding Principles specific to the topic of cost-reflective rate design. In addition, please refer to Attachment 3, detailing the Company's conclusions regarding this topic.

The Company notes certain suggestions included within Attachment 3 specific to cost-reflective rate design could be pragmatically challenging, but the Company attempted to highlight the most cost-reflective rate design for each rate component. Similar to a transition to fixed charges, any transition in the overall rate design would need to be carefully considered and evaluated. Eversource looks forward to participating in these discussions within this proceeding.

5. Each Distribution Company shall illustrate the bill impacts to ratepayers of changing each individual volumetric reconciling delivery charge and cumulatively for all reconciling delivery charges (excluding charges that are required by statute to be volumetric) to fixed charges. The Distribution Companies shall provide the illustrative bill impacts for the following usages: 25th percentile, 50th percentile, and 75th percentile.

Please refer to Attachment 4 for a detailed analysis and illustrative example of the bill impacts for each percentile of average customer usage.

IX. Summary and Conclusion

Eversource appreciates the opportunity to participate in this investigation and thanks the Department for initiating a thoughtful and collaborative process to examine the key objectives identified above. Eversource looks forward to working collaboratively with the Department, stakeholders and all other docket participants on these important topics as this proceeding moves forward. The Company is committed to providing meaningful input and supporting the Department's efforts to advance outcomes that are fair, transparent, and in the best interests of customers.

Affordability is a key consideration in fulfilling the objectives set forth in the Order. However, developing meaningful recommendations will require a shared and uniform understanding of the principles that constitute affordability for utility service. Defining affordability in an actionable manner warrants careful consideration, including recognition that measures intended to benefit one group of customers may result in cost impacts to others. Accordingly, it is important that, within this docket, the Department and all participants review and analyze all charges included on customer utility bills to identify key considerations moving forward.

Again, Eversource thanks the Department for initiating this important docket and looks forward to continuing to provide additional comments in this proceeding, including, as appropriate, refinement of the recommendations discussed herein.