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

JOINT DIRECT TESTIMONY OF

ROBERT W. FRANK
AND ASHLET N. BOTELHO

Revenue Requirement Analysis

On behalf of

NSTAR Electric Company
d/b/a Eversource Energy

January 14, 2022

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

JOINT DIRECT TESTIMONY OF

ROBERT W. FRANK AND ASHLEY N. BOTELHO

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DIRECT TESTIMONY OF

ROBERT W. FRANK AND ASHLEY N. BOTELHO

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Robert W. Frank. My business address is 247 Station Drive, Westwood, Massachusetts 02090.

Q. By whom are you employed and in what position?

A. I am the Director, Revenue Requirements - Massachusetts for Eversource Energy Service Company ("ESC"). In this position, I am responsible for the oversight, coordination, and implementation of revenue requirement calculations for the Massachusetts operating subsidiaries of Eversource Energy, including NSTAR Electric Company ("NSTAR Electric" or the "Company"), NSTAR Gas Company ("NSTAR Gas"), and Eversource Gas Company of Massachusetts ("EGMA") each d/b/a Eversource Energy. In addition, I have the overall responsibility for regulatory interfaces for all revenue requirement-related filings before the Department of Public Utilities (the "Department").

Q. Please describe your educational background and employment experience.

A. I graduated from University of Massachusetts in 1982 with a Bachelor of Science degree in Accounting. I subsequently earned a Master of Business Administration from Providence College in 1988. I was hired by the Company as a Principal Financial Analyst in April 1998 and was responsible for the development of the

Company's Annual Financial Operating Plan. I have held a variety of positions at Eversource, including Manager, Investment Planning, and have over 22 years of experience in the industry. I was promoted in November 2019 to Director, Revenue Requirements - Massachusetts.

Q. Have you previously testified in any formal hearings before regulatory bodies?

A. Yes. I have sponsored testimony before the Department in D.P.U. 20-54, NSTAR Electric's 2019 Grid Modernization cost recovery filing and D.P.U. 19-114, NSTAR Electric's Resiliency Tree Work ("RTW") Plan recovery filing. I have also sponsored testimony in D.P.U. 20-96 and D.P.U. 21-106, NSTAR Electric's 2020 and 2021 Performance Based Ratemaking Adjustment ("PBRA") filings.

Q. Please state your name and business address.

A. My name is Ashley N. Botelho. My business address is 247 Station Drive, Westwood, Massachusetts 02090.

Q. By whom are you employed and in what position?

A. I am the Manager, Revenue Requirements - Massachusetts for ESC. In this position, I am responsible for the oversight, coordination, and implementation of revenue requirement calculations for the Massachusetts operating subsidiaries of Eversource Energy, including NSTAR Electric, NSTAR Gas, and EGMA. In addition, I have the overall responsibility for regulatory interfaces for all revenue requirement-related filings before the Department.

Q. Please describe your educational background and employment experience.

A. I graduated from Drexel University in Philadelphia, Pennsylvania in 2010 with a Bachelor of Science degree in Business Administration and a concentration in finance. In 2013, I graduated from the Bryant University Graduate School of Business with a Master of Business Administration. I began working as a contractor for NSTAR Electric in July 2010 in support of NSTAR Electric's Smart Grid programs. In October 2011, I was hired as a Smart Grid Associate Project Manager. In December 2012, I assumed the role of Analyst in Revenue Requirements for Massachusetts. In July 2014, I was promoted to a Senior Revenue Requirements Analyst. I was promoted to my current role of Manager, Revenue Requirements, Massachusetts, in January 2018.

Q. Have you previously testified in any formal hearings before regulatory bodies?

A. Yes. I have sponsored testimony before the Department in the recent base distribution rate proceeding for NSTAR Gas, D.P.U. 19-120, and participated in the development of testimony and exhibits supporting the Company's previous base distribution rate proceeding, D.P.U. 17-05. I have also sponsored testimony and exhibits in the NSTAR Electric and NSTAR Gas Three-Year Energy Efficiency Plan for 2016 through 2018 ("Three-Year Plan") and Energy Efficiency Surcharge ("EES") filings from 2015 through 2021, as well as the Western Massachusetts Electric Company ("WMECO") Storm Cost Recovery Adjustment Factor ("SCRAF") in D.P.U. 17-162; NSTAR Electric's SCRAF in D.P.U. 18-125, 19-128, D.P.U. 20-130, and D.P.U. 21-133; and the Company's RTW program filings from 2018 through 2019. I have sponsored testimony in support of the Company's request for recovery of costs related to the March 2018 Nor'easter Event as an Exogenous Cost in D.P.U. 18-101. Most recently, I sponsored testimony and exhibits in the Company's Performance-Based Rate Adjustment in D.P.U. 21-106.

Q. What is the purpose of your testimony?

A. Our testimony presents the revenue requirement calculation and existing revenue deficiency for NSTAR Electric. The calculations supporting the revenue requirement are provided in Exhibit ES-REVREQ-2. As part of the revenue requirement analysis, our testimony discusses the mechanics of the Company's proposals for certain rate base and expense adjustments, including the transfer of investments and certain expenses to base distribution rates associated with programs currently recovered through other reconciling mechanisms. These mechanisms are the: (1) 2018-2021 Grid Modernization Plan ("Grid Modernization" or "GMP"); (2) Solar Program Cost Adjustment ("SPCA") and Solar Expansion Cost Recovery Mechanism ("Solar Expansion") (collectively, "Solar Program Investments"); (3) Solar Massachusetts Renewable Target program ("SMART"); and (4) Resiliency Tree Work Program ("RTW"). This testimony also presents the results of the Company's lead/lag study, which is used as the basis for the working-capital component of rate base in this proceeding.

Additionally, our testimony provides the rationale and support for several other ratemaking issues that the Company is presenting for resolution, including:

(1) revisions to the Storm Fund approved in D.P.U. 17-05, the Company's most recent base distribution rate case; (2) continuation of the existing Storm Cost Recovery Adjustment Factor ("SCRAF") to address the deficit in the Storm Fund attributable to unrecovered storm costs, adjusted as described in the testimony of Company Witness Hallstrom and Horton; (3) recovery of exogenous expenses associated with increased property tax valuations; (4) adoption of the model tariff for Advanced Metering Infrastructure ("AMI") investment beginning in 2022; and (5) to resolve the impasse relating to prior period pension recovery, which has been pending for many years and needs to be addressed prior to the implementation of a 10-year performance-based ratemaking ("PBR") Plan as supported in the Appendix to this testimony by Company Witnesses Horton, Frank and Botelho in Exhibit ES-REVREQ-7.

Lastly, our testimony provides support for the Company's request to implement the PBR Plan, which would adjust the base distribution rates set in this case on an annual basis in accordance with a formula to be approved by the Department. If approved, the Company would forego its statutory right to file a base-rate case pursuant to G.L. c. 164, § 94 for a 10-year period. To that end, the Company has incorporated elements into the PBR Plan that are necessary for the Company to commit to an extended stay-out. Our testimony discusses the elements of the cost of service that are proposed as part of the PBR Plan.

Q. Is the corporate consolidation of NSTAR Electric and the former WMECO complete?

A. Yes. On January 13, 2017, NSTAR Electric and the former WMECO jointly submitted an application to the Federal Energy Regulatory Commission ("FERC"), under Section 203 of the Federal Power Act, requesting approval to complete a corporate consolidation of NSTAR Electric and the former WMECO. FERC approved the consolidation on March 2, 2017, in Docket No. EC17-62-000.

On January 17, 2017, in D.P.U. 17-05, NSTAR Electric and the former WMECO sought Department authorization to consolidate WMECO with and into NSTAR Electric, with NSTAR Electric as the surviving entity. D.P.U. 17-05, at 29. The Department reviewed the proposed consolidation consistent with G.L. c. 164, § 96 and Guidelines and Standards for Mergers and Acquisitions, D.P.U. 93-167-A and determined that the consolidation was consistent with the public interest as the benefits of the proposed consolidation outweighed the costs. D.P.U. 17-05, at 36-44.

On December 31, 2017, Western Massachusetts Electric Company was merged with and into NSTAR Electric Company, with NSTAR Electric Company as the surviving entity pursuant to the Department's approval in D.P.U. 17-05 under G.L. c. 164, § 96. NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy, D.P.U. 17-05, at 36-44. On January 1, 2018, the legal name of Eversource Energy's electric distribution company in Massachusetts became NSTAR Electric Company d/b/a Eversource Energy.

Q. Please describe the impact of the corporate consolidation on financial reporting?

A. In D.P.U. 17-05, the Department required the Company to maintain separate accounts for NSTAR Electric and WMECO, as well as financial records and service quality data. Id. at 44-45. The Department also confirmed that all of WMECO's franchise rights and obligations would continue with NSTAR Electric following the consolidation. Id. at 55. On the federal level, the outcome of FERC's "Reorganization Transaction" eliminated the preparation and filings of WMECO reports under Securities and Exchange Commission ("SEC") Forms 10-K and 10-Q, and FERC Forms 1 and 3-Q.

Since D.P.U. 17-05, Eversource's financial reporting systems and processes were consolidated to reflect a single, consolidated company. This includes the consolidation of depreciation rates, as discussed below in our testimony. The proposed consolidation is consistent with the previous merger of Cambridge Electric Light Company, Commonwealth Electric Company, Boston Edison Company and Canal Electric Company into NSTAR Electric Company, which was approved by the Department in D.T.E. 06-40. The consolidation of financial reporting will not prevent the Company from maintaining separate rates for customers in the pre-merger service territories of NSTAR Electric and WMECO, nor will it prevent the Company from maintaining separate service quality data until such time that any consolidation of rates or service quality data is proposed and approved by the Department.

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

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

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Q. How is your testimony organized?

A. Our testimony is organized into the following sections:

- **Section I** – provides the introduction to our testimony.

- **Section II** – provides an overview of the NSTAR Electric revenue requirement analysis.
- **Section III** - sets forth a comprehensive review of the Company's calculation of the test-year revenue requirement, including a discussion of the normalizations and adjustments to test year operating expenses for NSTAR Electric; a summary of the Company's proposed changes to the Storm Fund, previously approved in D.P.U. 17-05; as well as additional discussion regarding the transfer of recovery from certain reconciling mechanisms into base rates in this proceeding including Grid Modernization, Solar Program Investments, SMART, and the RTW Program recovery mechanism.
- **Section IV** – describes the various adjustments to the per-books account balances as of December 31, 2020, for purposes of computing the NSTAR Electric rate base.
- **Section V** – summarizes the required lead-lag analyses for NSTAR Electric, which is presented in Exhibit ES-REVREQ-5.
- **Section VI** – sets forth a comprehensive explanation of the Company's storm cost recovery proposals, including (1) changes to the Company's Storm Fund, previously authorized in D.P.U. 17-05; (2) review of the Department's decision in D.P.U. 21-76 regarding the request for deferral and recovery of major storm threshold amounts; and (3) proposed recovery of the unrecovered Storm Fund Balance beginning on January 1, 2023.

- **Section VII** – describes the Company's proposal with respect to property taxes that qualify under the exogenous cost provisions resulting from the transition of municipalities in the Company's territory to a new valuation methodology that substantially increases the level of property tax expense contemplated in the following rate plans: (1) the NSTAR/Northeast Utilities merger-related settlement agreement from D.P.U. 10-170 for the period January 1, 2012 through December 31, 2015; and (2) the Company's performance based-ratemaking plan established in the Company's last rate case, D.P.U. 17-05, beginning on January 1, 2018 and expiring on December 31, 2022.
- **Section VIII** – supports adoption of the model tariff for NSTAR Electric for Advanced Metering Infrastructure ("AMI") investment beginning in 2022, as discussed further in the testimony of Company Witnesses Conner, Schilling and Horton (Exhibit ES-AMI-1).
- **Section IX** – discusses the support and documentation for filings submitted from 2011 through 2018 in the pension adjustment mechanism ("PAM") with matters that remain at an impasse and are currently pending before the Department.
- **Section X** - provides the conclusion to our pre-filed testimony.

II. SUMMARY OF REVENUE REQUIREMENT ANALYSIS

Q. What is the test year period that NSTAR Electric used for the revenue requirement analyses presented in this case?

A. The test year period used for the revenue-requirement analysis is the 12-month period ending December 31, 2020.

Q. What is the "rate year" in this case?

A. The term "rate year" refers to the first 12 months during which the rates established in this proceeding will be in effect. The Company's filing in this proceeding is designed to establish new base distribution rates for NSTAR Electric effective January 1,2023. Therefore, the rate year is the period January 1, 2023 through December 31, 2023, and the midpoint of the rate year is July 1, 2023.

Q. Would you please summarize the NSTAR Electric distribution cost of service and resulting revenue requirement?

A. Yes. Exhibit ES-REVREQ-2, Schedule 1 presents the Revenue Requirement Summary for NSTAR Electric, computing a total cost of service of $1,266,939,340. For the rate-year ending December 31, 2023, the calculated distribution revenue deficiency is $89,477,861, based on adjusted test year revenues of $1,177,461,479. The computation of the NSTAR Electric revenue deficiency reflects total rate base of $4,263,662,613 and assumes a weighted cost of capital of 7.32 percent as supported by the testimony of Company Witness Rea. Exhibit ES-REVREQ-2, Schedule 7, summarizes the expense adjustments and Exhibit ES-REVREQ-2, Schedule 8, presents the expense adjustments by FERC account. The net distribution revenue deficiency includes the adjustments discussed in detail below, as well as the transfers of costs currently recovered through various reconciliation mechanisms, as discussed further below.

Q. Did the Company make any adjustments to the test year Operating Revenues for NSTAR Electric?

A. Yes. Exhibit ES-REVREQ-2, Schedule 6 presents: (1) test year revenue per books; (2) normalizing adjustments to test year revenues; and (3) pro forma adjustments to other revenues. These adjustments are described in more detail in Section III.B, below.

Q. Did the Company make any adjustments to the test year Operating Expenses for NSTAR Electric?

A. Yes. The Company made adjustments to test year Operating Expense for NSTAR Electric to: (1) remove costs recovered through ratemaking mechanisms that operate outside of base rates; (2) to normalize the booked test year amounts for ratemaking purposes; (3) to transfer certain expenses to base rates currently recovered through other ratemaking mechanisms, including Grid Modernization, Solar Program Investments, SMART and RTW; and (4) to account for known and measurable changes in operations and maintenance ("O&M") expense levels occurring after the end of the test year and through the midpoint of the rate year. The normalizations and adjustments reflect a number of increases and decreases to the cost of service. Exhibit ES-REVREQ-2, Schedule 9, provides a summary of all normalizing adjustments and Schedule 7 provides a summary of all pro forma adjustments made to Operating Expenses for NSTAR Electric. These adjustments are also described in more detail in Section III.C below.

Q. What is the Company's proposal with respect to post-test year changes associated with capital additions placed into service after the end of the test year?

A. As discussed further below, the Company is proposing to reflect in base rates effective on January 1, 2023 the following; (1) roll-in of Company investments placed in service by December 31, 2021 reflected in the Company's rate base; and (2) known and measurable expense changes associated with Enterprise IT additions placed in service by December 31, 2021; and (3) two specific Enterprise IT projects to be placed in service by Q2 2022.

Separately, in recognition of the fact that the Company is proposing a long-term rate plan, and consistent with the Department's findings in D.P.U. 19-120, the Company in this proceeding is requesting the Department allow the Company to update base rates January 1, 2024 to reflect actual capital additions placed in service during 2022. The Company is requesting the Department also allow at that time (i.e., on January 1, 2024), rates be updated to reflect NSTAR Electric's portion of expense associated with service company additions placed in service in 2022.

Q. What are the Company proposals related to the Department's consideration of rate-base additions?

A. There are three elements of the Company's proposal on rate-base additions. First, the Company has presented the testimony of Company Witnesses Landry and

Griffin providing the requisite project documentation and support for capital additions made since D.P.U. 17-05 through the end of the test year, December 31, 2020 (not already included in rate base in D.P.U. 17-05). This includes capital additions related to Grid Modernization and Solar Program Investments not previously included in base rates.[1]

Second, to accommodate the implementation of the PBR Plan and the associated 10-year PBR Plan, the Company is proposing to reflect capital additions completed through December 31, 2021 in base rates effective January 1, 2023 in this case. Due to the use of a test year ending December 31, 2020, the Company will complete nearly two full years of plant additions and retirements during the pendency of this case, with a large proportion of those additions (all of 2021) completed during the earliest phase of the case. To capture the actual, going forward revenue requirement associated with the completed capital projects, the Company's revenue-requirement computation includes projected plant additions, retirements and depreciation activity through December 31, 2021. The Company plans to submit the project cost documentation relating to 2021 plant additions during the course of this proceeding to facilitate review by the Department and the Attorney General's office. All necessary project documentation for capital projects completed in 2021

[1] The Department determined investments included for recovery through the SPCA were prudently incurred as part of its decisions in the Company's annual Solar Program compliance filings.

will be submitted no later than April 15, 2022, so that there is an opportunity for review of all completed and documented projects.

Third, as part of the PBR Plan implementation and related stay-out, the Company is proposing to reflect capital additions completed through December 31, 2022 in base rates taking effect on January 1, 2024. The Company's proposals in this case regarding the PBR Plan are designed to enable the Company to commit to a 10-year stay-out and provide a platform to facilitate a review to be conducted mid-PBR term, no later than January 1, 2028. Under Massachusetts law, electric companies are required to submit "rate schedules" to the Department in five-year intervals in a form determined by the Department. The most significant cost pressure on both electric and gas utilities in this operating environment is the need for persistent and increasing infrastructure investment. Therefore, for the Company to commit to a stay-out of 10 years or more, it will be necessary for the Company to recover its allowed return on capital investments completed through December 31, 2022 beginning with the first PBR annual rate adjustment on January 1, 2024.

Q. How has the Company computed the rate base for purposes of the revenue requirement analysis?

A. As noted above, the proposed rate base for NSTAR Electric in this case incorporates plant in service through December 31, 2020, plus an estimate of 2021 plant additions. The Company plans to update rate base through December 31, 2021 during the course of the case, providing all associated documentation and allowing adequate time for discovery on the documentation provided. In this way, although the Company is presenting an estimate of 2021 plant additions with this initial filing, the Company is not requesting the Department incorporate an estimate into rates effective January 1, 2023. The Company will submit project documentation associated with actual plant additions that are completed, in service, and used and useful in 2021, such that the rates the Company is requesting the Department approve for effective January 1, 2023, will be based either on actuals, or on known and measurable adjustments to actuals, consistent with Department precedent.

Rate base has increased nearly 35 percent since D.P.U. 17-05, the Company's most recent base distribution rate case, as summarized on Exhibit ES-REVREQ-2, Schedule 29. As shown therein, the calculated rate base includes:

- Actual plant in service, accumulated depreciation and accumulated deferred income taxes as of December 31, 2020, with an estimate of 2021 plant in service, accumulated depreciation and accumulated deferred income taxes;

- The inclusion of actual 2018 through 2020 Grid Modernization investments in rate base, with an estimate of 2021 Grid Modernization investments;

- The inclusion of actual investment through 2020 for Solar Program Investments in rate base, currently recovered through the SPCA and Solar Expansion reconciling mechanisms; and

- Other adjustments to rate base, such as: (1) reductions for customer deposits and customer advances as of December 31, 2020; and (2) increases to rate base for materials and supplies and cash working capital.

The Company plans to provide updates to its capital project documentation and associated rate-base computation during this proceeding to incorporate actual capital additions placed in service in 2021. The Company will provide the requisite revenue requirement updates and supporting project documentation by April 15, 2022. This schedule is designed to allow ample time for the Department and intervenors to review documentation for 2021 in advance of evidentiary hearings.

Q. How has the Company calculated the test year pro forma rate base balance as of December 31, 2021?

A. The Company has computed the test year pro forma rate base balance at December 31, 2021, using:

- Projected capital additions, retirements, accumulated depreciation and cost of removal through December 31, 2021; and
- Projected accumulated deferred income tax balances as of December 31, 2021 based on the expected book and tax amounts.

The Company has also incorporated associated depreciation and amortization expense calculations based on the estimated December 31, 2021 balances into the calculations presented herein and will incorporate an update for associated property tax expense during the proceeding.[2] The Company will update rate base and incorporate the associated changes to the revenue requirement for the actual December 31, 2021 balances coincident with the submission of project documentation no later than April 15, 2022.

Q. Is the Company's pro forma rate base adjustment consistent with the Department's accepted ratemaking practices?

A. Yes. As stated above, the Company plans to update rate base for actual plant balances as of December 31, 2021 during this proceeding. Project documentation will be submitted in this proceeding with adequate time for review by the Department and the Attorney General, no later than April 15, 2022. This approach is also consistent with the Department's recent decisions in Massachusetts Electric Company and Nantucket Electric Company in D.P.U. 18-150 (2019) and NSTAR Gas Company in D.P.U. 19-120 (2020).

Lastly, the Company is proposing to roll-in plant investment incurred through December 31, 2022, as part of the first annual PBR adjustment to take effect January 1, 2024. This is consistent with the Department's directives to National Grid in D.P.U. 18-150, at 178-179, and the timing ultimately approved for NSTAR Gas in D.P.U. 19-120, adjusted for the timing specific to the circumstances of this case. No later than April 1, 2023, prior to the first annual PBR rate adjustment

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[2] Property tax expense will be updated for the December 31, 2021 balances coincident with the submission of the FY 2023 Form of Lists ("FOLs") as described in more detail later in this testimony. The FY 2023 FOLs will be available in Q1 2022. Following the submission of the FOLs, the Company will make the necessary updates to the revenue requirement and provide the FOLs for Department review.

filing to be made on September 15, 2023, the Company will submit the project documentation for Company capital projects completed during calendar year 2022. In accordance with the Department's directives in D.P.U. 18-150, and D.P.U. 19-120, the Company will evaluate its proposal to determine whether the resulting impact for any one customer class is no more than ten percent, and if so, to propose a change that is in compliance with G.L. c. 164, § 94I.

In addition, the Company recognizes that a failure to provide clear, cohesive, and reviewable evidence demonstrating eligibility of the proposed capital additions through rates as part of the 2024 PBR adjustment may result in disallowance of these costs in the PBR mechanism. Therefore, the Company will provide a timely, organized, clear and comprehensive filing of all supporting documentation of the 2022 capital-project costs, which will include but not be limited to: (1) project descriptions, (2) project authorization forms, (3) construction work orders, (4) project closure reports, (5) variance analyses explaining the reasons for cost overruns and for demonstrating prudency, and (6) a summary of all proposed projects.

Q. What is the "Revenue Requirement Factor" referenced in Exhibit ES-REVREQ-2, Schedule 3?

A. On Exhibit ES-REVREQ-2, Schedule 2, we have calculated the operating income shortfall that exists based on the test year ended December 31, 2020 financial information, as adjusted. The Revenue Requirement Factor for NSTAR Electric calculates the revenue increase that is needed to recover the operating income shortfall, along with the associated federal income taxes, Massachusetts income taxes and uncollectible expenses attributable to the increase. In other words, for NSTAR Electric to earn $1.00 of operating income, the Department must allow $1.38 to be recovered through rates in order to account for the federal income taxes, Massachusetts state income taxes and uncollectible expense that the Company will incur in relation to each $1.00 of operating income. Multiplying the Revenue Requirement Factor by the operating income shortfall listed on Line 27 of Exhibit ES-REVREQ-2, Schedule 3 yields the total revenue deficiency of $89,477,861 for NSTAR Electric.

Q. The Company's filing encompasses other rate-related proposals. Do these proposals affect the computation of the revenue requirement?

A. No, these proposals do not affect the revenue requirement computation. In D.P.U. 17-05, NSTAR Electric proposed, and the Department approved, the implementation of a revenue-decoupling mechanism ("RDM") consistent with the Department's directives in Rate Structures to Promote the Efficient Deployment of Demand Resources, D.P.U. 07-50-A (2008). The RDM does not affect the computation of the revenue requirement or revenue deficiency in this case.

Additionally, in D.P.U. 17-05, the Department approved the Company's proposal to implement a performance-based ratemaking mechanism ("PBRM") that sets rates annually in accordance with a revenue-cap formula. In this proceeding, the Company is proposing certain modifications to the PBRM, which are discussed further in the testimonies of Company Witnesses Hallstrom, Horton, Kaufmann, Meitzen, and Nicholas A. Crowley provided as Exhibit ES-CAH/DPH-1, Exhibit ES-PBR/Plan-1 and Exhibit ES-PBR/TFP-1.

The PBRM does not affect the computation of either the NSTAR Electric revenue requirement or revenue deficiency in this proceeding.

Q. Has the Company prepared an exhibit to summarize the transfer of investments and certain expenses to base distribution rates currently recovered through other reconciling mechanisms?

