COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Petition of NSTAR Electric Company d/b/a Eversource Energy for Approval of a Performance-Based Ratemaking Plan and Increase in Base Distribution Rates for Electric Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00	)	D.P.U. 22-22

DIRECT TESTIMONY OF

Craig A. Hallstrom
Douglas P. Horton

Case Overview

On behalf of

NSTAR Electric Company
d/b/a EVERSOURCE ENERGY

January 14, 2022

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CRAIG A. HALLSTROM AND DOUGLAS P. HORTON

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I. INTRODUCTION

Craig A. Hallstrom

Q. Please state your name, position and business address.

A. My name is Craig A. Hallstrom. I am President, Regional Electric Operations for Connecticut and Massachusetts for Eversource Energy Service Company ("Eversource Service Company" or "ESC"). For work performed in Massachusetts, my business address is 247 Station Avenue, Westwood, Massachusetts 02090.

Q. What are your principal responsibilities in this position?

A. My principal responsibility in this role is to assure that Eversource customers in Massachusetts and Connecticut are provided with safe, reliable and resilient electric service. To this end, I have oversight for electric field operations and electric system operations in Massachusetts for NSTAR Electric Company d/b/a Eversource Energy ("NSTAR Electric," "Eversource" or the "Company"), which encompasses the Eastern MA and Western MA operating divisions ("EMA" and

"WMA").[1]

In Connecticut, Eversource Energy has recently named Stephen T. Sullivan as President of The Connecticut Light and Power Company ("CL&P"). Therefore, in Connecticut, my responsibilities relate to the oversight of shared electric system operations, including the System Operating Center ("SOC") and dispatch, which serve both Connecticut and Massachusetts. Also, as President, Regional Operations, I have responsibility for Emergency Preparedness for the entire Eversource Energy enterprise (New Hampshire, Connecticut and Massachusetts) and I act as Chair of the Eversource Energy Emergency Coordination Team ("ECT").

In my role as President, Regional Electric Operations, I lead a team of approximately 2,413 employees and manage an annual budget of approximately $1.2 billion for transmission and distribution operations and associated capital work. In this proceeding, I am testifying on behalf of NSTAR Electric.

Q. What is the function and organization of the ECT?

A. Eversource Energy operates with an organizational structure that is subject to an emergency oversight and coordination annex to the All-Hazards Emergency Response Plan ("ERP"). The Eversource Energy emergency oversight and

[1] On December 31, 2017, Western Massachusetts Electric Company was merged with and into NSTAR Electric with NSTAR Electric as the surviving entity. NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy, D.P.U. 17-05, at 36-44 (2017).

coordination annex to the ERP establishes the ECT, with the ECT reporting directly to the Eversource Energy Executive Vice President and Chief Operations Officer, Mr. Werner J Schweiger. The ECT is comprised of the business unit leads that align and support the functional areas of its Incident Management Team ("IMT"). The IMT is the more specific ERP team responding to ERP events.

Eversource Energy has designated a different Incident Commander for each state jurisdiction within which Eversource Energy operates (Massachusetts, Connecticut, and New Hampshire) and the Incident Commander oversees the IMT during an event, while the ECT members remain constant regardless of event type or location. This ensures consistency across the organization in planning for emergency events while also allowing the individuals with the right expertise to oversee individual events.

Q. What are your responsibilities as Eversource Energy, Chair of Emergency Preparedness?

A. As the Chair of Emergency Preparedness, I am responsible for assuring that Eversource is ready to respond to all types of events that may impact our ability to serve customers safely and reliably, while meeting all applicable compliance, regulatory and financial commitments. For example, in this role, I am the Incident Commander for the Eversource Energy response to the COVID-19 pandemic. Each business lead within the Eversource Energy enterprise is responsible for developing a business continuity plan and assuring that their business unit is ready to perform their designated role when an ERP is declared. In this role, I work closely with the Director of Emergency Preparedness, Mr. Richard Tobin, to develop a common strategy for coordinating the overall Eversource Energy response to major weather events and other emergency conditions, such as the COVID-19 pandemic. Mr. Tobin and I also work to ensure and coordinate the appropriate level of resources and support for the IMTs.

Q. Please summarize your professional and educational background.

A. In 1981, I received an Associate degree in Electric Engineering Technology from Wentworth Institute of Technology. In 1985, I graduated from Merrimack College with a Bachelor of Science degree. In 1991, I received a Master of Business Administration degree from Northeastern University. I began my career at Massachusetts Electric Company in 1981 and joined NSTAR Electric (formerly, Boston Edison Company) in 1989. Since that time, I have served in several managerial and supervisory roles with successive responsibility, including Senior Supervising Engineer; Manager, Splicing Division/Northeast Division/Trouble & Maintenance Department; Director Electric Operations; and Vice President of Electric Operations. I was named President of NSTAR Electric and the former Western Massachusetts Electric Company in 2013. In June 2016, I was named to my current position.

Q. Have you previously testified before the Department of Public Utilities or other regulatory agencies?

A. Yes. In Massachusetts, I most recently testified on behalf of the Company in its most recent rate-case proceeding, NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy, D.P.U. 17-05 (2017) ("D.P.U. 17-05"), regarding the case overview and the Company's grid-modernization proposals. Prior to D.P.U. 17-05, I testified before the Department of Public Utilities ("the Department") in relation to the Department's investigation of the Company's storm performance in NSTAR Electric Company, D.P.U. 11-86-B/11-119-B (2012) and the Company's storm-cost recovery in NSTAR Electric Company, D.P.U. 13-52 (2013), as well in several generic proceedings involving electric operations and service quality among other matters.

Douglas P. Horton

Q. Please state your name, position and business address.

A. My name is Douglas P. Horton. I am Vice President, Distribution Rates & Regulatory Requirements for ESC. For work performed in Massachusetts, my business address is 247 Station Ave, Westwood, Massachusetts 02090.

Q. What are your principal responsibilities in this position?

A. ESC provides centralized services to the natural gas and electric operating subsidiaries of Eversource Energy. In this role, I have overall responsibility for rates and rate-related policies and procedures, as well as preparation and presentation of regulatory filings made by the Eversource Energy operating affiliates to the respective regulatory commissions in Connecticut, Massachusetts and New Hampshire. In this proceeding, I am responsible for supervising and presenting the Company's calculations and supporting exhibits pertaining to the request for an adjustment to base distribution rates and renewal of the Performance Based Ratemaking Plan approved by the Department in D.P.U. 17-05 for NSTAR Electric.

Q. Please summarize your professional and educational background.

A. I graduated from Bentley College (now Bentley University) in Waltham, Massachusetts in 2003 with a Bachelor of Science degree. In 2007, I graduated from Bentley's McCallum Graduate School of Business with a Master of Business Administration. I was hired by NSTAR as a Senior Financial Planning Analyst in August 2007, and promoted to Project Manager, Smart Grid in March 2010. In 2012, I was promoted to Manager, Revenue Requirements, Massachusetts and was subsequently promoted to Director, Revenue Requirements, Massachusetts, in February 2015. I was promoted to my current role as Vice President, Distribution Rates & Regulatory Requirements in December 2018.

Q. Have you previously testified before the Department or other regulatory agencies?

A. Yes. In Massachusetts, I sponsored testimony in NSTAR Electric's most recent distribution rate proceeding, D.P.U. 17-05, as well as NSTAR Gas's most recent distribution rate proceeding, D.P.U. 19-120. I have sponsored testimony in Eversource's portion of the Department's docket, Investigation of the Federal Income Tax Rate Change, D.P.U. 18-15 (2018). I also sponsored testimony for Western Massachusetts Electric Company d/b/a Eversource Energy ("WMECO") in relation to its 2012 through 2016 Annual Solar Compliance Filings, docketed by the Department in D.P.U. 12-91, D.P.U. 13-174, D.P.U. 14-123, D.P.U. 15-151, and D.P.U. 16-173, respectively. I testified in support of WMECO's Annual Rate Change filings in D.P.U. 12-88, D.P.U. 13-168, and D.P.U. 14-122; and, in WMECO's Storm Reserve Recovery Cost Adjustment in D.P.U. 13-135, D.P.U. 14-126, D.P.U. 15-149 and D.P.U. 16-179.

In addition, I sponsored testimony supporting NSTAR Electric's annual Distribution Rate Adjustment/Reconciliation filings in D.P.U. 12-112, D.P.U. 13-172 and D.P.U. 14-121; and NSTAR Electric's Smart Grid projects in D.P.U. 11-92 and D.P.U 12-78. I testified on behalf of NSTAR Electric's gas affiliate, NSTAR Gas Company d/b/a Eversource Energy ("NSTAR Gas"), in support of its petition for approval of a gas service agreement between NSTAR Gas and Hopkinton LNG Corp. ("HOPCO") in D.P.U. 14-64, and in support of the HOPCO demand charge that became effective on January 1, 2016, as part of the NSTAR Gas base-rate proceeding docketed as D.P.U. 14-150, among other proceedings.

Q. What is the purpose of this joint testimony?

A. With the expiration of the PBR Plan approved in D.P.U. 17-05, it is necessary for the Company to petition the Department to incorporate the infrastructure investment made over the past five years into new base rates and to present evidence as to the basis for a renewal of the PBR Plan that will continue to serve the interests of customers into the future. Therefore, in this proceeding, the Company is requesting a change in base rates along with renewal of the Performance-Based Ratemaking Plan ("PBR Plan") approved by the Department in D.P.U. 17-05, for up to a 10-year term. Our testimony discusses several aspects of the Company's current operating environment and prospects for future operations and describes the Company's PBR Plan and ratemaking proposals put forth in this proceeding.

In D.P.U. 17-05, the Department approved a five-year PBR Plan commencing January 1, 2018, allowing for four annual revenue adjustments calculated in accordance with a revenue-cap formula that took effect on January 1 of each year, 2019 through 2022. Below, our testimony discusses the benefits that customers have received as a result of the first term of the PBR Plan. These benefits include substantial investment in electric distribution infrastructure reinforcing the reliability and resiliency of the distribution system; strict control over operating expense lowering the cost of service in this proceeding; and achievement of performance metrics measuring key outcomes sought by Commonwealth energy policy, and rate stability associated with smaller sequential changes occurring annually, rather than more significant impacts occurring every two to three years.

Operationally, the Company's primary focus in D.P.U. 17-05 was the initiation of a comprehensive grid-modernization plan to modernize and automate the grid for enhanced system reliability and resiliency, and to enable the interconnection of distributed energy resources ("DER") and clean energy alternatives. Since D.P.U. 17-05, NSTAR Electric has made substantial strides to initiate and build upon a comprehensive grid-modernization plan, furthered by participation in the Department's important docket on DER interconnections, <u>Inquiry into Distributed Generation, Interconnection System Planning and Cost Allocation</u>, D.P.U. 20-75. Although significant work remains to be done on grid modernization, the next stage of system transformation is starting to take shape.

Specifically, in this second generation PBR Plan, the Company's proposals are developed with the knowledge and recognition that grid modernization will continue to evolve over the next PBR Plan term alongside a significant push for electrification. Over the next 10 years, NSTAR Electric will play a central, pivotal role in supporting the Commonwealth's electrification and carbon-reduction goals over the PBR Plan term through infrastructure investment. Accordingly, the Company's proposals in this proceeding are founded on the proposition that NSTAR Electric has a fundamental, continuing obligation to provide safe and reliable service to electric customers, through an equitable, modernized grid, while taking the steps necessary to assure that its transmission and distribution infrastructure is ready and able to support the Commonwealth's electrification goals.

With the proposed modifications and updates, the Company's PBR Plan will enable Eversource to support electrification through very large-scale investments in critical infrastructure, along with more traditional capital investments that will enhance reliability for residential and business customers while furthering the Commonwealth's ambitious clean-energy goals and promoting long-term cost control. For example, development of certain "Major Station Capacity Projects" over the next 10 years will be vital to the Company's ability to meet customer demand in suburban and urban communities that are experiencing substantial load growth, including numerous "environmental justice" communities. Without the ability to plan, build and support additional capacity infrastructure, opportunities for electrification and the introduction of clean energy strategies are blocked for customers living and working in these communities. Therefore, in moving forward with a proposed 10-year PBR Plan, this consideration weighs heavily in the equation.

In addition, to provide transparency associated with achievement of the clean energy and customer-service goals under the proposed PBR Plan, the Company's filing includes updates to the PBR metrics proposed by Eversource following the

Department's approval of the initial PBR Plan in D.P.U. 17-05.[2] The updates that the Company is proposing in this filing include both refinements of existing metrics and the implementation of new metrics. Since D.P.U. 17-05, the Company is on track to meet each of the PBR metrics proposed to the Department by the end of the existing PBR term in 2022. The performance metrics proposed in this filing build on these successes and create consistency with current Commonwealth policy goals.

Lastly, the filing proposes to continue the gradual consolidation and alignment of rates from the NSTAR Electric legacy service territories and to improve tariff language, while also complying with G.L. c. 164, § 94I. Rate consolidation and alignment is proposed consistent with the Department's directives in D.P.U. 17-05, which found that the unit embedded costs for general service rate classes had differences that were not within an acceptable range, allowing for approval of consolidation at that time. To achieve the gradual consolidation and alignment objectives set forth in the Department's final decision in D.P.U. 17-05, the Company is not proposing to consolidate rates and tariffs fully but to make modest

[2] As discussed in greater detail in the testimony of Company Witnesses Chatterjee, Conner, Finneran and Renaud (Exh. ES-METRICS-1), the Department has not yet issued a decision on the PBR metrics proposed in NSTAR Electric Company d/b/a Eversource Energy, D.P.U. 18-50. However, pending the Department's decision in D.P.U. 18-50, Eversource has continued to submit annual filings reporting on its progress with respect to the proposed metrics. The most recent filing was submitted to the Department and docketed as D.P.U. 21-106. Exhibit ES-METRICS-1 discusses proposed changes and additions to the metrics under consideration in D.P.U. 18-50 to reflect the evolution of the PBR Plan; the interaction of the Commonwealth's current policy goals; and the need for transparency in whether the Company is achieving goals and objectives benefitting electric distribution customers.

steps toward this goal.

Q. Are you presenting any exhibits in addition to your testimony?

A. Yes. We are presenting the following exhibits as part of our testimony in this case:

Exhibit	Purpose
Exhibit ES-CAH/DPH-1	Testimony of Craig A. Hallstrom and Douglas P. Horton
Exhibit ES-CAH/DPH-2	Analysis of Storm Impact on SAIDI/SAIFI (excel only)

Q. How is your testimony organized?

A. This joint testimony is organized as follows: Section I is the introduction. Section II discusses the reasons that the Company is filing this case and describes the testimony accompanying the Company's filing in support of its proposals. Section III discusses the Company's operating environment and the impact that industry trends have in shaping the Company's proposals for a 10-year PBR Plan. Section IV describes the Company's proposed PBR Plan and reviews each component of the Company's proposal for a 10-Year PBR Plan, as well as an alternative 5-Year PBR Plan. Section V reviews the Department's criteria for PBR implementation and discusses how the Company's proposed PBR Plan meets those criteria. Section VI discusses other proposals the Company is making in this case relating to electric operations. Section VII discusses certain qualitative considerations that the Department should take into account for NSTAR Electric in relation to the authorized return on equity that the Department will set in this proceeding. Section

VIII is the conclusion.

II. OVERVIEW OF THE COMPANY'S FILING

Q. What are the principal elements of the Company's filing in this proceeding?

A. There are three categories of proposals encompassed in the Company's filing in this proceeding. First, the Company is petitioning for an extension of the PBR Plan approved for NSTAR Electric in D.P.U. 17-05 for a 10-year term starting January 1, 2023, or at least a 5-year term if the Department so determines. The 5-Year PBR Plan approved in D.P.U. 17-05 was set to expire as of December 31, 2022. Therefore, it is necessary for the Company to present information to the Department as to the basis for a renewal of the PBR Plan that will continue to serve the interests of customers into the future.

As part of the PBR Plan, the Company is proposing to implement a performance-based ratemaking mechanism ("PBRM") that would adjust rates annually in accordance with a revenue-cap formula to be approved by the Department in this case. The PBRM substitutes for a capital-cost recovery mechanism with the goal of furthering the Commonwealth's clean energy goals, creating stronger incentives for cost efficiency, and assuring continued achievement of top-tier service-quality performance. Within the PBRM, Eversource is proposing certain mechanisms to enable a prolonged, 10-year PBR term fostering strong incentives for cost control, stabilizing rates for electric service and promoting the goals of electrification through critical infrastructure development. The Company's PBR Plan proposals are detailed further in the testimony identified below.

Second, the Company is proposing to reset the cast-off rates for the extension of the PBR Plan. Specifically, the Company is requesting that the Department approve new delivery rates to alleviate a revenue deficiency of approximately $89 million. This revenue deficiency is associated with increases associated with increased capital investment, storm costs, enterprise IT projects and a transfer of vegetation management expense currently collected outside of base rates to the base revenue requirement. General operating expense has not increased since the test year in D.P.U. 17-05, due to the Company's rigorous efforts to control cost impacts during the initial PBR term. As explained by the Company's witnesses, addressing this base-revenue deficiency creates a relatively modest increase of approximately 7.6 percent in total distribution revenue.

Third, the Company is putting forth certain other proposals regarding its Massachusetts electric operations, including modifications to the Department's reporting for System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") to account for the impact of system investment; proposals on modified storm-cost recovery, the transfer of costs associated with the resiliency tree work program from the reconciling mechanism to base rates and resolution of the pension adjustment mechanism impasse, as well as adoption of a company-specific rate tariff to enable the Company's AMI Implementation Plan.

Q Is the Company proposing to institute new performance metrics as part of the proposed PBR Plan?

A. Yes. With the Department's approval of the PBR Plan, Eversource will be authorized to continue to move forward with its commitments to grid modernization and a more reliable, resilient grid, coupled with strong incentives to control the costs of system investments and operating costs to maintain stable, efficient customer rates. With this authorization, the Company proposes to implement numerous individual metrics within certain performance categories that will provide transparency in relation to the Company's performance, allowing the Department and other stakeholders to gauge the Company's progress on its PBR Plan commitments. The metrics are designed with the specific intention to yield information and insight into the Company's activities and progress in specified areas of interest. The metrics are also designed to produce gains in knowledge and experience that will inform future development of the modernized electric grid.

Performance on these metrics will be the basis for discussions with stakeholders over the system investment horizon and will help to confirm the course of action or to suggest other potential success areas. In addition, the Company will remain subject to the Department's rigorous service-quality guidelines, which were recently updated in D.P.U. 12-120-D (2015), requiring improved performance by electric utilities on electric reliability indices.