A. Yes. The Company has prepared Exhibit ES-REVREQ-4, Schedule 9, to summarize the revenue requirement the Company has embedded in its cost of service and is proposing to transfer to base distribution rates associated with the following programs: (1) 2018-2021 Grid Modernization Plan, or GMP; (2) Solar Program Cost Adjustment, or SPCA; (3) Solar Expansion Cost Recovery Mechanism; or SECRM, (4) Solar Massachusetts Renewable Target program, or SMART; and (5) Resiliency Tree Work Program, or RTW. The Company discusses these costs further in Section III and IV.

Q. Is the Company proposing changes to existing reconciling mechanisms as part of this case?

A. Yes. The Company is proposing adjustments to certain reconciling mechanisms in place for NSTAR Electric, summarized below:

- For the GMP, the Company is proposing to transfer the recovery of investments through 2021 to base rates for all plant investment and other rate base items such as accumulated depreciation, accumulated deferred income taxes, and cash working capital. The Company also reflects property tax expense for these investments as well as certain expenses as listed in Exhibit ES-REVREQ-4, Schedule 9. Lastly, the Company is including the corresponding revenues associated with the rate base and expenses described above for purposes of reflecting the appropriate revenue deficiency. The Company is also incorporating GMP related internal labor operating and maintenance ("O&M") expense into base rates as part of this proceeding. The Grid Modernization Factor ("GMF") will continue after the close of this proceeding in order to recover incremental capital investments not reflected in base rates as part of this proceeding. The GMF will also continue to recover GMP contractor-related expenses which are not included in base rates, as well as potentially incremental internal company employees, to the extent such resources are necessary, and are incremental to amounts recovered in base rates.

- For the SPCA, the Company is proposing to transfer the recovery of investments through 2021 to base rates for all plant investment and other rate base items such as accumulated depreciation, accumulated deferred income taxes, and cash working capital. The Company also reflects property tax expense for these investments as well as certain expenses as listed in Exhibit ES-REVREQ-4, Schedule 9. Lastly, the Company is including the corresponding revenues associated with the rate base and expenses described above for purposes of reflecting the appropriate revenue deficiency. The Company is not imbedding SPCA revenues associated with the sale of product revenues (Sale of Energy, Forward Capacity Market Revenues and Sale of solar renewable energy credits ("SRECs") as an offset to base rates in this proceeding. As such, these revenues will continue to be reflected as a credit to customer rates in the SPCA reconciliation mechanism going forward.

- For the SECRM, the Company is proposing to transfer the recovery of investments through 2021 to base rates for all plant investment and other rate base items such as accumulated depreciation, accumulated deferred income taxes, and cash working capital. The Company also reflects property tax expense for these investments as well as certain expenses as listed in Exhibit ES-REVREQ-4, Schedule 9. Lastly, the Company is including the corresponding revenues associated with the rate base and expenses described above for purposes of reflecting the appropriate revenue deficiency. Similar to the SPCA described above, the Company is not imbedding SECRM revenues associated with the sale of product revenues (Sale of Energy, Forward Capacity Market Revenues and Sale of SRECs) as an offset to base rates in this proceeding. As such, these revenues will continue to be reflected in the SECRM reconciliation mechanism.

- For SMART, the Company is proposing to transfer the recovery of expenses as listed in Exhibit ES-REVREQ-4, Schedule 9 into base rates as part of this proceeding. The Company is including the corresponding revenues associated with these expenses described above for purposes of reflecting the appropriate revenue deficiency. SMART revenues associated with the sale of product revenues (Sale of Energy, Forward Capacity Market Revenues and Sale of SRECs) will continue to be included in the SMART mechanism, as well as, the (1) Incentive Payments for RPS Class I Renewable Generation Attributes and/or Environmental Attributes produced by a Solar Tariff Generation Unit; (2) Alternative On-Bill Credits for energy generated by an Alternative On-Bill Credit Generation Unit; (3) the basis upon which Incentive Payments and Alternative On-Bill Credits are determined; and (4) the recovery of any such Incentive Payments, Alternative On-Bill Credits, and certain incremental administrative costs associated with the implementation and operation of the SMART Program.

- For RTW, 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 as listed in Exhibit ES-REVREQ-4, Schedule 9. The remaining program costs for 2017 through 2022 would be recovered through the RTW factor. The Company is proposing to maintain the RTW factor ("RTWF") in place to recover the costs associated with the municipal hazard tree removal pilot program as discussed by Company Witness Van Dam in Exhibit ES-WAV-1.

Q. Please describe the current Grid Modernization Factor.

A. The Grid Modernization Factor ("GMF") provides for the recovery of incremental costs associated with the Company's GMP approved by the Department in D.P.U. 15-122/15-123 (2018). The Department preauthorized the Company's first three-year short-term investment plan Eligible GMP Projects and spending cap in D.P.U. 15-122 (2018), establishing three years of GMP spending for the GMP Investment Years 2018 through 2020 (first authorization term). The Department extended the first authorization term by one year, establishing four years of GMP spending for the GMP Investment Years 2018-2021 in D.P.U. 15-122-D (2020). To be eligible for recovery through the GMF, GMP costs must be (1) be preauthorized by the Department; (2) be incremental relative to the Company's current investment practices or new types of technology for capital investments; (3) be incremental to those costs that the Company currently recovers through its base distribution rates for O&M expenses and solely attributable to preauthorized grid modernization investments; (4) be prudently incurred; (5) have aggregate total expenditures for preauthorized Eligible GMP Projects less than the four-year expenditure cap determined by the Department; and (6) be recorded as in-service by December 31 of each GMP Investment Year. The operation of the GMF tariff is applicable to Eligible GMP Investment and Allowed O&M Expense associated with the first two GMP terms (2018 through 2021, and 2022 through 2025). In this proceeding, the

Company is only proposing to transfer the GMP investments associated with the first GMP term, 2018 through 2021, into base rates. The GMF will continue after this proceeding in order to recover incremental GMP costs not reflected in base rates.

Q. Please describe how the Company intends to transfer Grid Modernization investments into base rates in this proceeding, while ensuring no costs are double recovered.

A. The Department has previously found that the recovery of the revenue requirement through the Gas System Enhancement Adjustment Factor ("GSEAF") for investments associated with the Gas System Enhancement Program ("GSEP") where the recovery of investments is transferred into rate base does not constitute double recovery, so long as the recovery through the GSEAF relates to revenue requirement accumulated before the investment is reflected into base distribution rates. D.P.U. 18-GSEP-06, at 49. A reduction to GSEP recovery must account for new base distribution rates to ensure that the GSEP is recovering only the revenue requirement the transferred investments accumulated before the effective date of new base distribution rates recovering the revenue requirement of those investments. Id. Based on these findings, the Department has directed NSTAR Gas to make an adjustment removing the revenue requirement that would result in double recovery through the GSEAF if the adjustment were not made concurrent with new base distribution rates. Id. at 50.

In this filing, the Company has included actual Grid Modernization investments placed in service through December 31, 2020. In addition, the Company has projected the level of Grid Modernization investments that will occur through December 31, 2021 and is proposing to include the revenue requirement associated with those investments in the computation of the revenue requirement underlying base rates authorized to become effective on January 1, 2023. The Company will provide an update to rate base during the course of the proceeding to incorporate capital additions placed in service in 2021, including Grid Modernization investments.

Under the operation of the currently effective GMF tariff provisions, the Company begins to earn a revenue requirement for Grid Modernization investments at the point that investments are placed into service up through the effective date of new base distribution rates. In this case, the Company is proposing to transfer the recovery to base rates for Grid Modernization investments placed in service through December 31, 2021, for base distribution rates effective January 1, 2023. The Company will begin to recover the revenue requirement associated with Grid Modernization investments placed in service from January 1, 2018 through December 31, 2021 through base rates beginning on January 1, 2023.

However, the Company will not have recovered the revenue requirement earned under the GMF tariff prior to new base distribution rates taking effect due to the timing of the GMF filings, which go into effect on July 1st of each year and include a substantial lag up to 18 months between when investments are placed in service to when recovery begins through the GMF. The earned revenue requirement between January 1, 2021 through December 31, 2022 on the investments the Company is proposing to transfer to base rates will not be fully recovered per the current timing of the GMF until June 30, 2024. Therefore, this two-year, earned revenue requirement will need to be recovered through the GMF, in accordance with the tariff, which will occur after the effective date of new base rates to allow recovery for the earned revenue requirement prior to this date, i.e. January 1, 2023. The timing of the GMF filings are as follows:

- On May 15, 2022, the Company will file its annual GMF filing for actual investments placed in service on or before December 31, 2021, consistent with the timeline set in M.D.P.U. No. 73E. The associated GMF will be effective July 1, 2022 through June 30, 2023 to allow for the recovery of the 2021 revenue requirement on those investments.
- On May 15, 2023, the Company will file its annual GMF for actual investments placed in service on or before December 31, 2022. The associated GMF will be effective on July 1, 2023 through June 30, 2024 to allow for the recovery of the 2022 revenue requirement on those investments.
- On May 15, 2024, the Company will file its annual GMF for actual investments placed in service between January 1, 2023 through December

31, 2023. The associated GMF will be effective on July 1, 2024 to allow for the recovery of the 2023 revenue requirement, which is the first GMF filing that will exclude GMP investments placed in service from January 1, 2018 through December 31, 2021.

Q. Following the Department's decision in this proceeding, does the Company anticipate filing a revision to the GMF rate in effect as of January 1, 2023?

A. No. The Company anticipates a decision from the Department in this proceeding on or about December 1, 2022, for rates effective January 1, 2023. Following the issuance of that decision, the Company does not anticipate a compliance filing in the GMF is required to reduce the current GMF rate in effect. The rate in effect on January 1, 2023 is recovering the earned revenue requirement for 2021, and therefore, the Company is eligible to recover the 2021 revenue requirement that was earned prior to the date of new base rates.

Q. Will the Company transfer GMF investments that are placed into service in 2022 at the time of the Company's first PBRA adjustment?

A. No. The Company does not intend to incorporate the revenue requirement on rate-base additions associated with 2022 GMP investments as part of its request to roll-in capital additions during 2022 as part of the first PBRA adjustment.

Q. What is the timing of the Department's review for the GMP Investments?

A. In D.P.U. 15-122, the Department stated it will review the reasonableness and prudence of the Companies' actual grid modernization expenditures at the conclusion of the investment term in the Grid Modernization Term Reports ("Term

Report"), which are to be filed on April 1, 2022. NSTAR Electric Company d/b/a Eversource Energy, D.P.U. 21-116, Hearing Officer Memorandum (October 25, 2021); D.P.U. 15-122, at 144, fn. 50; D.P.U. 15-122-D at 4, fn. 3. The Department indicated that once it has made the appropriate findings in those proceedings, the Company may move the applicable capital investments into rate base in its next base rate proceeding thereafter. D.P.U. 15-122, at 144, fn. 50.

However, as initially prescribed by the Department, the grid modernization investment term was set to be three years, 2018-2020, and the final Term Report was to be filed on April 1, 2021. D.P.U. 15-122, at 114-115. As outlined above, due to the COVID-19 pandemic, the Department recognized the pandemic may have a negative effect on the Company's deployment of grid modernization investments in 2020. D.P.U. 15-122-D at 3. Accordingly, the Department allowed the Company to implement its approved grid modernization investment plans, subject to the Company-specific budget cap, for an additional year through calendar year 2021 (for a total initial investment term of three years and seven months). Id. at 4.

The Department further allowed the Company to petition for a supplemental budget if it encountered any budget constraints related to the approved grid modernization investments as a result of the extension of the investment term. Id. at 7, fn. 7. In July 2020, the Company requested, and the Department approved, a supplemental budget to implement the approved grid modernization investments through 2021. NSTAR Electric Company d/b/a Eversource Energy, D.P.U. 20-74, at 41.

Due to this extension, the Term Report will be filed a year later than originally anticipated, creating timing issues resulting from the conclusion of the Company's initial five-year PBR and the current base distribution rate proceeding. As discussed above, in this proceeding, the Company is requesting a 10-year PBR plan and is proposing a stay out until the year 2032. Therefore, the Company would be precluded from transferring the 2018-2021 grid modernization investments into base rates until its next base distribution proceeding in 2032.

To remedy this, the Company is producing the necessary documentation for the 2018-2021 grid modernization investments for the Department to conduct its prudence review in the present proceeding. Company Witnesses Landry and Griffin discuss the project documentation for these investments.

As a result, the Department will have determined prudency of the GMP Investments coinciding with the Department's final decision in this proceeding, anticipated on or before December 1, 2022, which will allow for the inclusion of these investments into base rates. Any adjustments deemed necessary as part of the Department's decision in its review of the 2018-2021 GMP would be reflected as part of the Company's compliance filing in this proceeding.

Q. Please describe the current Solar Program Cost Adjustment (SPCA).

A. The SPCA recovers the investment and ongoing maintenance associated with three solar facilities commissioned by the Company: (1) a 1.8 MW solar facility located on eight acres of brownfield property in Pittsfield, MA (the "Silver Lake Solar Facility"); (2) a 2.3 MW solar facility on twelve acres of brownfield property located in Springfield, MA (the "Indian Orchard Solar Facility"); and (3) a 3.9 MW solar facility on 22 acres of a landfill located in Springfield, MA (the "Cottage Street Solar Facility"). The Company recovers the revenue requirement associated with these facilities for the prior year, offset by the sale of energy, capacity, SRECs, and any other non-customer revenue offsets that the Company is able to obtain from or for its solar facilities, beginning on January 1st of each calendar year.

On February 12, 2009, WMECO filed with the Department a proposed program to construct, own, and operate generation facilities that produce solar energy. WMECO filed its Solar Program pursuant to G.L. c. 164, § 1A(f), as added by Section 58 of Chapter 169 of the Acts of 2008 ("Green Communities Act"). On June 18, 2009, WMECO and the Attorney General's Office ("AGO")(together, "Stipulating Parties") filed a Stipulation Agreement offering a settlement of the six-MW development phase of the Solar Program, which was then expanded to eight MW in 2013. Western Massachusetts Electric Company, D.P.U. 09-05, at 20; Western Massachusetts Electric Company, D.P.U. 13-50, at 8. In its order approving the Stipulation Agreement in D.P.U. 09-05, the Department noted that the Stipulation Agreement segregated the rate base associated with the Solar

Program from WMECO's overall rate base. D.P.U. 09-05, at 19. As a result, the Department encouraged the Stipulating Parties to explore reaching an agreement that would transfer the Solar Program rate base into the WMECO's overall rate base in a future base rate filing. Id.

The Company began implementing the Solar Program during the fourth quarter of 2009, and to date has successfully commissioned the entirety of the approved scope of 8 MW as approved by the Department in D.P.U. 09-05 and D.P.U. 13-50.

Q. Please describe the current Solar Expansion Cost Recovery Mechanism (SECRM).

A. The SECRM recovers the investment and ongoing maintenance costs of solar generation projects constructed, owned and operated by the Company pursuant to Section 1A(f) of Chapter 164 of the General Laws, as amended by An Act Relative to Solar Energy ("Act"), offset by any credits for (1) the sale of energy, (2) either the sales of RECs into the ISO-NE market or the market value of RECs used to comply with the Renewable Portfolio Standard ("RPS"), (3) capacity sales, if any. The Company began implementing the Solar Expansion program with the approval of D.P.U. 16-105 on December 29, 2016, and to date has successfully commissioned the full approved scope of 62 MW. The Company placed into service ten solar facilities equaling 28.14 MW by June 30, 2018, which were approved by the Department on August 31, 2020, in D.P.U. 18-124. An additional seven solar facilities equaling 21.96 MW were placed into service between July 1, 2018 and December 31, 2018 and were approved by the Department on October

19, 2020 in D.P.U. 19-59. The final two solar facilities that were placed into service between January 1, 2019 and June 30, 2019 equaling 11.90 MW were approved by the Department on February 25, 2021 in D.P.U. 19-127.

Q. Please describe how the Company intends to transfer the SPCA investments into base rates in this proceeding, while ensuring no costs are double recovered.

A. In this filing, the Company will be including actual Solar Program Investments placed in service through December 31, 2021 for both the SPCA and the Solar Expansion reconciling mechanisms. The Company is proposing to include the revenue requirement associated with those investments in the computation of the revenue requirement underlying base rates authorized to become effective on January 1, 2023.

Under the operation of the currently effective SPCA tariff provisions, the Company begins to earn a revenue requirement for investments at the point that investments are placed into service up through the effective date of new base distribution rates. In this case, the Company is proposing to transfer the recovery of investments into base rates for the SPCA investments placed in service through December 31, 2021. The Company will begin recovering the revenue requirement associated with SPCA investments placed in service through December 31, 2021 in base rates beginning on January 1, 2023. However, the Company will not have recovered the revenue requirement earned under the SPCA tariff prior to new base distribution rates taking effect due to the timing of the SPCA filings, which go into effect on January 1st of each year and include a 12-month lag between when investments are placed in service to when recovery begins through the SPCA. The earned revenue requirement between January 1, 2022 through December 31, 2022 on the investments the Company is proposing to transfer to base rates will not be fully recovered per the current timing of the SPCA until January 1, 2025. Therefore, this one-year, earned revenue requirement will need to be recovered through the SPCA, in accordance with the tariff, which will occur after the effective date of new base rates to allow recovery for earned revenue requirement prior to this date, i.e. January 1, 2023. The timing of the SPCA filings are as follows:

- By November 1, 2022, the Company will file its annual SPCA filing for actual investments placed in service on or before July 31, 2022, consistent with the timeline set out M.D.P.U. No. 66. The associated SPCA will be effective January 1, 2023 through December 31, 2023 to allow for the recovery of the actual 2021 and estimated 2022 revenue requirement.

- By November 1, 2023, the Company will file its annual SPCA filing for actual investments placed in service on or before December 31, 2022, consistent with the timeline set out M.D.P.U. No. 66. The associated SPCA will be effective January 1, 2024 through December 31, 2024 to allow for the recovery of the actual 2022 revenue requirement and the estimate 2023 sale of product revenues (Sale of Energy, Sale of SRECs and FCM credits).

- By November 1, 2024, the Company will file its annual SPCA filing for actual sale of product revenues through December 31, 2023 and estimate 2024 sale of product revenues, consistent with the timeline set out M.D.P.U. No. 66. The associated SPCA will be effective January 1, 2025 through December 31, 2025 to allow for the recovery of the actual 2023 and estimated 2024 revenue requirement. At this point, the SPCA will no longer recover investments that have been reflected in base rates as of January 1, 2023 and continue to utilize the SPCA to pass-through credits to customers associated with the sale of energy, capacity, SRECs, and any other non-customer revenue offsets that the Company is able to obtain from or for its solar facilities. Any over/under recoveries will be reconciled in subsequent filings.

Q. Following the Department's decision in this proceeding, does the Company anticipate filing a revision to the SPCA rate in effect as of January 1, 2023?

A. No. The Company anticipates a decision from the Department in this proceeding on or about December 1, 2022, for rates effective January 1, 2023. Following the issuance of that decision, the Company does not anticipate a compliance filing in the SPCA to reduce the current SPCA rate in effect. The rate in effect on January 1, 2023 will be recovering the earned revenue requirement for 2022, and therefore, the Company is eligible to recover the revenue requirement earned in 2022 prior to the date of new base rates.

Q. Has the Department determined prudency of the SPCA investments that the Company proposes to be transferred to base rates?

A. Yes. The Department has completed its review of the documentation for these capital additions and has found them to be prudent and used and useful to the benefit of the Company's customers. Therefore, the Company is requesting to transfer the recovery of the approved SPCA additions into base rates in this proceeding.

Q. How does the Company intend to transfer costs currently recovered through the SECRM to base rates, ensuring no costs are double recovered?

A. Under the operation of the currently effective SECRM tariff provisions, the Company begins to earn a revenue requirement for investments at the point that investments are placed into service up through the effective date of new base distribution rates. In this case, the Company is proposing to transfer the recovery of investments into base rates for the SECRM investments placed in service through December 31, 2021. The Company will begin recovery of the revenue requirement associated with SECRM investments placed in service through December 31, 2021 in base rates beginning on January 1, 2023. However, the earned revenue requirement between January 1, 2022 through December 31, 2022 on the investments the Company is proposing to transfer into base rates will not be fully reconciled per the current timing of the SECRM until January 1, 2025. Therefore, the difference between the estimated 2022 revenue requirement as compared the actual 2022 revenue requirement will need to be reconciled through in the 2023 SECRM for effect on January 1, 2023, in accordance with the tariff, coinciding with the effective date of new base rates, January 1, 2024. The SECRM will no longer recover investments that have been reflected in base rates as of January 1, 2023, except for reconciling adjustment associated with the 2022 revenue requirement. The Company will continue to utilize the SECRM to pass-through credits to customers associated with any credits for (1) the sale of energy, (2) either the sales of RECs into the ISO-NE market or the market value of RECs used to comply with the Renewable Portfolio Standard ("RPS"), (3) capacity sales, if any.

Q. Following the Department's decision in this proceeding, does the Company anticipate filing a revision to the SECRM rate in effect as of January 1, 2023?

A. Yes. The Company anticipates a decision from the Department in this proceeding on or about December 1, 2022, for rates effective January 1, 2023, which is after the Company submits its filing for the SECRM by November 1, 2022. Following the issuance of that decision, the Company will make a compliance filing in the 2022 SECRM filing to eliminate the 2023 revenue requirement included in the rate effective on January 1, 2023, if the Company's proposal to transfer these investments is accepted by the Department.

Q. Has the Department determined prudency of the SECRM investments that the Company proposes to be transferred to base rates?

A. Yes. The Department has completed its review of the documentation for these capital additions and has found them to be prudent and used and useful to the benefit of the Company's customers. Therefore, the Company is requesting to transfer the recovery of the approved Solar Expansion additions into base rates in this proceeding.

Q. Please describe the current Solar Massachusetts Renewable Target (SMART) mechanism.

A. Chapter 75 of the Acts of 2016, An Act Relative to Solar Energy (the "Act"), required the Massachusetts Department of Energy Resources ("DOER") to develop a statewide solar incentive program to encourage the development of solar renewable energy generating resources that lowers the cost of the Commonwealth's solar incentive programs for all customers. St. 2016, c. 75, § 11. In compliance with the Act, DOER promulgated regulations to implement the SMART Program, as set forth in 225 C.M.R. § 20.00 ("SMART Regulations").

The SMART Regulations established a voluntary statewide solar incentive program and required the Distribution Companies to jointly develop and file a tariff to implement the SMART Program, subject to review and approval by the Department. The Distribution Companies filed a proposed tariff, referred to as the SMART Provision, on September 12, 2017. The Department issued a final order in D.P.U. 17-140 on September 26, 2018 approving the Distribution Companies' model SMART Provision to implement the SMART Program, subject to several modifications. Joint Petition of Electric Distribution Companies for Approval of model SMART Provision pursuant to An Act Relative to Solar Energy , St. 2016, c. 75, § 11, and 225 CMR 20.00 to implement the Solar Massachusetts Renewable Target Program, D.P.U. 17-140-A (2018) (the "D.P.U. 17-140").

The Company is required to make an annual cost recovery and reconciliation filing for the SMART Factor on or before November 1st of each year, for effect January

1st of the next year. D.P.U. 17-140-A at 197. In accordance with D.P.U. 17-140, the Company filed annual SMART Factor filings in D.P.U. 18-132, D.P.U. 19-125, and D.P.U. 20-131 for the SMART program costs for 2019, 2020 and 2021, respectively. Through the SMART Factor, the Company is authorized to recover (1) the incremental O&M and capital costs; (2) an estimate of the net cost of the incentive payments, alternative on-bill credits ("AOBC"), and revenues generated from the SMART program; and (3) a reconciliation adjustment with applied interest. M.D.P.U. No. 74A, §14.0; D.P.U. 17-140-A at 143-160.

The Company is proposing to transfer certain incremental administrative costs into base rates associated with the implementation of the SMART program, including billing system improvements.

Q. Please describe how the Company intends to transfer SMART into base rates in this proceeding, while ensuring no costs are double recovered.

A. In this filing, the Company will include actual SMART investments placed in service through December 31, 2021. The Company is proposing to include the revenue requirement associated with those investments in the computation of the revenue requirement underlying base rates authorized to become effective on January 1, 2023.

Under the operation of the currently effective SMART tariff provisions, the Company begins to earn a revenue requirement for investments at the point that investments are placed into service up through the effective date of new base distribution rates. In this case, the Company is proposing to transfer the recovery of expenses associated with the SMART investments for ESC capital placed in service through December 31, 2021 charged to the Company as Enterprise IT expense. The Company will begin to recover the revenue requirement associated with SMART investments placed in service through December 31, 2021 in base rates beginning on January 1, 2023. However, the Company will not have recovered the revenue requirement earned under the SMART tariff prior to new base distribution rates taking effect due to the timing of the SMART filings, which go into effect on January 1st of each year and include a 12-month lag between when investments are placed in service to when recovery begins through the SMART. The earned revenue requirement between January 1, 2022 through December 31, 2022 on the investments the Company is proposing to transfer to base rates will not be fully recovered per the current timing of the SMART until January 1, 2024. Therefore, this one-year, earned revenue requirement will need to be recovered through the SMART, in accordance with the tariff, which will occur after the effective date of new base rates to allow recovery for earned revenue requirement prior to this date, i.e. January 1, 2023. The timing of the SMART filings are as follows:

- By November 1, 2022, the Company will file its annual SMART filing for actual investments placed in service on or before August 30, 2022, consistent with the timeline set out M.D.P.U. No. 74. The associated SMART Factor will be effective January 1, 2023 through December 31, 2023 to allow for the recovery of the 2022 revenue requirement on administrative costs.

- By November 1, 2023, the Company will file its annual SMART filing for actual investments placed in service on or before August 30, 2023, consistent with the timeline set out M.D.P.U. No. 74. The associated SMART Factor will be effective January 1, 2024 through December 31, 2024 to allow for the recovery of the 2023 revenue requirement on administrative costs. At this point, the SMART factor will no longer recover investments that have been reflected in base rates as of January 1, 2023.

Q. Following the Department's decision in this proceeding, does the Company anticipate filing a revision to the SMART rate in effect as of January 1, 2023?

A. No. The Company anticipates a final decision from the Department in this proceeding on or about December 1, 2022, for rates effective January 1, 2023. Following the issuance of that decision, the Company does not anticipate a compliance filing in the SMART is required to reduce the current SMART rate in effect. The rate in effect on January 1, 2023 will be recovering the earned revenue requirement for 2022, and therefore, the Company is eligible to recover the revenue requirement for 2022 earned prior to the date of new base rates.

Q. Has the Department determined prudency of the SMART investments that the Company proposes to be transferred to base rates?

A. No. The Department has not conducted its prudency review of the 2019, 2020, and 2021 SMART program investments. The Company is providing the project documentation for the 2019, 2020 and 2021 project costs that have not been examined for review and approval by the Department in this proceeding. The 2019, 2020 and 2021 SMART program documentation is discussed by Company Witnesses Landry and Griffin in Exhibit ES-ADDITIONS-1 Therefore, the Company requests that the Department authorize the inclusion of the SMART investments in base rates.

Q. Does the NSTAR Electric cost of service include costs incurred by a centralized service company on behalf of the Company?

A. Yes. In the test year, service company charges were billed to NSTAR Electric by ESC.

Q. Please explain the service company structure during the test year.

A. Beginning with the effective date of the merger of Northeast Utilities and NSTAR, April 10, 2012, and through December 31, 2013, Northeast Utilities Service Company ("NUSCO") and NSTAR Electric & Gas Service Company ("NE&G") operated as a single service company organization despite being separate legal entities. Effective January 1, 2014, NE&G was legally merged into NUSCO, with NUSCO as the surviving entity. Effective February 2, 2015, Northeast Utilities and all of its subsidiaries began doing business as Eversource Energy, and NUSCO was renamed as Eversource Energy Service Company, or "ESC" in this proceeding.

ESC provides administrative, corporate and management services to NSTAR Electric and the other operating subsidiaries of Eversource Energy. The cost of service for NSTAR Electric reflects charges from ESC in the test year ending December 31, 2020. Service company charges are comprised of "direct charges" billed for costs incurred and work performed by service-company personnel directly related to the respective subsidiary, and "common costs," which are allocated among the respective subsidiaries receiving the service based on appropriate allocation factors.

Q. How are ESC costs incorporated into the NSTAR Electric revenue requirement calculations?

A. ESC charges to NSTAR Electric are recorded on the NSTAR Electric books and then incorporated into the appropriate expense categories used in the test year and rate year cost of service.

Q. Are charges billed to NSTAR Electric in conformance with a service agreement?

A. Yes. During the test year period, there was an operating agreement in effect between ESC and NSTAR Electric. This agreement provided in Exhibit ES-REVREQ-4, Schedule 10, identifies the services that are provided to NSTAR Electric from ESC.

Q. Is there any other analysis that you have relied on to prepare the NSTAR Electric revenue requirement?

A. Yes. To compute the NSTAR Electric revenue requirement, the Company has used the recommended cost of capital presented by Company Witness Rea. The cost of capital is based on the Company's pro forma capital structure of 53.80 percent common equity, 0.49 percent preferred stock and 45.71 percent debt.

Employee payroll adjustments are discussed in the testimony of Company Witness Lazor. Employee benefits are discussed in the testimony of Company Witness, Synan.

Lastly, the NSTAR Electric revenue requirement includes depreciation expense derived from the depreciation studies prepared by Company Witness Spanos.

III. REVENUE REQUIREMENT ANALYSIS

Q. What adjustments have you made to the NSTAR Electric revenue requirement calculation?

A. The NSTAR Electric revenue requirement includes adjustments to Operating Revenues, O&M Expense, Depreciation, Amortization, Taxes and Rate Base. The Company describes these adjustments in detail below.

Q. How is Exhibit ES-REVREQ-2, Schedule 7, which illustrates the post-test year adjustments to O&M expense, organized?

A. Exhibit ES-REVREQ-2, Schedule 7 summarizes the proposed post-test year adjustments to O&M expense and other operating expenses such as depreciation, amortization, and taxes other than income taxes. Column B of Schedule 7 shows the adjusted test year figures for O&M expense and other operating expenses with normalizing adjustments. Column C of Schedule 7 itemizes the Company's proposed post-test year adjustments to the adjusted test year. Column D of Schedule 7 shows the Test Year Pro Forma amount included in the revenue requirement. Column E of Schedule 7 shows the sum of the previous columns, including the proposed increase or decrease to revenues and expenses. Supporting exhibits are referenced in the last column.

Exhibit ES-REVREQ-2, Schedule 8 provides a similar schedule of expenses as Schedule 7, further breaking out these expenses by FERC account. Schedule 8, Page 1, Column C starts with the balances as reported on the Company's FERC Form 1 as of December 31, 2020. Column D presents adjustments required to remove expenses related to costs recovered through various reconciliation mechanisms among other adjustments further itemized on Schedule 8, Page 2. Column E presents the mechanisms that the Company is transferring recovery from various reconciling mechanisms into base rates, i.e., Grid Modernization, SPCA, SECRM, SMART and RTW. Column F presents the total adjusted test year expense. Columns G through W show the pro forma adjustments. The rate year distribution expense is presented in the last column, Column X.

Exhibit ES-REVREQ-2, Schedule 8, page 2, columns D through U, provides details supporting the amounts listed on Schedule 8, page 1, column D, and reflect the removal of expenses related to adjustment clauses. These amounts are recovered through other mechanisms and have therefore been removed from the distribution revenue requirements in this proceeding. Schedule 8, page 2, column V, reflects the reclassification of indirect costs for purposes of presenting the revenue requirement in this proceeding. This reclassification is intended for ease of presentation of certain cost categories and, as described in more detail later in this testimony, has no net effect on the revenue requirement presented in this proceeding. Column W presents the normalizing adjustments to the test year expenses. Column X presents the adjusted test year expense by calculating the sum of Columns C through W.

Exhibit ES-REVREQ-2, Schedule 9 provides details supporting the amounts listed on Schedule 8, page 2, column W, and an itemized explanation of each normalizing adjustments to test year expenses included in the revenue requirement. These adjustments are described in more detail below.

Q. What adjustments are you proposing in Schedule 8 to the test year levels of O&M expenses for NSTAR Electric?

A. In Exhibit ES-REVREQ-2, Schedule 8, page 1, the per-book test year O&M expense total for NSTAR Electric is $1,934,034,730. A total net decrease of $1,472,936,044 to the test year O&M total is derived through the following adjustments: (1) removal of non-distribution lines of businesses recovered through other reconciling mechanisms; (2) normalization of test year expense to exclude non-recurring items; (3) reclassification of indirect costs to attribute expense to the appropriate O&M expense accounts; (4) transfer of expenses to base distribution rates from other reconciling mechanisms; and (5) adjustment of expenses for known and measurable changes occurring through the mid-point of the rate year, including inflation on residual expenses. The Company further details the adjustments in Column D on Schedule 8, page 1 in Columns D, E, and G through W. These adjustments result in total net distribution O&M of $461,098,686 in Column X. Each of the pro forma adjustments listed on Exhibit ES-REVREQ-2, Schedule 8 is discussed in turn below.

A. Department Schedules

Q. Has the Company developed the Department's nine schedules to accompany the presentation of the revenue-requirement analysis?

A. Yes. The Department's standard filing requirement schedules are included as Exhibit ES-REVREQ-2, Schedule 1.

B. Operating Revenues

Q. Which schedules show the adjustments to Operating Revenues for NSTAR Electric?

A. Exhibit ES-REVREQ-2, Schedule 6, shows test year revenue per books in Column B; normalizing adjustments to distribution revenue are shown in Column C; a reclassification in Column D to reflect $58,061,907 Grid Modernization, SPCA, SECRM, SMART and RTW revenues, which were recognized in the test year as revenue from reconciliation mechanisms; the removal of revenues from other reconciliation mechanisms are shown in Column E; adjusted test year revenues are reflected in Column F; and pro forma adjustments to test year revenues are shown in Column G. Total test year pro forma revenues are shown in Column H.

Q. Please describe in more detail how the adjusted test year amount on Exhibit ES-REVREQ-2, Schedule 6, column F is derived.

A. Exhibit ES-REVREQ, Schedule 6 shows: (1) test year revenue per books in Column B; (2) normalizing adjustments in Column C as supported further by Company Witness Chin; (3) reclassifications to reflect cost items that were previously collected through recovery mechanisms in Column D for purposes of presenting the revenue deficiency; (4) revenues collected within reconciling mechanism other than distribution rates in Column E; (5) adjusted test year revenues are shown in Column F; and (6) pro forma adjustments to test year revenues are shown in Column G. Total test year pro forma revenues are shown in Column H. These adjustments are discussed in greater detail below.

Q. Please describe in more detail how the pro forma adjustments to Other Revenues listed on Exhibit ES-REVREQ-2, Schedule 6, column G are derived.

A. The Company has included increases in other revenues of: (1) $66,784,356 reflecting additional PBR revenues in calendar years 2021 and 2022 (2) $4,589,903 in additional Miscellaneous Service Revenues; and (2) $694,623 in Other Electric Revenues, as detailed further on Exhibit ES-REVREQ-3, Work Paper 6. Changes in the level of customer fees are discussed by Company Witness Chin.

Q. Please elaborate on the adjustments to Miscellaneous Service Revenues and Other Electric Revenues.

A. The increase in Miscellaneous Service Revenues of $4,589,903 is detailed on Exhibit ES-REVREQ-3, Work Paper 6, pages 1 and 5, which consist of the following: (1) an increase of $104,760 to reflect changes in the return check fee; (2) increase of $4,316,689 to reflect changes in account restoration fee (meter, pole and manhole); and (3) an increase of $168,454 to reflect changes in the warrant and sales tax abatement fee.

The increase in Rent from Electric Property of $694,623 is detailed in Exhibit REVREQ-3, Work Paper 6, pages 1 through 4. As shown therein, there are three underlying adjustments:

- An increase in revenues of $216,826 associated with the Company's share of the Westwood facility, which is jointly owned by NSTAR Electric and NSTAR Gas. The revenues are assigned based on the NSTAR Electric ownership share of the building as shown on Exhibit ES-REVREQ-3, Work Paper 6, pages 1 and 2.

- An increase in rent revenues from NSTAR Gas of $471,432 relating to shared facilities owned by NSTAR Electric for service centers in New Bedford, Plymouth, Somerville and Hyde Park. These facilities are owned by NSTAR Electric which charges rent to NSTAR Gas for its proportionate use based on the costs to NSTAR Electric as shown on Exhibit ES-REVREQ-3, Work Paper 6, page 1 and 4.

- An increase of $6,365 related to rental income received from tenants that occupy the Westwood facility office facility space as shown on Exhibit ES-REVREQ-3, Work Paper 6, page 1 and 3. Tenant revenue received for the Westwood facility is assigned to NSTAR Electric based on NSTAR Electric ownership share of the building.

C. Adjustments to O&M Expense

Q. What is the amount of per-book test year O&M Expense?

A. In the test year, NSTAR Electric incurred $1,934,034,730 in O&M expense, as shown on Exhibit ES-REVREQ-2, Schedule 8, Page 1, Column C, at line 87.

Q. Has the Company removed non-distribution expenses, such as those associated with the procurement of Basic Service and the provision of energy efficiency programs pursuant to the Green Communities Act?

A. Yes. Non-distribution expenses are removed in Exhibit ES-REVREQ-2, Schedule 8, Page 1, Column D. Additional details supporting Column D are provided on Schedule 8, page 2, Columns D through W. As shown on page 2, the Company has removed non-base distribution expenses recovered through other rate mechanisms established by the Department, including transmission, transition, SMART, Solar Program Cost Adjustment, Long-Term Renewable contracts, Solar Expansion, Solar Program, basic service, NSTAR Green, NewSTART, energy efficiency charges, the Pension Adjustment Mechanism (“PAM”), Grid Modernization, Resiliency Tree Work, the SCRAF, Tax Act Credit Factor (“TACF”), Attorney

General Consultant Expense ("ACGE") and credits associated with net metering facilities installed by customers.

Q. Please describe the Indirect Cost reclassification included in Exhibit ES-REVREQ-2, Schedule 8, page 2, Column V.

A. ESC employees perform work functions that support multiple operating companies within the Eversource Energy enterprise. ESC employees charge their labor costs to each operating company in accordance with the Company's cost charging policies, which are designed to assign or allocate costs in accordance with cost-causation principles. Employee benefit costs and other service company charges "follow" labor to the operating company via ESC's "indirect" cost rates.

Generally speaking, ESC's indirect rates are designed to assign the specific costs associated with an ESC employee to the O&M or capital activity that the employee supports. More specifically, when ESC employees provide services to support an operating company activity, their labor is charged to that operating company, along with associated costs included in the General Service Company Overhead rate ("ZGS"). These costs include employee benefits, payroll taxes, corporate insurance, intercompany leases, and ESC capital costs, such as enterprise IT projects, which follow the associated labor to the O&M or capital activity. Because ESC employees charge the appropriate activity for their labor costs, each respective cost included in ZGS is credited to Account 403, 408, 925, 926, 930 and 931. A similar process occurs for Operating Company employees, except that the indirect costs follow labor only to capital or other balance sheet accounts. For Operating

Company employees, indirect costs generally do not follow the labor costs charged by employees to expense accounts because the costs are incurred and recorded directly to expense accounts rather than coming "indirectly" from ESC. Therefore, for Operating Company employees, the expense portion of indirect costs (for example, benefits) reside in Account 926. In this way, the amounts residing in Account 926 for Operating Company employees are presented net of a credit for amounts charged to capital and other balance sheet accounts.

During the test year, by function of the indirect cost allocation process described above, a total of $61,854,410 of indirect costs detailed on Work Paper 8 were recorded to various O&M accounts, following labor costs to those accounts. For purposes of presenting the cost of service in this proceeding, the Company has reclassified the ESC indirect costs charged to the respective FERC accounts (Account 403, 408, 925, 926, 930 and 931) so that the Company's O&M expense is more closely aligned to each cost category (for example, benefits expenses associated with ESC employees have been reclassified to account 926 from the account they were charged via application of the ZGS indirect rate to various O&M and A&G accounts). In addition, the Company reclassified a total of $17,762,811 in ESC depreciation expense from Account 403 to Account 930, to reflect the amount of ESC depreciation in O&M expense for the adjusted test year. Because ESC depreciation expense is not reflected in the Company's depreciation expense proposed in Exhibit ES-REVREQ-2, Schedule 25, this reclassification was necessary for presentation purposes to reflect the test year amount of depreciation expense, which is included in the Company's enterprise IT project expense adjustment discussed further below. The allocation of ESC depreciation expense to each operating company is based on the subsidiaries/business segments receiving the benefit.

As shown on Exhibit ES-REVREQ-2, Schedule 8, Page 2, Column V, there is no net impact to the cost of service of making the reclassification described above, as it is merely a geography change from various expense accounts to Account 403, 408, 925, 926, 930 and 931. Additionally, the Company provides the actual O&M associated with overheads and burdens in Exhibit ES-REVREQ-4, Schedule 12 to be utilized in various reconciling mechanisms as part of the overhead and burdens adjustment beginning on January 1, 2023.

Q. Did you make any other adjustments to the test year level of expenses for the NSTAR Electric cost of service?

A. Yes. To remove out-of-period or non-recurring items from the test year level of expense activity, the Company conducted a detailed review of account activity to normalize out-of-period or non-recurring activity. The result of this analysis and review is summarized in the normalizing adjustments schedule provided as Exhibit ES-REVREQ-2, Schedule 9.

Q. Please describe the normalizing adjustments included in Exhibit ES-REVREQ-2, Schedule 9.

A. The normalizing adjustments relating to expenses are presented on Exhibit ES-REVREQ-2, Schedule 9, resulting in a increase to test year expense of $56,122,940. This increase is mainly comprised of three adjustments:

1. An increase to account 407 for $48,380,245 to reclassify a net credit balance related to decoupling activity in the test year. An identical reclassification for the same amount was made to increase distribution revenue to reflect a more accurate presentation of decoupling in the cost of service. The net effect of the two decoupling reclassifications on the revenue deficiency is zero.

2. An increase to payroll expense (accounts 546, 556, 580, 903, 908, 920) of $3,194,556 to normalize the test year amounts to actual employee salaries as of December 31, 2020. This adjustment is necessary because the test year payroll expense represents payroll charges at the beginning of the year that were recorded at prior employee salary levels, as annual base salary merit increases take effect each April 1 as described by Company Witness Lazor. By utilizing the actual salaries at December 31, 2020 and applying those salaries to the active and filled positions as of December 31, 2020, the Company is able to determine the adjusted test year payroll expense more accurately.

3. An increase to variable compensation in account 920 of $2,496,764 to normalize the test year level to exclude the impact of accounting entries recorded in the test year. These entries occur during the test year but are related to the prior calendar year. Therefore, an adjustment is required so that only the amounts related to the test year activity remain.

The remainder of the normalizing expense adjustments reflected on Exhibit ES-REVREQ-2, Schedule 9 result in a net increase in test year expenses of $2,050,575. These adjustments are itemized on Schedule 9, and are summarized as follows:

- Removal of rate case expenses in account 407 related to D.P.U. 17-05 of ($939,486). Although expensed in the test year, these costs will be fully amortized by the beginning of the rate year (January 1, 2023) are removed from the cost of service.

- Removal of amortization expenses in account 407 of (270,900). Expensed during the test year, these costs are being removed from the cost of service.

- Increase to expense in account 407 of $58,727, representing the removal of credit adjustments associated with a cancelled project. The expense reductions relate to a prior period and are non-recurring, and, as a result, are being added back to the cost of service.

- Removal of ($451,057) of MA FMLA expenses in Account 408. Although expensed during the test year, the Company does not expect to incur these costs in the rate year and are removing them from the cost of service.

- Increase to expense for $1,823,800 in Account 408 related to one-time, non-recurring MA employee retention credit associated with the COVID-19 pandemic relief that was present in the test year but is not expected to continue.

- Increase to expense in Account 408 for $735,464 related to a property tax settlement with the Town of Medway. One-time, non-recurring settlement decreased property tax expense in the test year; it has been added back to the cost of service to normalize the adjusted test year starting point.

- Removal of ($490,737) in Account 593 for vegetation management expenses. This amount related to an out-of-period adjustment and has been removed on that basis.

- Addition of postage costs of $5,864 in Account 903 to normalize the month of January 2020. This adjustment is necessary because the Bulk Rate (First Class Letter) was updated in late January 2020 and therefore the expenses in January 2020 were not reflective of this updated rate.

- Increase to expense of $354,460 in Account 903 related to vendor Alorica. Invoices for the period October 1, 2020 through December 31 were not included in the test year and this normalizing adjustment restates the correct adjusted test year level.

- Increase to expense of $56,352 in Account 903 related to vendor Century Bank. Invoices for the period October 1, 2020 through December 31, 2020 were not included in the test year and this normalizing adjustment restates the correct adjusted test year level.

- Removal of ($278,090) in Account 903 expense related to net metering activity. Net-metering, class 3 customer cash-out accounts credits/debits should net to zero, expense is removed to normalize the activity in Account 903.

- Removal of administrative expenses in Account 921 for ($220,922). Although these expenses represent valid and necessary business expenses, the Company has opted to remove these costs from the cost of service presented for review in this proceeding.

- Removal of certain costs from Account 923 in the amount of ($3,770) associated with dues and memberships.

- Removal of ($49,027) in Account 923 related to vendor Sprinklr. Test year included two renewal invoices. This adjustment normalizes the adjusted test year level by removing the out-of-period invoices.

- Removal of certain costs from Account 930 in the amount of ($11,577) associated with dues and memberships.

- Removal of certain costs from Account 930 in the amount of ($1,967) associated with energy efficiency.

- Removal of shareholder-related expenses from Account 930 in the amount of ($75,204).

- Addition of bank fees of $166,823 to Account 930, reclassified from account 431.

- Addition of $124,355 in Account 930 to reclass customer deposit interest from Account 431. This adjustment is necessary because customer deposits are a reduction to rate base, and therefore customers receive a return on their deposits at the weighted average cost of capital. Any interest that is accrued on the deposits and paid to customers is therefore recoverable to avoid crediting customers with interest twice (once through a reduction in rate base and once through interest on their deposit).

- Addition of ESC return in Account 930 in the amount of $1,001,428 to adjust for the Department's precedent requiring the Company to determine its allocated share at the proposed return on equity for NSTAR Electric in this proceeding at 10.50 percent. D.P.U. 19-120, at 256; D.P.U. 18-150, at 267-269; D.P.U. 17-05, at 218-221; D.P.U.10-55, at 266-267; D.P.U. 08-27, at 84.

- Addition to Account 931 rental expense for $577,305 related to various intercompany rental facilities (Berlin, Hartford, Southborough, Windsor, Auburn) to adjust for the Department's precedent requiring the Company to determine its allocated share at the proposed return on equity for NSTAR Electric in this proceeding at 10.50 percent. D.P.U. 19-120, at 268; D.P.U. 18-150, at 267-269; D.P.U. 17-05, at 218-221; D.P.U.10-55, at 266-267; D.P.U. 08-27, at 84.

- Removal of ($61,266) in rent expense in Account 931 related to Eversource Energy's Washington, DC office.

Q. Has the Company made an adjustment to the revenue requirement for advertising expense?

A. No. As required by Department precedent, the Company reviewed its advertising activity in the test year in order to categorize its test year advertising expenses into four groupings designated by the Department. The result of this review confirmed that the Company's test year advertising activity was informational in nature.

Therefore, no adjustment was required to test year distribution expenses in order to remove costs not recoverable in rates under Department precedent, such as certain types of image and promotional activities. However, during its review of the test year advertising expenses, the Company identified a $6,235 invoice related to Energy Efficiency that was inadvertently included in the cost of service. As such, the Company will remove the expense associated with this invoice in its next update to the cost of service.

Exhibit ES-REVREQ-4, Schedule 2 presents copies of NSTAR Electric's print advertisement activity for the test year with the exception of promotional materials related to its energy efficiency programs. All costs related to energy efficiency programs are recorded within specific expense accounts and recovered separately from customers. Therefore, we have not included copies of those print advertisements within these schedules.

During the test year, the Company incurred a total advertising expense amount of approximately $230,190, including the reduction for the energy efficiency-related invoice as described above. As shown by the print advertisement copies provided in the referenced exhibit the messaging on this material is informational in nature. Therefore, the Company has made no adjustment to the test year levels of advertising expense.

D. Post-Test Year Expense Adjustments

1. Compensation: Payroll Expense

Q. Have you made post-test year adjustments for payroll expense for NSTAR Electric?

A. Yes. As shown on Exhibit ES-REVREQ-2, Schedule 10, the post-test year adjustment associated with NSTAR Electric's payroll expense is an increase of $13,138,206. These adjustments account for known and measurable compensation increases for union and non-union employees through the midpoint of the rate year for NSTAR Electric employees.

Q. How was the payroll O&M expense determined for the NSTAR Electric revenue requirement?

A. To determine the appropriate payroll expense for new rates effective January 1, 2023, the Company first examined the test year payroll amounts to determine whether those amounts would continue to be the same in the rate year, or whether any known and measurable changes would occur. As discussed above, test year payroll expense was normalized to reflect actual employee salaries for active and filled positions as of December 31, 2020. In addition, the Company determined that changes would occur for both union and non-union payroll expense for NSTAR Electric. Therefore, the Company made the necessary adjustments to account for these changes.

Q. Why are these adjustments necessary?

A. The adjustments are necessary to determine the level of O&M Payroll that NSTAR Electric will experience during the rate year. The adjustments apply the actual percentage payroll rate increases for 2021 and expected increases for 2022 and 2023, separately by union and non-union categories, to the normalized level actual payroll amounts charged to O&M during the test year. The 2022 payroll increase will be granted to non-union employees April 1, 2022 and will be validated during this case. Similarly, the 2023 payroll increase is expected to be granted to non-union employees on April 1, 2023. The Company has included a merit increase of 3.00 percent for effect April 1, 2023 and will supplement the record with a written management commitment letter later in the proceeding, as is typically required by the Department in such instances. Union increases are determined based on the schedules contained in the respective bargaining agreement.