Q. Please describe the Company's request for a change in base rates.

A. As noted above, the Company's filing in this proceeding is requesting that the Department approve new delivery rates to alleviate a revenue deficiency of approximately $89 million. This proposed base-rate change is based on a cost of service measured in the test-year ending December 31, 2020, adjusted for known and measurable changes. The proposed revenue requirement is based on a total rate base of $4.263 billion and an overall weighted cost of capital of 7.32 percent, reflecting a proposed return on equity of 10.5 percent. The total rate base reflected in the proposed revenue requirement is the product of nearly $2.05 billion in plant placed in service over the past five years, including contributions in aid of construction ("CIAC"), plus the cost of removal, and less accumulated depreciation, accumulated deferred income taxes occurring since the Company's most recent distribution rate case in D.P.U. 17-05.

If the Company's proposals are approved without modification, a typical residential customer consuming 530 kWh in a month would, on average, experience a total monthly bill increase of $7.14 or approximately 5.2 percent, effective January 1, 2023. For NSTAR Electric's commercial and industrial ("C&I") customer classes, average monthly bill impacts would vary across rate classes with the average for the group below 10 percent, as of January 1, 2023.

The Company's filing encompasses the calculation of the proposed revenue requirement; an updated depreciation study; an allocated cost of service study; and other testimony and exhibits, as described below.

Q. What is causing the Company to have a revenue deficiency, notwithstanding the four annual PBR adjustments that were authorized to take effect on January 1, in 2019 through 2022?

A. As demonstrated below, the revenue deficiency is motivated primarily by enterprise information-system investments, storm costs and the transfer of the Resiliency Tree Work program into base rates. General operations and maintenance ("O&M") expense is ***not*** a driver of the Company's rate request, underscoring the validity of the cost control incentives inherent in the PBR Plan. In terms of the drivers of the $89 million revenue deficiency, the Company's analysis shows the following:

Table 1: Drivers of $89 Million Revenue Deficiency

Driver of Revenue Deficiency	Contribution to Revenue Deficiency	Percent of Total
Growth in Rate Base Since 17-05	$131 million	147%
Rate Base Transferred from Existing Rates	$46 million	52%
Enterprise IT Upgrades	$34 million	38%
Transfer of Resiliency Tree Work Costs to Base Rates	$28 million	31%
Proposed Annual Storm Fund Contribution	$25 million	28%
Increase to Increase Authorized ROE from 10% to 10.5%	$16 million	18%
Payroll-Related Costs	$5 million	6%
Lower Cost of Debt	($12 million)	(-13%)
Revenues Obtained Per Annual PBRM, 2019-2022	($135 million)	(-152%)
Revenues from Existing Rate Mechanisms	($58 million)	(-65%)
Miscellaneous	$9 million	4%
Revenue Deficiency	**$89 million**	**100%**

The information provided in Table 1 demonstrates that the PBRM revenues from the PBR Plan have almost precisely supported the Company's capital additions over the PBR Plan term (2017-2022), which provided strong incentives for containment of operating expense.[3] With the level of PBR revenues equating to the additional rate base added since 2017, a strong incentive for containment of operating expense is created because the PBR revenues are not sufficient to cover *both* the cost of carrying capital investment and increases in operating expense. As a result, with a five-year stay-out commitment, the Company had to work diligently and creatively to control operating expense to stay on target from an earnings perspective. Thus, the increase that customers will experience as a result of this case is made necessary only to pay for infrastructure investment, investments in enterprise information technology systems and storm cost recovery. The benefit of controlled operating expense is passed directly onto customers in this proceeding because the base revenue requirement is lower than it would otherwise be due to the absence of increases in operating expense. Thus, the bill impact is tempered and held to a more moderate level than would ever have occurred in a traditional base-rate case environment.

Q. What has the Company achieved over the past five years in relation to its system investments?

A. As noted above, the Company has made total gross investments in rate base since the test year in D.P.U. 17-05, totaling $2.045 billion across three broad categories of capital investment, including New Business and Peak Load Growth, Basic

[3] As shown in Table 1, the growth in the revenue requirement associated with new rate base is approximately $131 million annually, as compared to annual revenues of $135 million enabled by the cumulative impact of four PBR adjustments.

Business Requirements and Aging Infrastructure. In the past five years, Eversource has installed, expanded or upgraded its infrastructure to accommodate electric demand growth and installed or replaced new distribution equipment that reduced the number of outages experienced by customers.

Q. What are the categories of infrastructure investment that the Company undertakes in its annual capital investment plan to provide safe and reliable service to customers?

A. The Company's capital investments encompass a range of project categories necessary to build, maintain and operate a distribution system with high service reliability, including new customer growth; capacity expansion; reliability improvements; regulatory commitments; and routine business operations, such as remediation of equipment failures, transformer replacements and third-party/joint-ownership work.

Q. What is the decision-making framework that is used to prioritize capital projects in these categories?

A. From an overall perspective, the Company's capital-planning objective is to arrive at capital budgets that represent the optimal balance of executing investments necessary to maintain and improve the performance of the system, while assuring a cost-efficient use of the Company's limited resources. The Company also maintains a level of flexibility in the budget process to deal with contingencies that inevitably occur during the year. On an annual basis, the Company develops the capital plan by each operating area in collaboration with the Engineering and

Operations departments to identify specific needs in each area. A variety of factors are considered during the prioritization process for each territory, including but not limited to aging infrastructure needs; system conditions; reliability improvements and initiatives; new customer growth; and resource availability. The portfolio of projects is ultimately evaluated by the Company's senior executives through an extensive budget-review process conducted by executive management at the end of each year. Multi-year funding for major projects is also reviewed through the annual budgeting process.

Q. What is the level of infrastructure investment that the Company has made over the past five-year term of the PBR Plan?

A. Since 2017, NSTAR Electric's distribution plant-in-service has increased by almost 24 percent, or by 22 percent in the EMA division and 35 percent in the WMA division. This infrastructure investment translates directly into improved service reliability for customers as evidenced by the Company's continued top decile performance on months between interruptions ("MBI") when measured against its industry peers. For example, in 2020, WMA experienced its best performance year ever for the System Average Interruption Duration Index ("SAIDI") at 58.6 minutes.

Table 2, below, shows the Company's gross plant additions (including cost of removal) in each year over the PBR Plan term since the test-year end for D.P.U. 17-05 (June 30, 2016).

Table 2

Annual Capital Additions (2016-2020)

Year	Eversource East Annual Capital Additions	Eversource West Annual Capital Additions	Total Capital Additions
Calendar Year 2016	$335M	$35M	$370M
2017	$258M	$49M	$307M
2018	$310M	$130M	$440M
2019	$324M	$87M	$411M
2020	$364M	$86M	$450M

**Total capital additions plus cost of removal*

In addition, the Company is in the final stages of planning and developing a series of large substation and operating-center projects, which are critical to the provision of reliable electric service and furtherance of the Commonwealth's electrification goals. These projects will entail new substations in the following areas:

- Burlington
- Natick
- Hyde Park-Dorchester
- Falmouth
- Dennis – Brewster
- Somerville
- Downtown Boston
- Metro Boston

In addition, capacity expansions may be required at the following substations or distribution feeders:

- Somerville
- Mystic Substation
- Electric Avenue
- Alewife
- Seafood Way
- Action - Maynard

Q. Has the Company's infrastructure investment resulted in increased rate base since the Company's base rates were last set in D.P.U. 17-05?

A. Yes. Figures 1, 2 and 3, below, show that the Company's net plant-in-service has grown considerably since the 2017 rate case. Specifically, NSTAR Electric's distribution plant-in-service has increased by almost $1.4 billion since the prior test-year end (12-months ending June 30, 2016). The incremental rate base created since D.P.U. 17-05 is significant and not currently recovered through rates.

Figure 1: NSTAR Electric – Distribution Plant in Service

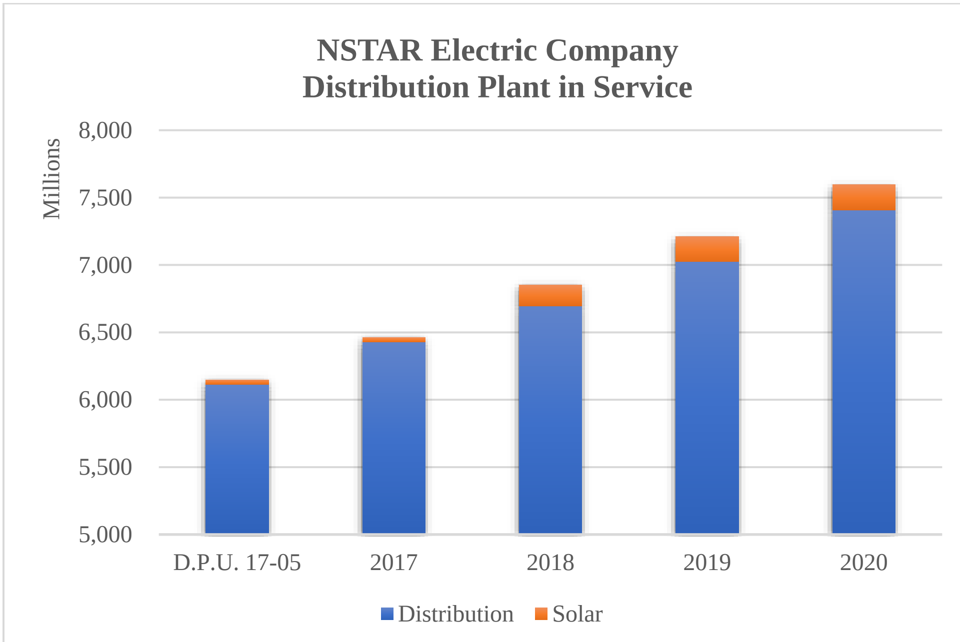


Figure 2: NSTAR Electric – EMA Distribution Plant in Service

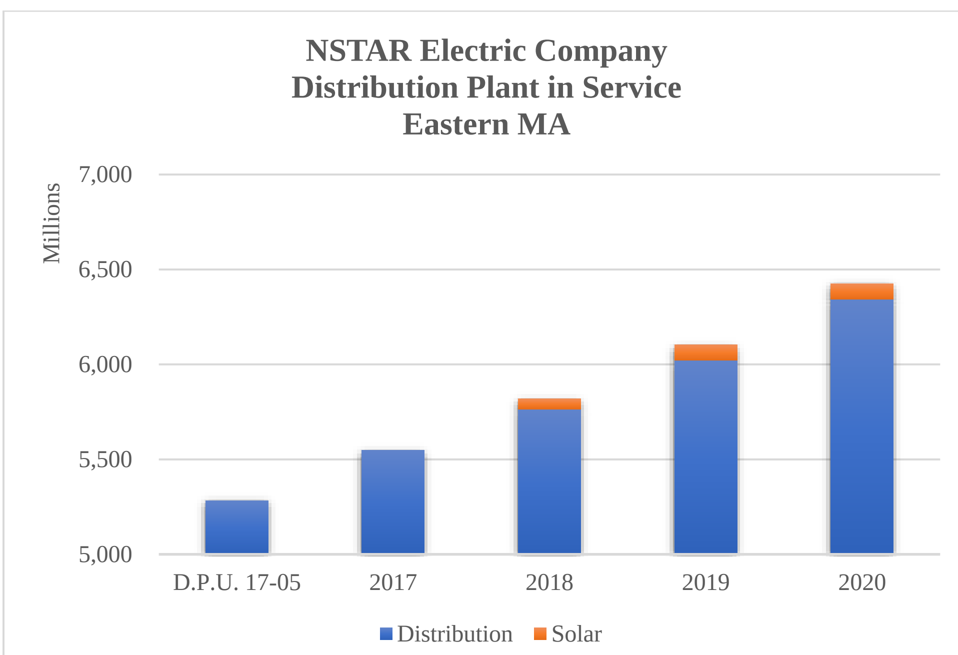
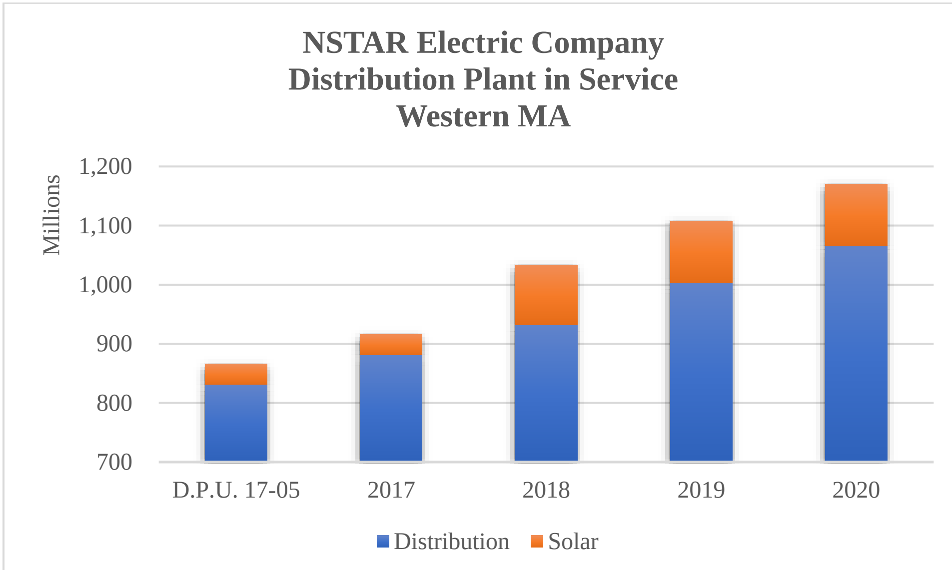


Figure 3: NSTAR Electric – WMA Distribution Plant in Service



The Company's traditional capital investment activities are critical to maintaining a safe and reliable electric distribution system for customers, particularly in the current operating environment where there is virtually zero tolerance for service outages. At the same time, current energy policies are shifting focus away from traditional energy efficiency (that reduces kilowatt hours) and encourages adoption of electrification for heating/cooling and adoption of electric vehicles.

Q. What is the Company's track record on containment of operating and maintenance expense?

A. Over the term of the PBR Plan, the Company has worked diligently to contain operating expense given the commitment to a 5-year stay-out with revenue increases capped at the level allowed by the PBR annual adjustment mechanism. Some of the initiatives that enabled operating efficiencies and associated cost reductions including implementation of robotic process automation, using more data analytics to streamline and automate reliability reporting and other work processes; fleet standardization; contract renegotiations; leveraging of supply chain partnerships and use of contractors of choice for engineering work, among many other initiatives across all functions of ESC and the Company.

Excluding storm costs, the Company held distribution O&M constant overall, subject to year-to year-fluctuations to meet operating conditions.

Figure 4: NSTAR Electric – Distribution O&M (excluding Storm Costs)

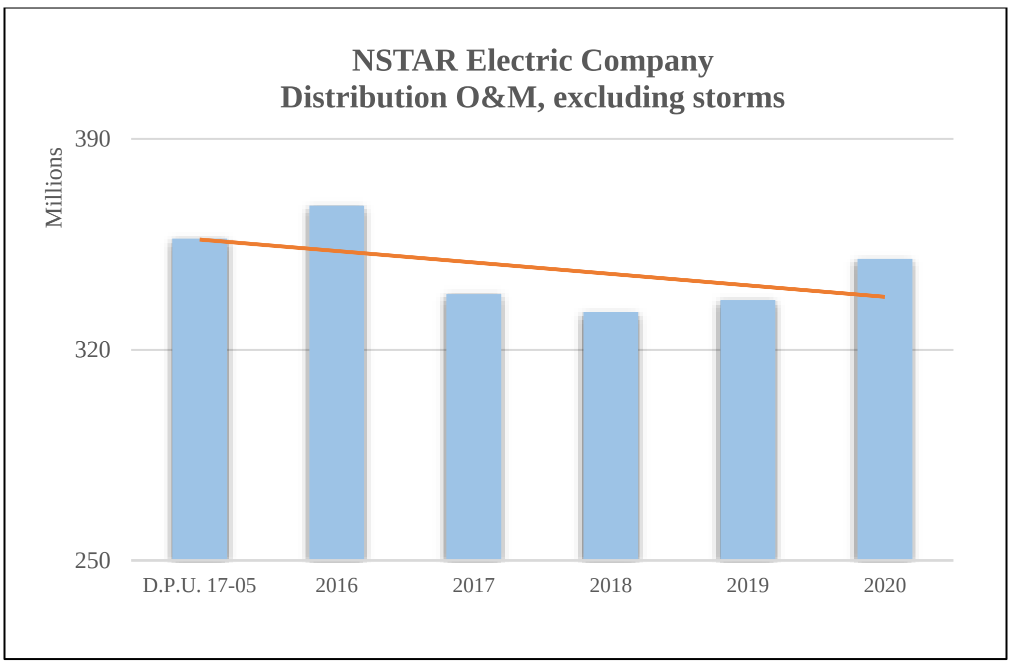


Table 3

NSTAR Electric Company
Distribution O&M (excluding Storm Costs)

Year	Total O&M (excl. storm costs)	Year-Over-Year Change
Test Year End D.P.U. 17-05	$356,846,523	
2016	$367,820,261	3.08%
2017	$338,395,076	(8.00%)
2018	$332,535,145	(1.73%)
2019	$336,510,667	1.20%
2020	$350,176,516	4.06%
Cumulative Change		**(1.40%)**

Q. Would you please review the testimony that the Company is submitting in support of its proposed change in distribution rates and other proposals?

A. Yes. In addition to this overview testimony, the Company has submitted the following testimony in support of its proposals:

Mark E. Meitzen, Ph.D. and Nicholas Crowley -- Dr. Meitzen is Senior Consultant, Christensen Associates Energy Consulting LLC ("Christensen Associates"). Mr. Crowley is a Senior Economist at Christensen Associates. Christensen Associates has performed the economic analysis of electric industry cost trends to establish the revenue-cap formula that would apply in the PBRM.

Lawrence R. Kaufmann – Dr. Kaufmann is President of LKaufmann Consulting and a Senior Advisor to Pacific Economic Group and Black & Veatch Management Consulting. Dr. Kaufmann evaluates the Company's implementation of the existing PBR Plan and presents two complementary cost benchmarking studies to support the Consumer Dividend component for the PBR Plan.

Digaunto Chatterjee, Lavelle A. Freeman and Gerhard Walker -- Digaunto Chatterjee is Vice President, System Planning at ESC. In this role, he is responsible for Transmission and Distribution Planning across Eversource Energy's tri-state footprint. Lavelle A. Freeman is Director, Distribution System Planning for ESC, overseeing Distribution System Planning and DER interconnection activities in Connecticut, Massachusetts and New Hampshire. Gerhard Walker is Principal Engineer, System Planning for ESC. In this role, he is responsible for transitioning Eversource Energy's distribution planning processes to account for DER growth and output, non-wires alternatives and broader electrification. Mr. Chatterjee, Mr. Freeman and Mr. Walker provide testimony that discusses the large-scale, Major Station Capacity Projects that are planned for the NSTAR Electric system to meet the expected demand requirements of the Commonwealth's electrification policy.

Penelope M. Conner, Digaunto Chatterjee, Catherine A. Finneran, and Paul R. Renaud – Ms. Conner, Mr. Chatterjee, Ms. Finneran, and Mr. Renaud present the Company's proposed updates to the Performance Based Ratemaking Metrics. Ms. Conner is Executive Vice President, Customer Experience and Energy Strategy for ESC. Mr. Chatterjee is Vice President, System Planning for ESC, Ms. Finneran is Vice President, Sustainability and Environmental Affairs for ESC. Mr. Renaud is Vice President of Distribution Engineering for ESC. Their testimony discusses the evolution of the Company's climate change policies and PBR framework and how this evolution is incorporated into the Company's updated PBR metrics.

Robert W. Frank and Ashley N. Botelho – Mr. Frank is Director, Revenue Requirements, Massachusetts for ESC and Ms. Botelho is Manager, Revenue Requirements, Massachusetts for ESC. The testimony of Mr. Frank and Ms. Botelho provides the revenue-requirement analysis and revenue-deficiency calculation for NSTAR Electric.

Vincent V. Rea – Mr. Rea is Managing Director of Regulatory Finance Associates, LLC, an independent financial and regulatory consulting firm serving the utility industry. Mr. Rea's testimony presents his recommendation regarding the appropriate rate of return and capital structure that should be used in establishing base rates for the Company in this proceeding.

Sasha Lazor -- Mr. Lazor is Director, Compensation for ESC. The testimony of Mr. Lazor presents the Company's employee compensation programs, including base and variable pay elements of compensation.

Michael P. Synan – Mr. Synan is Director, Benefits and Human Resources Operations for ESC. The testimony of Mr. Synan presents the Company's employee-benefit programs and associated costs, including healthcare expense, pension and retirement benefits.

Leanne M. Landry and John G. Griffin – Ms. Landry is the Director, Budget and Investment Planning for ESC. Mr. Griffin is Director, Performance Management. Ms. Landry and Mr. Griffin's testimony describes the capital planning and approval process in place to manage the capital expenditures for NSTAR Electric; presents project documentation for capital additions made since the Company's last general distribution rate proceeding in D.P.U. 17-05; and provides information on several post-test year service company capital additions that the Company is proposing for inclusion in base distribution rates in this case.

John J. Spanos – Mr. Spanos is President, Gannett Fleming Valuation and Rate Consultants, LLC. The testimony of Mr. Spanos presents the depreciation studies for NSTAR Electric in support of depreciation expense.

Penelope M. Conner, Douglas P. Horton and Jennifer A. Schilling – Ms. Schilling is Vice President, Grid Modernization for ESC. Ms. Conner, Mr. Horton and Ms. Schilling present the details of NSTAR Electric's investments in advanced metering infrastructure ("AMI") and other foundational information technology infrastructure in support of the Department's approval of M.D.P.U. No. 80 (NSTAR Electric AMI Recovery Tariff). These investments represent the next phase of NSTAR Electric's customer-side, grid modernization progress.

William A. Van Dam – Mr. Van Dam is Director, Vegetation Management for ESC. His testimony discusses NSTAR's proposed changes to its vegetation-management program including the proposal to move from a four-to-five year trim cycle to a cycle based on reliability and resiliency prioritization. Mr. Van Dam's testimony also describes the results of Eversource's Resiliency Tree Work ("RTW") Pilot Program that was approved in D.P.U. 17-05. The RTW Pilot has been successful, and the Company is requesting to transfer recovery of the RTW costs into base distribution rates as routine operating expense, and to continue operation of the RTW mechanism to facilitate municipal initiatives that are not appropriate for recovery as part of base distribution rates.

Bruce R Chapman – Mr. Chapman is Vice President with Christensen Associates Energy Consulting, LLC. The testimony of Mr. Chapman presents the Company's allocated cost of service study.

Richard D. Chin –Mr. Chin is the Manager of Rates for ESC, supporting the Company's operating affiliates in Massachusetts, including NSTAR Electric. Mr. Chin's testimony presents the Company's proposed rate design, tariff changes and associated bill impacts.

III. OPERATING ENVIRONMENT

Q. How would you describe the current operating environment and what is NSTAR Electric's vision for the future?

A. The confluence of operating dynamics confronting electric distribution companies at this stage is unprecedented in the Company's experience. The operating environment for electric utilities is extraordinarily challenging, influenced by: (1)

energy and climate policy motivating massive change in the nature, scale and technological intricacy of electric operations; (2) the emergence of new technologies not contemplated by the existing design of the electric system; (3) uncompromising customer expectations and engagement promoted through the use of digital technologies; (4) challenges in hiring, training and retaining skilled personnel willing to make the types of personal sacrifices that storm restoration requires; (5) substantial quantities of aging infrastructure that must be replaced, upgraded and maintained to meet all other expectations; and (6) changing weather patterns with frequent winter and summer storms with catastrophic impact. As an electric distribution company responsible for meeting the expectations of customers, these challenges are both daunting and invigorating, but in either case – thoroughly resource consuming.

Over the past 10 years, Massachusetts has established itself as a national leader in progressive energy and climate policy and this leadership is providing a strong impetus for change on the electric distribution company systems serving customers in Massachusetts. Eversource recognizes that, fundamentally, the economic and environmental health of the Massachusetts communities existing within the Company's service territory depend upon the availability of safe, reliable, sustainable and affordable energy resources within the context of the Commonwealth's policy direction. Conversely, the Company's ability to provide those resources is a function of capital investment and the skill and dedication of the workforce. The Company needs to make substantial – and constant – investment in the distribution system to raise the system capabilities to the level that will be required to meet expectations. For this task, the Company needs highly skilled, dedicated employees at all levels of the organization to do that – from the crews in the field that build and restore the system – to employees managing information systems and engineering capital projects, just to mention a few areas of importance. The implementation of PBR is an important piece of the puzzle in that it allows the Company to focus on the business and fulfillment of the operating mission under the dynamic circumstances that exist today, without the constant distraction of year-long administrative proceedings to obtain the revenue support needed for operations.

Moving forward, the Company envisions that today's operating dynamics will continue to evolve bringing even greater technological complexity; eminently larger investment requirements; and an unrelenting need to find and develop talent to manage the enterprise to meet the expectations of customers on a day-to-day basis. The testimony of Company Witnesses Chatterjee, Freeman and Walker provides insight into how the Company is planning for the future, with particular focus on building capabilities to meet future service requirements in an electrified environment. PBR is critical in this type of operating environment because it provides the Company with the latitude to focus on operations and meet expectations placed on the system, while providing the critical resources necessary to make ends meet.

Q. How are the Commonwealth's policies on climate change and emissions reductions defining the operating environment for Eversource and other electric utilities?

A. For electric companies in the Commonwealth, the impetus for change stems, in large part, from the series of legislative actions taken by the Massachusetts legislature since 2008 to advance clean energy goals and addressing climate change concerns through both mitigation and adaption. In 2008, the Massachusetts legislature enacted Chapter 169 of the Acts of 2008, An Act Relative To Green Communities ("Green Communities Act") and An Act Establishing the Global Warming Solutions Act, St. 2008 c. 298, § 7 ("GWSA"). The Green Communities Act established an entirely new construct for energy efficiency program planning, paving the way for the aggressive expansion of demand resources (energy efficiency, demand response, combined heat and power, and renewable generation). The GWSA put in place a comprehensive policy framework designed to result in marked reductions to greenhouse gas emissions on a designated timeline.

In the 14 years that have passed since the enactment of the Green Communities Act and the GWSA, the operating environment for electric distribution companies has experienced a profound transformation, evolving into a highly dynamic setting characterized by declining electric consumption on a per-customer basis, coupled with intensifying pressure for more reliable electric service, unbounded digital access and the widespread accommodation of DER, among other factors. In just the past few years, a shift in focus to future electrification has placed electric utilities at a crossroads where the ability to extract revenue from the system to cover necessary operating costs and capital investment has been declining, while the obligations and demands for performance to meet a range of stakeholder interests is rapidly expanding anticipating a future with exponentially expanded reliance on the electric grid.

Many initiatives are underway to achieve the goals and objectives of the Green Communities Act and GWSA, by promoting the development of the electric-vehicle market and associated charging infrastructure; to expand the use of electric storage; and to enable DER interconnection, as examples.[4] The goals and objectives of the Green Communities Act/GWSA were affirmed by the Baker Administration's Executive Order No. 569, Establishing an Integrated Climate Change Strategy for the Commonwealth (September 16, 2016) ("Executive Order No. 569"), setting directives for the reduction of greenhouse gases and preparation for the impacts of climate change.

When the Massachusetts legislature acted in 2008, the Department recognized that

[4] See, e.g., electric-vehicle rebate programs (http://www.mass.gov/eea/pr-2016/increased-funding-for-electric-vehicle-rebate-program.html); electric storage programs (*State of the Charge, Massachusetts Energy Storage Initiative* issued by the Massachusetts Department of Energy Resources); DER interconnection (D.P.U. 11-75-A through D.P.U. 11-75-F and D.P.U. 13-70).

the full deployment of energy efficiency and demand response in the Commonwealth would cause a potentially substantial decline in electricity consumption and a direct and significant financial impact for electric companies (and it has). See, Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50-A (2008) (the "Decoupling Order"). In its Decoupling Order, the Department adopted full revenue decoupling as a method to mitigate the negative impact of declining electric consumption that electric and natural gas distribution companies were expected to experience as efforts to pursue a cleaner, more efficient energy future evolve.

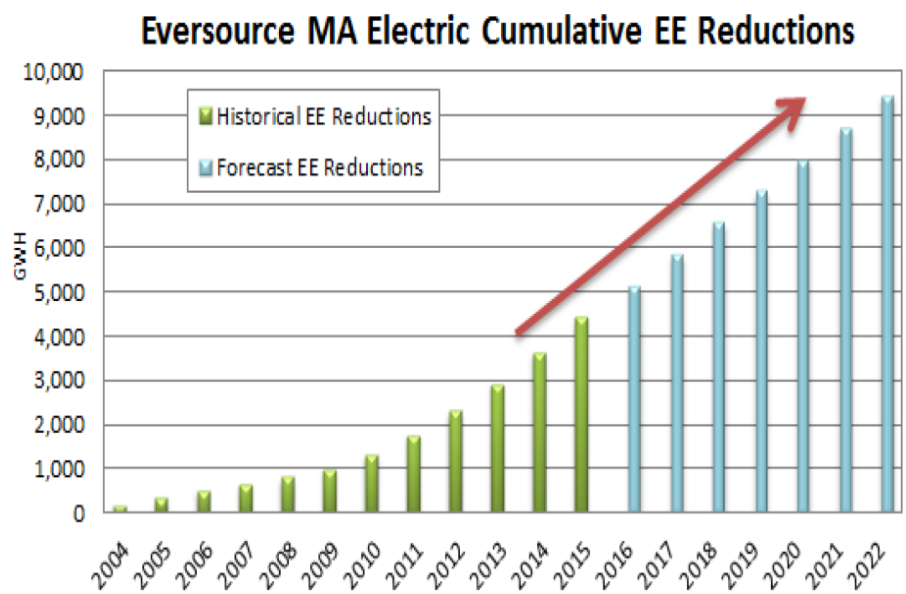
The Department also acknowledged that distribution companies historically experienced (and retained) sales growth from increased numbers of customers and/or growth in usage per customer between rate cases. D.P.U. 07-50-A at 48. The Department recognized that distribution companies were previously able to use the increased revenues from sales growth to pay for system reliability and capital expansion projects, but that with the implementation of revenue decoupling, there would be no incremental sales revenue retained by electric companies to cover operating expenses and/or capital investment on a year-to-year basis. Therefore, the Department acknowledged that additional recovery mechanisms may be needed to provide funding for needed infrastructure maintenance and upgrade projects or increasing operating expenses between base-rate cases. D.P.U. 07-50-A at 48-50. With electrification on the horizon, PBR is an appropriate vehicle to make the transition between operating environments because of the vital support it provides for capital investment.

Q. Did the Department's vision of substantially reduced and declining customer consumption actually occur on the Eversource system?

A. Yes. Beginning in 2008, Massachusetts has been hugely successful in reducing the consumption of electricity by customers through aggressive deployment of energy efficiency and other demand-reduction initiatives. In the period 2008 through 2020, the compound annual growth rate in total sales reversed from approximately 1.7 percent in the years 1997 through 2007, to -1.0 percent in the period 2008-2020 in the NSTAR Electric service area, representing a cumulative reduction of approximately 2,536 gigawatthours ("GWH"), since 2008.

Similarly, in Eversource's western service area the compound annual growth rate in total sales reversed from 0.8 percent in the years 1997 through 2007, to -1.2 percent in the period 2008-2020, representing a cumulative reduction of approximately 524 GWH, since 2008. Collectively, this represents a total reduction of 3,060 GWH for Eversource in relation to its Massachusetts electric operations. In D.P.U. 17-05, this decline in sales volume served as an important impetus for the commencement of the PBR Plan because of the loss in sales revenues to support infrastructure investment. In D.P.U. 17-05, cumulative reductions in load attributable to the Company's energy-efficiency program were forecast, as depicted in Figure 4, below:

FIGURE 4: Cumulative Energy Efficiency Reductions As Forecast in D.P.U. 17-05



From the vantage point of 2017, when the PBR Plan was first approved, the reduction in sales volumes arising from the steep ramp-up of energy efficiency enabled by the Green Communities Act was tangible and historic, vastly decreasing the sales volumes that would have otherwise been available to the Company to generate revenue to offset increases in the cost of service. At that time, a multitude of factors were imposing downward pressure on the Company's sales volumes beyond the Company's energy efficiency programs. Some of these factors include more stringent building codes to compel the construction of highly energy-efficient buildings; increased solar installations and other distributed energy resources; appliance efficiency; smart thermostats; energy management strategies for commercial and industrial customers; changing household structures (single family versus multi-family); transition from desktop computing to mobile computing; non-utility sponsored energy efficiency savings and customer conservation. In addition, the impact of proliferating DER has had downward pressure on the Company's sales volumes. With over 1,119,000 kW of DER on the Eversource system in Massachusetts, the Company estimates a corresponding reduction in electric sales of over 1,400 GWh (and continuing to climb).

Q. Is the landscape changing in terms of the potential for sales revenues to stabilize and potentially increase?

A. Yes. In the past few years, the Massachusetts General Court has enacted legislation to promote electrification as a clean energy policy. In particular, the two statutory provisions that are having the greatest impact are Chapter 8 of the Acts of 2021 (the "Climate Act") and Chapter 448 of the Acts of 2016. The Climate Act involved several legislative changes requiring reductions in greenhouse gas ("GHG") emissions limits by 2050, including:

(1) Amendments to G.L. c. 21N, which effect the following:

(a) Require the Office of Energy and Environmental Affairs, the Department of Environmental Protection and the Department of Energy Resources ("DOER") to adopt interim GHG limits periodically through 2050 that achieve net zero emissions (no higher than 85% below 1990 emissions levels) by that year; and

(b) Set sector based GHG limits for electric power, transportation, commercial and industrial heating and cooling, residential heating and cooling, industrial processes, and natural gas distribution and service.

(2) Amendments to G.L. c. 25, which effect the following:

(a) Broaden the authority of the Department by directing the DPU to prioritize reductions in GHG pursuant to Chapter 21N, along with safety, security, reliability of service, affordability, and equity;

(b) Require the Department to consider the social value of GHG emission reductions in its determination of the cost-effectiveness of energy efficiency programs; and

(c) Require energy efficiency three-year plans to include an estimate of the social value of GHG emissions reductions that will result from the plan, including a numerical value of the plan's contribution to meeting each statewide GHG emissions limit and sublimit set by statute or regulation; and

(3) Amendments to G.L. c. 25A, which effect the following:

(a) Require the DOER to develop and promulgate a municipal opt-in stretch energy code that includes net zero building performance standards; and

(b) Direct Municipal Lighting Plants to establish GHG emissions standards

To date, the Executive Office of Energy and Environmental Affairs has implemented these statutes most prominently by advocating for significantly increased adoption of air source heat pumps to move heating from fossil fueled sources of energy to renewable sources of energy. This policy transition is reflected directly in the composition of the 2024-2024 Three-Year Energy Efficiency Plans.

Q. Please summarize the key provisions in Chapter 448 of the Acts of 2016.

A. Chapter 448 of the Acts of 2016 ("Chapter 448") promotes electric vehicle ownership and the development of electric vehicle charging stations, including utility-owned and operated charging stations. Specifically, Chapter 448 authorizes electric distribution companies to submit a proposal to the Department for approval of cost recovery to construct, own, and operate publicly available electric vehicle charging infrastructure including charging stations; provided, however, that approval shall be granted only if a proposal is in the public interest, meets a need regarding the advancement of electric vehicles in the Commonwealth and does not hinder the development of the competitive electric vehicle charging market.

In addition, Chapter 448 authorized the state board of building regulations and standards to include requirements for electric vehicle charging for residential and appropriate commercial buildings. In addition, the law required DOER and the Massachusetts Department of Transportation to conduct a study on the opportunities for electrification of the state fleet, including the vehicles used by the regional transit authorities.

Q. How has this legislation and the underlying policy direction affected the composition of the 2022-2024 Three Year Energy Efficiency Plans?

A. With the 2022-2024 Three Year Energy Efficiency Plan, the Commonwealth's reliance on energy efficiency as the principal tool for achieving clean energy objectives is transitioning to a push for electrification. As a result, looking forward over the next 10 years, it is clear that a reversal in the sales trend is likely to occur with energy efficiency efforts yielding to electrification initiatives that will increase electric sales, perhaps substantially. As clean energy is mostly generated in the form of electricity, end uses such as transportation and heating become a critical focus in shaping a sustainable energy future.

From a sustainability perspective, adoption of electric vehicles is the primary strategy for transitioning the transportation sector to a more sustainable model. Similarly, assuring heating and cooling for customers will require electrification; passive building design and urban planning to meet demand requirements in a sustainable way. In particular, electrification of heating equipment is currently viewed as the principal alternative to a more sustainable energy future. The Massachusetts 2050 Decarbonization Roadmap reports that "electrification of end uses, particularly space heating through the use of electric heat pumps, …[is] the most economically advantageous and cost-effective decarbonization strategy for widespread deployment across the Commonwealth's building sector…"[5]

[5] See, https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download, at page 45.

The Northeast Energy Efficiency Partnerships' Heating Electrification Initiative reports that sales of air source heat pump units in the Northeast have increased more than three-fold since 2013,[6] and efforts are underway to continue to transform the market so that efficient heat pumps become widely accepted and adopted in the marketplace.[7] Although the issues surrounding the use of natural gas and fossil fuels for transportation and heating remain under discussion both regionally and nationally, it is clear that a transition is occurring and will continue to occur, potentially reversing the declining sales volumes for electric distribution companies.

Q. Are the Company's energy efficiency plans transitioning toward a model that is focused less on marginal gains in conservation and more on spurring broad-based electrification in the Commonwealth?

A. Yes. For example, on November 1, 2021, the Massachusetts Energy Efficiency Program Administrators ("PAs"), including Eversource submitted the 2022-2024 Three-Year Plan to the Department representing the largest and most ambitious investment in energy efficiency and greenhouse gas ("GHG") emissions reduction in the Commonwealth since the passage of the Green Communities Act of 2008. The PAs proposed aggressive energy savings and GHG emissions reduction goals to be delivered through integrated gas and electric statewide energy efficiency

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6 See, https://neep.org/smart-efficient-low-carbon-building-energy-solutions/air-source-heat-pumps.