Q. What is the basis used to make an adjustment to the payroll-union test year expense?

A. As discussed in the testimony of Company Witness Lazor, the majority of NSTAR Electric union employees are covered by collective bargaining agreements for Local 369 of the Utility Workers Union of America, AFL-CIO (“Local 369”), Local 455 of the International Brotherhood of Electrical Worker, IBEW, (“Local 455”) and Local 12004, United Steelworkers of America, AFL-CIO (“Local 12004”). Mr. Lazor describes the impact of future union wages based on existing union agreements and recommends the known and measurable changes that are included in our analysis to compute the payroll-union adjustments for NSTAR Electric.

Q. What process did you use to develop the union payroll adjustments for NSTAR Electric?

A. The Company included annualized base salaries of active positions. Active positions are filled positions as of December 31, 2020 for union employees, plus annualized overtime wages in the test year. These calculations were completed for each union at NSTAR Electric based on the respective contract increases and effective dates. The total union increases included in the NSTAR Electric revenue requirement are shown in Exhibit ES-REVREQ-2, Schedule 10, pages 2 through 5. Specifically, the total union increases for NSTAR Electric are $7,376,698.

Under the currently effective collective bargaining agreement for Local 369 employees, increases of 3.00 percent took effect on June 1, 2020 and June 1, 2021. Additional increases of 3.00 percent will be effective on June 1, 2022 and June 1, 2023.

Under the currently effective collective bargaining agreement for Local 455 employees, increases of 3.00 percent took effect on October 1, 2020 and October 1, 2021. An additional increase of 3.00 percent will be effective on October 1, 2022. The increase for Local 455 effective on October 1, 2023 is past the mid-point of the rate year and is not included in the Company's payroll adjustment.

Under the currently effective collective bargaining agreement for Local 12004 employees, increases of 3.00 percent took effect on April 1, 2020 and April 1, 2021. Additional increases of 3.00 percent will be effective on April 1, 2022 and April 1, 2023.

Q. What adjustment was made for non-union payroll?

A. The Company included annualized base salaries of active positions as of December 31, 2020. Active positions are filled positions for non-union employees, plus annualized overtime wages in the test year. The non-union payroll adjustment is $5,761,507 for NSTAR Electric. ESC employees are predominantly non-union employees and are included in these amounts. These adjustments represent actual wage increases in 2021 and planned increases in 2022 and 2023. The merit increase percentages for 2022 and 2023 are based on the recommendation provided by Mr. Lazor in his testimony. Details on the calculations undertaken to produce these adjustments are provided at Exhibit ES-REVREQ-2, Schedule 10. Additional supporting information is also provided in the corresponding workpapers in Exhibit ES-REVREQ-3, Work Paper 10.

Q. Does your testimony present the requisite documentation for the inclusion of employee compensation and benefit expense, as well as adjustments thereto, for NSTAR Electric?

A. As described in Company Witness Lazor's testimony, non-union employees of NSTAR Electric and ESC received an annual base salary merit increase in 2020 and 2021 and are forecasted to receive adjustments in 2022 and 2023. On April 1, 2020 and April 1, 2021, a three percent merit increase took effect for exempt and non-exempt, non-union employees.

The Company anticipates that, based on historical practice, a merit increase will also occur in 2022 and 2023 for non-union employees. In 2022 and 2023, the merit increase for exempt and non-exempt non-union employees is anticipated to be three percent, to be implemented in the first quarter of 2022 and 2023. In 2021, the merit increase for exempt and non-exempt non-union employees was three percent, consistent with past practice. The 2022 increase will occur during the case and will be demonstrated in the proceeding. The merit increase for 2023 will occur after the close of record in this proceeding. The Company has included a merit increase of 3.00 percent for effect April 1, 2023 and will supplement the record with a written management commitment letter later in the proceeding, as is required by the Department.

As a result, those changes are or will be known and measurable during this case and will be confirmed by the Company when the changes occur.

Mr. Lazor's testimony discusses both NSTAR Electric's plan for producing the documentation required by the Department to support the Company's employee benefit and compensation expense levels and post-test year adjustments. We have used the information and documentation provided by Mr. Lazor to determine whether, and to what extent, adjustments to test year costs for NSTAR Electric are appropriate.

Q. Please summarize the Company's payroll adjustments.

A. Exhibit ES-REVREQ-2, Schedule 10 details the payroll adjustments that increase the test year payroll for known and measurable increases that occurred in 2020 and 2021; that will occur during this case in 2022, and that are planned for 2023. The adjustment increases test year O&M payroll by $13,138,206, including an increase of $7,376,698 for union payroll and $5,761,507 for non-union payroll.

2. *Compensation: Variable Compensation*

Q. Have you adjusted the level of expense for variable compensation for NSTAR Electric?

A. Yes. There are three main factors contributing to the lower amount of proposed rate year variable compensation expense as compared the amount of expense recognized in the test year. These adjustments are as follows: (1) as described above, we have normalized the test year level of expense to remove out of period and non-recurring items for NSTAR Electric, as shown on Exhibit ES-REVREQ-2, Schedule 11, Page 2, Column C; (2) as explained below, since NSTAR Electric paid out incentive compensation at greater than the target level in the test year, we have reduced the revenue requirement to include the amount of variable compensation at target levels; and (3) removed the cash incentive for both the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") consistent with the Department's findings in D.P.U. 17-05 and D.P.U. 19-120, NSTAR Gas Company's most recent base distribution rate case. The combination of these adjustments is shown on Exhibit ES-REVREQ-2, Schedule 11, page 2, column E.

Q. Please explain the adjustments you have made to variable compensation for NSTAR Electric.

A. As shown on Exhibit ES-REVREQ-2, Schedule 11, the post-test year adjustment associated with variable-compensation expense is a decrease of ($6,821,176) for NSTAR Electric.

As described in the testimony of Company Witness Lazor, the Company's variable compensation plan represents the variable portion of the wages and salaries paid to non-union employees serving NSTAR Electric. Variable compensation is paid to employees in March for performance in the prior year ending December 31st based on NSTAR Electric and individual performance criteria and compensation guidelines. Variable compensation is included in the NSTAR Electric revenue requirement at the "target" payment amount for the respective incentive compensation plans. In the test year, NSTAR Electric paid out incentive compensation at greater than the target level. Additionally, as noted above, the CEO and CFO cash variable compensation has been removed from the revenue requirement. The total target-level distribution-related, variable-compensation expense, after an allocation to transmission of $1,106,690, is $8,877,981 for NSTAR Electric. For NSTAR Electric, this amount is then escalated to the mid-point of the rate year by multiplying the total by 9.0635 percent (the appropriate payroll escalation amount for NSTAR Electric payroll increases) and adding the resulting $804,653 to the adjusted distribution target amount described above. This results in total target-level rate year variable compensation expense of $9,682,634 for NSTAR Electric and a net reduction to the cost of service of ($6,821,176).

3. Dues and Memberships

Q. What adjustment has the Company made for dues and memberships?

A. Exhibit ES-REVREQ-2, Schedule 12 reflects an adjusted test year expense of $926,494. As detailed on Exhibit ES-REVREQ-3, Work Paper 12, the Company decreased the actual test year expense of $941,846 by $15,352 to reflect normalizing adjustments to arrive at the adjusted test year of $926,494.

4. Employee Benefits

Q. What adjustment has the Company made for employee benefit expense?

A. For NSTAR Electric, the post-test year adjustment made on Exhibit ES-REVREQ-2, Schedule 13 is an increase of $7,164,314. Exhibit ES-REVREQ-2, at Schedule 13, summarizes the pro-forma adjustments related to employee-benefit expense. The employee benefit offerings for NSTAR Electric employees and ESC employees serving NSTAR Electric are discussed in the testimony of Company Witness Synan. Although the benefits-related expense adjustment represents an increase over test year levels, the Company's test year total was lower than normal as the COVID-19 pandemic had a direct impact on the Company's health care expenses. This is further discussed in the testimony of Company Witness, Synan.

Q. Please describe how you determined the adjustment for employee-benefit expense.

A. For NSTAR Electric, an adjustment was made for two categories of adjustments associated with employee benefits: (1) medical/prescription, vision, and dental expense and (2) Pension/PBOP exclusion. The two categories are discussed in additional detail below:

Medical, Dental and Vision – Eversource Energy is self-insured for its healthcare benefits for active employees. Therefore, to determine the amount of the rate-year healthcare benefit expense to include in the revenue requirement, it was necessary to apply an appropriate benefit-expense rate per employee for NSTAR Electric to a representative number of employees for each of the operating companies, as well as to ESC employees. To complete that analysis, we obtained the medical, dental and vision "working rates" from the Eversource Human Resources Department. The working rates are described in more detail in the testimony of Company Witness Synan. The working rates are provided to the Company by its external benefits consultants and represent, for NSTAR Electric, the per employee expected claims levels for the following year. The working rates are utilized to determine the employee contribution required by employees. The Company applied the per employee rates to the actual staffing levels and benefits plan participation at NSTAR Electric as of December 31, 2020.

The analysis presented on Exhibit ES-REVREQ-2, Schedule 13, page 3 provides the computation for NSTAR Electric. This analysis supports the rate year level of medical expense of $24,511,996; vision expense of $114,277; and dental expense of $1,140,153. To these totals, the Company removed an allocation for transmission of ($2,984,442). After this deduction, the rate year total for distribution expense is $22,781,984. The Company has relied upon the working rates to develop the revenue requirement in this proceeding. The working rate calculation is based on the Company's actual insurance claims and cost trends experienced during the two years prior to the test year (i.e., March 2018 through February 2019 and March 2019 through February 2020).

Pension/PBOP and PBOP – Consistent with the Company's proposal in D.P.U. 17-05, which the Department approved (D.P.U. 17-05, at 324), all pension/post-retirement benefits other than pension ("PBOP") costs are recovered through the PAM and there is no credit in the PAM to reflect amounts recovered in base distribution rates. The exclusion of pension and PBOP costs from base distribution rates is shown on Exhibit ES-REVREQ-2, Schedule 8, page 2, Column P.

5. Enterprise IT Projects Expense Adjustment

Q. Please describe the Enterprise IT Projects Expense Adjustment.

A. The Enterprise IT Projects Expense Adjustment is required to reflect the additional costs associated with the IT systems needed to further enhance the Company's ability to provide safe, reliable, and quality service to customers. Enterprise IT projects that support more than one operating company are installed at the ESC level as a way to: (a) efficiently implement a new solution as one integrated solution to be used on a shared basis, rather than having to deploy several distinct and different instances of the same application, or different applications, serving the same business need at each separate operating company; and (b) to charge the costs of shared infrastructure across multiple entities on an efficient basis. These projects are charged to the operating companies as expense and capitalized by ESC through application of the ZGS, described above. Therefore, the post-test year adjustment described in the following section is an adjustment to expense, rather than a post-test year plant addition at NSTAR Electric.

As shown in Exhibit ES-REVREQ-2, Schedule 14, the Company's is seeking to adjust its Enterprise IT Projects expense by $10,869,443 to reflect: (1) expected changes in the Enterprise IT expense through December 31, 2021, for which the Company plans to update with actuals during the course of the proceeding, and (2) certain capital projects undertaken by ESC for the benefit of the Company and its customers that will go into service in early 2022, but for which the Company is requesting the Department all to be reflected in rates effective January 1, 2023, since the projects are of a level of significance to warrant inclusion as a post test year adjustment to rates, and the projects will be in service and used and useful to customers during the pendency of this proceeding. Specifically, ESC is investing in the Oracle Utilities Analytics ("OUA") and Network Management System ("NMS") projects. These Enterprise IT Projects are discussed in more detail below. Lastly, the Company is proposing an adjustment to Enterprise IT expense for all projects placed in service as of December 31, 2022, as part of the Company's first PBR adjustment effective on January 1, 2024.

Q. Please describe the OUA investment placed into service after the test year and why it is necessary for ESC.

A. To provide continued quality service to customers, the Eversource Energy operating companies, including NSTAR Electric, strive to operate as "One Company" with standardized operations processes implementing industry best practices. This enterprise-wide service culture is hampered by outdated legacy systems that rely on disparate work tracking and management solutions. These disparate processes and systems impact the organization's ability to fully optimize operations as one company. Following an in-depth assessment during 2021, Eversource Energy has determined that its existing outage management systems and storm-related reporting systems require additional functionality, capacity and accessibility during storm responses efforts and, as configured, do not meet the going forward business needs of the Eversource Energy electric distribution companies, given the high expectations of customers and communities during storm response.

For example, Eversource Energy currently utilizes ASEA Brown Boveri's (ABB) FocalPoint reporting systems to support the enterprise outage management process for operational reporting and key performance metrics during storm response. The current system operates on a legacy software/hardware platform that has been phased out by the vendor. As a result, there are no viable system upgrade paths available to Eversource Energy for this legacy solution, which creates enterprise risk for storm response.

Further, Eversource Energy's Engineering, Emergency Preparedness, Performance Management, Customer Care and Corporate Communications struggle day-to-day with the limitations of the current FocalPoint reporting systems. These limitations include outage data that is stored in multiple, disparate databases, which makes accurate, consistent reporting across Eversource Energy unachievable. Additionally, due to the technical complexities associated with maintaining multiple FocalPoint databases, the system currently experiences performance issues extracting and loading outage data, which sometimes causes delays to data transfer/refresh cycles for operationally critical systems, like outage maps. Delays in populating customer-facing data portals is highly problematic during storm response and high-volume usage periods.

The OUA project will replace FocalPoint with the industry leading OUA business intelligence solution, deployed with new server hardware, to establish a modernized, technically current software/hardware platform that is vendor supported through 2023. The implementation of OUA will address current outage reporting system limitations by providing a single, enterprise outage reporting system that is architected to integrate with ESC enterprise outage management system (i.e. the Oracle Network Management System – NMS version 2.4 Upgrade, which is described in further detail below) to provide outage related data in near real-time through a robust, high performance outage reporting platform. The OUA Implementation and NMS version 2.4 Upgrade and Enhancements projects will be worked in parallel and implemented together.

Q. What are the benefits of the new OUA investment for Eversource Energy and the Company?

A. There are numerous business and operational benefits to both Eversource Energy and the Company with the implementation of the new OUA system. The OUA project benefits include the following:

- Enhanced business capabilities through OUA pre-built, industry standard outage dashboards, reports and analytical tools to meet current and emerging business needs;
- Elimination of legacy technology software/hardware platform limitations;
- Elimination of latency issues for the outage management interface to outage reporting system data transfer by providing seamless integration and near real-time system performance;
- Enhanced standardization through the elimination of redundant reporting;
- Enhanced communications with customers, media, regulators and employees through timely, consistent, accurate outage information;
- Easy to use intuitive system that reduces learning curve and training time;
- Capability for users to access outage dashboards and reports from a mobile device;
- Reduced complexity of system upgrades/maintenance due to a single vendor Oracle integrated solution for OUA and NMS;
- Adoption of common business processes aligned with OUA solution to enhance operational effectiveness and efficiencies.

Q. Please describe the NMS investment placed into service after the test year and why Eversource Energy views this as a critical upgrade.

A. Currently, Eversource Energy utilizes Oracle's NMS to support the enterprise-wide, operationally critical outage management process that manages and restores power to customers. Eversource Energy is operating on Oracle's NMS software version 1.11, which has been out of vendor support since Q3 2017. As a result, ESC does not receive software maintenance patches and general fixes from Oracle necessary to maintain a highly reliable, fully supported technology environment. Additionally, there are several high business-value system enhancements that cannot be deployed until the upgraded NMS software/hardware platform is in place.

The NMS project will upgrade NMS to the latest Oracle software version 2.4 in conjunction with the implementation of new server hardware that will enhance system performance and reliability to provide a modernized, technically current software/hardware platform that is fully vendor supported through 2023. Additionally, four high business-value system enhancements, which include Training Simulator, Outage Mobile Application, Automated Single Outage No Light Closeout and Automated Overlay Google Map Satellite Imagery, will be implemented as part of the NMS project to deliver significant new business capability that directly support and advance operational excellence across ESC.

Q. Please describe the business and operational benefits to both ESC and the Company as a result of the NMS project.

A. The NMS project will enhance NMS performance and reliability along with addressing current technology software/hardware platform obsolescence. Further, it will increase NMS User Counts capacity by 25% from 400 to 500 per NMS instance to meet required major storm demand with no system performance degradation and increase NMS Customer Outage Counts capacity by 25% from 800,000 to 1,000,000 per NMS instance for interfaced partner systems (e.g. Outage Maps) to meet required major storm demand with no system performance degradation. Implementing the new NMS configuration capability also that allows the system to be switched from "Active" environment to "Standby" environment quickly to enhance system availability and reduce maintenance durations and system downtime.

Further, the NMS project will implement Oracle Training Simulator enhancement module to provide NMS operator trainers with the capability to record, pause, modify and monitor scenarios based on customer calls and field device operations which are "played back" for operator trainees to provide individual training feedback. Additionally, the Oracle Outage Mobile Application ("OMA") enhancement module will provide first responders with the capability to report emergency conditions from a mobile device. OMA allows field personnel to be registered, assigned work, update status, report blocked roads, enter damage assessment details and update outage event information such as estimated restoration time.

Lastly, NMS will implement enhancements to the automated process to identify single customer no light outage tickets. The NMS system will automatically close outage tickets if the customer confirms power has been restored based on response to an automated calling campaign. This will reduce the manual labor and cycle time required to support the storm restoration work process. The automated process will also overlay google map satellite imagery on the NMS Viewer to provide users with an easy way to identify where specific field equipment is located relative to local landmarks. This will allow users to identify field equipment location to address any outages efficiently and effectively.

Q. How do the Enterprise IT projects described above affect ESC costs that are associated with services provided to NSTAR Electric pursuant to executed service agreements?

A. Enterprise IT projects that support multiple operating companies are recorded by ESC and charged to the operating companies through the general service company overhead rate, ZGS. As described above, the ZGS is an indirect adder to labor and is charged to the account where the associated labor is charged. Because the projects will be utilized by multiple Eversource operating companies, project costs will be recorded on ESC's books as a capital asset. For purposes of determining the appropriate post-test year adjustment, the costs associated with these projects are reflected in the NSTAR Electric revenue requirement as an adjustment to expense. The amount that will be shared by each operating company will be cost-based and will be included in the ZGS rate charged by the service company. Therefore, the Enterprise IT Projects Expense adjustment for NSTAR Electric represents its allocated portion of the OUA and NMS projects revenue requirement during the rate year in this proceeding.

Q. How is the allocated portion of the project's revenue requirement determined?

A. When costs are incurred to serve more than one subsidiary/business segment and cannot be directly assigned, such costs are allocated based on an allocation methodology. The allocation methodologies are designed to be proxies for cost causation within a particular function. Allocations are made only after it is determined that it is not practical or reasonably possible to perform a direct assignment of the costs. There is no one-size-fits-all process and each IT asset placed in-service is reviewed on its own merit and allocated accordingly. The allocation is determined based on the intended usage of the application or equipment. That determination is evaluated for each product placed in-service. The projects described above that serve as the basis for this adjustment will be utilized only by NSTAR Electric Company, Connecticut Light and Power, and Public Service of New Hampshire and are not utilized by other operating affiliates

Q. Please describe the post-test year adjustments made to the NSTAR Electric revenue requirement associated with the Enterprise IT Projects described above

A. The post-test year adjustments for NSTAR Electric are shown on Exhibit ES-

REVREQ-2, Schedule 14, page 2, lines 27 through 50. As shown on this schedule, the adjustment to expense is based on the total project's estimated $13.4 million revenue requirement and adjusted for each affiliate as follows:

1. To determine the amount of expense allocable to NSTAR Electric, the Company first applied the allocation percentage of 32.44 percent, representing the NSTAR Electric proportionate share of net income and gross plant assets. For NSTAR Electric, this percentage allocator is a total company allocator and includes Transmission. Therefore, for NSTAR Electric an additional adjustment is required (described below) to remove the portion of this expense attributable to Transmission.

2. Service company employees perform both capital and expense functions. Therefore, the service company expense ratio of 64.05 percent is applied against the total for NSTAR Electric. This adjustment is necessary in order to include only the expense portion of the OUA and NMS projects in the revenue requirement as a post-test year adjustment in this proceeding. The balance of charges (approximately 35.95 percent) is charged to capital or other balance sheet accounts, and therefore not included in the expense adjustment at this time.

The net increase to the revenue requirement of $2,448,266 for NSTAR Electric is shown on Exhibit ES-REVREQ-2, Schedule 14, page 2 on line 50. Detailed supporting documentation for the revenue requirement described above is provided as Exhibit ES-REVREQ-4, Schedule 5(b).

This expense adjustment is based on the estimated plant in service of approximately $76.953 million. However, because the actual amount of the project will become known and measurable during this proceeding, the Company will update the revenue requirement to reflect the appropriate expense levels based on the actual revenue requirement to be allocated to each entity, along with appropriate supporting documentation as it becomes available during this proceeding.

Q. Has the Company presented the requisite documentation associated with the Enterprise IT Projects to warrant recovery as a post-test year adjustment to expense?

A. Yes. The Department does not recognize post-test year additions or retirements to rate base, unless the utility demonstrates that the addition or retirement represents a significant investment that has a substantial effect on its rate base. NSTAR Electric Company, D.P.U. 17-05, at 101; Boston Gas Company, D.P.U. 96-50-C at 16-18, 20-21 (1997); D.P.U. 96-50 (Phase I) at 15-16; D.P.U. 95-118, at 56, 86; D.P.U. 85-270, at 141 n.21; Massachusetts-American Water Company, D.P.U. 1700, at 5-6 (1984).

As a threshold requirement, a post-test year addition to plant must be known and measurable, as well as in service. D.P.U. 17-05, at 101. The Department has historically judged the significance of an investment by comparing the size of the addition in relation to rate base and not based on the particular nature of the addition. Id. Proposals to incorporate post-test year capital additions into rate base must be accompanied by sufficient project documentation, including but not limited to project authorization documents, capital budget estimates, work orders, project cost sheets, variance explanations, and closing reports, to enable the Department to determine whether (1) the costs associated with the projects are known and measurable, (2) the costs were prudently incurred, and (3) the projects are in service and used and useful. Id. at 104-110.

Recent Department orders addressing post-test year expense adjustments have provided different determinations regarding the need to provide project documentation in support of post-test year expense adjustments. Traditionally, in order to successfully incorporate a post-test year adjustment to expense associated with capital investments undertaken at the service company or parent company level in the revenue requirement, a utility needed to demonstrate that the costs at issue were known and measurable and that the underlying capital investment was in service for the benefit of customers. D.P.U. 17-05, at 233.

In D.P.U. 15-155, National Grid proposed to incorporate into its revenue requirement certain IT and facilities rent expenses representing charges billed to National Grid for computer and information systems and leased facilities provided by National Grid Service Company ("NGSC"). D.P.U. 15-155, at 276, 279-280. NGSC allocated both IT and facilities costs using a coding system that apportions the costs by an affiliate's percentage share of expenses or use of space measured in square feet. Id. at 277. National Grid did not provide project documentation on the IT projects in the same manner as it would have been required to if it sought to include the IT projects in rate base. The Department approved the Company's proposal, finding that the IT projects constituted expense, not rate base items, and included the expenses in National Grid's cost of service. D.P.U. 15-155, at 299-300.

In D.P.U. 17-05, NSTAR Electric proposed to treat the Supply Chain Project as a capital asset on ESC's books, and to recover the costs associated with this project, including depreciation, property taxes, and a return component, through a post-test year adjustment to expense to be reflected in its revenue requirement. D.P.U. 17-05, at 224. The Department, in denying the Company's request, found that the Company did not adequately support its proposal with sufficient documentation. D.P.U. 17-05, at 234. The Department found that the record contained no billing statements, invoices, or other related documentation to substantiate the actual allocation of costs to the NSTAR. Id. Therefore, the Department stated that it could not determine whether NSTAR Electric's proposed adjustments to test year information systems expense represented the level of expense to be incurred during the rate year. Id.

In D.P.U. 18-150, National Grid included in its revenue requirement the costs associated with its service company rent expense, which represents charges billed to National Grid for capital costs incurred by its service company to develop and own IT that will be used on a shared basis by National Grid and other National Grid

USA subsidiaries. D.P.U. 18-150 at 259. In reviewing the IT rent expense, the Department determined that, for future cases, will not use the reasonableness standard for IT-related investments and IT-related lease expense between affiliates. Id. at 273-274. The Department established the following criteria as the standards necessary for rents associated with an affiliate's capitalized IT investments to be included in rates. First, the investments underlying the rent expense must be in service and used and useful. Id. at 274. Second, the underlying investments must be prudently incurred. Id. Third, the underlying investments must be fairly allocated to the company, with an explanation of how the company and its customers benefit from the investment. Id.