7 Both the Northeastern Electric Power Cooperative and Mass Save are working on market transformation efforts to support electrification through heat pumps. See, https://neep.org/smart-efficient-low-carbon-building-energy-solutions/air-source-heat-pumps; https://ma-eeac.org/wp-content/uploads/Exhibit-1-Three-Year-Plan-2022-2024-11-1-21-w-App-1.pdf.

programs, with overall statewide benefits of nearly $13 billion and a proposed $3.95 billion investment. For the 2022-2024 term, electrification initiatives are proposed as one of three key priorities. In that regard, the Three-Year Plan effects a measurable shift from past three-year plans to provide incentives for customers to electrify heating and cooling measures and move them away from using fossil-fueled equipment.

In that regard, one of the key strategies to achieving the Commonwealth's GHG goals is widescale transition from heating systems using heat pump technology. The market transformation strategy for heating electrification encourages accelerated adoption of heat pumps through engagement of all market actors (manufacturers, distributors, contractors, and customers), enhanced incentives, training, education, and marketing. A key component of an effective market transformation program is that it affects the market as a whole, not just the program participants.

More specifically, the 2022-2024 Plan includes the following volumes of residential cold climate heat pump installations and high efficiency C&I heat pump installations, as well as an extensive focus on market transformation through work with manufacturers, distributors, contractors and customers, as follows:

- Investment of over $800 million to achieve the heat pump installation goals, which is expected to result in a total of 43,370 "household equivalent" electric heated homes (17,677 full displacement homes and 36,590 partial displacement homes).

- Implementation of all-electric new construction offerings for residential and commercial buildings in 2022.

- Commitment to work with customers, contractors, and manufacturers to drive market transformation and generate customer demand, with specific key performance indicators/measures of success and milestones.

- Discontinuance of new non-heat pump central air conditioning residential incentives starting in January 2022.

The 2022-2024 Plan also reduces support for fossil-fuel heating and hot water equipment through:

- Elimination of residential incentives for all oil-fired boilers in 2022-2024. For all other residential fossil fuel heating systems, the PAs will only offer, with limited exceptions, incentives to customers who have non-condensing heating systems and are converting to condensing heating systems.

- Phasing out natural gas combined heat and power ("CHP") incentives. No new natural gas CHP projects will be incentivized in 2022-2024 except for agreed upon, already committed CHP projects agreed upon by the PAs, the Attorney General and the DOER. Any additional applications of CHP will only be established consistent with the Commonwealth's policies, and only if parameters are agreed upon in advance by the DOER.

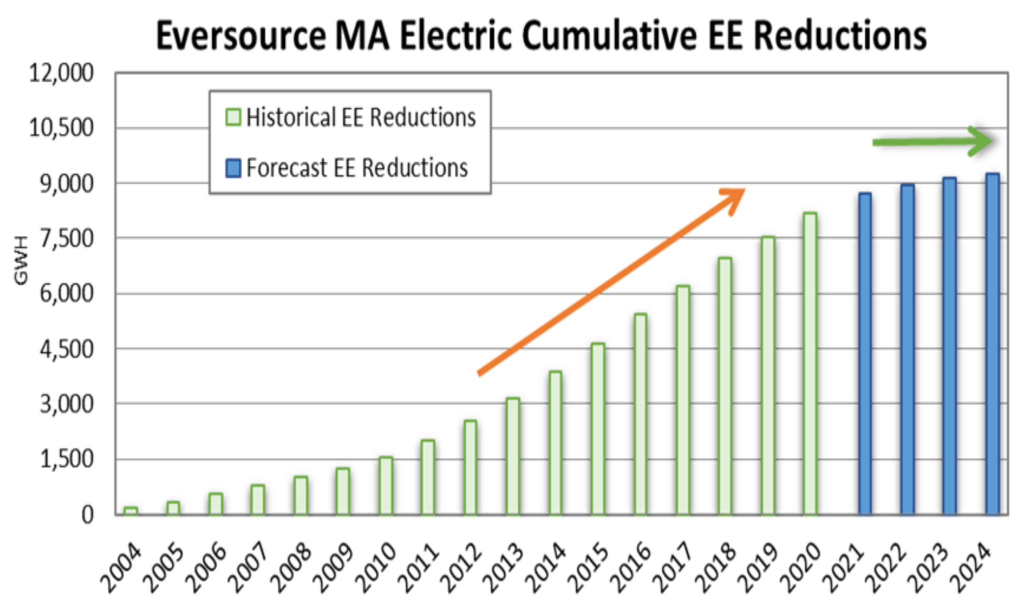
- Phasing out support for fossil fuel generators. Starting in 2022, fossil fuel generators will not be eligible to participate in Active Demand Reduction offerings, including Daily Dispatch or Targeted Dispatch, in 2022-2024.

Q. Does the current forecast for the impact of energy efficiency on sales volumes differ from the forecast existing in D.P.U. 17-05?

A. Yes. As shown in Figure 4, above, cumulative energy efficiency reductions were forecast to increase unabated over the term of the PBR Plan, through 2022. Today, the 2022-2024 Three-Year Plan is pending before the Department and the initiatives contained in that plan are changing the trajectory of anticipated reductions to electric sales volumes. Figure 5, below, highlights this change in the energy efficiency forecast, indicating a leveling off of energy efficiency reductions as a transition to electrification objectives occurs.

FIGURE 5

Cumulative Energy Efficiency Reductions
Forecast Through 2024



Q. Have the Company's capital requirements trended in parallel with the trends in sales volumes?

A. No, the trends in the Company's distribution system investment requirements have not followed the 15-year history in declining sales volumes – in fact, quite the opposite. Regardless of whether sales volumes are declining as a result of concerted energy efficiency initiatives – or are *inclining* to meet electrification objectives -- the Company's investment levels continue to increase as a matter of necessity. Broader energy sales reductions that have occurred in the past have not translated into reduced infrastructure requirements primarily because of the confluence of localized demand growth and localized infrastructure capacity. For good reasons, the Commonwealth's energy efficiency programs were not specifically targeted to localized areas where new or expanded substation capacity was needed. If 100 MWs of energy efficiency is spread over 100 stations, it will not defer the need that may exist at a single station that may be 5 MW below capacity and will experience 6 MW of demand growth over the next five to 10 years, for example.

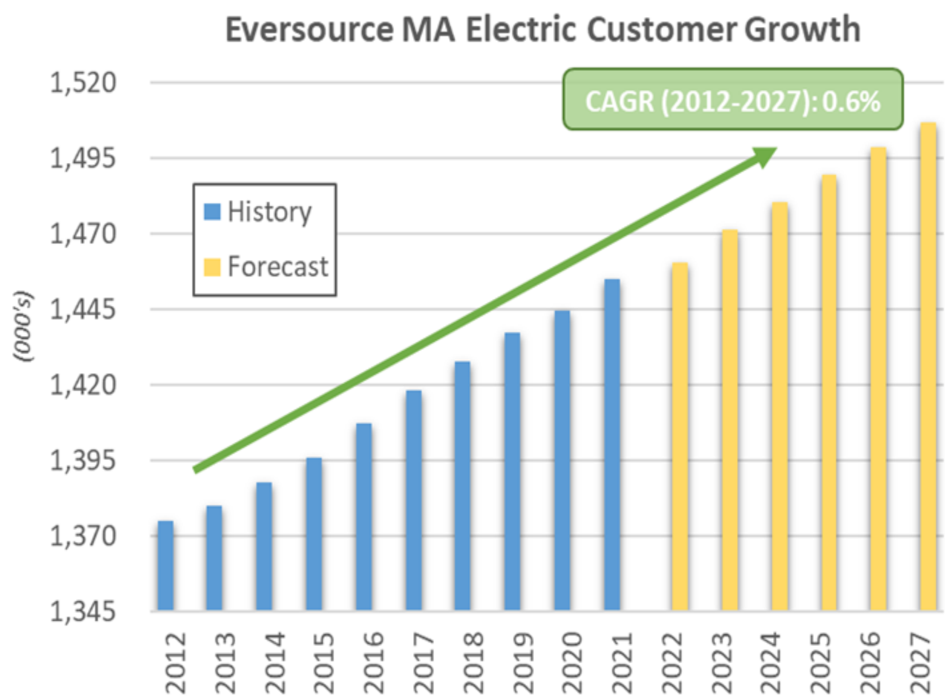
As a result, traditional investments are more critical than ever to maintain and improve system reliability and resiliency to meet the increasing expectations of customers. And, in parallel, there is an escalating need for new investment in the "next generation" electric grid, including support for electrification. This is the conundrum of the current operating environment for electric utilities, *i.e.*, even if overall electric consumption is levelling off, the requirements for system investment are increasing as the need for a more resilient, modern electric grid becomes ever more necessary. In parallel, cyber-security concerns continue to demand extraordinary vigilance and investment from the Company, particularly in view of increased utilization of digital technology and the integration of DER.

In fact, electric utilities are now operating within a paradigm where customers are demanding highly reliable service, better information about that service, and increased accessibility to customer-account services through digital technology. In addition, while the proliferation of DER is a factor in declining sales volumes, the physical interconnection of DER requires substantial capital investment to modernize the system, increase its capacity and allow for the changing power flows that have to be accommodated in order to enable the system to work on an integrated basis and with a continuing high level of safety and reliability for all customers. This reality is the impetus for the Department's investigation in D.P.U. 20-75.

Q. Would you describe the growth that is occurring on the distribution system currently and that is forecast for the future?

A. Yes. Unlike the circumstances with *sales volumes*, where the compound average growth rate is negative in the period 2008-2020, as compared to 1997-2007, the compound average growth rate for the *number of customers* has slowed, but is still positive, as shown in Figure 6, below:

Figure 6: Eversource Customer Growth (2012-2027)



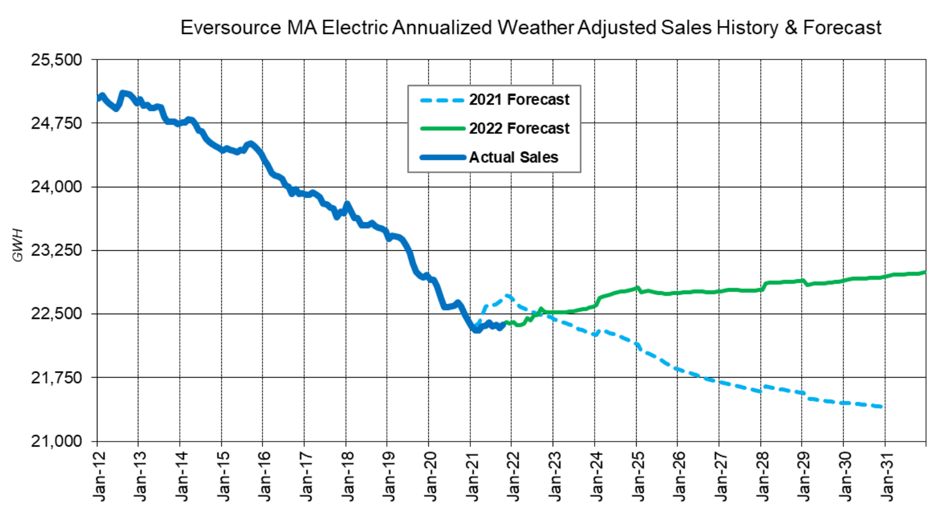
Specifically, the compound average growth rate in the number of customers in the Eversource service territory was 0.8 percent in the period 1997-2007 and approximately 0.6 percent in the years 2008-2020. The Company experiences growth in the number of customers regardless of the massive deployment of energy efficiency and other load-shaving initiatives because Massachusetts enjoys relatively strong and consistent trends in total employment, gross state product and household income, which are all economic drivers of new customers and associated electric sales. Notwithstanding the impact of the COVID-19 pandemic in the past 18 months, the NSTAR Electric service territory represents one of the strongest growth platforms in the Northeast United States, requiring substantial and constant capital investment regardless of the sizeable reductions in overall sales volumes and declining per-customer consumption achieved through state policy initiatives.

Q. Has the composition of the 2022-2024 Three Year Energy Efficiency Plans changed the Company's planning outlook in relation to sales volumes?

A. Yes, most definitely. Figure 7, below, presents the Company's FY2021 sales forecast versus the FY2022 forecast. The FY2022 forecast incorporates the energy efficiency reductions expected out of the 2022-2024 Three Year Energy Efficiency Plan, highlighting the significant transition in expected electric sales volumes for the future:

FIGURE 7

Annualized Sales History and FY2021, FY2022 Forecast



Q. What is the Company's track record for capital investment over the past 10 years, as sales volumes have declined?

A. Notwithstanding declining sales volumes, the Company has had to consistently invest substantial capital resources to construct, replace and maintain its distribution infrastructure. Table 3, below, shows the Company's investment record since the ramp-up of the Commonwealth's energy efficiency initiatives through the test year in this filing (year-ending December 31, 2020).

Table 3: Annual Capital Additions Since 2009 (incl. cost of removal)

Year	Eversource East Annual Capital Additions	Eversource West Annual Capital Additions	Combined Total
2009	$206M	$51M	$257M
2010	$199M	$40M	$239M
2011	$208M	$45M	$253M
2012	$272M	$39M	$311M
2013	$188M	$45M	$233M
2014	$246M	$37M	$283M
2015	$256M	$53M	$309M
2016	$335M	$35M	$370M
2017	$258M	$49M	$307M
2018	$310M	$130M	$440M
2019	$324M	$87M	$411M
2020	$364M	$86M	$450M

Q. What are the dynamics existing on the Eversource electric distribution system that drive the need for increasing investment, despite declining or flat sales volumes?

A. From an operating perspective, there is a convergence of factors that are affecting the Company's planning and investment horizon. As an initial matter, electric utilities are fundamentally focused on the installation and maintenance of delivery infrastructure. In today's operating environment, the installation and maintenance of electric delivery infrastructure is involving more and more sophisticated technology, which is increasingly costly to procure, handle, install and maintain, and requires on-going changes and improvements to employee training strategies. Due to the nature of the service the Company is providing, i.e., a public necessity delivered over broadly located physical assets, considerations relating to physical and/or cyber security, the need to minimize environmental impact and achieve data capabilities becomes paramount. Although the Company has always had to deal with considerations regarding security and environmental impact, the operating environment has become much more challenging in relation to these items.

In addition, there is a growing need for investment to achieve storm resiliency. Perfect, reliable power is always a goal, but there are inevitably challenges that cannot be avoided. Particularly, when it comes to extreme weather including hurricanes, tornadoes, and blizzards. The question is not whether an outage will occur, but how quickly the distribution system can recover from it. Experience has shown that the formula for withstanding hurricanes and other weather disasters is part preparation and part recovery. The more effort and resources that the Company is able to invest in preparation (including resistance to storm damage), the more success customers can expect with recovery. Extreme weather events are hugely disruptive to customers in vast and lasting ways, and the significance of support investment on the electric distribution system is most evident when the physical foundation is rendered usable for extended periods.

Lastly, as monitoring and switching systems become more automated on the distribution system, there is a need to protect the security of the data processes behind that automation. These dynamics, coupled with labor costs that often increase at a rate greater than inflation, pose huge challenges to the electric system at a time when overall sales volumes are declining.

Q. Is the push for electrification compelling substantial capital investment over the next 10 years?

A. Yes. At the end of 2020, the Commonwealth issued its Energy Pathways to Deep Decarbonization Study,[8] outlining a variety of pathways for the Commonwealth to achieve its goals of a carbon neutral future. A key component of both the Commonwealth's decarbonization objectives is the electrification of the transportation and heating sector. Both sectors today are supplied through their independent fuel infrastructures, be it natural gas pipelines or a network of gas stations. With the push to electrification, all the energy that traditionally has been transported through this infrastructure must be picked up by the electric power system. This creates a significant increase in peak demand and energy moved

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[8] Energy Pathways to Deep Decarbonization, A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study, December 2020.

across the electric system.

To proactively buildout the necessary infrastructure to meet this electrification future, accounting for land acquisition, siting, permitting and construction challenges in New England, investment decisions need to be made and initiated -- **today**. Therefore, beginning in 2020, the Company has worked to create a detailed, assessment of electric demand to facilitate infrastructure planning through the years 2040, and 2050, initially focusing on substation development. The goal of the assessment is to provide visibility into how local investments in distribution and transmission infrastructure will be needed to enable the statewide transition to a carbon neutral future over the coming decades.

To undertake this assessment, the Company deployed advanced forecasting and modeling methods, including 8760 time-series power flow models and probabilistic simulations to assess need and develop solutions. The data and information used to develop and assess electric demand were derived from various sources, including publicly available data; the Commonwealth's Clean Energy Pathways; state agencies; internal Company databases and institutional knowledge; and external experts. Along with other analysis that the Company has undertaken to further the objectives of DER interconnection (under consideration in D.P.U. 20-75), this detailed scoping effort has indicated the need for several large-scale substation developments and upgrades to numerous substation facilities through the

Company's service territory.

Q. Would you provide an example of the type of substation facilities that will be required to support electrification, particularly in urban load areas that involve environmental justice considerations for electrification efforts?

A. Yes. The primary example of the Company's forward-looking, critical infrastructure requirements is the development of Station #8025, in East Cambridge, Massachusetts (the "Cambridge Substation"). The Cambridge Substation involves the installation of: (1) a new 115/14-kV substation with three 115/14 -kV Bulk transformers expandable to accommodate a fourth Bulk Transformer in East Cambridge; and (2) five, new 115-kV underground transmission line duct banks connecting the Cambridge Substation with the existing Brighton (#329), Somerville (#402), East Cambridge (#875), and Putnam (#831) substations (the "New Lines"), along with 36 distribution feeders. Connections to the Brighton Substation facility require the construction of two new 115-kV transmission line duct banks, whereas connections to the other substation facilities located in Somerville and Cambridge require the construction of one new transmission line duct bank each, resulting in a total of five new transmission line duct banks to address load requirements. The Cambridge Substation is an integrated, long-term solution to address reliability needs in areas of the City of Cambridge that are experiencing rapid economic development and sustained load growth.

Major new commercial developments within the Project Area include Cambridge Center, Cambridge Research Park, Technology Square, and One Kendall Square, as well as several large lab and office buildings along Binney Street. The Project Area is home to some of the largest employers in Cambridge, including MIT, Biogen, Novartis, Sanofi Aventis, Takeda Pharmaceuticals, the Cambridge Innovation Center, the U.S. Department of Transportation, Google, Hubspot, the Broad Institute, Akamai Technologies, and Pfizer.

The testimony of Company Witnesses Chatterjee, Freeman and Walker discusses the work underway by Eversource to develop sophisticated modelling routines to assess and define the need for major station capacity projects, including the Cambridge Substation and certain other planned facilities, and to evaluate that need as a function of future electrification, including rooftop solar, electric vehicles and the installation of heat pumps. Specifically, for power-system planning, the following components of the Commonwealth's proposed pathway stand out:

- Widespread adoption of heat pumps and resistive electric heating in buildings, which is poised to transfer significant energy demand from the other fuel sources to electric infrastructure.
- Widespread adoption of electric vehicles that will drive a charging demand transitioning the existing gasoline supply infrastructure to the electric infrastructure.
- The addition of significant distributed renewable generation, mostly in form of photovoltaic systems at the distribution level and offshore wind at the transmission level.

The Company recognizes that accurately projecting the precise system demand several decades into the future is extremely challenging, if not impossible, and will be influenced by the speed and direction of efforts implemented to achieve the Commonwealth's carbon-reduction goals. Key learnings from the "All Options" pathway is summarized as: (1) stringent removal of fossil fuels from building applications; (2) wholesale electrification of the transportation sector; and (3) a significant increase in solar and wind generation.

In addition, the Company's Long-Term Load Assessment confirms that the Commonwealth's objectives to decarbonization will continue to drive load in the region significantly. To ensure a seamless transition into a decarbonized future and to provide enough headroom for new commercial development, new investments in the electric infrastructure are necessary – and planning these infrastructure improvements proactively is imperative. Even aggressive energy efficiency and demand response programs would not obviate the need for the investment in the next decade. With the Commonwealth's firm commitment to enabling the decarbonization and ensuring that future growth in the region is possible, the system's capacity must be expanded.

Below, our testimony discusses the Company's proposal to account for Major Station Capacity Projects that are contemplated over the next 10 years to support reliability, resiliency and clean energy objectives.

Q. Given the changing landscape transitioning from energy efficiency to electrification, should the Department consider eliminating the Revenue

Decoupling Mechanism as a method of motivating electrification?

A. No, it is not yet appropriate for the Department to eliminate the use of the Revenue Decoupling Mechanism ("RDM") because there is significant investment required to prepare the system for the level of customer demand anticipated in the future. Development of electric infrastructure is necessary to enable electrification and infrastructure investment must be expected to precede the availability of customer revenues associated with increased sales volumes. If the tactic is to wait for incremental customer load to materialize before planning for infrastructure capacity increases so that increased revenues will pay for the increased investment, a massive safety and reliability risk will arise. Because Eversource will not allow increased risk to the safety and reliability of electric service, the natural outcome is a negative feedback loop that will compel limitations on electrification growth, notwithstanding the Company's obligations to deploy a certain amount of EV charging infrastructure and heat pumps, for example. Customer revenues will not materialize at the *outset* of the process, but rather will be realized later in the process. For the utility to make proactive investments for a seamless transition, the utility needs to have recovery of the investments as those investments are made, which means that the RDM should remain in place until such time that the anticipated increases in sales revenues have *actually* materialized.

For this reason, the combination of PBR and the RDM continues to be an appropriate approach over the long term. The PBR approach provides flexibility for the utility to pursue initiatives associated with digital technology, DER integration, cyber-security and system resiliency, coupled with stronger incentives for cost control and the opportunity to incorporate performance metrics that are meaningful and in furtherance of the public policy goals. The PBR approach also has the significant benefit of alleviating administrative burden by avoiding frequent rate reviews, which are difficult for all parties involved to get through. However, the RDM remains necessary to assure that the Company will actually collect the allowed revenues in furtherance of the investment objectives.

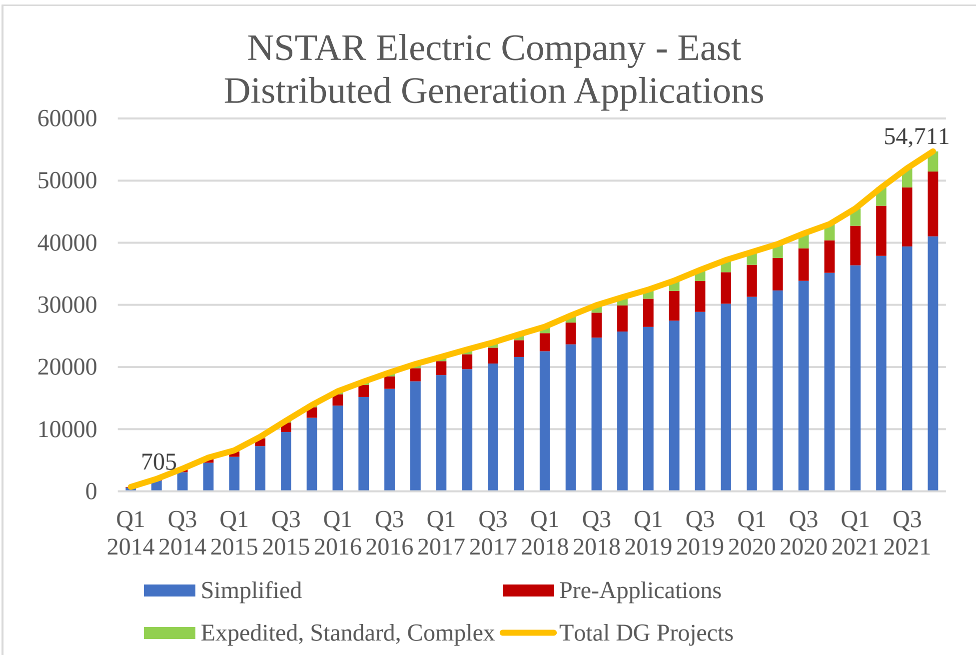
Q. What is the Company's experience with DER integration to date?

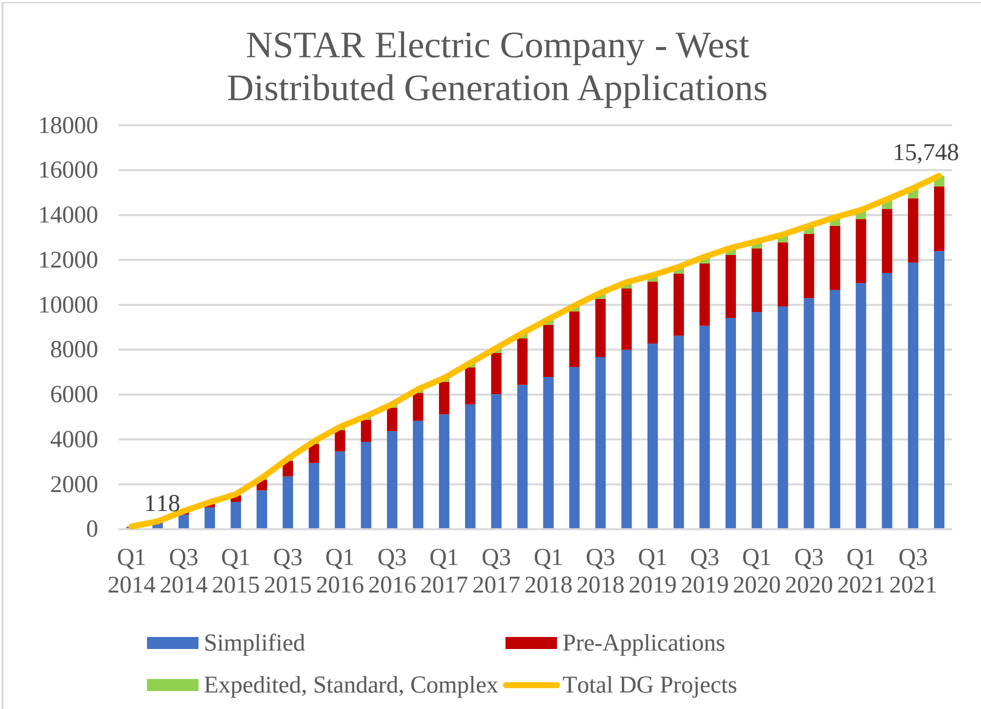
A. DER is playing an important role in helping to advance the Commonwealth's clean energy and environmental policy goals and the Company supports the effort to facilitate the interconnection of DER to the electric distribution system. Currently, there are primarily three types of DER that are interconnecting with the Eversource distribution system: solar, wind and natural gas (including combined heat/power). Anaerobic digestion and hydropower are other resources that the Company has or expects to interconnect with as this technology evolves. Solar interconnections by far account for the bulk of the interconnecting facilities and the number of these facilities interconnecting with the Company has vastly accelerated in recent years. In fact, Massachusetts is currently fifth in the nation in terms of the number of completed solar interconnections.

In the fourth quarter of 2021, the Company had approximately 54,711 DER projects installed or in process in the Eversource East area, and 15,748 projects in the Eversource West area. The Company has had almost as many requests for new DER interconnections in the past year as for new electric service and, in some areas, the Company has more requests to connect DER than new customer connect requests. This level of change is depicted for Eversource East and Eversource West in Figure 8, below:

Figure 8

NSTAR Electric Company - DER Applications





Although the Company has met and exceeded performance requirements for the processing of DER applications, the pressing demand for interconnection is causing the Company to hire new resources and incur costs to meet this demand. It is important for the Commonwealth's objectives for the Company to keep moving on its processing of DER applications and investment in enabling infrastructure and the Company takes this responsibility very seriously.

IV. PROPOSAL FOR RENEWAL OF PBR PLAN

Q. Why is the Company proposing to renew the PBR Plan?

A. The Company is proposing to renew the PBR Plan because it has proven to be an innovative mechanism that is effective in promoting rigorous cost control, while enabling investment in emerging technologies that will enhance reliability for residential and business customers and help Massachusetts meet its ambitious clean-energy goals, including substantial investment in distribution automation, electric-vehicle infrastructure and other clean energy capabilities. As demonstrated by the results of the first PBR term, PBR provides strong incentives to control costs and promote performance that furthers public-interest objectives. Cost control, in particular, is a critical objective in an environment where electric utilities are facing financial challenges resulting from the increased costs of energy infrastructure, stagnant customer sales and increased DER deployment.

During the first term of the PBR Plan, the PBR construct challenged the Company to find better, more innovative ways to achieve cost reductions while still providing customers with safe and reliable service, which benefits the overall system, whether in relation to the integration of DER, energy storage, or other electrification purposes. The PBR construct also was effective in maintaining a level of rate stability and predictability, avoiding relatively larger rate changes that typically accompany a base-rate proceeding.

Q. Would you please describe the overall structure of the PBRM?

A. The Company's proposed PBRM generally follows from the model approved by the Department in D.P.U. 17-05. For example, the Company's proposed PBRM is designed as a "revenue cap" formula that would be used to adjust rates on an annual basis in lieu of an annual capital cost recovery mechanism. The PBRM formula is derived through economic analysis of utility cost trends as indicated by measures of inflation, input prices and total factor productivity. The specific revenue-cap formula proposed by the Company is discussed in the testimony of Company Witnesses Meitzen and Crowley. Dr. Meitzen and Mr. Crowley have performed the in-depth economic research and analysis supporting the Company's proposed revenue-cap formula and their testimony details the methodological underpinnings for the revenue-cap formula.

Although generally following from the model approved by the Department in D.P.U. 17-05, a major difference in this proceeding is that the Company is proposing a 10-year term for the PBR Plan with a five-year, mid-term "rate schedule filing" to meet the requirements of G.L. c. 164, § 94, as discussed below. As a 10-year PBR Plan, the Company has adopted components of the NSTAR Gas Company PBR Plan, which the Department has considered and approved as appropriate elements of a 10-year plan. The Company is also proposing an alternative PBR Plan with a five-year term should the Department not accept the proposed 10-year term and associated ratemaking mechanisms.

Q. Are there other components of the PBRM, aside from the revenue-cap formula developed by Dr. Meitzen?

A. Yes. The Company is proposing other elements to the PBRM, including a proposed minimum annual adjustment for the revenue cap formula; a proposed Consumer Dividend to provide a "stretch factor," applicable when inflation equals or exceeds two percent; a rate base roll-in for 2021 and 2022 capital investments; a return on equity risk factor triggered by significant changes up or down in Treasury rates; cost treatment in the second five years of the PBR Plan for critical infrastructure; an earnings-sharing mechanism, and an exogenous cost provision. Each of these components is described in detail below. The Company is also proposing to make annual compliance filings to implement the rate change allowed in accordance with the PBRM. In the annual filings, the Company would report on its progress on the PBR Plan in accordance with a series of progress or "performance" metrics that the Company is proposing to institute to allow for monitoring and evaluation of plan objectives.[9]

A. Term and Annual Compliance Filings

Q. Would you please review the mechanics of the Company's proposed PBR Plan?

A. Yes. The PBRM is based upon a "revenue cap" rate formula that would be instituted in conjunction with the RDM. The specific revenue-cap formula proposed by the Company is discussed in the testimony of Company Witnesses Meitzen and Crowley. With the Department's approval of the PBRM in this proceeding, the first rate change pursuant to the PBRM would occur on January 1, 2024, and annually each year thereafter through and including January 1, 2032.

[9] As described in the testimony of Company Witness Conner, Chatterjee, Finneran and Renaud, the Company's proposed performance metrics have a five-year timeline. If a 10-year PBR Plan is approved, the metrics would be revisited as part of the mid-term review during the PBR term.

Q. Would the Company make an annual filing to implement the annual PBRM rate change and demonstrate progress on the performance metrics?

A. Yes. For each year that the PBRM is in effect, the Company would submit an Annual PBR Plan Compliance Filing to the Department on or before September 15 of each year, for implementation of new rates on the subsequent January 1. The compliance filing would include, among other things: (1) the calculation of the annual revenue-cap adjustment, including documentation associated with any exogenous costs for the prior year, if applicable; (2) the development of new rates consistent with the revenue-cap formula, (3) an earnings-sharing computation, as applicable, and (4) class-by-class bill impacts. The first annual compliance filing for the PBRM computation would be submitted to the Department on or before September 15, 2023, for effect on January 1, 2024.

B. Revenue Cap Formula

Q. What is the revenue-cap formula supported by the economic analysis performed by Dr. Meitzen and Mr. Crowley?

A. The testimony of Company Witnesses Meitzen and Crowley presents the revenue-cap formula derived from the results of his economic analysis, along with a detailed explanation as to the theoretical underpinnings of the economic analysis and how it is performed is provided as Exhibit ES-PBR/TFP-1. The economic analysis performed by Dr. Meitzen and Mr. Crowley yields a revenue-cap formula of "I-X," with "I" representing a measure of economy-wide output inflation, such as the Gross Domestic Product – Price Index, or "GDP-PI," as measured by the U.S.

Commerce Department, and "X" based on the differences in productivity and input price growth between the electric-distribution industry and the overall economy.

Dr. Meitzen and Mr. Crowley explain that the allowed rate of change for the revenue-cap index is equal to the rate of general price inflation in the aggregate economy less an adjustment factor (the X factor). The X factor consists of the differential in expected productivity growth between the electric-distribution industry and the overall economy and the differential in expected input price growth between the overall economy and the electric-distribution industry. Although X is typically determined by a productivity study based on historical information, X is forward-looking as it is based on what differentials are expected to occur going forward.

Combined with the "I" factor, "I – X" represents the expected unit cost performance of an average performing company in the industry. The analysis conducted by Dr. Meitzen and Mr. Crowley indicates an "X" factor consisting of the differential in expected productivity growth between the industry and the overall economy (-0.28 percent) and the differential in expected input price growth between the overall economy and the industry (-1.17 percent), or a total of (-1.45 percent) [Exhibit ES-PBR/TFP-1, at 20]. The revenue-cap formula also includes components for the Consumer Dividend and the exogenous factor. In D.P.U. 17-05, the Department approved an X factor of -1.56 percent. D.P.U. 17-05, at 392.

C. Inflation Factor

Q. How would the Company compute the inflation index for each annual filing?

A. As described in the testimony of Dr. Meitzen and Mr. Crowley, the price-inflation index included in the revenue-cap formula would be based on the GDP-PI, as measured by the U.S. Commerce Department. This information is published each September in the Survey of Current Business, a publication of the U.S. Commerce Department, Bureau of Economic Analysis. The inflation index would be adjusted annually and would be calculated as the percentage change between the current year's GDP-PI and the prior year's GDP-PI. For each year, the GDP-PI would be calculated as the average of the most recent four quarterly measures of the GDP-PI as of the second quarter of the year.

The Department approved the use of GDP-PI for the inflation factor in D.P.U. 17-05 on the basis that GDP-PI is: (1) readily available; (2) more stable than other inflation measures; and (3) maintained on a timely basis. D.P.U. 17-05, at 393.

D. Minimum Annual PBRM Adjustment

Q. Is the Company proposing to establish a minimum level of inflation for the PBRM?

A. No. In D.P.U. 17-05, the Company proposed that the Department identify a minimum level of inflation floor of one percent for the PBRM due to the fact that the Company was proposing to commit to $400 million of incremental investment over the five-year term of the PBR Plan, which was not reflected in the base revenue requirement for that case. In the final decision in D.P.U. 17-05, the Department rejected the Company's proposal and the Company is not renewing that request here. See, D.P.U. 17-05, at 393-394.

Q. Is the Company proposing instead to establish a floor for the annual PBRM adjustments?

A. Yes, after experience with the first term of the PBR Plan, the Company is proposing that the Department find that there will not be a *negative adjustment* to the PBRM should negative inflation exceed the X factor. In other words, if there is zero inflation, the annual PBRM adjustment would be equal to the proposed X factor of -1.45 percent. Similarly, if negative inflation were to occur up to -1.45%, the annual PBRM adjustment would approach zero, meaning that the negative inflation would deduct from the X factor of -1.45% in computing the annual adjustment. However, if negative inflation were to *exceed* -1.45%, then the annual PBRM adjustment would be held at zero maintaining base rates at the level last set in the most recent annual PBRM adjustment.[10] The Company is requesting this treatment because it would never be the case that the Company's overall cost of service is declining, even in a deflationary period, particularly where the Company's annual investment plan is continuing.

[10] As explained in the testimony of Company Witness Dr. Kaufmann, this eventuality is extremely unlikely given that inflation is moving in the other direction. Nevertheless, with a 10-year stay-out commitment, the Company needs certainty on the parameters of the PBR Plan under various operating conditions.

E. Stretch Factor

Q. What is your understanding as to the theoretical basis for a "stretch" factor?

A. The economic principles guiding the development of incentive-regulation plans call for parties to be made better off, meaning that both consumers and utilities should share in the benefits produced by incentive regulation. One of the benefits anticipated from incentive regulation is an improvement in the cost performance of the organization. The "stretch factor" is intended to share expected gains in cost performance under the PBR plan with customers. The Company recognizes this principle and agrees that customers should benefit from the implementation of a ratemaking mechanism that will work in tandem with the RDM to increase performance incentives, while simultaneously producing sufficient revenues for the Company to operate the system on a highly reliable basis while pursuing clean-energy goals.

The theoretical basis is one of the reasons the Company is proposing to implement the PBRM in place of the traditional capital-cost recovery mechanism. The Company recognizes that the PBRM will give the Company more flexibility to address the significant challenges it has in front of it, while at the same time providing a very certain, long-term benefit to customers due to the fact that the platform provides a much stronger incentive for the Company to identify ways to reduce operating and maintenance costs and to control both O&M and investment costs. The greater the level of cost control achieved under the PBRM, the greater the level of benefit for customers in the next general distribution rate proceeding.