The Department also specified new documentation requirements for service company-allocated IT investments to be submitted as part of a company's filing, including but not limited to project sanctioning reports, project closure reports, variance analyses, project descriptions, and the Company's long-term investment plan. Id. at 275.

Subsequently, in D.P.U. 19-120, NSTAR Gas provided documentation concerning Enterprise IT projects as well as updates during the proceeding. The Department found that the Company provided project documentation and updates for post-test year investments in accordance with the filing requirements established in D.P.U. 18-150. See, also, D.P.U. 17-05, at 252.

Per the Department's decision in D.P.U. 18-150 and D.P.U. 19-120, the Company is providing information in this filing regarding: (1) expected changes in the Enterprise IT expense through December 31, 2021, for which the Company plans to update with actuals during the course of the proceeding; and (2) two capital projects undertaken by ESC for the benefit of the Company and its customers that will go into service in early 2022, but for which the Company is requesting the Department all to be reflected in rates effective January 1, 2023, since the projects are of a level of significance to warrant inclusion as a post-test year adjustment to rates, and the projects will be in service and used and useful to customers during the pendency of this proceeding. This information is designed to meet the Department's new standard pertaining to the recovery of post-test year expense associated with the Enterprise IT Projects. The Company is proposing post-test year additions in this case associated with Enterprise IT. Therefore, the Company is providing the requisite information to support its requested adjustments and plans to provide any relevant additional documentation prior to the close of discovery in this proceeding as further described by Company Witnesses Landry and Griffin in Exhibit ES-ADDITIONS-1. The Company has also included the monthly support for the Enterprise IT expenses charged to the operating company in the test year, through ESC depreciation expense in Exhibit ES-REVREQ-4, Schedule 5(a).

Q. When will the Company file the requisite project documentation supporting the Enterprise IT expense for 2022 to be reflected in the first PBR adjustment on January 1, 2024?

A. No later than April 1, 2023, prior to the Company's second PBRA filing for effect on January 1, 2024, the Company will provide a timely, organized, clear and comprehensive filing of all supporting capital documentation for ESC plant investment completed between January 1, 2022 and December 31, 2022 to substantiate the increase in Enterprise IT costs including but not limited to: (1) project descriptions, (2) project sanctioning papers, or project authorization forms, (3) construction work orders, (4) project closure reports, (5) variance analyses explaining the reasons for cost overruns and for demonstrating prudency, and (6) a summary of all proposed projects.

6. Insurance Expense and Injuries & Damages

Q. What adjustment have you made for Insurance Expense and Injuries & Damages deductibles?

A. The post-test year adjustment made on Exhibit ES-REVREQ-2, Schedule 15, shows an increase of $1,462,386. The increase is detailed in Exhibit ES-REVREQ-2, Schedule 15, pages 2 and 3. These increases in expense are the combined effect of: (1) an increase in corporate property and liability insurance premiums; and (2) the difference between the five-year average of self-insured claims paid and the actuarially determined expense booked during the test year.

Q. Please describe the NSTAR Electric corporate insurance for property and liability coverage.

A. Property and liability coverage includes a number of categories of insurance that provide protection from property loss, general liability and other damages that NSTAR Electric may incur in the conduct of its business. ESC manages the corporate insurance program through which NSTAR Electric is insured. The corporate insurance program includes both premium-based and self-insured coverage in order to obtain the most cost-effective loss protection.

Q. How does ESC manage its liability insurance costs?

A. All insurance programs and policies are evaluated annually with the aid of insurance brokers in order to secure the best available coverage and rate. In order to balance the risk mitigation that insurance provides and the level of premium costs, an appropriate level of self-insurance or deductible is negotiated with insurance carriers. Higher deductible levels result in lower insurance premiums which also results in a higher retention of risk of loss. It is the balance between the two that the Company must manage.

Eversource Energy utilizes a well-accepted process when procuring insurance programs. To achieve the optimal coverage at the best cost, the Company utilizes its brokers to facilitate this process. Eversource compiles the market submission and the broker works with various insurance markets to solicit quotes for insuring the Eversource program. Eversource Corporate Insurance presents to insurance underwriters, covering key risk topics that insurers are concerned with such as maintenance practices. The Company has service agreements with three main insurance brokers ensuring a competitive process.

Currently, the Company uses Lockton for its property insurance; Aon for crime insurance, and Marsh for excess liability, cyber risk, Directors & Officers, fiduciary, Workers' Compensation, and auto liability insurance programs. Each year, a service level agreement is renewed with Lockton, Aon and Marsh. These agreements include negotiated fees for each program the Company uses the brokerage service for. Fees remain flat year over year unless the risk profile of the Company changes (i.e., additional companies to procure insurance for or the complexity of the market changes). The Company decides which programs the brokers will be used for, based on the respective area of expertise and what the Company's experience has been with the services they provide. The Insurance Department benchmarks the Company’s brokers against others used in the industry through benchmarking surveys such as the Edison Electric Institute (“EEI”) insurance survey. Approximately three to four months prior to the renewal date of the program, Eversource’s Corporate Insurance team holds a strategy meeting with the broker to discuss the current coverage in place, opportunities for improvement in coverage and upcoming renewal requirements, and strategies for presenting the Company’s risk mitigation requirements to the market in order to optimize the coverage Eversource have in place.

Eversource participates in various industry groups to stay abreast of insurance issues and trends including working groups within EEI and American Gas Association. The Company's Corporate Insurance group also maintains knowledge of key company initiatives that lower the Company's risk profile, helping to ensure the underwriting process goes smoothly. In addition to this information, and to the industry trend information provided by the broker, Eversource also utilizes independent sources such as Edison Electric Institute and other insurance surveys to evaluate market trends.

On a combined basis, these processes assist in assuring that the Company's corporate liability costs are as reasonable as possible.

Q. How are the pro forma adjustment related to NSTAR Electric's insurance coverage calculated?

A. To determine the appropriate level of insurance expense to be included in the revenue requirement, the most recent insurance policies entered into by ESC were obtained along with the portions of the premium of each policy that applied to NSTAR Electric. The resulting premiums form the basis of the insurance expense included in the revenue requirement. The prepayment of these costs is recorded and amortized over the appropriate fiscal period.

Exhibit ES-REVREQ-3, Work Paper 1,5 provides cost detail on these expenses for NSTAR Electric. This analysis resulted in an increase of $970,407 to the test year actual expense amount on NSTAR Electric's books, as reflected in Exhibit ES-

REVREQ-2, Schedule 15, Page 2, line 23 plus line 32. Based on the coverage periods, the Company will update the actual premium amounts for certain policies set to expire during the course of the proceeding, which will be known and measurable by the time the record closes in this case.

Q. How are the pro forma adjustments for injuries and damages calculated for NSTAR Electric?

A. On NSTAR Electric's books of account, the expenses related to the self-insured portion of general liability and Workers' Compensation are recorded based on actuarially determined liability amounts. To normalize these expenses, the Company obtained a listing of the actual claims paid in these categories for each of the years in the five-year period ended December 31, 2020. The Company then calculated the average annual claims payment amount of that five-year period. This resulted in a decrease of $2,281,674 to the test year actual expense amount on NSTAR Electric's books, as reflected in Exhibit ES-REVREQ-2, Schedule 15, page 2, line 36.

The total pro forma adjustment after capitalization results in an increase in insurance expense and injuries and damages of $1,462,386 for NSTAR Electric, as shown on Exhibit ES-REVREQ-2, Schedule 15.

Q. Please describe the Loyalty Credits included in Exhibit-REVREQ-2, Schedule 15, Page 2, Line 31.

A. The Loyalty Credits presented on Exhibit-REVREQ-2, schedule 15, page 2, line 31 represent credits granted by AEGIS to its policyholders who purchase coverages from a specified number of eligible lines of business which are renewed over the next year. AEGIS offers two levels of eligibility under this program; Level I for members who purchase coverages from at least four out of seven eligible lines of business, and Level II for members who purchase coverages from at least five out of seven eligible lines of business. In 2020, ESC was eligible for both Level I and Level II Loyalty Credits from the 2019 program and therefore received a credit of $397,705 in the test year from the 2019 program, of which $116,335 was allocated to the Company.

7. Postage Expense

Q. Did you adjust the test year Postage Expense for ratemaking purposes?

A. The revenue requirement reflects a total increase of $106,232 in postage expense to reflect: (1) annualization of the 2020 test year amount to account for a 1.57 percent increase in the 2020 first class postage rate that took effect at the end of January 2020 (from $0.383 to $0.389); and (2) adjust for a known and measurable first class postage rate increase of 2.31 percent that took effect in January 2021 (from $0.389 to $0.398), as shown on Exhibit ES-REVREQ-2, Schedule 16.

8. Lease Expense

Q. What adjustments have you made to increase test year lease expense for NSTAR Electric?

A. As shown on Exhibit ES-REVREQ-2, Schedule 17, the post-test year adjustment associated with lease expense is an increase of $942,762. The computation of the pro forma expense levels is shown in Exhibit ES-REVREQ-2, Schedule 17, page

2. This adjustment pertains to increased costs associated with operating and maintaining the Martha's Vineyard diesels operated by Vineyard Reliability.

Vineyard Reliability LLC bought the Martha's Vineyard diesel generating units in January 2021, from GenOn Canal LLC and GenOn Energy Management, LLC. The Martha's Vineyard Diesel Units are operated and maintained under contract by Vineyard Reliability LLC to ensure the units are available when needed for the purpose of maintaining reliability of service to customers. Vineyard Reliability LLC reviewed the expenses previously being charged by GenOn, resulting in increased amounts for direct O&M, indirect overhead costs, plant management, and property taxes. These increases resulted in an additional $942,762 in yearly expense. During the course of this proceeding, the Company will update this cost for 2021 once available.

9. Regulatory Assessments

Q. Has NSTAR Electric made adjustments for regulatory assessments?

A. Yes. As shown on Exhibit ES-REVREQ-2, Schedule 18, the adjusted test year regulatory assessment expense, adjusted to remove transmission related expenses and out of period adjustments totals $11,804,920. This amount is comprised of three invoices received during the test year: (1) AGO Assessment of $1,129,831; (2) General Assessment $7,501,994; and (3) Trust Assessment $2,226,932. These three invoices total $10,858,757. The invoices supporting these amounts are provided in Exhibit ES-REVREQ-4, Schedule 4. The difference between the adjusted test year total and the invoices relate to prior period accounting adjustments that will be eliminated when the Company provides updated regulatory assessment amounts during the course of this proceeding. The invoices supporting these amounts are provided in Exhibit ES-REVREQ-4, Schedule 4.

Annually, regulatory assessments levied by the Department are allocated to each electric or gas company based on each company's proportionate share of total intra-state operating revenues. Total intra-state operating revenues includes distribution revenues and other revenues, including various reconciling rate mechanisms, including basic service energy costs.

As mentioned above, the 2022 regulatory assessments are expected to be known and measurable by the time the record closes in this case and the Company plans to update these amounts in a future revenue requirement update.

10. Rate Case Expense

Q. Was it necessary for the Company to retain outside consultants and legal services for this case?

A. Yes. The Company retained the services of four expert consulting firms and one law firm to assist with the presentation of this case. One hundred percent of these services were retained through a competitive bid process. Specifically, the Company is utilizing the following vendors: (1) John J. Spanos of Gannett Fleming Valuation and Rate Consultants LLC ("Gannet Fleming") for the depreciation study; (2) Vincent V. Rea, Managing Director of Regulatory Finance Associates

LLC for cost of capital and capital structure; (3) Bruce R. Chapman, Vice President of Christensen Associates Energy Consulting LLC ("Christensen Associates") for the allocated cost of service study ("ACOSS"); (4) Mark E. Meitzen, Ph.D Senior Consultant and Nicholas Crowley, Senior Economist for Christensen Associates and Dr. Lawrence R. Kaufman Senior Advisor to Pacific Economics Group Research LLC and the Black and Veatch Knowledge Network, to present the economic analysis of electric-industry cost trends and productivity analysis to establish the revenue-cap formula that would apply in the PBRM; and (5) the law firm of Keegan Werlin LLP ("KW") for legal services.

Q. Did you participate in the process to procure outside services for this case?

A. Yes. We supervised and participated in the procurement process for the cost of capital/capital structure witness and the PBRM witness. The procurement process for the depreciation study, outside legal services and ACOSS witnesses were directly conducted by the subject matter experts within the Eversource accounting group, legal group and rates group, respectively. However, we were informed as to the steps that they took to conduct the procurement process, and they were consistent with the process used for all other outside services.

Q. Please describe the general process that was utilized to retain the Company's external witnesses and service providers.

A. The Company invited a set of skilled vendors to participate in each RFP and established an electronic bidding process through the Ariba system. The Company designated an internal review committee for each RFP to evaluate submitted bids.

The bid evaluation included a review of the vendors' qualifications and relevant experience, capabilities, and personnel to support the Company's rate petition, proposed fee structure and other factors. In some cases, the committees conducted interviews with vendors as part of the overall evaluation process. The Company's external witnesses and service providers were ultimately selected based on this evaluation process and determination of the vendor that could provide the necessary service at a reasonable price.

Q. Please describe any relevant details specific to the procurement of the Company's cost of capital/capital structure witness.

A. The RFP process for selection of the cost of capital/capital structure witness was conducted during April 2021 through June 2021. We participated on the internal review committee for this process along with team members from the Finance Organization and a Procurement Consultant from the Purchasing Department. The committee developed an initial list of qualified vendors, with input on vendors taken from a list that was developed for a similar solicitation process recently conducted by NSTAR Gas Company, an Eversource Energy operating Company, for its 2019 rate case; from Connecticut Light and Power ("CL&P"), an Eversource Energy operating company, for its 2014 rate case; from the NSTAR Electric rate case in 2017; and from other similar solicitations. The committee selected potential vendors on that list to participate in the cost of capital/capital structure RFP. After issuing the RFP to those vendors, the Company reviewed qualifying bids. The committee evaluated the bids based on both the overall cost of the bid proposals and other key criteria that included corporate capability, project team capabilities, technical approaches, proposal quality, and commercial review the areas of cost of capital, capital structure, decoupling, and prior experience as an expert witness. Mr. Vincent V. Rea of Regulatory Finance Associates LLC was ultimately retained as the Company's expert witness as a result of this process.

Q. Please describe any relevant details specific to the procurement of the depreciation study witness.

A. The RFP process for selection of the depreciation witness was conducted in April 2021 through May 2021. The RFP sought bids on a scope of work that would support the NSTAR Electric rate case, as well as rate case filings for other Eversource Energy operating companies. Once the process began, all communications including bid packages from prospective bidders were managed by a Procurement Consultant from the Purchasing Department. The scope of work included an anticipated timeline, the types of schedules and analysis to be delivered and the number of FERC plant accounts involved. The internal review committee for this RFP consisted of four staff members from the Plant Accounting department, including the Director of Accounting Services and Manager of Plant Accounting. The committee developed a list of qualified vendors and issued the RFP. The Company subsequently reviewed qualifying bids from all firms. The committee evaluated the bid packages based on ability to meet scheduled commitments; company background, including industry reputation, prior rate case experience, personnel qualifications, support staffing model, and price. Mr. Spanos of Gannett

Fleming was selected as the Company's expert witness on depreciation as a result of this process.

Q. Please describe any relevant details specific to the procurement of the allocated cost of service study and rate design witnesses.

A. The RFP process for selection of experts for the ACOSS and rate design was conducted from April 2021 through June 2021. The internal review committee for this process included the Company's Director of Rates, Manager of Rates and a Procurement Consultant from the Purchasing Department. The committee developed a list of qualified vendors that were invited to participate in the RFP. The committee evaluated the bids based on the following six criteria: (1) corporate capability, including overall experience and corporate experience with similar issues, with NSTAR Electric, Eversource Energy and other affiliates, and with the Department; (2) project team capabilities, including qualifications of the proposed staff, qualifications of the proposed staff in the subject matter and the flexibility to work closely with Eversource staff; (3) the technical approaches, including the response to the RFP requirements and proposed innovative approaches; (4) proposal quality; (5) pricing, including the proposed price for the work and proposed unit rates, including markup; and (6) a commercial review, including both minor and major commercial impediments (e.g., conflicts of interest, etc.). Mr. Chapman of Christensen Associates was selected as the Company's expert witnesses on the ACOSS.

Q. Please describe any relevant details specific to the procurement of the Company's incentive-based or performance-based distribution ratemaking witness.

A. The RFP process for the selection of the performance-based ratemaking witness was conducted from July 2021 through August 2021. We participated on the internal review committee for this process, along with team members from the Finance Organization and a Procurement Consultant from the Purchasing Department. The committee developed the RFP subsequently reviewed qualifying bids. Bids were evaluated on six dimensions: (1) overall capability; (2) project team capabilities, including qualifications of the proposed staff and qualifications of the proposed staff in the subject matter; (3) the technical approaches including the response to the RFP process; (4) proposal quality; (5) pricing, including the proposed price for the work and proposed unit rates, including markup; and (6) a commercial review, including both minor and major commercial impediments (e.g., conflicts of interest, etc.) The committee conducted interviews with key personnel of select firms. Mr. Mark E. Meitzen and Nicholas Crowley of Christensen Associates and Dr. Larry Kaufman were selected as the Company's expert witnesses for the performance-based ratemaking topic as a result of this process.

Q. Please describe any relevant details specific to the procurement of the Company's outside legal services for this case.

A. The RFP process for outside legal services was conducted in March 2021 through April 2021. The RFP was issued to five law firms deemed to have the requisite experience and knowledge. Eversource Legal reviewed the proposal to ensure that there were no conflicts; that the commercial terms were proper; and to determine the proper billing methodology. The award for this RFP was then made to Keegan Werlin to represent the Company for this rate application.

Q. Has the Company included any contractor labor for recovery in this rate case?

A. Yes. The Company has included an estimated amount of contractor labor necessary in support of this case in the amount of $700,670. It was necessary for the Company to hire contractors in support of the case to: (1) assist in the compilation and review of the extensive capital project documentation supporting plan additions since the time of the last rate case; and (2) perform rate-case coordination and provide administrative support to assist in the development of the revenue requirement and respond to discovery during the course of the proceeding.

Q. Is the Company proposing to recover its rate-case expense in this proceeding?

A. Yes. The Company is proposing to recover rate-case expense totaling $3,816,170 based on a five-year amortization period, as shown on Exhibit ES-REVREQ-2, Schedule 19 and the accompanying workpaper in Exhibit ES-REVREQ-3 Work Paper 19. Also as shown on Exhibit ES-REVREQ-2, Schedule 19, the annual expense amount included in the revenue requirement is $763,234.

Q. How did NSTAR Electric develop the estimated rate-case expense for this proceeding?

A. Eversource developed the estimates set forth in Exhibit ES-REVREQ-2, Schedule 19 based on discussions with outside consultants and an evaluation of the costs incurred in prior regulatory proceedings. The Company will update and confirm the actual expenses incurred as the proceeding progresses, as is consistent with Department precedent. The Company recognizes that, because of the extended duration of the proceeding, costs to conduct the proceeding will likely differ from the estimated amount. The Company will work to control rate-case expense as circumstances occur by closely monitoring the costs of its outside consultants. The Company will review each invoice for accuracy and reasonableness and maintain a spreadsheet identifying when each invoice is approved for payment and charged to the appropriate account on the Company's general ledgers.

Q. What is the basis for the Company's proposed five-year recovery period?

A. Typically, the Department determines the appropriate period for recovery of rate case expense by taking the average of the intervals between the filing dates of a company's last four rate cases, including the present case, rounded to the nearest whole number. D.P.U. 17-05, D.T.E. 05-85, D.T.E. 92-250. Using the Department's normalization method, the average period between the last four rate cases is ten years for NSTAR Electric, as calculated in Exhibit ES-REVREQ-4, Schedule 3.

However, Massachusetts law now dictates that electric companies must file base-rate proceedings no later than every five years, except in limited circumstances. Accordingly, in D.P.U. 15-155, the Department found that the G.L. c. 164, § 94 requirement for electric companies to file rate cases every five years effectively caps the normalization period at five years. Therefore, in instances where a normalization period calculated pursuant to Department precedent results in a period greater than five years, the Department will instead impose a five-year normalization period. D.P.U. 15-155, at 244.

In accordance with these directives, the Company has proposed a 5-year normalization period for rate-case expense in this proceeding.

11. Uncollectible Accounts

Q. Did you adjust the test year Uncollectible Expense for ratemaking purposes?

A. Yes. As shown on Exhibit ES-REVREQ-2, Schedule 20, bad-debt expense for NSTAR Electric is computed in accordance with the Department's practices and the method used and approved for NSTAR Electric in D.P.U. 17-05. Specifically, the Company totaled non-basic service retail revenues and net write-offs for 2017, 2018 and 2019, as shown in Exhibit ES-REVREQ-2, Work Paper 20. Net write-offs are comprised of the actual customer accounts written off for non-payment minus recoveries related to previously written off account balances. The resulting ratio of actual customer account write-offs to retail revenues is 0.6928 percent and is noted in Exhibit ES-REVREQ-2, Work Paper 20, page 2. This net write-off ratio is intended to represent the portion of the Company's non-basic service billed revenues that it will ultimately be unable to collect from its customers.

The starting point for the NSTAR Electric analysis was the adjusted test year balance for Account 904 (Uncollectible Accounts) in the amount of $15,281,020, as shown on Exhibit EX-REVREQ-2, Schedule 20, page 1, line 19. This reflects gross bad-debt expense booked on an accrual basis during the test year related to retail revenues, less amounts removed for reconciling mechanisms (basic service and arrearage management program). The test year level of bad-debt expense computed using the Department's three-year normalizing convention is $14,114,756, as shown on Exhibit ES-REVREQ-2, Schedule 20, page 1, line 21. The difference between this amount and the adjusted test year total results in a pro-forma decrease of ($1,166,264) in bad-debt expense, as shown on Exhibit ES-REVREQ-2, Schedule 20, page 1, line 23.

Q. How did the Company adjust the Uncollectible Expense in light of the impacts of the COVID-19 pandemic on the test year?

A. The Company utilized the net write-offs for the three-year period prior to the test year, 2020 to eliminate the impact of the COVID-19 pandemic on its amount to recovered in base rates beginning on January 1, 2023. The Company, along with other distribution companies, currently has a pending request in front of the Department related to the ratemaking proposal for the treatment of costs related to the financial impacts of COVID-19 pandemic in D.P.U. 20-91. In the joint distribution companies' direct testimony filed on March 1, 2021, the distribution companies proposed to recover the incremental bad debt costs to be determined by setting a baseline bad debt amount *using the greater of* the amount of delivery-related bad-debt cost included in each company's most recent rate case; or (2) the three-year average of the delivery-related net charge offs for the years 2017 through

2019. Consistent with the Company's proposal in this case, these amounts would be the same and serve to establish the appropriate baseline to determine future incremental recovery of bad debt costs resulting from the COVID-19 pandemic.

12. Vegetation Management Expense

Q. Have you made adjustments for expenses associated with the Company's Vegetation Management program?

A. Yes. We have reviewed the Company's most recent RTW program filing, D.P.U. 20-97, to determine the appropriate level of (1) traditional vegetation management costs and (2) RTW program costs for inclusion in base rates. The Company has included an adjustment in the revenue requirement to include the collection of (1) $20,007,619 in vegetation management expense and (2) $23,200,000 in RTW program expense (see Exhibit ES-REVREQ-2, Schedule 21). This results in a total of $43,207,619 in annual vegetation management-related expenses to be recovered through base rates.

Q. Is the Company proposing to change how it recovers costs associated with vegetation management?

A. Yes. In D.P.U. 17-05, the Department approved the Company's proposal to implement the Resiliency Tree Work ("RTW") program. The Department approved the Company's RTW program for the expanded application of Enhanced Tree Trimming ("ETT"), hazard tree removals and additional mid-cycle pruning and found it consistent with the criteria established in D.P.U. 15-155.

The Department directed the Company to file a tariff for recovery of the costs associated with the RTW program through an annual reconciling factor. The Department further directed the Company to track and maintain information related to the RTW Program including costs, benefits, and contribution to reliability improvements. The RTW tariff contains the Resiliency Tree Work Factor ("RTWF") designed to recover the costs of the RTW program. The tariff states that the Company shall make a filing with the Department on September 15th each year for rates effective January 1st. The current RTW program is discussed more fully in the testimony of Company Witness Van Dam. Mr. Van Dam also discusses the Company's proposal to continue the operation of the RTW mechanism to recover the costs of the municipal hazard tree removal pilot program to identify and remove hazard trees more efficiently and effectively. 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. Why is the Company proposing to transfer recovery of costs associated with the RTW Program out of the RTW factor and into base rates?

A. The Company is proposing to transfer the costs of the RTW Program to base rates because: (1) the RTW Program has generated immense reliability improvements and there is a critical need to continue the program into 2023 and beyond; and (2) the costs of the program are stable and representative of future costs, obviating the need for reconciling recovery; and (3) the administrative burden associated with the RTW Program is detracting from the Company's ability to focus on the program.