This principle of incentivizing the attainment of lower operating costs than would have otherwise occurred has served the Company's customers well over the past many years, promoting stable distribution rates due to the ability to resist the periodic base-rate increases that would have been made necessary to recover increasing O&M costs. The benefit of strong cost-control incentives inures directly and inevitably to the benefit of customers in setting the next base revenue requirement.

As indicated by the cost-benchmarking analyses prepared by Company Witness Kaufmann, the Company comes to this exercise at this juncture with an efficient cost structure. In addition, the Company has outperformed the unit cost benchmarks embedded in the current PBR formula. These performance gains have helped to keep O&M expense at a level that has obviated the need for a change in the revenue requirement attributable to general O&M expense. Although any distribution rate increase causes an impact for customers, the impact in this case is far lower than what would have otherwise occurred without the substantial cost reductions already achieved for the benefit of customers.

Q. What is the Company's proposal in relation to the stretch factor?

A. There are two aspects of the Company's proposal for the stretch factor, which correlate to the analysis developed by Company Witnesses Meitzen, Crowley and

Kaufmann.

First, as discussed by Dr. Meitzen and Mr. Crowley, the use of a "revenue-cap" model as opposed to a "revenue-per-customer" model is significant in that it does not allow revenue to change with customer growth. The customer growth that will inevitably occur on the Company's system imposes a cost that is not accounted for in the revenue-cap methodology. Conversely, the "revenue-per-customer" model allows revenues to grow as a result of both (i) changes in revenue per customer given by the "I – X" cap; but also (ii) the number of customers. The revenue-cap formula does not account for the growth in the number of customers and therefore, incremental costs associated with this growth will be absorbed by the Company. In other words, in using a "revenue cap" model rather than a "revenue per customer" model, the Company is including an implicit stretch factor in its cap equal to the rate of customer growth.

Over the 2005-2020 period, NSTAR Electric had average annual customer growth of 0.68 percent. This means that, under a revenue-per-customer model, revenue would be allowed to grow 0.68 percent more each year than it would under a revenue cap model (i.e., 1.45% plus 0.68 percent, or 2.13 percent, plus inflation). Eversource is not proposing to apply a revenue-per-customer model in its PBRM, or to increase the proposed productivity factor by this amount. As a result, there is an implicit stretch factor of -0.68 percent associated with customer growth already reflected in the X factor.

Second, the Company is proposing to implement an explicit Consumer Dividend of 15 basis points where inflation exceeds two percent. This additional stretch factor is proposed by the Company to ensure that customers benefit from the achievement of cost efficiencies over the term of the PBRM. The addition of an explicit efficiency component results in the following aggregated Stretch Factor, accounting for both implicit and explicit deductions:

Inflation Factor	**Customer Growth**	**Consumer Dividend**	**Cumulative Deduction from X**
GDP-PI < 2%	-0.68	0%	**-0.68%**
GDP-PI > 2%	-0.68	-0.15%	**-0.83%**

Q. What is the basis for the Company's Consumer Dividend of 15 basis points?

A. In preparing the proposed PBRM in this proceeding, the Company consulted with Dr. Kaufman as to the theory of the Consumer Dividend and the possible methods for determining an appropriate value given the Company's specific circumstances. Dr. Kaufman advised the Company that while the ultimate determination of a consumer dividend value is largely subjective, quantitative data on the Company's cost performance can help inform the Department on appropriate consumer dividend values in light of the Company's current circumstances, as well as other elements of the PBR proposal that may provide benefits to customers [Exhibit ES-PBR/TFP-1, at 55]. Dr. Kaufmann also advised that the value of the consumer dividend should vary depending upon factors that would reduce the magnitude of the stretch factor or nullify the stretch factor altogether. These considerations include but are not limited to whether the PBR proposal updates a previously-approved PBR plan, the inclusion of an earnings sharing mechanism in the PBR plan, and the potential for customers to receive substantial benefits at the termination of the plan when cost gains made under PBR are passed through into rebased distribution base rates [id.].

In this case, the Company is proposing a 15 basis-point Consumer Dividend factor to demonstrate the Company's commitment to provide customers with an explicit, tangible benefit in relation to operating-cost control. Under circumstances where inflation is greater than two percent, the Company's operating costs will be increasing at a fairly substantial pace, and the 15 basis-point Consumer Dividend will force the Company to work hard to find ways to suppress cost increases to the direct benefit of customers in the next rate case.

In D.P.U. 17-05, the Department approved a Consumer Dividend of 0.15 percent where inflation exceeds two percent. D.P.U. 17-05, at 395. However, in this case, the Company is petitioning the Department for implementation of a second generation PBR Plan, which will follow over 20 years of operation under a series of rate freezes, long-term rate plans and, most recently, a five-year PBR Plan. The Company is entering the PBR Plan as a cost-efficient utility with a rationalized operation reflecting a relatively high level of efficiency. As discussed by Dr.

Kaufmann, the Company is not facing a circumstance where the implementation of the PBRM represents a first-time transition from traditional cost-of-service regulation to an incentive framework. Instead, the Company is coming to the PBRM after sequential, long-term stay-out agreements explicitly designed to promote cost reductions. Accordingly, the Consumer Dividend is appropriately set at 15 basis points when inflation is greater than 2 percent, and there is no quantitative justification for setting it at a different level. The Company is voluntarily committing to the 15 basis points as part of the regulatory compact encompassing the PBRM so that there is an explicit customer benefit incorporated to the PBRM. Dr. Kaufmann's testimony validates the imposition of a Consumer Dividend for the second generation PBR of 0.15 percent.

F. Rate Base Roll-In, 2021 and 2022

In D.P.U. 19-120, the Department found that a ten-year term will give the plan sufficient time to achieve its goals and to evaluate administrative efficiencies, while providing the appropriate economic incentives for cost containment and long-term planning. NSTAR Gas Company d/b/a Eversource Energy, D.P.U. 19-120, at 65-66 (2020). The Department further found that the proposed capital investment roll-in of 2019 and 2020 capital investments (non-GSEP) is necessary to cover the expected increase in costs associated with necessary capital investments. D.P.U. 19-120, at 72.

Similarly, in this case, the Company is proposing a 10-year PBR Plan. To make a

10-year PBR Plan term feasible, the Company is first requesting that the Department allow the roll-in of 2021 and 2022 capital investment. Thus, in base distribution rates effective January 1, 2023, the Company's rate base will be determined by the test-year net plant updated to incorporate the 2021 plant additions. As required in D.P.U. 19-120, the Company will adjust the rate base for depreciation expense, return on rate base, associated federal and state income taxes, property taxes, and revenues for all capital additions ending December 31, 2021. During this proceeding, the Company will provide project documentation to support the 2021 capital additions. Id. at 73. This documentation is presented and discussed by Company Witnesses Landry and Griffin.

Second, the Company is requesting that the Department allow the Company to update rate base to incorporate the 2022 plant additions along with associated accumulated depreciation as part of the first annual PBRM filing effective January 1, 2024. The Company will file no later than April 1, 2023, all relevant project documentation and supporting testimony to demonstrate that the costs associated with the 2022 investments were prudently incurred and that the plant is used and useful in service to customers. The Company will adjust the base distribution rates for depreciation expense, return on rate base, associated federal and state income taxes, and property taxes for all existing assets ending December 31, 2022. The Department will establish an appropriate procedural schedule to provide interested parties an opportunity to review the project documentation and supporting testimony.

G. Return on Equity Risk Adjustment

Q. What is the Company proposing in terms of the Return on Equity Risk Adjustment?

A. In this case, the Company is proposing a Return on Equity Risk Adjustment ("ROERA") mechanism to recover costs arising from material changes in capital market conditions during the duration of the 10-year PBR Plan. In light of the intensive capital requirements that the Company will face over the next 10 years, the Company's cost of capital will be impacted by material changes in capital markets. Capital market changes are beyond the control of, and therefore exogenous to, the Company. However, these types of cost changes are not associated with accounting, regulatory, judicial, and legislative acts, for which cost recovery is allowed under the exogenous cost factor. The full cost impact of changes in capital market conditions will also not be reflected in economy-wide inflation indices such as the GDP-PI.

Therefore, the Company is proposing the ROERA Mechanism is based on a proposal that was previously put forward by Boston Gas Company in D.P.U. 96-50 (1997). The ROERA Mechanism would be triggered in the event that the yield on 10-Year Treasury bonds increases or decreases by at least 200 basis points from the yield that was in effect at the outset of the PBR Plan. If, and when, these circumstances were to occur, a rate adjustment would take place. The adjustment would apply only to approved rate base at the outset of the PBR Plan and not for additions made while the PBR Plan is in effect. This proposal is discussed in detail in the testimony of Company Witness Kaufmann.

H. Cost Treatment for Major Station Capacity Projects

Q. Please describe the types of major infrastructure that the Company will have to build over the next 10 years to support reliability, resiliency and electrification in the NSTAR Electric East service area.

A. The testimony of Company Witnesses Chatterjee, Freeman and Walker provides detail regarding the types of major infrastructure that the Company will have to build over the next 10 years to meet existing, forecasted customer demand through 2030, and incremental electrification demand through 2050. In that regard, Mr. Chatterjee's system planning group is developing comprehensive plans to position the NSTAR Electric transmission and distribution system to meet the needs of customers both from a reliability and resiliency perspective, but also in relation to future electrification. The Company's reliability-based capacity expansion plans require the installation of new substations, feeders and underground transmission lines necessary for a long-term solution through 2050.

For example, Mr. Chatterjee's system planning group is developing the Cambridge Electrification Project for Station #8025. The project is designed to address both the need for additional substation capacity and to mitigate the potential for existing transmission line overloads that would result in a loss of service to customers in the project's area under certain contingencies. The increased demand in this area is attributable to the numerous, biotechnology firms and laboratories, educational facilities, medical facilities and increasing retail, hospitality and residential developments centralizing in Cambridge. The Company's current electric power system feeding this area is no longer capable of meeting the increasing energy needed to sustain the area's economic growth and future energy needs. This is also true for other areas in the Company's system making it necessary for the Company to make allowance for these facilities during the proposed 10-year term of the PBR Plan.

Q. Are these types of major infrastructure investment critical to assure that environmental justice areas are able to participate in future electrification?

A. Yes. Both Environmental Justice ("EJ") and non-EJ communities require reliable electric service and the necessary infrastructure such as electric substations to deliver electricity, support public health and further economic activity such as electric vehicles and heat-pump installations. Major substations are located throughout the state where electrically needed to serve customer load and, where there are no substations, the ability to serve increased electric load has the potential to be impaired. Many cities and towns in Eversource's territory have substations, including Cambridge, Newton, Winchester, Sudbury, Needham, and Hopkinton. Rapidly increasing load makes need for new or expanded substation facilities more acute in the geographic location where that load exists.

Given the long lead time for these types of projects, and the likelihood of permitting and siting challenges, the Company has to plan years ahead to be in a position to serve increased load in the future. In the current operating environment, that means that the Company needs to plan, develop and build several major infrastructure projects over the next 10 years in order to be ready to serve increased customer load happening in the time frame of 2030-2050. It is not an exaggeration to state that the Commonwealth's clean energy agenda depends directly on the development of these types of major infrastructure projects. In relation to several of these projects, participation by environmental justice communities in electrification and clean energy initiatives will be blocked if infrastructure is not developed to enable that participation.

Q. What projects does the Company anticipate completing in the next 10 years that fall into the category of Major Station Capacity Projects?

A. There are many projects that the Company will be completing in the next 10 years that qualify as "major infrastructure projects," including substations and new circuits across the NSTAR Electric service territory. However, there is a subset of projects that are characterized by a level of criticality that transcends other projects and a magnitude of cost that is multiples of the Company's entire annual capital budget for distribution operations. These projects are identified in Exhibit ES-ENGP-2 by Company Witnesses Chatterjee, Freeman and Walker, as "Major Station Capacity Projects." As shown in Exhibit ES-ENGP-2, the following major infrastructure projects are anticipated for completion in the next 10 years:

- Burlington
- Natick
- Hyde Park-Dorchester
- Falmouth
- Dennis – Brewster
- Somerville
- Downtown Boston
- Metro Boston

In addition, capacity expansions are under evaluation at the following substations or distribution feeders:

- Somerville
- Mystic Substation
- Electric Avenue
- Alewife
- Seafood Way
- Action – Maynard

Q. What are the estimated costs of these projects?

A. The total cost forecast to complete the contemplated Major Station Capacity Projects is presented in the testimony of Company Witnesses Chatterjee, Freeman and Walker. However, the capital additions associated with these projects total approximately $956 million in the aggregate over the next 10 years.

Q. What is the cost treatment that the Company proposes in relation to these projects in the event that the Department considers approval of a 10-year PBR Plan?

A. Eversource cannot commit to a 10-year PBR Plan without a plan for cost treatment of the revenue requirement associated with the substantial investment that will have to be made in furtherance of these critical, major capacity upgrades during the 10-year terms of the PBR Plan. Therefore, the Company proposes that the Department provide the opportunity to commence recovery of the revenue requirement associated with a list of Major Station Capacity Projects, designated as eligible in this proceeding. The Company proposes to have the opportunity to file to commence recovery of the revenue requirement on the designated projects, <u>if completed and placed in service in accordance with the designated timelines</u>. The Company is not asking to recover any portion of costs on capital expenditures not yet resulting in projects placed in service, even if designated in this proceeding as an eligible project. Moreover, all project costs would be subject to a prudence review before any revenue requirement would be allowed for recovery.

Q. What would be the schedule for filing for cost treatment of Major Station Capacity Projects?

A. One difficulty with these projects is that projects of this magnitude generally require approval by the Massachusetts Energy Facilities Siting Board, as well as having to satisfy numerous other state and local regulatory permitting requirements. As the Department is aware, the siting and permitting process for these types of projects is arduous and subject to delays beyond the control of the Company. The

10-year term of the PBR Plan would start on January 1, 2023 and end on December 31, 2032, with the five-year mid-point being January 1, 2028. Thus, the Company proposes to have three possible points at which costs could be submitted for a prudence review and cost treatment. This schedule would be as follows:

Eligible Cost Period	Filing Date	Rates Effective Date	Estimated Capital Additions
Capital Additions through 12/31/2025	April 1, 2026	January 1, 2027	$431M
Capital additions through 12/31/2027	April 1, 2028	January 1, 2029	$352M
Capital additions through 12/31/2029	April 1, 2030	January 1, 2031	$102M

Q. How does the Company propose collecting the revenue requirement for pre-designated projects that are placed into service?

A. Eversource proposes to collect the revenue requirement associated with project costs that are reviewed and approved by the Department through the MSC factor, as part of the PBRM. The MSC Factor is the annual revenue requirement associated with the Major Station Capacity Projects. The Company would reflect the revenue requirement, including depreciation expense, return on rate base, and property tax associated with the Major Station Capacity Projects for capital investments placed in service at intervals over the Company's 10-year rate plan as reflected in the table above. The MSC Factor is included in the PBRAF formula as follows:

$$PBRAF_T = (GDPPI_{T-1} - X - CD) + [(Z1_{REV})_T + \boldsymbol{(MSC_{REV})_T} / BASE\_REV_{T-1}]$$

The PBRAF equals the percentage change in the Base Revenue Requirement as calculated by the addition of (1) GDP-PI, less an X Factor of -1.45, less a Consumer Dividend of 0.15 when inflation exceeds 2.0 per cent; and (2) the sum of cost impacts of Exogenous Events requiring a permanent change to the Base Revenue Requirement (positive or negative) plus the MSC Revenue Requirement associated with the Major Station Capacity Projects, which is then divided by the Base Revenue Requirement from the prior year to reflect the revenue requirement for these specific costs on a percentage basis. In this way, the Company is reflecting the PBRAF percentage change for the Base Revenue Requirement for the current period based on the I – X formula, including adjustments for Exogenous Events and the Major Station Capacity Projects.

I. Exogenous Cost Changes

Q. What is the Company's proposed criteria for the exogenous cost factor?

A. For purposes of the PBRM, "exogenous costs" would be defined as positive or negative cost changes that are beyond the Company's control and not reflected in the GDP-PI. The Company would include any such request for exogenous cost recovery in its annual compliance filing and would bear the burden of demonstrating the following criteria for recovery: (1) that the cost change is beyond the Company's control; (2) that the change arises from a change in accounting requirements, or regulatory, judicial or legislative directives or enactments; (3) that the change is unique to the electric distribution industry as opposed to the general economy; and (4) that the change meets a threshold of "significance" for qualification, which the Company is proposing initially to be $4 million. If the threshold is reached, the Company would qualify for recovery (or refund) of the quantified, qualifying cost without deducting any amounts below the threshold. Exogenous cost changes can be permanent in nature or non-recurring. The Company proposes to reflect recurring exogenous costs as a change in base distribution rates and that a non-recurring exogenous cost would be collected through a separate reconciling factor.

Q. Is the Company's proposed $4 million threshold of significance set using the formula previously identified by the Department for exogenous costs?

A. Yes. As noted by the Department in D.P.U. 17-05, the Department has consistently found that an exogenous cost significance threshold was reasonable where it was equal to a multiple of 0.001253 times a company's total operating revenues. D.P.U. 17-05, at 397, citing, Bay State Gas Company, D.T.E. 05-27, at 396 (2005); Boston Gas Company, D.T.E. 03-40, at 491 (2003); The Berkshire Gas Company, D.T.E. 01-56, at 22-26 (2001); Eastern Enterprises/Colonial Gas Company, D.P.U. 98-128, at 53-56 (1999).

For NSTAR Electric, the Department's current eligibility threshold of 0.001253 times total annual operating revenues would establish a threshold of $4 million, using revenue requirements developed in this proceeding for the computation.

The calculation to determine the appropriate threshold was as follows:

Total Operating Revenues	$	3,136,349,876
Exogenous Multiple		0.001253
Exogenous Threshold	$	3,929,846

Note: Operating revenues listed on Exhibit ES-REVREQ-2, Schedule 6

Q. Is the Company proposing that the $4 million threshold of significance change with the rate of inflation?

A. Yes. The Company is proposing that the exogenous cost threshold of significance be set at $4 million for calendar 2023, but thereafter would be subject to annual adjustment based on changes in GDP-PI, as measured by the U.S. Commerce Department.

Q. Are there any circumstances that the Company anticipates occurring within the foreseeable future that would meet the criteria for exogenous cost recovery?

A. Yes. There are two items of note in this regard. First, the testimony of Company Witnesses Frank and Botelho discusses the fact that the Company continues to challenge the new valuation methodology for utility property subject to municipal property tax. The exogenous cost provision of the PBRM obviates the need for the Department to establish a separate, designated mechanism for this specific property-tax change. Therefore, the Company is requesting that the Department acknowledge that an adverse ruling on the municipal property tax issue would qualify as an exogenous event, so long as the financial impact is greater than $4 million per year for NSTAR Electric, as adjusted by GDP-PI.