In D.P.U. 17-05, the Department declined to incorporate the RTW Program into base rates because the future cost and programmatic effectiveness of the RTW Program was largely unknown, with no historical data from which to build upon and the costs were not determined to be known nor measurable. D.P.U. 17-05, at 583. However, in 2018, the Company established, and the Department approved, the RTW Program plan and RTWF tariff. The Company has been effectively implementing the RTW Program since the Department's approval, providing known and measurable costs and programmatic effectiveness, including historical data showing increased reliability in its annual RTW Program filings.

For the Company (and for other parties), there is a significant administrative burden associated with the RTW Program and the vegetation management group is called on to prepare and handle the filings. This takes considerable time and focus from the main purpose of managing the vegetation management program. Therefore, the Company has determined that, at this point, it will be more cost efficient to transfer recovery into base rates and manage the program based on the historical costs actually incurred.

Q. Please describe the costs associated with the RTW Program activities that the Company is requesting to include in base rates.

A. The Company is requesting to include the incremental RTW Program O&M costs approved for recovery through the RTWF in the Company's last base rate proceeding, D.P.U. 17-05. As outlined in the RTWF tariff provided in Exhibit ES-WAV-3, the Company was authorized to recover $23.2 million annually incremental RTW Program O&M expenses. The Company has utilized this amount to accomplish the goals of the program, as reported to the Department annually, 2017-2022. Therefore, the Company proposes to recover this amount annually in base rates and track the RTW Program yearly activities and costs as outlined below. The Company will continue to commit to discretely tracking the RTW Program costs separate from those in the base vegetation management program to facilitate the Department's review of the Company's RTW Program yearly progress and related costs in its next base-rate proceeding.

Q. Is the Company also requesting to transfer recovery of costs associated with the 2017-2022 RTW Program into base rates in this proceeding?

A. No. The Company is proposing to commence recovery of RTW Program costs in base rates for work performed after January 1, 2023. However, for the costs incurred for the RTW Program in the years 2017 through December 31, 2022, the Company is requesting to recover the program costs through the RTW factor through completion.

Q. What is the procedural background for program costs in the years 2017-2022?

A. The Company has finalized and filed all the costs and associated project documentation for the January 1, 2017 through December 31, 2020 RTW Program expenses with the Department in D.P.U. 18-102, D.P.U. 19-114, and D.P.U. 20-97, respectively. On September 5, 2021, the Company filed the 2021 RTW Program estimated expenses with the Department and committed to filing the final costs and documentation following the close of calendar year 2021 in docket D.P.U. 21-108. Therefore, the Company proposes to supplement this filing with the relevant information for the 2021 RTW Program from January 1, 2021 through December 31, 2021 by April 1, 2022.

Further, the Department has not issued final decisions regarding the prudency of the 2017-2021 RTW Program expenses and only approved these costs for inclusion in the Company's RTWF subject to further investigation and reconciliation through Phase 1 orders. D.P.U. 18-102, at 4; D.P.U. 19-114, at 4; D.P.U. 20-97, at 4; D.P.U. 21-108, at 4. Therefore, the Company requests that the Department approve the 2017-2021 RTW Program project documentation and costs in this proceeding to finalize those program years. Once 2022 is concluded, the Company will file those costs for review on April 1, 2023 and the reconciliation of the RTW Factor would occur on January 1, 2024, which would be the last year of recovery of the RTW Program outside of base rates.

Q. Please describe the documentation the Company is providing for the review and approval of the 2017-2021 RTW Program.

A. The Company is presenting the actual expenses incurred from January 1, 2017 through December 31, 2020. Exhibit ES-WAV-5 presents the RTW Program cost detail summarized by invoice in order to provide the monthly amounts for each program work order in calendar years 2017-2020. Exhibit ES-WAV-6 presents the invoice documentation for the actual RTW Program expenses in 2017-2020. The

Company will supplement these exhibits to include the invoice summary and invoices for the 2021 RTW Program by April 1, 2022.

13. Post-Test Year Adjustment for Qualifying Storm Thresholds

Q. Please provide a brief description of the Company's proposals in this proceeding regarding storm cost recovery.

A. There are three components of the Company's proposal related to storm cost recovery for qualifying storm events in this proceeding. These components are listed below and are described in more detail in the pages that follow:

(1) **Storm Cost Adjustment**: As a result of the changes proposed relating to the Storm Fund Adjustment, it will be necessary to include a normalized level of storm costs in the revenue requirement. This adjustment to expense is required in order that the storm cost threshold (i.e., the amount of storm costs incurred below the qualifying storm threshold level, not includable for deferred treatment to the Storm Fund) is included in rates.

(2) **Storm Fund Adjustment**: The Company is proposing certain adjustments to the mechanics and to the level of base-rate contribution to the Storm Fund mechanism currently in effect for NSTAR Electric. These changes would take effect with the implementation of new rates in this proceeding and would apply for qualifying storm events occurring on and after January 1, 2023. The various elements of the Company's Storm Fund proposal are described in more detail below and in Section VI.

(3) **Recovery of Outstanding Storm Cost Balance**: The Company has a significant outstanding balance of unrecovered storm costs for qualifying storms that have occurred since 2018, but for which the Company has not yet started recovering costs above the base amount in rates. In addition to those storms that have occurred, the Company may also incur additional costs for qualifying storms prior to January 1, 2023. As described in more detail below, the Company is proposing to begin recovery of balance of unrecovered costs effective January 1, 2023 and maintain the current SCRAF in effect as the existing amortization approved in D.P.U. 17-05 is ending as of December 31, 2022.

Q. Briefly describe the Company's proposed Storm Cost Adjustment.

A. As discussed below in Section VI of this testimony, the Company is proposing limited modifications to the Storm Fund design in this proceeding. The proposals are discussed below in Section VI; however, the Company's proposals result in a post-test year adjustment to the proposed revenue requirement. Specifically, the Company is proposing a post-test year adjustment to expense in relation to the Qualifying Storm Threshold included in rates. The adjustment to the test year level of expense is a decrease of $4.2 million, as shown on Exhibit ES-REVREQ-2, Schedule 23, Page 1. The Company determined that six major events should be included in the revenue requirement. The total of six storms was derived based on prior experience with major events, computed as 24 qualifying storms divided by 4 years, which is the number of years over which the qualifying storms occurred (see,

Exhibit ES-REVREQ-2, Schedule 23, page 2). Therefore, the Company is proposing that a total of $7.8 million is collected through base rates annually to cover the first $1.3 million deductible per storm ($1.3 million * 6 storms), also as shown in Exhibit ES-REVREQ-2, Schedule 23, Page 2.

The Company is also proposing to increase the Storm Fund contribution collected through base rates from $10 million annually to $31 million annually, as shown on Exhibit ES-REVREQ-2, Schedule 22. This proposal is discussed in Section VI, below.

14. Residual O&M Inflation Adjustment

Q. Have you calculated inflation adjustments for the NSTAR Electric revenue requirement?

A. Yes. As shown on Exhibit ES-REVREQ-2, Schedule 24, the post-test year adjustment associated with the NSTAR Electric residual inflation adjustment is an increase of $7,077,380. The computation of NSTAR Electric's pro forma expense level is shown in Exhibit ES-REVREQ-3, Work Paper 24. Consistent with Department precedent, Eversource has calculated an inflation allowance to recognize the expected changes in cost that will occur between the end of the test year and the midpoint of the rate year. Under Department precedent, the adjustment applies only to those expenses that are not adjusted separately (i.e., "residual O&M expense").

Q. Please describe the adjustment for inflation.

A. NSTAR Electric's inflation adjustment of $7,077,380 is shown on Exhibit ES-REVREQ-3, Work Paper 24, with the computation in relation to residual NSTAR Electric O&M expenses shown on the same exhibit. The inflation allowance is based on the projected inflation rate of 7.691 percent from the midpoint of the test year to the midpoint of the rate year. To determine the level of test year residual O&M expense, the Company reduced test year O&M expense by expenses that have been adjusted separately. The inflation rate was separately calculated in Exhibit ES-REVREQ-3, Work Paper 24 and was measured by the projected growth in the Gross Domestic Product Implicit Price Deflator ("GDPIPD") from the mid-point of the test year to the mid-point of the rate year.

15. Depreciation

Q. Did the Company prepare a depreciation study for this case?

A. Yes. Company Witness Spanos prepared a detailed depreciation study for NSTAR Electric. The results of that study are incorporated into the proposed depreciation expense for each company. Please see Mr. Spanos' direct testimony (Exhibit ES-JJS) for support of the updated depreciation rates.

Q. What level of depreciation is the Company proposing for its revenue requirements?

A. NSTAR Electric has calculated a pro forma depreciation expense of $231,820,683 at Exhibit ES-REVREQ-2, Schedule 25. This is an increase of $17,373,812 from the test year amount of $214,446,872.

Q. Please describe in more detail the calculation of depreciation expense?

A. The Company has applied the depreciation rates resulting from the depreciation study performed by Mr. Spanos as of the test year ending December 31, 2020 to projected account balances of depreciable plant at December 31, 2021, including an estimate for 2021 plant additions to determine depreciation expense for each utility plant account. As described in Mr. Spanos' testimony and his accompanying exhibits, the depreciation rates proposed for NSTAR Electric represent a net decrease versus current levels. This is primarily a function of a decrease in amortization expense on intangible assets, which is a result of using longer amortization periods than are currently utilized, a decrease in depreciation expense on distribution plant, primarily reflecting lower proposed accrual rates for account 367, Underground Conductors and Devices, or the Company's largest depreciable group; and longer life spans for Company service centers in general plant account 390, Structures and Improvements. As reflected in, the depreciation analysis prepared by Mr. Spanos indicates many accounts have longer service lives than are reflected in current rates. One exception is account 370, Meters, which reflects a shorter service life than reflected in current rates due to higher meter replacement practices. Although the overall rates proposed by Mr. Spanos represent a decrease from current levels, the Company's depreciation expense has increased in total due to the significant plant investment since the Company's last rate case, augmented by the inclusion of solar and grid modernization plant investment, which were not part of the Company's 2017 rate case.

Exhibit ES-REVREQ-3, Work Paper 30, page 1, provides a listing of the projected depreciable plant balances by account as of December 31, 2020. Columns (D) through (I) present adjustments to remove non-distribution related items and to add estimated 2021 plant additions to arrive at the distribution plant in service in Column (J). In Exhibit ES-REVREQ-2, Work Paper 25, the Company has applied the depreciation accrual rates for NSTAR Electric as presented in Exhibit ES-JJS-2 to the distribution plant in service balance presented in Exhibit ES-REVREQ-2, Work Paper 30, Column (J). The calculated depreciation expense is the sum of the depreciation expense for each utility plant account. This total of $231,820,683 is shown on Exhibit ES-REVREQ-3, Work Paper 25.

16. Amortization of Deferred Assets

Q. Have you adjusted the test year amortization expense?

A. Yes. Exhibit ES-REVREQ-2, Schedule 26, shows a net increase to distribution related amortization expense of $3,427,522. The detail supporting this adjustment is provided in the schedules accompanying the workpaper provided in Exhibit ES-REVREQ-3, Work Paper 26, pages 1 through 5.

Q. Please provide a summary of the information contained in Exhibit ES-REVREQ-2, Schedule 26.

A. Exhibit ES-REVREQ-2, Schedule 26 identifies several amortization items for inclusion in the distribution cost of service. The items subject to amortization are (a) Acquisition Premium Amortization; (b) Hardship Receivables; (c) Merger Costs to Achieve; (d) Former Flowthrough; (e) Farm Discounts; (f) Basic Service

Administration costs; (g) Contribution in Aid of Construction ("CIAC") Tax Gross-up; (h) Regulatory Credits and Debits; and (i) Exogenous Property Taxes.

(a) Acquisition Premium Regulatory Asset

Q. What is the acquisition premium regulatory asset amortization?

A. The annual pro forma amortization relating to the acquisition premium is $14,472,828, as shown at Exhibit ES-REVREQ-2, Schedule 26 and the accompanying workpaper in Exhibit ES-REVREQ-2 Work Paper 26, page 1. The amortization of merger-related acquisition premium was approved by the Department in BECO/COM Acquisition, D.T.E. 99-19 (1999). In that case, the Department approved the 40-year amortization and recovery of the merger-related acquisition premium with the annual amortization estimated at $20.6 million on a tax-effected, NSTAR-wide basis. D.T.E. 99-19, at 6-7, 46-47, 56-62, 81-86.

Q. Please further describe the treatment of the acquisition premium approved by the Department in BECO/COM Acquisition, D.T.E. 99-19 (1999)?

A. In D.T.E. 99-19, the Department approved a rate plan associated with the merger of BEC Energy and Commonwealth Energy Systems (the "BECO/COM Merger"), applying to the operating subsidiaries of Boston Edison Company, Cambridge Electric Company, Commonwealth Electric Company and Commonwealth Gas Company. These operating subsidiaries were legally merged together in 2006 to become NSTAR Electric as a result of the Department's decision in NSTAR Electric Company, D.T.E. 06-40 (2006).

In D.T.E. 99-19, the Department approved the 40-year amortization and recovery of an acquisition premium associated with the BEC/COM Merger estimated at that time to be $500,059,252 noting that the final acquisition premium amount would not be determined until after the merger. Id. at 6-7, 46-47, 56-62, 81-86. Based on this determination, the Department directed the NSTAR to: (1) provide the journal entries or a schedule summarizing such entries upon completion of the merger in order to determine the actual acquisition premium; and (2) develop a cost allocation system for transactions among the four operating subsidiaries, including the allocation of the acquisition premium. Id. at 62, 91-94. On April 2, 2001, NSTAR submitted a final accounting for the merger to the Department, quantifying the actual acquisition premium as $490,023,538. The actual acquisition premium balance determined as of the merger-closing date of $490,023,538 was allocated to the operating companies of NSTAR. The Department approved the amortization and recovery from customers of the acquisition premium balance because the savings as a result of the merger were found to be significantly greater than the costs incurred to achieve the merger, including the acquisition premium.

Q. How was the allocation of the acquisition premium determined?

A. In 1999, the Company allocated the acquisition premium balance among the operating affiliates based on the relative size of the companies' operations. In order to determine the allocation, the Company calculated an allocator based on the combination of net utility plant and distribution O&M expenses. The resulting allocator for NSTAR Electric was 85.86 percent. Of the $490 million acquisition premium amount, approximately $420.7 million was allocated to NSTAR Electric.

Q. What was the Department's finding in the NSTAR Gas rate case proceeding in D.P.U. 14-150 relating to the valuation of ComEnergy Steam?

A. In the Department's Order in D.P.U. 14-150 at 232 it stated the following:

> The Department has reviewed the Company's calculation of the remaining amortization amount related to the D.T.E. 99-19 acquisition premium. Based on our review, the Department finds that the basis adjustment does not include all of ComEnergy's unregulated affiliates. Specifically, the revaluations are confined to Advanced Energy Systems, a combined heat and power facility, and four real estate companies. At the time of the merger, however, ComEnergy also operated ComEnergy Steam, which provided steam service in the City of Cambridge. The Department questions the Company's implicit assumption that ComEnergy Steam had no market value as of the date of the merger. While the Department will not adjust the Company's calculation of its basis adjustment here, we put NSTAR Gas on notice that this calculation will be the subject of inquiry in the Company's next base rate proceeding.

D.P.U. 14-150, at 232 (citations omitted).

Q. Did the Company provided evidence in D.P.U. 17-05 to rebut the Department's conclusion in D.P.U. 14-150? Do you agree with the Department's conclusion that in?

A. Yes. The Department's conclusion that, in the revaluation of ComEnergy's unregulated subsidiaries, NSTAR determined that ComEnergy Steam, which was operated by ComEnergy and provided steam service to the City of Cambridge, had no market value was incorrect. In D.P.U. 17-05, the Company provided evidence that the Department had misinterpreted the referenced document originally provided in D.P.U. 14-150 as Exhibit AG-6-25, Att. (c) at 5 and also provided in this case as Exhibit ES-RevReq-4, Schedule 6. This document shows basis adjustments to various entities included in the consolidated COM/Energy common equity balance. In other words, amounts shown on the referenced exhibit indicated that, for purposes of determining the acquisition premium, the book value of certain entities was adjusted, as shown on that schedule. The absence of ComEnergy Steam on that exhibit does not, as the Department concluded, reflect the view that ComEnergy Steam had "no market value as of the date of the merger."

In D.P.U. 17-05, the Company demonstrated that the absence of ComEnergy Steam on that referenced exhibit simply meant that the Company *made no adjustment* to its book value in determining the acquisition premium and thatthere were other affiliated entities operated by ComEnergy that were also not referenced on that exhibit, including Hopkinton LNG Corp. Exhibit ES-DPH-4, Schedule DPH-9 at page 4, as filed in D.P.U. 17-05, provided the document originally provided in D.P.U. 14-150 as Exhibit AG-6-25(c), which illustrated the original calculation of the estimated acquisition premium balance immediately following the merger in August 1999. This calculation was filed with the Department on November 23, 1999 as required in the decision. Exhibit ES-DPH-4, Schedule DPH-9 at page 16, as filed in D.P.U. 17-05, provided a memo prepared at the time of the merger in 1999, which documented the rationale for each basis adjustment listed on Exhibit ES-DPH-4, Schedule 9 at 8, as well as the rationale for *basis adjustments not made*, including any impact on ComEnergy Steam.

Q. In D.P.U. 17-05, did the Company demonstrate that, in calculating the amount of the acquisition premium to be amortized, NSTAR included costs related to change in control provisions contained in then-existing employment contracts in the calculation?

A. Yes. As the Company demonstrated in D.P.U. 17-05, NSTAR included the costs of certain change in control provisions, as was explicitly anticipated by the Department's decision in D.T.E. 99-19. As part of this calculation, NSTAR included the amount $5,992,297 representing actual costs incurred as part of the merger transaction for employment contracts that COM/Energy had in place with three of its officers prior to the merger. These pre-existing employment contracts were part of the business acquired and represented known and anticipated costs associated with the change-in-control provisions included in certain COM/Energy employment contracts that were in existence at the time of the merger. The actual payments to the departing executives equaled $5,861,107, representing a difference of less than two percent from the amount anticipated in the computation of acquisition premium consistent with applicable accounting standards.

Q. In D.P.U. 17-05, did the Company demonstrate that costs associated with employment contract change in control provisions were properly included in a goodwill calculation?

A. Yes. The BECO/COM Merger, as reviewed and approved by both the Department and FERC, was governed by Accounting Principles Board Opinion No. 16, Business Combinations ("APB 16"), issued in August of 1970, and Statement of Financial Accounting Standards No. 38, "Accounting for Pre-Acquisition Contingencies of Purchased Enterprises" ("SFAS 38"), issued in September of

1980. Both SFAS No. 38 and APB 16 provide for the inclusion of "change in control payments" in the goodwill computation.

APB 16, paragraph 11, describes the purchase method of accounting for a business combination and states that "…. [t]he acquiring corporation records at its cost the acquired assets less liabilities assumed. A difference between the cost of an acquired company and the sum of the fair values of tangible and identifiable intangible assets less liabilities is recorded as goodwill." APB 16 further indicates in paragraph 21.a. that a company should record in an acquisition "all assets and liabilities which comprise the bargained cost of an acquired company, not merely those items previously shown in the financial statements of an acquired company." The change-in-control payments made to certain, former COM/Energy personnel resulted from employment contracts that were part of COM/Energy upon acquisition. The costs of those contracts were triggered by the merger transaction, and therefore, were properly (and unavoidably) part of the purchase price of COM/Energy. The departure of those executives resulted in future savings for customers. The Company provided Exhibit ES-DPH-4, Schedule DPH-9 ininin D.P.U. 17-05 in support for the costs of those contracts.

Q. How was the amortization period determined?

A. As demonstrated in D.P.U. 17-05, the amortization period was based on the accounting standards in effect at the time of the merger. At that time, entities were required to amortize goodwill over the estimated economic period of the goodwill balance, not to exceed 40 years. In D.T.E. 99-19, the Company proposed, and the Department approved, a straight line 40-year amortization period. This reflects the fact that the customer savings are realized over an extended period of time. As shown on Exhibit ES-REVREQ-3, Work Paper 26, page 1, the Company has amortized 256 months of 480 months as of December 31, 2020.

Q. What did the Department determine in D.P.U. 17-05 regarding the acquisition premium?

A The Department found that, in determining the basis adjustment to be applied to their nonregulated affiliates, the NSTAR Companies appropriately determined the fair market value of each of ComEnergy's nine unregulated affiliates. D.P.U. 17-05, at 292. The values of Hopkinton LNG and ComEnergy Steam were found to have no change in book value, based on various contracts in effect at that time, and the NSTAR Companies determined that the fair market value of these affiliates was represented by their book value. Id. The Department stated that it was satisfied that the NSTAR Companies appropriately calculated the basis adjustment applied to ComEnergy's unregulated affiliates, negating the concerns it had raised in D.P.U. 14-150. Id.

The Department also found that the change-in-control payments were appropriately part of the purchase price of ComEnergy and that the $5,992,297 in change-in-control payments was less than the total change-in-control payments ultimately paid out to ComEnergy employees, and thus represented a conservative measure of the actual change-in-control payments made as part of the BEC/ComEnergy

Merger. Id. at 294. The Department approved the inclusion of $5,992,297 in the calculation of the acquisition premium. Id.

The Department determined that the inclusion of the change-in-control payments in the calculation of goodwill produces a total goodwill balance of $490,023,538, of which $420,710,605 was allocated to NSTAR Electric. Id. In D.P.U. 17-05, the Department found that, based on the current amortization rate, the unamortized goodwill attributable to NSTAR Electric would be $238,427,071 as of the end of 2016. Id. With the inclusion of an additional $95,847,683 in deferred income taxes and an additional $64,432,473 in associated income taxes, the Department calculated the Company's unamortized goodwill and associated income taxes to be $398,707,477 as of the end of 2016. Id. Accordingly, the Department found that the $398,707,477, divided by the remaining amortization period of 272 months as of the effective date of the rates authorized in D.P.U. 17-05, produced an annual amortization expense of $17,590,044, which the Company had proposed in its filing in D.P.U. 17-05. Id. at 294-295. Consistent with these findings, the Company calculated a $14,472,828 test year amortization expense as shown in Exhibits ES-REVREQ-2, Schedule 26 and ES-REVREQ-3, Work Paper 26, page 1.

Q. How is the tax impact of the amortization treated for purposes of the revenue requirement?

A. The amortization is not deductible for federal or Massachusetts income tax purposes. Therefore, the revenue requirement related to the acquisition premium amortization must contain a gross-up to ensure that the Company is able to collect the income tax liability as a result of the billed revenue. By doing this, the revenue requirement calculation reflects the appropriate tax treatment of the amortization.

17. Amortization of Hardship Accounts Arrearage Balances

Q. What is the amortization of hardship receivables?

A. In addition to the normal level of accounts receivable charge-offs, the Company has included an amount for the recovery of uncollectible amounts associated with "hardship protected accounts." Hardship protected accounts are residential accounts that are protected from shut-off by the utility for non-payment under 220 C.M.R. §§ 25.03, 25.05. To qualify for protected status from service termination, customers must be elderly or demonstrate that they have a financial hardship and meet certain other requirements, such as suffering from a serious illness or residing with a child under twelve months of age (220 C.M.R. § 25.03(1); 220 C.M.R. § 25.03(3); 220 C.M.R. § 25.05(3)). All qualified accounts are protected from shut-off for non-payment year-round, except for heating customers with a financial hardship. These heating accounts are protected from shut-off for non-payment only during the winter moratorium period, November 15th through March 15th (220 C.M.R. §§ 25.03(1)(a)3, 25.03(1)(b)).

Pursuant to Department regulations, an account qualifies for protected status where the customer has a financial hardship, and: (1) a person residing in the household is seriously ill; (2) a child under the age of twelve months resides in the household; (3) the customer takes heating service between the period November 15th and

March 15th; or (4) all adults residing in the household are age 65 or older and a minor child resides in the household (220 C.M.R. § 25.03). An account also qualifies for protected status where all residents of the household are age 65 or older (220 C.M.R. § 25.05). Customers who meet the income eligibility requirements for the Federal Low-Income Home Energy Assistance Program ("LIHEAP") are deemed to have a financial hardship (220 C.M.R. § 25.01(2)).

Because these accounts cannot be disconnected, the accounts remain "active" and continue to receive service despite slow or non-payment of amounts due. As the accounts stay active, they do not become part of the write-off calculation to be included for recovery from customers. NSTAR Electric's total "active protected" hardship accounts receivable balance outstanding over 360 days is $38,185,097 as of December 31, 2020, as shown in Exhibit ES-REVREQ-3, Work Paper 26, page 2 and Table 1 below. The Company is proposing to amortize the balance of "active protected" receivables over a five-year period. After reducing hardship accounts receivable for balances included in prior distribution rate case requests, the resulting annual amortization expense is $6,239,165, as shown on Exhibits ES-REVREQ-2, Schedule 26 and ES-REVREQ-3, Work Paper 26, page 2. The Company plans to update the hardship accounts receivable and related amortization expense during the course of the proceeding due to the pandemic moratorium on disconnects, which has delayed customer enrollment in hardship programs to avoid disconnects. The Company anticipates that the hardship receivable balances as of

December 31, 2020 are understated due to the pandemic and are expected to grow significantly in 2021 as the Company resumes disconnects.

Q. Could you provide additional detail on the Company's proposed amortization of "hardship receivables"?

A. Yes. If an active hardship protected customer's account balance is in arrears, the Company is prohibited from initiating the procedures it would normally follow to collect the balance and, if necessary, to terminate service to the customer. As a result of the Department's requirements and practices in relation to this customer group, the active hardship protected customer accounts receivable balances in arrears have grown significantly. The table below provides a breakdown of the active hardship protected balances as of December 31, 2020:

Table 1

Age of Accounts	NSTAR Electric Balance ($)
0 to 30 days	$ 1,731,120
30 to 60 days	$ 1,212,558
61 to 90 days	$ 1,063,492
91 to 120 days	$ 1,225,200
121 to 360 days	$ 9,795,463
Over 360 days	$ 38,185,097

Q. Is this request consistent with Department precedent?

A. Yes. In Western Massachusetts Electric Company, D.P.U. 10-70 (2011), the Department approved the company's request to amortize arrearage balances for active hardship accounts over 120 days. D.P.U. 10-70, at 214-216. However, in that decision, the Department stated that it was appropriate for WMECO to amortize outstanding balances over 360 days (versus 120 days) over a five-year amortization period. Id. at 216. In addition, the Department directed that any payments made by customers toward balances that WMECO has amortized would be credited to WMECO's Residential Assistance Adjustment Clause. Id.

In Fitchburg Gas and Electric Light Company, D.P.U. 13-90, at 158-160, 163-167 (2014), the Department affirmed the treatment of allowing a five-year amortization of arrearage balances for active hardship over 360 days. This adjustment has also been approved by the Department for NSTAR Gas in D.P.U. 14-150, at 235, and National Grid in D.P.U. 15-155 at 252.

Q. Is the Company currently able to collect arrearages related to active hardship protected customer accounts?

A. No. Arrearages are recoverable only to a very limited extent. The Company currently has a Residential Assistance Adjustment Factor ("RAAF"), which is a recovery mechanism for arrearage forgiveness that is provided to customers who participate in the Company's NewStart program**.** A customer must enroll and stay in the NewStart program for his/her unpaid balance to qualify for recovery in the RAAF. A limited number of the Company's customers who qualify for protected status participate in the NewStart Program, but the majority of active hardship-protected customers do not participate or are unable to remain in the program for various reasons, including failure to meet the minimum required payments. As a result, arrearages related to active hardship protected accounts continue to grow and the Company has no mechanism to recover them.

(a) Amortization of Merger-Related Costs to Achieve

Q. Did the Department approve the amortization of merger-related costs to achieve in D.P.U. 17-05?

A. Yes. Northeast Utilities and NSTAR entered into an agreement and plan of merger dated October 16, 2010, as amended on November 1, 2010. The transaction was approved by the Department on April 4, 2012 in D.P.U. 10-170-B and closed on April 10, 2012. Upon completion of the merger, NSTAR and its subsidiaries, including NSTAR Electric and NSTAR Gas, became wholly-owned subsidiaries of Northeast Utilities. Effective February 2, 2015, Northeast Utilities and all of its subsidiaries began doing business as Eversource Energy.

The Department approved the merger transaction on D.P.U. 10-170 subject to the terms and conditions of the AG-DOER Settlement Agreement and a second settlement agreement between Northeast Utilities and the Department of Energy Resources (the “DOER” Settlement Agreement”) (collectively, the “Settlement Agreements”). Under the Settlement Agreements and the Department’s precedent, the Company was allowed to recover merger-related costs upon a showing that merger-related savings equal or exceed those costs. D.P.U. 17-05, at 298-299.

In D.P.U. 17-05, the Department found that the Company demonstrated that its merger-related savings exceeded its merger-related costs and that the Company was eligible to recover $30,523,721 in merger-related costs over a ten-year period at a rate of $3,052,372 annually. Id. at 301-302.

Q. Please describe how the Company has reflected the amortization of the merger-related costs in the cost of service.

A. As allowed by the Department in D.P.U. 17-05, the Company has included the annual amortization in the amount of $3,052,372 in the cost of service, as shown in Exhibit ES-REVREQ-2, Schedule 26, line 21.

18. Taxes Other Than Income Taxes

Q. Please summarize your adjustments to Taxes Other Than Income Taxes?

A. As shown on Exhibit ES-REVREQ-2, Schedule 7, at line 63, NSTAR Electric is proposing to increase Taxes Other Than Income Tax by $13,932,246.

19. Property Taxes

Q. Has the Company adjusted the test year expense for property taxes?

A. Yes. The Company has adjusted test year property taxes as shown on Exhibit ES-REVREQ-2, Schedule 27 by $12,977,117.

Q. How did you determine this adjustment?

A. The adjustment to property tax expense is computed on Exhibit ES-REVREQ-2, Schedule 27. The known and measurable adjustment reflected on page 1 begins with the adjusted test year distribution property tax expense, which has been adjusted to remove non-distribution related property tax expense and out-of-period items, as shown on page 2. The total property tax expense is reflected on Schedule

27, page 2, line 19. This amount is itemized by municipality on Exhibit REVREQ-3, Work Paper 27. The total property tax expense is then adjusted to remove non-distribution related components to arrive at the distribution rate-year property tax expense shown on Schedule 27, page 1, line 20. Following these references above, for NSTAR Electric, the adjusted test year distribution-related property tax expense is $121,658,085 and the rate-year distribution-related property tax expense is $134,635,202, representing an increase of $12,977,117 to the adjusted test year expense, as shown on Exhibit ES-REVREQ-2, Schedule 27, page 1.

This adjustment will be updated during the course of the case to reflect the most recent mill rates, personal property values from the latest "Form of List" ("FOL") and real estate assessments from the municipalities in which the Company owns assets, as described in more detail below.

Q. Prior to the Company's last base distribution rate proceeding, D.P.U. 17-05, what was the Department's precedent for establishing the base level of property taxes in a distribution rate case?

A. Historically, the Department's general policy is to base the pro forma level of property taxes that should be included in the revenue requirement on the most recent property tax bills from municipalities in which it has property. See, e.g., D.P.U. 15-155, at 213; D.P.U. 15-80/D.P.U. 15-81, at 166; D.P.U. 14-150, at 209; D.P.U. 12-25, at 330; D.P.U. 08-35, at 150; D.P.U. 96-50 (Phase I) at 108-109; Colonial Gas Company, D.P.U. 84-94, at 19 (1984).

However, as of the time of this filing, the latest property tax bills for NSTAR

Electric were received in the first half of 2021 and were for Fiscal Year ("FY") 20212021.[3] Due to the manner in which municipalities prepare their property tax bills, the personal property portion of these bills was based on the net book value of property **as of December 31, 2019** as reported to the municipalities by the Company. This lag in the plant balances, combined with the Department's 10-month suspension period, results in a substantial under-estimation of property tax expense in future periods, following the rate case. Due to this systematic under-estimation, distribution companies in Massachusetts have recently proposed alternative methods of calculating and including property tax expense in the revenue requirement.

Beginning in D.P.U. 17-05, the Department approved a new methodology for setting representative property tax expense. This methodology closely follows the municipal tax process, and therefore, generates a more reliable representation of rate-year property tax expense. Specifically, the Department approved the new method for NSTAR Electric and WMECO in D.P.U. 17-05, at 250-251, as well as for National Grid in D.P.U. 17-170 and D.P.U. 18-150, and NSTAR Gas Company in D.P.U. 19-120. NSTAR Electric has used the same method of property tax calculation approved in these proceedings, as explained in greater detail below.

[3] Fiscal year 2021 is for the twelve months ending June 30, 2021.

Q. What are the various components of property tax expense issued by the municipalities to the Company?

A. The various components of each property tax bill are itemized on Exhibit ES-REVREQ-3, Work Paper 27. Copies of the latest actual property tax bills for NSTAR Electric are provided at Exhibit ES-REVREQ-6(b). As shown on those schedules, the property tax bills are comprised of the following components:

- **Personal Property Assessment**: This is based on the net book value of Company-owned assets reported to the municipality on the FOL annually. There are a limited number of municipalities who rely on an alternative, hybrid valuation methodology, and therefore do not rely on the FOL in determining the personal property assessment. The municipalities that rely on an alternative method are listed in Exhibit ES-REVREQ-3, Work Paper 27, Page 4 and described in more detail below.

- **Real Property Assessment**: This is based upon the full and fair market value of all real estate established by the municipalities as of January 1st of each year. The fair market value (or the assessment) becomes the basis for taxation.

- **Mill Rate**: All municipalities establish the mill rate, which represents the amount per $1,000 of the assessed value of property. This rate is used to calculate the amount of property tax owed.

- **Total Tax**: Total Tax is the calculation of total assessed value (Personal Property plus Real Property) multiplied by the mill rate, and then divided by 1,000.

- **Community Preservation Act ("CPA")**: CPA allows communities to create a local community preservation fund for open space protection, historic preservation, affordable housing and outdoor recreation. Community preservation monies are raised locally through the imposition of a surcharge of not more than three percent of the tax levy against real property, and municipalities must adopt CPA by ballot referendum.[4]

- **Water/Sewer:** Certain municipalities include surcharges for water and/or sewer system usage on their property tax bill.

Q. Please describe the typical process and timing for municipalities issuing property tax bills in a given year.

A. Please refer to Figure 1 below for a timeline of how property tax bills are generated by the municipalities. This illustrative example is based on a FY 2022 bill.

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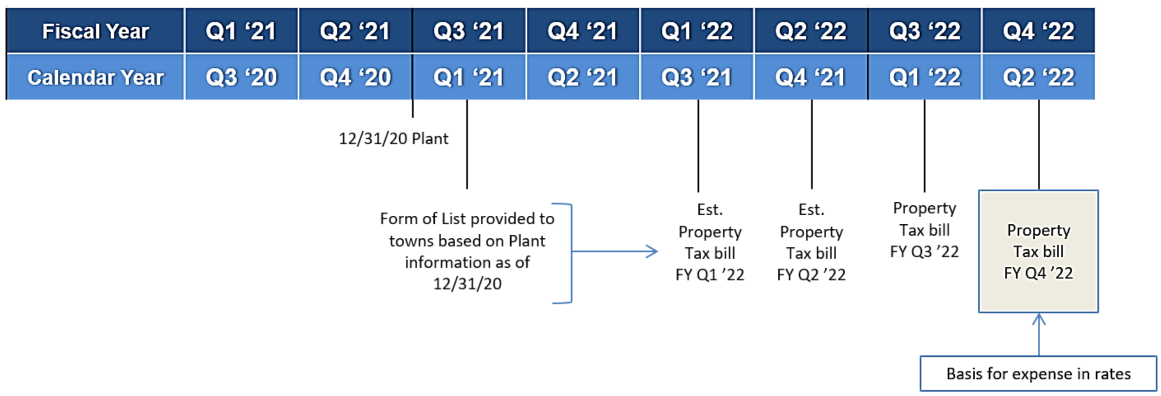
[4] http://www.communitypreservation.org/content/cpa-overview

Figure 1



In the first quarter of each calendar year the Company produces a "Form of List," for submittal to each municipality in which the Company owns property. The FOL reports the net book value of assets owned by the Company as of the end of the most recent calendar year. With few exceptions, municipalities rely on the FOL to bill the Company for personal property taxes. However, as shown in Figure 1, above, there is a substantial lag (as long as 18 months) from the point when the calendar year ends, and the associated net-book value information is included on the property tax bills. This means that the most recent bills in the Company's possession at the time of this filing (received in the first half of 2021) reflect the net book value of plant in service **<u>as of December 31, 2019</u>**.

Carrying this forward, based on the anticipated timing of the proceeding in this case, the latest bills received by the Company during this proceeding will be received in during the first half of 2022, and will be based on net book value **<u>as of December 31, 2020</u>**. This means that, at the mid-point of the rate year, July 1, 2023, adhering strictly to the Department's historic methodology for establishing property tax expense prior to D.P.U. 17-05, the Company will be recovering a level of property tax expense based on a net-book value of plant, which is at least 30 months old, i.e., the property tax expense recovered in rates as of 2023 will be based on net book value as of December 31, 2019.

Given that the Company is consistently increasing its plant in service and that municipalities routinely incorporate increases in their mill rates, a lag time of two and a half years as of the mid-point of the rate year is significantly underestimating property tax expense right out of the box and does not accurately establish a "representative" level of expense. Moreover, this situation is exacerbated by the fact that an increasing number of municipalities have adopted a new valuation method that results in substantial increases in property tax expense.

Q. How has the Company established the representative level of property tax expense in this proceeding?

A. Consistent with Department precedent in D.P.U. 17-05, D.P.U. 17-170, D.P.U. 18-150 and D.P.U. 19-120, the Company has calculated the property tax expense as follows:

For those municipalities that rely on the FOL provided by the Company, personal property tax expense will be based on the values provided by the Company on the FOL produced in the first quarter of 2021. The remaining components for each municipality (i.e., Real Property; Mill Rate; CPA; and Water/Sewer) will be based on the corresponding amounts listed by each municipality on the latest bills received during the proceeding. This is appropriate because the values provided on the FOL, in almost all cases, are identical to the values relied on by the municipality in valuing personal property on which to assess property tax expense.

As described further below, the Company will update this adjustment during the course of the case to reflect personal property values from the latest FOL, and real property assessments and most recent mill rates from the latest bills received from the municipalities in which the Company owns assets.

Q. Please describe the calculation of property tax expense for municipalities relying on a hybrid or alternative valuation method for establishing the personal property assessment.

A. Under the guidance provided by the Massachusetts Department of Revenue ("DOR"), an increasing number of municipalities have transitioned away from the traditional method of valuation using Net Book Values ("NBVs"), which are equal to installed cost less accumulated depreciation, to a "hybrid" method of the NBV approach as discussed further in Section VIII. Specifically, this approach involves alternative assessments in excess of NBV, with some municipalities adopting an approach that is based on 50 percent of the NBV valuations and 50 percent on valuations using the reproduction costs new less depreciation method, (or "Hybrid RCNLD/NBV Method"). The Hybrid RCNLD/NBV Method uses the property tax expense as reported on the town's most recent property tax bills, adjusted to recognize any changes in personal property valuations, which results in a significant increase in assessed value from the NBV method of assessment, attributable to the Hybrid RCNLD/NBV Method.

Six municipalities has adopted the Hybrid RCNLD/NBV Method at the time of the Company's last rate case.[5] An additional 82 municipalities began using the Hybrid RCNLD/NBV Method as of the FY 2021 tax year, the latest bills received ahead of the Company's initial filing in this proceeding. Consistent with the Department's approvals in D.P.U. 17-170, D.P.U. 18-150, and D.P.U. 19-120, the Company has reflected actual personal property valuations provided in the most recent property tax bills received to date for these communities, with an adjustment to reflect the change in assessed values between December 31, 2019 (i.e., the date at which the current invoiced assessments were established) and December 31, 2020, as captured by the change in net book values reported in the Company's FOLs sent to the municipalities for FY 2021.

[5] In D.P.U. 17-05, the Company reflected the amounts provided in the most recent property tax bill for FY 2017 for the towns utilizing an alternative valuation methodology (Boston, Brookline, Everett, Medway, Newton and Springfield).

The Company will update Exhibit ES-REVREQ-3, Work Paper 27, Page 4 to reflect additional municipalities that transition to the Hybrid RCNLD/NBV Method in the FY 2022 tax year as part of the bills received by the Company by Q2, 2022. This update will reflect actual personal property valuations provided in the property tax bills for FY 2022, i.e., the latest bills to be received prior to the close of this proceeding, with an adjustment to reflect the change in assessed values between December 31, 2020 and December 31, 2021, as captured by the change in net book values reported in the Company's FOLs for FY 2023, i.e., the latest FOLs to be received prior to the close of this proceeding.[6]

Q. What evidence did the Company provide in D.P.U. 17-05 to demonstrate that the "Form of List" serves as the basis for the property taxes assessed for personal property?

A. The Company's adjustment to property tax expense relies on: (1) FY 2022 FOL for personal property assessed values; (2) FY 2021 tax bills for real property assessed values; (3) FY 2021 tax bills for the mill rate; and (4) FY 2021 tax bills for the Community Preservation Act, water and sewer charges. To demonstrate that there is a direct link between the FOL provided by the Company and the amounts of assessment billed by the municipalities for Personal Property, the Company has provided the following information for every town in the Company's service territory:

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[6] The Company inadvertently excluded Medway and Springfield from the calculations shown in Exhibit ES-REVREQ-3, Work Paper 27, Page 3 and intends to include these municipalities in the Company's update to reflect the latest bills for FY 2022 tax year.

(a) Copies of the actual FOL as provided by the Company to each municipality for each of the most recent four years. See Exhibit ES-REVREQ-6(b), Schedules 2, 5, 8, and 11 for FY 2020, FY 2021, FY 2022, and FY 2023 (to be supplemented by Q1, 2022), respectively.[7]

(b) Copies of the actual bills received by the Company for each municipality for each of the most recent three years, which correspond to the FOLs referenced above. The property tax bills provide the actual mill rate used and the total amount of personal property taxes billed by each municipality. See, Exhibit ES-REVREQ-6(b), Schedules 3, 6, and 9 for FY 2020, FY 2021, and FY 2022 (to be supplemented when received by Q2, 2022).

(c) A summary schedule for FY 2020, FY 2021, FY 2022 and FY 2023 (to be supplemented by Q1, 2022), which shows the direct correlation between the FOL and the assessment billed by the municipality for Personal Property. See Exhibit ES-REVREQ-6(b), Schedules 1, 4, 7, and 10. The various components presented on this summary schedule include: (i) NBV as reported on the FOL; (ii) Mill Rate provided by the municipality on each corresponding bill; (iii) Calculated Personal Property Taxes by multiplying

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[7] FOLs utilized in producing the FY 2020 property tax bills were provided to each municipality in calendar Q1, 2019, representing the NBV as of December 31, 2018. FOLs utilized in producing the FY 2021 property tax bills were provided to each municipality in calendar Q1, 2020, representing the NBV as of December 31, 2019. FOLs utilized in producing the FY 2022 property tax bills were provided to each municipality in calendar Q1, 2021, representing the NBV as of December 31, 2020. FOLs that will be utilized in producing the FY 2023 property tax bills will be provided to each municipality by Q1, 2022 and provided in Exhibit ES-REVREQ-6(b) as Schedule 11.

the NBV by the Mill Rate and dividing by 1,000; (iv) Actual Personal Property amount billed to the Company as provided by the municipality on each corresponding bill; (v) the calculated variance between the level Personal Property tax expense derived from multiplying the (i) NBV reported on the FOL by (ii) the Mill Rate provided by the municipality, and the actual amount billed.

The last column includes an explanation of each variance, if applicable (<u>i.e.</u>, an example of a variance could be because the town is using an alternative methodology for assessing personal property); (vi) page number reference to the Exhibits listed in (a), above, for the FOL in which the NBV shown on the summary exhibit can be found; and (vii) page number reference to the Exhibits listed in (b), above, for copies of the property tax bills in which the Mill Rate and actual billed amount are shown.

As demonstrated in the summary schedule described above, 100 percent of the Personal Property tax expense is either accurately calculated by (i) utilizing the methodology described above for those municipalities who rely on the FOL provided by the Company; or (ii) utilizing the amounts listed on the latest property tax bills for municipalities relying on an alternative, hybrid method for establishing the personal property assessment.

Q. Did the Department accept the Company's proposed method of calculating property taxes in D.P.U. 17-05?

A. Yes. After reviewing the Company's proposal and evidence, the Department found that the use of the most recent FOLs in conjunction with information contained in the most recent tax bills (i.e., real property assessment, mill rate, CPA charge, and water/sewer charge), produces a non-speculative, reliable measure of the Company's rate year tax expense and satisfies the Department's known and measurable standard. D.P.U. 17-05, at 251. The Department approved the Company's proposed method to calculate property tax expense for communities that use the NBV valuation method and found that use of the method in D.P.U. 17-05 resulted in a known and measurable change to test year property tax expense. Id. at 251-252.

Q. Will the Company update the rate year level of property tax expense throughout the case?

A. Yes. During the course of this proceeding the Company will provide (i) updated FOLs provided to each municipality in calendar Q1, 2022 (for FY 2023),[8] (ii) the latest property tax bills provided by each municipality by calendar Q2, 2022 (for FY 2022),[9] and (iii) an updated calculation of rate year property tax expense, which

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8 The FY 2023 FOLs are available in Q1 2022 and will be included in Exhibit ES-RevReq-6(b), Schedule 14. Following the submission of the FOLs, the Company will make the necessary updates to the revenue requirement and provide the FY 2023 FOLs for Department review.

9 The latest actual bills that will be available during this proceeding are for FY 2022 tax year to be received in Q2, 2022. Following its review of the bills, the Company will make the necessary updates to the revenue requirement and provide the bills for Department review.

will rely on the amount of Real Property, Mill Rate, CPA and Water/Sewer, as reported on the latest actual bills, as well as the calculation of the Personal Property as reported on the calendar Q1, 2022 FOL, multiplied by the Mill Rate per the latest bills received in 2022 to determine the level of Personal Property tax expense.

Consistent with the other property tax expense proposals recently approved by the Department, the Company's proposal represents a known and measurable method for determining a representative level of property tax expense in the rate year, since, as described above, the Personal Property tax expense for FY 2023 bills will be based on the FOL provided to each municipality in Q1, 2022.

Q. Does the total Property Tax expense include taxes on non-utility or transmission plant?

A. No. Property taxes related to non-utility or transmission property from both the adjusted test year and the rate year property tax expense.

20. Payroll Taxes

Q. Please describe the adjustment for payroll taxes.

A. The adjustment for payroll taxes is an aggregate increase of $955,129 for NSTAR Electric, as shown on Exhibit ES-REVREQ-2, Schedule 28. This adjustment calculates the change in Federal Insurance Contribution Act ("FICA") and Medicare payroll tax expense based on the increase in test year labor charges through the mid-point of the rate year. The percentage increase in payroll tax expense is taken from Exhibit ES-REVREQ-2, Schedule 10, page 2 as referenced and calculated on Exhibit ES-REVREQ-3, Work Paper 28, page 2.

21. Federal and State Income Tax

Q. Have you provided the Department with a description of adjustments to per-book operating results relative to Income Taxes?

A. Yes. Exhibit ES-REVREQ-2, Schedule 1, page 8shows the computation of Massachusetts Income Taxes and Federal Income Taxes calculated using the rate base and rate of return methodology according to Department standard. The Federal tax rate is 21 percent and the Massachusetts tax rate is 8.0 percent. The Massachusetts tax rate increased to 8.0 percent for utilities effective January 1, 2014.

Q. Have you made any adjustments to return on rate base in order to calculate the taxable income base?

A. The Company adjusted the taxable income base for FAS109 Income Taxes, ITC amortization, interest expense, and flow through and permanent items, such as depreciation flow-through and non-deductible merger costs, all shown on Exhibit ES-REVREQ-2, Schedule 1, page 8.

Q. Did the Company make any adjustments to the taxable income base for Excess Deferred Income Taxes, or EDIT?

A. No. EDIT was created by a reduction in the federal income tax rate to 21 percent. EDIT represents the portion of accumulated deferred income taxes that is no longer owed to the Internal Revenue Service due to lower tax rates effective January 1, 2018. In the Department's decision in the <u>Investigation into the Effect of the Reduction in Federal Income Tax Rates</u>, D.P.U. 18-15-E, it was determined that

NSTAR Electric shall return EDIT to ratepayers through a 2017 Tax Act Credit Factor ("TACF") to be included as a separate reconciling adjustment mechanism. Due to the possibility of future tax rate changes, the Company proposes to continue to reflect EDIT in the TACF will return these amounts to customers in the most efficient manner possible. As a result, the Company did not propose any EDIT-related post-test year adjustments to the cost of service in this proceeding.

Q. Please describe the inclusion of non-deductible merger costs.

A. As described above, in accordance with the AG-DOER Settlement Agreement, the Company has included the recovery of merger costs in its revenue requirement. Because certain of these costs are not deductible for federal or Massachusetts income tax purposes, the revenue requirement must contain a gross-up to ensure that the Company is able to collect the income tax liability as a result of the billed revenue. By doing this, provided merger-cost recovery is approved by the Department in this proceeding, the revenue requirement calculation will reflect the appropriate tax treatment of the merger-cost recovery.