The Department's ruling in this case would simply designate that this item is eligible for exogenous cost recovery. The Company would retain the burden of making a filing to the Department to demonstrate that the computation of the cost is correct, and as computed, it meets and/or exceeds the threshold for eligibility. Any potential exogenous events in the future under the PBRM -- the terms of recovery from customers or refund to customers would occur in accordance with the Company's PBRM tariff, presented to accompany the testimony of Company Witness Chin, as Exhibit ES-RDC-6.

Q. Aside from property tax valuations, is there another circumstance that the Company is requesting the Department to consider for exogenous cost recovery?

A. Yes. Again, with the commitment to a 10-year stay-out to enable the PBR Plan, the Company is requesting the opportunity to propose exogenous cost recovery for certain Enterprise Information Technology ("IT") initiatives that equal or exceed 1.5 times the exogenous cost threshold for a single system implementation.

Q. What is an "Enterprise IT" project?

A. For most of the information systems implemented by Eversource Energy, the systems are shared by two or more operating affiliates. This approach is efficient and makes it affordable for operating utilities to install or upgrade IT infrastructure that is needed to provide a high level of service to customers. These types of shared projects are capital projects undertaken by Eversource Service Company. The revenue requirement associated with these ESC capital additions is charged out to the operating affiliates that are sharing in the use of the system.

Q. Why is the Company requesting to make a proposal for exogenous recovery in relation to Enterprise IT?

A. A major change is occurring in the way that Eversource and other electric utilities are developing Enterprise IT projects. Historically, Eversource Energy has primarily completed Enterprise IT projects as capitalized, on-site infrastructure maintained and operated by Eversource Energy. Going forward, it is becoming much more cost-effective to utilize cloud computing, which will mean that the cost of systems will be more likely to be incurred as expense rather than capital. Deploying IT resources by purchasing or developing on-premise IT infrastructure and software requires a substantial complement of internal and external staff to manage and operate the systems. Historically, this required a significant investment in computing capacity and software that was typically treated as a capital expense. In today's operating environment, cloud-based software is becoming prevalent usually involving the payment of a subscription fee for services. These fees are typically treated as an annual operating expense.

Q. Is there a benefit to customers associated with a transition to cloud computing?

A. Yes. There are substantial benefits associated with a transition to a cloud-based computing environment and use of Software-as-a-Service ("SaaS") model. For this reason, regulatory commissions, including the National Association of Regulatory

Commissioners ("NARUC") have recognized that it is in the interests of customers to enable and support the transition to cloud-based computing for utility companies. The recognized benefits of cloud computing and SaaS models include:

- **Quicker time to value** – Utilities can deploy and adopt cloud applications much more quickly than on-premise solutions. Reducing hardware and heavy integration work creates real cost savings for customers.
- **Flexibility** – Utilities can ramp cloud solutions up and down as programs and business models change, allowing the utility to pay only for the service or functionality that is needed.
- **Innovation** – Software vendors large and small focus their research and development on cloud applications. Rather than waiting for annual releases and costly upgrades of on-premise software, utilities can now continuously access the latest features in SaaS software.
- **Accessibility** – Administrators and program managers can grant secure remote access to employees, customers, and business partners. These external users are already very familiar with web and mobile applications.

Q. Why is the Company requesting a threshold of 1.5 times the exogenous cost threshold for Enterprise IT?

A. In this proceeding, the Department will review and approve a base revenue requirement that will include expense items for Enterprise IT projects that are already in service. As a result, there is a base level of Enterprise IT expense that will be collected through rates and that will be subject to the annual PBRM adjustments. Over the 10-year period, the Company will be adding new systems and other systems will become fully amortized and drop off. Therefore, there is a base level of Enterprise IT expense that will be covered in distribution rates as a matter of "ebb and flow," subject to the annual changes enabled by the PBRM.

As Eversource Energy transitions to a cloud-based computing strategy, the costs that are included in base rates may become mis-aligned with the Company's actual costs. Given the extended timeframe of a 10-year PBR Plan, it is difficult for the Company to assess whether the amount of Enterprise IT expense that will be locked into rates in this case, and that will be adjusted annually by the PBRM will reasonably keep pace with the Company's actual costs. Therefore, the Company is requesting that the Department allow for an exogenous cost adjustment only to the extent that the Company can demonstrate that there is a material deviation equal to or greater than 1.5 times the exogenous cost threshold. In this demonstration, the Company would compare the base level of Enterprise IT expense established in this case to the actual IT expense, adjusted for amortizations that have ended. By monitoring the change in Enterprise IT expense as compared to the test year level, as adjusted annually by the PBRM, the Company will be able to ascertain the cost impact of the transition to cloud-based computing.

J. Earnings Sharing Mechanism

Q. What is the Company's proposal for an earning sharing mechanism?

A. The Company views the implementation of an earnings-sharing mechanism to be appropriate within the context of the PBRM, although under economic theory the implementation of an earning-sharing mechanism is viewed as counteracting the cost-reduction imperative inherent within a performance plan. The Department has found that earnings-sharing mechanisms are reasonably designed where the

Company/customer sharing ratio provides adequate and appropriate economic incentives and there is a bandwidth that balances Company and customers risks.

In NSTAR Gas Company d/b/a Eversource Energy, D.P.U. 19-120 (2020), the Department determined the appropriate design for an earning-sharing mechanism applicable to a 10-year PBR Plan. Therefore, consistent with the Department's ESM design in D.P.U. 19-120, the Company is proposing an earning-sharing mechanism that would trigger sharing with customers on a 75/25 basis where the computed distribution ROE exceeds 100 basis points above the ROE authorized in this case (75% to the customers and 25% to the Company). Conversely, sharing with customers would be triggered at 150 basis points below the authorized ROE on a 50/50 percent basis (i.e., 50 percent to ratepayers and 50 percent to shareholders) for losses between 150 and 200 basis points below the authorized ROE, and on a 75/25 percent basis (i.e., 75 percent to ratepayers and 25 percent to shareholders) for losses more than 200 basis points below the authorized ROE is appropriate in this case. The Department found in D.P.U. 19-120 that these ratios will provide adequate incentive for the utility to pursue savings while protecting customers from any unforeseen financial windfall or underearning for the Company.

The earnings calculation for the ESM would exclude Department-approved incentive payments, such as energy efficiency incentives, and would also exclude service quality penalties (if any), as well as any amounts recognized in the current period resulting from regulatory or court settlements or decisions related to prior periods (if any), as well as any revenues or credits to customers from the prior application of the ESM.

For any year in which the ROE is above or below the bandwidth, the percent portion that is to be shared with customers would be credited to customers in the succeeding year, and the impact of this prior year adjustment would be excluded in calculating the subsequent year's sharing.

Q. How would the Company propose to compute the ROE to be used in the earnings-sharing mechanism?

A. To avoid disputes, it is necessary for the Department to be precise about the computation of ROE for purposes of the earnings-sharing mechanism.[11] ROE would relate to distribution only (i.e., would exclude transmission) and would be computed to exclude incentive payments, such as energy efficiency incentives; transition-incentive mitigation; long-term contract remuneration, and conversely, would exclude service-quality penalties, if any as well as any amounts recognized in the current period resulting from regulatory or court settlements or decisions related to prior periods if any. Distribution ROE would be calculated using the

[11] Distribution Return on Equity (ROE) = Total Net Utility Income less Transmission Net Income, less other amounts as described in the testimony, all divided by Average Distribution Common Equity. Distribution Common Equity = (Total Company capitalization (including long term debt, preferred stock, and common equity, all per the FERC Form 1) less Transmission capitalization, calculated as Total Transmission Investment Base) X % Common Equity. Transmission Net Income is defined as the total Transmission Investment Base times the Company's weighted common equity cost of capital plus the regional network service (RNS) incentive and other incentive adders. Transmission Investment Base is the rate base for all Massachusetts Transmission investments, including LNS, RNS, and Schedule 1.

Distribution earnings available for common equity and the capital structure approved by the Department in this case. Any adjustment shall be subject to investigation and a full adjudicatory hearing before the Department.

K. Five-Year PBR Term

Q. Is the Company proposing to implement a 5-Year PBR Plan if the Department does not approve a 10-Year PBR Plan?

A. Yes. If the Department does not approve a 10-Year PBR Plan for Eversource, or in the alternative, does not approve a 10-Year PBR Plan that is sufficient to support a stay-out commitment, the Company proposes to implement a 5-Year PBR Plan that would commence January 1, 2023 and expire on December 31, 2027.

Q. Are there are modifications to the Company's proposed PBR Plan that would be associated with the implementation of the 5-Year PBR Plan?

A. Yes. In the event that a 5-Year PBR Plan is implemented, certain features of the 10-Year PBR Plan would not apply. Specifically, the following modifications would be made, consistent with Department precedent:

1. Only capital additions completed through December 31, 2021 would be eligible for a rate-base roll-in and those additions would be included in base rates set in this proceeding.

2. The ROE Risk Adjustment would not apply. The Company is proposing the ROERA only as part of the 10-Year PBR Plan.

3. The ESM would be asymmetrical with upside sharing for customers, but no downside adjustment for the Company.

L. Five-Year Mid Term Filing

Q. What is the Company's proposal to meet the statutory requirements of G.L. c. 164 § 94 for the filing of "rate schedules" at no more than a five-year interval?

A. We are not lawyers and compliance with the statutory requirements set forth in G.L. c. 164, § 94 appears to be a question of legal interpretation that could be addressed by legal brief. However, the Company's proposal for a mid-term filing of "rate schedules" would include the following:

1. A summary computation of the Company's cost of service for the year-ending December 31, 2026, to be submitted to the Department on September 15, 2027.

2. An updated sales forecast through the end of the PBR Plan term, or December 31, 2032.

3. An updated capital expenditure forecast through the end of the PBR Plan term, or December 31, 2032.

4. A PBR Performance Report summarizing the Company's performance on the performance metrics approved in this proceeding, and recommendations for continuing, modifying, or augmenting the performance metrics in place for the last five years of the PBR Plan term.

The submission of this analysis and documentation will provide the Department with appropriate information and documentation to continue the PBR Plan term over the second five years of the plan.

V. MEETING THE DEPARTMENT'S CRITERIA FOR PBR IMPLEMENTATION

Q. What are the criteria established by the Department for the review and approval of incentive regulation proposals?

A. In prior decisions, the Department has outlined specific criteria to be used in evaluating incentive-regulation proposals. In particular, these criteria require that incentive proposals:

(1) must comply with Department regulations, unless accompanied by a request for a specific waiver. Incentive proposals that comply with statutes and governing precedent are strongly preferred;

(2) should be designed to serve as a vehicle to a more competitive environment and to improve the provision of monopoly services. Incentive proposals should avoid the cross-subsidization of competitive services by revenues derives from the provision of monopoly services;

(3) may not result in reductions in safety, service reliability or existing standards of customer service;

(4) must not focus excessively on cost recovery issues. If a proposal addresses a specific cost recovery issue, its proponent must

demonstrate that these costs are exogenous to the company's operation;

(5) should focus on comprehensive results. In general, broad-based proposals should satisfy this criterion more effectively than narrowly targeted proposals;

(6) should be designed to achieve specific, measurable results. Proposals should identify, where appropriate, measurable performance indicators and targets that are not unduly subject to miscalculation or manipulation; and

(7) should provide a more efficient regulatory approach, thus reducing regulatory and administrative costs. Proposals should present a timetable for program implementation and specify milestones and a program tracking and evaluation method.[12]

Q. How does the Company's proposal meet the Department criteria?

A. The PBRM component of the Company's proposed PBR Plan complies with Department regulations, to the extent that there are any that apply, and there is no request for a specific waiver. The Company's proposed PBR Plan, including the PBRM, complies with, and furthers, the objectives of statutes and governing precedent. The plan is designed to serve as a vehicle to a more competitive

[12] D.P.U. 96-50 November 29, 1996, pp. 243-244.

environment and to improve the provision of utility services. The PBRM does not involve any cross-subsidization of competitive services by revenues derived from the provision of utility services.

The PBRM will result in reductions in safety, service reliability or existing standards of customer service, but rather will enable and further these objectives. The Department's Service Quality Guidelines were recently updated in D.P.U. 12-120 (2015) and will apply during the period of the PBRM. The Department's Service Quality Guidelines are rigorous and include penalty metrics for performance falling below the requirement benchmarks. Eversource generally outperforms its required benchmarks and nothing in the proposed PBRM or the broader PBR Plan will have the effect of changing this.

The PBRM does not focus excessively on cost-recovery issues. By definition, the Company's proposal to implement a 10-year PBR Plan introduces significant risk that the Company's actual cost structure will deviate from the revenue provided through the PBRM. The components of the PBR Plan that the Company is proposing to address specific cost issues are limited to very significant impacts that could occur over a prolonged, 10-year term. Moreover, the Company's PBRM focuses on comprehensive results, including support for the Commonwealth's clean energy and electrification goals.

Lastly, the PBR Plan is designed to achieve specific, measurable results as demonstrated by the inclusion of a broad set of performance metrics. In addition to the Department's Service Quality Guidelines, which will remain applicable to the Company during the plan, the Company has developed measurable performance indicators and targets that are not unduly subject to miscalculation or manipulation to allow for monitoring and evaluation of progress on the Company's performance commitments.

Lastly, the PBR Plan will constitute a more efficient regulatory approach, obviating the need for sequential base-rate cases, thus reducing regulatory and administrative costs without eliminating the benefit of the plan. The Company has presented a timetable for program implementation and specified milestones and a program tracking and evaluation method.

VI. OTHER KEY PROPOSALS

A. Storm Cost Recovery

Q. What are the changes that the Company is seeking in relation to storm-cost recovery?

A. Storm Fund eligible events are becoming increasingly more common and more costly. Storms are more common due to weather patterns and meteorological characteristics associated with climate change. Storms are more costly for a number of reasons but primarily because customer and political expectations are compelling shorter and shorter restoration durations. To reasonably meet these expectations, the Company needs to rely on higher external crew complements brought onto the system at a much earlier point in time preceding the storm event. These circumstances are beyond the control of the Company and are creating an inexorable increase in the cost of storm response.

Accordingly, in this case, the Company is requesting that the Department consider certain changes to the Storm Fund construct. These changes are discussed in detail in the testimony of Company Witnesses Frank and Botelho. Specifically, the Company is requesting that the Department make the following three changes:

1. Increase the threshold for qualifying Storm Fund events from $1.2 million set in D.P.U. 17-05 to $1.3 million, consistent with Department precedent.

2. Increase the annual Storm Fund contribution included in base rates from $10 million to $31 million based on actual storm experience during the first term of the PBR Plan.

3. Increase the number of Storm Fund Thresholds in base rates from three storm events to six storm events, for a total of $7.8 million included in base rates based on the test year experience.

4. Allow that, for each storm event after the 7th storm event, the Company would be eligible to recover the Storm Fund Threshold of $1.3 million through the Storm Fund as storm costs. Conversely, allow that, if there are less than five qualifying events in a year, the threshold amount of $1.3 million would be credited to customers through the Storm Fund for each event below five qualifying events.

Q. Why should the Company be eligible to recover the Qualifying Storm Thresholds that may occur after the 7th storm event?

A. As is the case in each jurisdiction in which the Company operates, it makes sense for the Department to establish a "significance" threshold to determine whether the magnitude of incremental O&M costs incurred in relation to the ERP event warrants recovery through the Storm Fund. As an electric company, there is a level of storm activity that is "normally recurring" and therefore can reasonably be included in base rates based on the test year experience. In that regard, the Department has identified an appropriate cut-off for Storm Fund treatment (i.e., greater than $1 million) and has consistently applied a methodology setting the threshold for qualifying events from case to case by incorporating a measure of inflation.

Once a storm event involves a "significant" level of costs by exceeding the Storm Fund Threshold, then it is clear that a larger scale response is occurring. When this happens, there is no reason that the first $1.3 million of cost would be *barred* for recovery on the eighth, ninth, tenth storm or any storm after that. In fact, the Department's precedent establishing recovery for the Storm Fund Threshold amount is to include those amounts in base rates representing a determination that recovery of these costs is proper and reasonable. The issue is that it is not possible to identify a "representative" amount in base rates given that the number of larger-scale events that may occur in a year is a randomly occurring number and can well exceed any number of storms that the Department would find appropriate for base rates.

If the number of events included in base rates is too high, then customers are paying for storm costs that are not incurred. If the number of events included in base rates is too low, then the Company is losing recovery of valid and prudent storm costs without any basis for that disallowance other than the costs are the first costs incurred. Ironically, the first costs incurred are generally the cost of external crews pre-staged on the system to respond quickly to storm damage. Disallowing these costs with no finding that the costs were unreasonably incurred should not be an outcome where the actions taken directly contribute to the success of the storm restoration effort.

Therefore, the Company is requesting that the Department establish a system to allow for recovery (or credit to customers) of Storm Fund Thresholds that fall outside a "reasonable" number contemplated in base rates. Lastly, the testimony of Company Witnesses Frank and Botelho discusses the Company's request for recovery of the 2021 excess Qualifying Storm Thresholds, similar to the 2020 thresholds addressed in NSTAR Electric Company d/b/a Eversource Energy, D.P.U. 21-76 (2021).

B. Methodology for Department Reporting on SAIDI/SAIFI

Q. What is the problem that the Company is encountering in relation to the reporting of SAIDI/SAIFI pursuant to the Department's service-quality guidelines?

A. Over the past 10 years, the Company has invested a very significant amount of capital in its electric distribution system to improve reliability and resiliency. In particular, the Company has added automated switching capability to reduce length of outages; installed new circuit ties to add redundancy; and completed circuit rebuilds and segmentation projects to limit the potential for outages and the number of customers affected by outages when they do occur. One result of all of this work and associated investment is a reduction in the number of customers interrupted per outage event by approximately 30 percent, reducing customers interrupted from 109.57 customers per outage event in 2011 to 85.50 customers per outage event in 2020. This reduction in the number of customers interrupted per outage event directly evidences a substantial improvement in reliability for customers. However, for the Company, this improvement has ramifications for SAIDI/SAIFI performance creating the appearance that performance is declining, when it is actually improving.

Q. What challenge is created for the Company in relation to the reduction in the number of customers interrupted per outage event?

A. Under the Department's Service-Quality Guidelines, the term "Excludable Major Event" is defined as follows:

> "Excludable Major Event" means a major interruption event that meets one of the three following criteria: (1) the event is caused by earthquake, fire or storm of sufficient intensity to give rise to a state of emergency being proclaimed by the Governor (as provided under the Massachusetts Civil Defense Act); (2) any other event that causes an unplanned interruption of service to **fifteen percent** or more of the Electric Company's total customers in the Electric Company's entire service territory; or (3) the event was a result of the failure of another.

Attachment A at 3-4 (emphasis added).

Under this definition, storm events could occur and cause relatively significant damage. Yet, the storm may not qualify as an "excludable major event" because the number of customers affected does not rise to the 15 percent of customers threshold and no State of Emergency is called by the Governor. In 2020, the total number of customers on the Company's system was 1,438,097, with 15 percent creating a threshold of approximately 215,000 customers, which is a very substantial number of customers. This threshold was set by the Department in its original service-quality docket and it has remained unchanged over the past 20 years, notwithstanding technological and operational improvements.

Over this time span, two dynamics have occurred. First, the Company has made very substantial investments, including the widespread installation of distribution automation and circuit ties and other upgrades. These investments have materially reduced the number of customers experiencing service interruptions as a result of any given weather condition. Second, the nature and intensity of weather conditions occurring on the distribution system have changed. In particular, the intensity of *wind events* has greatly increased causing major damage but *in confined areas of the system*. Discussion of these weather conditions is provided below. The combination of these two factors results in a situation where the system is experiencing severe damage as a result of intensifying, localized weather conditions that is difficult to repair quickly, but the *number of customers* affected in relation to these outages is declining so that the storm event falls below the threshold for an "Excludable Major Event" under the Department's service quality guidelines. In these circumstances, the SAIDI measurement indicates poor performance but only because the Company has been successful in reducing the number of customers affected by that damage.

Q. Has the Company analyzed this issue to prove that severe weather events are occurring that are not excluded from the measurement of SAIDI and SAIFI due to the improvements in the number of customers interrupted per outage event?

A. Yes. The Company has developed a comprehensive analysis of the SAIDI and SAIFI performance measurements to prove that severe weather events are occurring that are not properly being excluded from the computation of SAIDI and SAIFI for measuring day-to-day reliability. Exhibit ES-CAH/DPH-2 presents this analysis.

Q. What does the analysis provided in Exhibit ES-CAH/DPH-2 show?

A. The analysis that the Company has developed shows that there are weather events that are occurring on the system and causing substantial damage without causing widespread outages. Specifically, the analysis shows that there are weather events that are causing SAIDI performance that are ***four*** standard deviations from the average performance representing the benchmark but are not causing 15 percent of customers to experience a service interruption. Inclusion of these weather events in the SAIDI/SAIFI computation is skewing performance, making it appear that performance is declining, when in fact, the substantial investment made on the system is reducing the number of customer interruptions experienced by outage.

The analysis presented in Exhibit ES-CAH/DPH-2 encompasses two perspectives: (1) computation of the standard deviations using only "blue sky data," which is the data that exists exclusive of Excludable Major Events under the Department's Service-Quality Guidelines; and (2) computation of the standard deviations using *all available data* including SAIDI and SAIFI values associated with major storm events that are excludable under the Department rules. Using these two perspectives shows that there are service-quality measurements that are affected by storm events that do not belong in the data set due to the relative severity.

Q. Would you review Exhibit ES-CAH/DPH-2 more specifically?

A. Yes. Looking at the table entitled "SQL Compare," the Company first compiled the historical data, confirming the data against the Company's annual service-quality filings on SAIDI and SAIFI. The numbers that were compiled are shown in Column R and S. Columns V and X show that data values that were previously reported to the Department. There are only slight differences between these columns. Columns R and S are the new data used for the purposes of this analysis, which reflects clean-up changes that may have been made over time.

Next looking at the 2016 Five-Year blue tab (blue sky), it has all the events that the Company is allowed to take out of the system according to the Department's Service-Quality Guidelines. Specifically, the Company used data for five years prior to the year subject to evaluation. So, data for the years 2011 through 2014 was used to calculate the values for 2016. The Company calculated a daily SAIDI value for all years and then took the log normal. It is necessary to take the log normal because, when you apply standard deviation statistics, you need a bell-shaped curve. What this does is bring the data that is highly skewed into a reasonable format to perform statistics on.

Looking to the "transform" tab, it shows an example of what the data looks like before the transformation, which is the chart showing up in Columns E through L on the transform tab. And then after it has been transformed, the chart showing up in P to Z columns on the transform tab shows you how the data is transformed into a bell-shaped curve based upon the log of SAIDI. Once the daily log of all the SAIDIs is computed, the average is used to figure out what the mean is of the transformed data. Then, the Company identified the standard deviation of the log

SAIDI data.

The next step is to calculate the "untransform," which is done by taking the exponential of the log SAIDI to convert it back into a normal number, yielding the transformed SAIDI value, as well as the average and the standard deviation in numbers that are understandable. From there, the Company calculated the different standard deviations. For example, you take the average plus four times the standard deviation to find out what the four standard deviation limit is.

In cells I18 and I19, the Company shows that the transformed SAIDI number. Then, SAIDI is ranked from largest to smallest and highlighted in Column P according to how many standard deviations the data was. As shown for 2016, there is one case where the measured SAIDI is in excess of the 4 standard deviations; one case where the measured SAIDI is greater than 2 standard deviations, and two cases where the measured SAIDI is greater than 1 standard deviation.

Q. What change is the Company proposing on the basis of this analysis?

A. This analysis shows that there are storm impacts that are influencing the computation of the Company's SAIDI/SAIFI performance that are inordinately severe, but are not excluded from the analysis due to the fact that investment made on the system has reduced the impact of the storm damage to individual customers. These identified events are in excess of four standard deviations from the mean and there are only [FOUR] of them that have occurred since 2017. For service-quality reporting purposes, the Company is requesting that the Department adopt the Company's methodology and allow storms with SAIDI/SAIFI measurements more than 4 standard deviations from the mean to be excluded from the computation of SAIDI/SAIFI performance for that year.

C. Vegetation Management Proposal

Q. What is the Company proposing in this case in relation to vegetation-management for reliability and resiliency purposes?

A. The testimony of Company Witness Van Dam discusses the Company's proposals with respect to the Company's trim cycle and Resiliency Tree Work ("RTW") Program. Mr. Van Dam's testimony puts forth three proposals that the Company is making in relation to the critical mission of meeting system reliability and resiliency performance objectives.

First, the Company is proposing to modify its base vegetation management program to eliminate the four to five year trim cycle and instead focus on prioritizing vegetation management to increase reliability. Currently, the Company follows an established trim cycle to ensure that all circuits -- regardless of performance -- are trimmed at least once in every four to five years, subject to circuit-specific considerations. In parallel, the Company uses reliability-based prioritization methods to identify the need for mid-cycle trimming or other corrective actions on a proactive basis to address poor performing circuits or other anomalies affecting routine operations. In the Company's experience and operating judgment, reliability-based prioritization methods are more effective operationally and more cost-efficient, as a result. In the four to five-year cycle, the Company is trimming vegetation with no associated reliability benefit, which is not an efficient expenditure of funds. Therefore, the Company is proposing to extend the reliability-based prioritization from mid-cycle trimming to the complete trim cycle. This would ensure that the Company is focusing on poor-performing circuits and other reliability improvement areas.

Second, the Company is proposing to transfer recovery of the costs of RTW Program activities to base rates for work performed after January 1, 2023, rather than recovering the costs of the reliability-based prioritization RTW work through the RTW mechanism. This would be accomplished by including a representative amount of annual 2017-2021 RTW Program expenses in the base revenue requirement in this proceeding. The remaining programs costs for 2017 through 2022 would be recovered through the RTW factor. The Company has illustrated the extensive benefits of the RTW Program through its annual RTW Program filings and the expenditures have become normalized so that a representative amount may be included in base rates.

Third, the Company is proposing to institute a municipal hazard tree removal pilot program to identify and remove hazard trees more efficiently and effectively. This pilot program will include municipal input and close coordination to facilitate the Company’s ability to address multiple hazard trees within a city or town at one time. Through partnerships with the communities, the Company would seek to achieve municipal approval for multiple tree removals at once, avoiding the current process of obtaining permission for only one or two trees each time. Again, this approach would be a more efficiency and effective use of customer funds. Thus, the Company proposes to recover the costs of this program through the RTW mechanism rather than base rates because costs will be variable and unpredictable unless and until the program matures.

Q. What is the Company proposing in this proceeding regarding adoption of the AMI tariff to support the AMI Implementation Plan?

A. The Company's proposal regarding adoption of a company-specific tariff for AMI implementation is discussed in the testimony of Company Witness Conner, Horton and Schilling. As discussed in their testimony, the Company is requesting that the Department adopt the model tariff submitted for the Department's review and approval in <u>NSTAR Electric Company d/b/a Eversource Energy for approval of Grid Modernization Plan, Calendar Years 2022 to 2025</u>, D.P.U. 21-80 (pending) ("D.P.U. 21-80") ("Model AMI Tariff"). As discussed below, the Company and National Grid have each requested approval of a model tariff in D.P.U. 21-80 and D.P.U. 21-81, respectively, to establish an annual reconciling mechanism to recover costs associated with the companies' respective AMI Implementation Plans. For Eversource, adoption of the model tariff in this proceeding as a company-specific tariff is the next step in establishing the predicate necessary to support the Company's AMI investment plan starting in 2022 and over the following six years.

Also, the Company's testimony establishes a cost-of-service baseline for the recovery of incremental meter costs associated with AMI implementation and other incremental operating and maintenance expenses. Lastly, the Company's testimony discusses the Company's plans to commence development of the first tranche of AMI investments and the request in this case for the Department to authorize the commencement of recovery of costs associated with this complement of investments. The first tranche of investments the Company will be making includes the implementation of Omni MA, the new Customer Information System and the Meter Data Management System necessary to serve as a foundation for NSTAR Electric's AMI investment.

VII. QUALITATIVE CONSIDERATIONS FOR SETTING THE AUTHORIZED ROE

Q. Has the Department recently issued guidance on how it will take into account qualitative factors in setting the authorized ROE?

A. Yes. The Department has recently issued guidance regarding "both quantitative and qualitative factors must be taken into account in determining an allowed ROE." Boston Gas Company d/b/a National Grid, D.P.U. 20-120, at 437 (2020). Specifically, the Department stated it will "consider qualitative factors such as management performance and customer service in setting a fair and reasonable ROE." Id. at 438.

Q. What qualitative factors should Department take into account in this case

when setting the Company's authorized ROE?

A. The Department should consider the Company's service-quality levels, management performance in relation to storm restoration, and risk associated with a 10-year PBR Plan in the current operating environment, consistent with the Department's guidance on what will be considered in setting the authorized ROE.

Q. Has the Company maintained high levels of service-quality performance since the current PBR Plan was instituted.

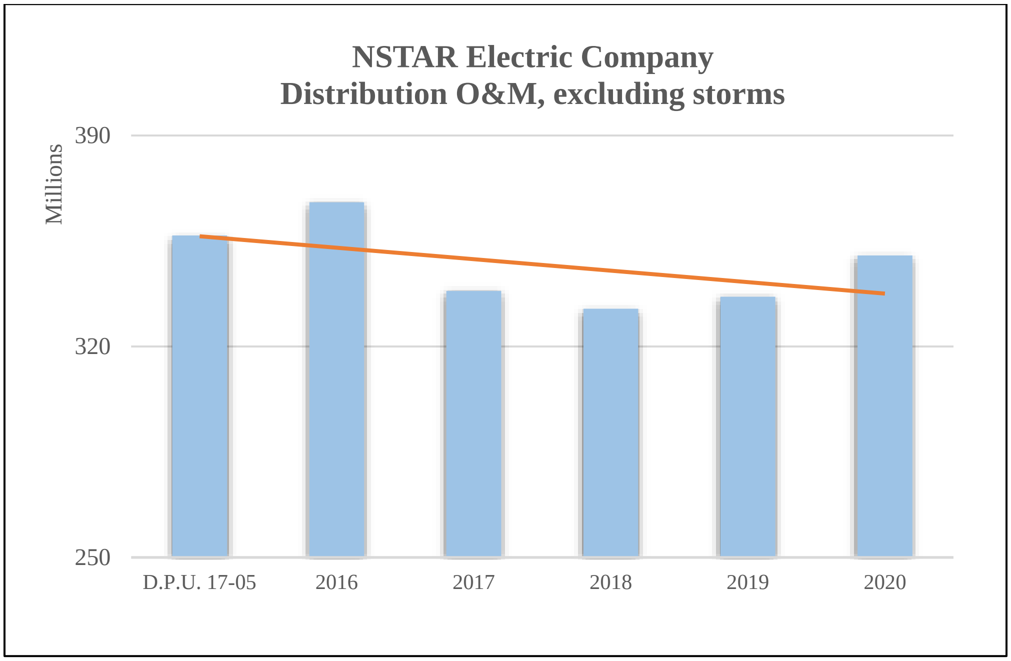
A. Yes. During the existing PBR Plan, the Company's service quality has been excellent. For example, in the years 2018-2020, NSTAR Electric exceeded its benchmarks in all performance measures, including established benchmarks in System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), Circuit Average Interruption Duration Index ("CKAIDI"), Circuit Average Interruption Frequency Index ("CKAIFI"), Service Appointments Met and Consumer Division Cases. The Company expects to update its service-quality performance with the filing of the Annual Service Quality Reports, due to be filed with the Department on March 1, 2022. The Company's performance for 2021 will similarly meet or exceed establish service-quality levels.

In addition, during the PBR Plan, the Company has accomplished the following benefits for customers:

- Reliability is strong. NSTAR Electric remains a top performer in the industry as measured in Months Between Interruption ("MBI").
- NSTAR Electric has reduced the duration of outages by 7 percent as measured by the SAIDI.
- NSTAR Electric has reduced the number of customers per outage by 31 percent through circuit rebuilds, installation of circuit ties and distribution automation and segmentation.
- NSTAR Electric has removed more than 100,000 hazard trees from the distribution system, eliminating a major cause of outages.
- Massachusetts-related J.D. Power scores – an independently conducted gauge of customer satisfaction – have increased by 10 percent since 2017.
- Customer digital engagement has increased 6 percent.

In addition, during the first term of the PBR Plan, the Company has successfully contained O&M cost, holding non-storm related O&M expenses to the test year level in D.P.U. 17-05, or slightly better. This cost control has directly benefitted customers in this proceeding, producing rates that are lower than they would have otherwise been without the Company's firm efforts to contain O&M costs.

NSTAR Electric – Distribution O&M (excluding Storm Costs)



In light of the Company's strong and consistent service-quality performance and unparalleled success in controlling O&M to the direct benefit of customers, the Company's authorized ROE should be set at the higher end of the reasonable range, as established in this proceeding.

Q. Please discuss the Company's storm restoration performance under the current PBR plan.

A. The Company has excelled at storm restoration during the PBR Plan term. From 2018 through 2021, the Company experienced 36 Emergency Response Plan ("ERP") events. These ERP events ranged in intensity from a Type 2 to a Type 4 events. These storms came in a variety of forms, including numerous winter storms and three, sequential storm events that occurred in March 2018 known as "March

2018 Nor'easter." Other ERP events included the Cape Cod Tornado (July 2019) and the Bomb Cyclone (October 2019). The Company also responded to damage and customer outages caused by tropical storms, including Tropical Storm Isaias (August 2020), Tropical Storm Elsa (July 2021), Tropical Storm Henri (August 2021), and Tropical Storm Ida (September 2021). Most recently, the Company experienced the October 2021 Nor'easter.

During these ERP events, the Company deployed up 1,300 external crews to restore service to customers as quicky as possible. Many times, the Company was able to return to normal operations within about 24 hours of the declaration of an ERP event. For all ERP events, including a Level 2 event in March 2018, the Company restored power within the timelines established by the ERP approved by the Department.

Because the Company's storm management performance resulted in the expeditious restoration of service to customers under a variety of storms with varying degrees of intensity, the Company's authorized ROE should be set at the higher end of the reasonable range established in this proceeding.

Q. Are there other factors that the Department should consider when setting the Company's ROE?

A. Yes. In setting the authorized ROE in this case, the Department should consider the increased risk to the Company of committing to a PBR Plan with an extended term of ten years in a very dynamic and demanding operating environment, particularly in the economic climate the Company faces today.

Q. How does a commitment to a 10-Year PBR Plan create risk for the Company?

A. The Department has previously stated that "a five-year stay-out provision … could increase the Company's risks in meeting its financial requirements." Massachusetts Electric Company and Nantucket Electric Company, d/b/a National Grid, D.P.U. 18-150, at 495 (2019). With respect to a 10-year stay-out provision in a PBR plan, the Department has unequivocally stated that it increases a utility's "risks in meeting its financial requirements." NSTAR Gas Company d/b/a Eversource Energy, D.P.U 19-120, at 405 (2020).

A major reason that there is substantial risk to the Company under a 10-year PBR plan is due to changes in the cost of capital. To address this risk to some extent, the Company is proposing a Return on Equity Risk Adjustment. However, this adjustment is not triggered except where a very significant change has occurred. This proposal is discussed in the testimony of Company Witness Dr. Lawrence Kaufmann.

Although the Company's PBR Plan includes factors that adjust for inflation and exogenous events, and if accepted by the Department – the capital cost adjustment, the Company's overall rate of return and ROE are fixed at the time the PBR plan is approved. As explained in the testimony of Company Witness Vincent V. Rea, there is strong evidence of upward pressure on U.S. interest rates from a variety of factors such as inflation, and the tapering of the Federal Reserve's bond-buying programs. Unlike the last few decades, the economy could be entering an extended period of inflation and higher capital costs. If the economy enters into a period of higher capital costs, and Company's ROE is fixed, the Company would be put in a very difficult financial situation that could affect the amount of capital investment that the Company can finance. This situation would be greatly exacerbated if the PBR Plan stay-out provision is ten years rather than five years. Therefore, it is imperative that the Department take into account the Company's increase in risk under a ten-year PBR plan when setting the authorized ROE.

Q. Other than uncertainty over long-term capital costs, are there other reasons why a ten-year PBR plan increases the Company's risk?

A. Yes. Not only does it appear that the Company is facing inflationary pressures, which have not been seen in decades, but the Company is the midst of transformative period in the electric utility here in Massachusetts.

In setting the authorized ROE, the Department has considered the "regulatory uncertainty for the gas industry" in relation to "an increased commitment to reduction of greenhouse gas emissions through a possible near-term restriction in the use of natural gas." D.P.U 19-120, at 405-406. Likewise, the electric utility industry is also facing regulatory uncertainty associated with changing the electrical system to help achieve reductions greenhouse gas emissions. Some of these changes to the electric system such as advanced metering, integration of distributed energy resources, and electrification will require significant increases in capital expenditures and operating expenses. There is regulatory uncertainty how transformation can be achieved, and at what cost.

Costs associated with the transformation of the electrical system will be significant, perhaps on a scale not easily contemplated. The Grid Modernization Plans and associated cost recovery address only a small part of the overall changes that will occur. Thus, the 10-year stay-out commitment is a risky proposition given the complexity of the transformation that is pending before the Company. Accordingly, the Department should take into account the Company's increased risk under a ten-year PBR plan when setting the authorized ROE. If the Department approves a 10-year PBR Plan, then the Department should establish the ROE at the higher end of the reasonable range established in this proceeding.

VIII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes. On behalf of Eversource, we appreciate the Department's consideration of the Company's proposals in this case.