Q. Once the taxable income base was calculated, how did you determine income tax expense?

A. To determine taxable income, I applied a tax gross-up factor of 1.3759 to the taxable income base. The taxable income amount is then multiplied by the Massachusetts income tax and Federal income tax rates to determine income tax expense at the statutory rate. To this total, the Company subtracted amortization of ITC and added FAS109 Income Taxes with the result being income tax expense.

IV. COMPUTATION OF RATE BASE AND RATE OF RETURN

Q. Please describe how you determined the Company's rate of return for ratemaking purposes.

A. Exhibit ES-REVREQ-2, Schedule 33, page 1 presents the test year-end capital structure and costs of common stock equity and long-term debt for NSTAR Electric. Schedule 33, page 2 presents the details of the test year-end outstanding long-term debt balances and associated costs.

The Company relied on the actual capital structure as of December 31, 2020 in this proceeding adjusted for projected 2021 activity. As shown on Exhibit ES-REVREQ-2, Schedule 33, NSTAR Electric's pro forma capital structure as of December 31, 2021 is comprised of 45.71 percent debt, 0.49 percent preferred stock, and 53.80 percent common equity.

Q. Have you prepared a summary of the Company's rate base computation?

A. Yes. Exhibit ES-REVREQ-2, Schedule 29 provides a summary of the rate-base computation. As shown therein, the distribution rate base balance, including adjustments described below, is $4,263,662,613.

Q. How has the Company calculated its rate base for the revenue requirement?

A. The Company has presented the calculations supporting rate base on Exhibit ES-REVREQ-2, Schedule 29. Column B identifies the December 31, 2020 balances for Utility Plant in Service, Reserve for Depreciation and Amortization, Reserve for Deferred Income Taxes (ADIT), FAS 109 Regulatory Liability, Customer Deposits, Customer Advances, Materials & Supplies and the cash working capital allowance. These specific components are consistent with Department precedent for inclusion in rate base. Column C reflects the total of the pro forma adjustments made to the per-books balances to develop the requested post-test year ("PTY") rate base amounts of $4,263,662,613 listed in Column D.

Q. Please describe the adjustments for PTY Rate Base in Exhibit ES-REVREQ-2, Schedule 29.

A. The pro-forma activity presented in Column C of Exhibit ES-REVREQ-2, Schedule 29 represents the addition to utility plant in service and associated ADIT relating to estimated 2021 capital additions for NSTAR Electric. For NSTAR Electric, the adjustments to plant in service are itemized by plant account on Exhibit ES-REVREQ-3, Work Paper 30.

Q. Please describe the adjustments to rate base necessary to reflect the pro-forma plant in service balances.

A. **Plant-in-Service**: Exhibit ES-REVREQ-3, Work Paper 30 provides detail supporting the balance of plant in service utilized for determining rate base in this proceeding. Column C illustrates actual test year plant balances as of December 31, 2020. Column D illustrates plant in service that is recovered through the Company's FERC approved transmission tariffs. Column E illustrates the sum of columns C and D, or the adjusted distribution December 31, 2020 balances. Column F illustrates reductions due to Asset Retirement Obligations ("AROs"). Column G is the sum of Columns E and F. Column H illustrates estimated 2021 capital additions by plant account. Column I is reserved for any additional plant in service adjustments. Column J is the sum of columns G through I and results in the pro forma plant in service balance used in determining distribution rate base in this proceeding.

Depreciation Reserve: Exhibit ES-REVREQ-2, Schedule 31, summarizes the depreciation reserve. Column C illustrates the actual balances per the Company's books as of December 31, 2020. Column D illustrates accumulated reserve that is recovered through the Company's FERC approved transmission tariffs. Column E illustrates the sum of columns C and D, or the adjusted distribution December 31, 2020 balances. Column F illustrates reductions due to Asset Retirement Obligations ("AROs"). Column G is the sum of Columns E and F. Column H illustrates estimated 2021 capital additions by plant account. Column I is reserved for any additional plant in service adjustments. Column J is the sum of columns G through I and results in the pro forma depreciation reserve balance used in determining distribution rate base in this proceeding.

Accumulated Deferred Income Taxes (ADIT): Exhibit ES-REVREQ-2, Schedule 32 provides detail supporting the balance of ADIT utilized for determining rate base in this proceeding. Column B provides the actual ADIT balances includable in rate base as of December 31, 2020. Column C illustrates the ADIT recovered through the companies FERC approved transmission tariffs. Column D illustrates the sum of columns B and C. Column E illustrates the ADIT associated with estimated 2021 plant additions. Column F illustrates the sum of columns D and E that reflects the rate-base portion of ADIT to be included in rate base.

Q. Please describe the remaining rate-base items presented in Exhibit ES-REVREQ-2, Schedule 29.

A. The remaining adjustments are related to FAS 109 Regulatory Liability (Line 26), Customer Deposits (Line 27), Customer Advances (Line 28), Materials & Supplies (Line 31), and Cash Working Capital (Line 32). The Cash Working Capital adjustment is detailed on Exhibit ES-REVREQ-2, Schedule 34 and reflects the results of the Lead Lag study described in Section V of this testimony. The Materials and Supplies balance reflects the 13-month average balance, as presented in Exhibit ES-REVREQ-3, Work Paper 29. The remaining amounts reflect the balances on the Company's books as of December 31, 2020.

V. LEAD LAG STUDY

Q. You mentioned earlier in your testimony that you prepared a lead lag study. Is that correct?

A. Yes. The Company prepared a lead lag study (the "Lead Lag Study") to update and establish the net lag days associated with Basic Service working capital collected through the Basic Service Adder for NSTAR Electric, and to establish the net lag days to be used for Other Operating Expense working capital that will be included in base rates. The Lead Lag Study is summarized and included in the Revenue Requirement Analysis as Exhibit ES-REVREQ-2, Schedule 34. Exhibit ES-REVREQ-5 contains the Lead Lag Study.

Q. What is cash working capital?

A. Cash working capital is the amount of money that is needed by NSTAR Electric to fund operations in the time period between when expenditures are incurred to provide service to customer and when payment is actually received from customers.

Q. What are the components of cash working capital?

A. The cash working capital allowance is divided into two components – (1) Basic Service Working Capital, and (2) Other O&M Working Capital to accommodate the assignment of recovery of the Basic Service component through the Basic Service Cost Adjustment (BSCA) mechanism and the Other O&M component through base rates. Each component uses revenue lag days and expense lead days to determine the cash working capital requirement.

Q. Please define the terms "revenue lag days" and "expense lead days."

A. Revenue lag is the time, measured in days, between delivery of a service to NSTAR Electric customers and the receipt by NSTAR Electric of the payment for such service. Similarly, expense lead is the time, again measured in days, between the performance of a service on behalf of NSTAR Electric by a vendor and payment of such service by NSTAR. Since base rates are based on revenue and expenses booked on an accrual basis, the revenue lag results in a need for capital while the expense lead offsets this need to the extent the Company is typically not required to reimburse its vendors until after a service is provided.

Q. Please describe the Lead Lag Study (Exhibits ES-DPH-6) and its findings.

A. The Lead Lag Study consists of 9 schedules. Schedule WC-1 summarizes the overall results of the study. Schedule WC-2 (pages 1 through 10) calculates the revenue lag. Schedule WC-3 calculates the lead related to purchased power costs. Schedule WC-4 through WC-9 calculate the lead related to various categories of operating expenses. The Lead Lag Study produced a net lag of -0.484848 days or -0.131313 percent (-0.48/365), and 32.95 days or 9.103 percent (32.95/365) for Other O&M expense.

Q. How is the revenue lag computed?

A. The revenue lag consists of a "meter reading or service lag," "collection lag" and a "billing lag." The sum of the days associated with these three lag components is the total revenue lag experienced by NSTAR Electric. See Exh. ES-REVEREQ-5, Schedule WC-2, Page 1 of 10.

Q. What lag does the Lead Lag Study reveal for the component "service or meter reading lag?"

A. The Lead Lag Study reveals 15.21 days. This lag was obtained by dividing the number of billing days in the test year by 12 months and then in half to arrive at the midpoint of the monthly service periods.

Q. How was the "collection lag" calculated and what was the result?

A. The "collection lag" for utility service totaled 26.00 days. This lag reflects the time delay between the mailing of customer bills and the receipt of the billed revenues from customers. The 26.00 days lag was arrived at by a thorough examination of utility service accounts receivable balances for all accounts using the accounts receivable turnover method. A combination of daily balances and end of month balances were utilized as the most accurate measure of customer accounts receivable. Exhibit ES-REVREQ-5, Schedule WC-2, pages 2 through 8, detail daily balances as provided in reports generated from the Customer billing system for the majority of the accounts receivable accounts. Schedule WC-2, Page 10, Line 16 further adjusts for balances of accounts not tracked on a daily basis (Special Ledger Accounts).

End of month balances are utilized for these accounts to calculate average daily balances. This same page also summarizes the month end reserve balances for uncollectible accounts. Exhibit ES-REVREQ-5, Schedule WC-2, page 1 shows the net sum of the average CIS balances, Special Ledger Accounts and Reserve for uncollectible accounts of $188,752,046. Exhibit ES-REVREQ-5, WC-2, page 9 calculated the average daily revenue of $7,258, 434 by dividing total revenue by 365 days. The resulting Collection Lag is derived by dividing the Average daily accounts receivable balance by the average daily revenue amount to arrive at the Collection lag of 26.00 days.

Q. How did you arrive at the 1.00 day "billing lag"?

A. Most of the Company's customers are billed the evening after the meters are read. Therefore, I have included a 1.00 day billing lag. I have not made an exception for large customers which may require additional time to process.

Q. Is the total revenue lag computed from these separate lag calculations?

A. Yes. The total revenue lag of 42.21days is computed by adding the number of days associated with each of the three revenue lag components. <u>See</u>, Exh. ES-REVREQ-5, Schedule WC–2, Page 1 of 10. This total number of lag days represents the amount of time between the recorded delivery of service to customers and the receipt of the related revenues from customers.

Q. What expense is Basic Service Cash Working Capital intended to address?

A. Basic Service Cash Working Capital provides cash working capital for expenses paid by NSTAR Electric on behalf of customers to wholesale electric power suppliers and renewable energy contract costs.

Q. How is Basic Service Cash Working Capital recovered as a cost component in the Companies tariffs?

A. As noted earlier, Basic Service Cash Working Capital is recovered as a separate cost component for NSTAR Electric through the BSCA tariff. As such, the Basic Service Cash Working Capital allowance is excluded from the total cash working capital included in distribution rate base.

Q. How was the Basic Service net lag days calculated?

A. The Basic Service net lag days are based upon data for the 12-months ended December 31, 2020. The Basic Service net lag days reflected in this study produced a net lag for Basic Service of -0.48 days as shown on Exhibit ES-REVREQ-5, Schedule WC-1 page 1, Line 4

Q. How were the weighted Basic Service lead days determined?

A. To determine the expense lead associated with Basic Service, all supplier invoices were identified that were paid during the calendar test year ended December 31, 2020. The number of days was calculated for each invoice from the midpoint of the related service period to the date the invoice was paid. The days were dollar weighted, totaled and averaged to arrive at an overall weighted average purchase gas expense lead. See Exhibit ES-REVREQ-5, Schedule WC-3.

Q. Please explain Other O&M Cash Working Capital?

A. The Other O&M Cash Working Capital component is composed of O&M expense, payroll taxes and property taxes. These are types of expenses that NSTAR Electric pays to underwrite the activities conducted in service to customers before it receives payment from customers for those services. It is appropriate for NSTAR Electric to recover its carrying cost for this service.

Q. Did your Lead Lag Study recalculate Other O&M Expense lag days for this proceeding?

A. Yes. The Other O&M & Tax Expense lead days are based upon calendar test year 2020 data, adjusted for known and measurable changes. As reflected on Exhibit ES-REVREQ-5, Schedule WC-4, the revenue lag and expense lead days resulting from the Lead Lag Study have been applied to adjusted test year O&M & Tax amounts to determine the Company's cash working capital requirements to be included in rate base.

Q. Is the term "lead days" in this Lead Lag Study the same as that defined for Basic Service?

A. Yes, it is. Lead days are the number of days between the average delivery date goods and services are purchased by NSTAR Electric or rendered by a vendor and the payment made by NSTAR Electric for those goods and services.

Q. In determining the expense lead period, how were the weighted lead days in payment of O&M costs determined?

A. First, total O&M expense excluding gas costs were disaggregated into 8 major cost categories, as shown on Exhibit ES-REVREQ-5, Schedule WC–4. Payments were reviewed and the lead days were calculated for each category. Depending on the volume and dollar amount of the payments, some categories' lead days were calculated using all payments and some were calculated using a sampling of the payments. Once the lead days for each category were determined, the lead days were summarized and dollar weighted to arrive at Other O&M expense lead days. See, Exhibit ES- REVREQ-5, Schedule WC –4.

Q. Briefly describe the lead days calculated for each category.

A. The payroll lead is shown on Exhibit ES-REVREQ-5, Schedule WC-5. NSTAR Electric have two individual pay groups: bi-weekly and weekly. The bi-weekly group is paid Friday for the previous two weeks' work while the weekly group is paid each Friday for the previous weeks' work (based on a work week of Sunday-Saturday). This results in an overall weighted lead of 8.90 days.

Q. Please explain the negative days associated with corporate insurance and the lead days calculated for regulatory commission expenses?

A. Corporate insurance premiums are paid in advance, generally on an annual basis depending on the coverage period of the individual policy. Payments made during the test year were reviewed and a negative 169.61 days was calculated reflecting prepayment of these costs. See, Exhibit ES- REVREQ-5, Schedule WC-7.

Regulatory Commission expenses are paid when invoiced during the year. In 2020, four such payments were made as illustrated on Exhibit ES- REVREQ-5, Schedule WC-6. Based on the timing of the payments, a lead of 118.51 days was calculated.

Q. How was the lead related to other O&M expenses which were not individually studied determined?

A. The Company obtained a complete list of vendor payments made by NSTAR Electric during the test year directly from the Company's Accounts Payable system. The Company randomly selected vendor payments and calculated the amount of time between the timing of the service provided as compared to when the payment for the service was actually made. This calculation resulted in an average lead of 38.55 days as shown on Exhibit ES- REVREQ-5, WC-8.

Q. Would you briefly describe the lead days associated with Other Taxes?

A. Yes. Exhibit ES-REVREQ-5, Schedule WC-9 summarizes the results of the analysis of lead days for property tax, FICA & Medicare and Federal Unemployment and State Unemployment tax expenses. The (13.37) property tax lead days were calculated based on a query of the tax payments made in 2020. The

FICA & Medicare, Federal Un-employment taxes, and State Unemployment Taxes leads of 7.96 days, 7.71 days, and 10.00 days, respectively, were calculated based on the 2020 payments made to the government for these payroll related taxes.

Q. How is the total O&M & Taxes Lag determined?

A. The lead in payment for the cost of goods and services purchased of 9.27 days is subtracted from the lag in receipt of customer revenue of 42.21 days to produce the total O&M Lag of 32.95 days. See, Exhibit ES-REVREQ-5, Schedule WC-1.

Q. Would you summarize the Company's proposal regarding Cash Working Capital?

A. Yes. The Basic Service Cash Working Capital component is not included in the cost of service and will be recovered in accordance with the NSTAR Electric BSCA Service tariff. The O&M Cash Working Capital component is 32.95 days or 9.03 percent. For purpose of our revenue requirement analysis, the cash working capital component proposed for inclusion in the calculation of distribution rate base is $53,688,003 for NSTAR Electric, which represents the cash working capital allowance calculated for Other O&M Expense and taxes. See, Exhibit ES-REVREQ-2, Schedule 34.

Q. Does the Lead Lag Study produce results within the Department's 45-day convention?

A. Yes. The Lead Lag Study produced lower results than the Department's 45-day convention, which ensures savings for customers.

VI. STORM COST RECOVERY

A. Guidelines for NSTAR Electric Storm Cost Recovery

Q. Please describe the NSTAR Electric Storm Fund approved in D.P.U. 17-05.

A. In D.P.U. 17-05, the Department authorized NSTAR Electric to operate a Storm Fund to provide for adequate recovery of storm costs from customers in a manner that is designed to create rate stability. NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy, D.P.U. 17-05, at 547. The Department further authorized the Company to operate the Storm Fund on a consolidated basis for EMA and WMA. Id. Recovery through the Storm Fund is triggered by qualifying storms wherein the Company has incurred incremental O&M expense in excess of $1.2 million for the event. D.P.U. 17-05, at 549-550. If the incremental costs incurred for an event exceed $1.2 million, then the Company is authorized to defer those costs into the Storm Fund, less the threshold amount of $1.2 million. Id. at 548-549. With respect to the storm thresholds, the Department included the threshold amount of $1.2 million in base distribution rates in D.P.U. 17-05 for three storm events, or for a total of $3.6 million. Id. at 549-550.

Additionally, the Department authorized an annual contribution amount through base distribution rates of $10 million to support the Storm Fund. Id. at 551-553. The Company is authorized to accrue carrying charges at the prime rate for Storm Fund-eligible events at the time that costs are incurred (billed). Id. at 556-557. See, also, Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 18-150, at 430 (2020).

To avoid the potential for the Storm Fund to fall into a significant deficit as a result of a single major storm event, the Department found it appropriate to exclude from Storm Fund eligibility any single storm event that exceeds $30 million in incremental costs (exclusive of costs for which Verizon is responsible under a joint operating agreement). Id. at 554-555. Instead, Eversource has the option to seek a deferral of storm costs that exceed $30.0 million until its next base distribution rate case, or alternatively, Eversource may seek cost recovery for a storm in excess of $30.0 million through the exogenous cost provision of the PBR mechanism approved in this proceeding. Id. at 554-555. In addition, the Department authorized the Company to seek cost recovery of outstanding balances in the Storm Fund through the exogenous cost provision of the PBR (pending a prudence review) provided that the combination of any single storm in excess of $30 million and balance of the storm fund exceed $75 million. Id. at 559.

Lastly, the Department found that a symmetrical cap of $30 million on the Storm Fund balance was appropriate to minimize the potential for frequent rate changes (either positive or negative), and to realign the risks associated with storm cost recovery to protect ratepayer's interests. Id. at 554-555. Therefore, the Company will only implement a rate change to the Storm Reserve Adjustment Mechanism ("SRAM") if the Storm Fund is in a surplus or deficit of $75 million. The Company recovers single storm events exceeding $30 million through the Exogenous Storm Costs Factor pursuant to Section 1.04 of M.D.P.U. 63E.

Q. What is the Company's current process by which the Company charges storm costs to the consolidated storm reserve fund?

A. When the Company incurs storm costs for a Storm Fund qualifying event, those costs are deferred to the Company's consolidated Storm Fund at that time. The Storm Fund balance is defrayed as contributions come into the Storm Fund, which was authorized in D.P.U. 17-05 to be $10 million annually (or approximately $800,000 monthly). The Storm Fund contribution of $10 million annually is theoretically supposed to offset costs charged to the Storm Fund as those costs are incurred, but this has not been the Company's experience. Interest is calculated on the consolidated Storm Fund on the average monthly balance of the Storm Fund. Additionally, recovery of the consolidated Storm Reserve and Storm Fund may occur when the fund is in a deficit greater than $30 million.

In D.P.U. 17-05, the Department set out specific eligibility requirements for the Storm Fund. No later than six months after the costs are finalized, the Company must submit a petition for recovery of storm costs, including complete and final documentation and supporting testimony. D.P.U. 17-05, at 562. If the Company is unable to prepare a final accounting of storm costs, along with supporting testimony and full documentation within six months of a storm event, the Company must file a petition for storm cost recovery as soon as such information is complete. Id. The Company complied with this filing directive for the 2018-2020 Storm Events.

Q. Please describe the Company's proposal in D.P.U. 20-29 to defer the prudence review of the 2018-2020 Storm Events.

A. Although the Department provided clear guidance and directives regarding Storm Fund eligibility in D.P.U. 17-05, the Department was silent as to the schedule it would adopt to review the prudence of costs incurred in relation to Storm Fund-eligible events. Given the increasing frequency and severity of both extreme weather events, such as Storm Isaias, as well as more "typical" weather events that still require the activation of the Company's ERP to prepare for and respond to these events, it is more than likely that the Company will continue to experience Storm Fund-eligible events going forward on a frequently recurring basis. D.P.U. 17-05, at 546, citing, Exhibits ES-DPH-2, Sch. DPH-21, at 2 (East); DPU-2-24, Att. (b) (outlining 21 major storm events between February 2010 and February 2016)).

Storm Fund Qualifying Event reports and the associated prudency review of the costs incurred in responding to those eligible storms will be necessitated unless other action is taken to anticipate and reduce the significant strain on the resources, personnel and time of the Department, the Company and other stakeholders, such as the Office of the Attorney General ("AGO") and the Department of Energy

Resources ("DOER"). To mitigate the administrative burden for all stakeholders, while providing for a comprehensive and thorough review of incurred costs, the Company requested that the Department delay the prudence review of the costs associated with the 2018-2020 Storm Events to the next base-rate proceeding. D.P.U. 20-29 Motion for Adoption at 7.[10]

Q. Would you please summarize the Department's recent rulings on the process for obtaining Department review of storm costs?

A. Yes. On December 21, 2021, the Department issued a decision in NSTAR Electric Company d/b/a Eversource Energy, D.P.U. 20-29 regarding a storm cost review process proposed by the Company to streamline the Department's review. In that decision, the Department declined to adopt the Company's proposed storm cost review process, where prudence reviews would be delayed until a subsequent base distribution rate proceeding. D.P.U. 20-29, at 5. Therefore, the Department found that conducting the prudence review of storm costs independently from a base rate proceeding is appropriate. Id. at 7.

The Department directed the Company to submit its storm fund qualifying events cost report and supporting documentation of its storm preparation and response

[10] On March 30, 2020, the AGO filed comments noting that it did not object to the Company's proposal that eligible Storm Fund costs sought for recovery be deferred for review and investigation to the occasion of the Company's next proposed change in general distribution rates, provided that: (1) no party or the Department requested an immediate review; or (2) the Company proposed no change to increase the Storm Fund Adjustment Factor ("SRAF"). D.P.U. 20-29, AGO Comments at 2. No party requested an immediate review of the 2018-2020 Storm Events and the Company did not propose to increase the SRAF as a result of the 2018-2020 Storm Events. D.P.U. 20-29, Exhs. ES-ANB/CD at 8; ES-ANB/CD-Supp. at 9.

costs associated with storm fund-qualifying events that occurred since February 2020 in D.P.U. 20-29, to the extent finalized costs are available, and to submit such documentation no later than January 30, 2022. Id. at 8-9. The Department stated that it would review the Company's annual 2019, 2020, and 2021 Storm Reserve Adjustment Factor ("SRAF") storm cost filings on a consolidated basis in the present proceeding in D.P.U. 20-29. Id. at 9. Lastly, the Department stated it would limit its investigation in D.P.U. 20-29 proceeding to a review of the prudence of, and eligibility for, recovery of the storm costs presented in the Company's SRAF filings for 2019, 2020, and 2021. Id. at 9. In this proceeding, the Company is proposing to maintain the current SCRAF in effect to commence recovery of the storm costs contributing to the storm fund deficiency as of December 31, 2022.

Q. What did the Department say about the recovery of the outstanding Storm Fund balance in its decision in D.P.U. 20-29?

A. The Department stated that, as of September 2021, the storm fund was in a deficit balance of approximately $122 million. The Department noted that, in the Company's 2021 SCRAF filing in D.P.U. 21-133, the Company indicated that it did not intend to seek an SRAF adjustment for effect January 1, 2022. Instead, the Company stated that it would propose a method to recover the storm fund deficit balance in the up-coming rate proceeding, which is this case (D.P.U. 22-22). Accordingly, the Department stated it would review the appropriate method for cost recovery of the storm fund deficiency balance in this case. D.P.U. 20-29, at 9-10.

B. Proposals for Modification to Storm Fund Recovery

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

A. As explained in the testimony of Company Witnesses Mr. Hallstrom and Mr. Horton, 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 structure. Specifically, the Company is requesting that the Department make the following four 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.
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 qualifying 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. How has the Company determined that the appropriate threshold for Storm Fund qualifying events is $1.3 million?

A. In D.P.U. 17-05, Eversource adjusted its storm-fund threshold by applying a cumulative inflation change factor to the then-existing threshold of $1 million, based on application of the GDP-PI from the U.S. Bureau of Economic Analysis. This yielded a qualifying threshold of $1.2 million. The Department found that this method was consistent with the method approved in Massachusetts Electric Company, D.P.U. 15-155, at 77 (2016). See, D.P.U. 17-05, at 548. Similarly, in this case, the Company applied the GDP-PI to the $1.2 million threshold approved by the Department in D.P.U. 17-05, to derive a new threshold of $1.3 million.

Q. What is the basis for the Company's request to increase the annual Storm Fund contribution recovered through base rates from $10 million to $31 million?

A. The Company used the same methodology as its most recent base distribution rate proceeding in order to determine a more appropriate level of base-rate contributions. Given the large disparity between the annual average of incremental O&M costs related to qualifying storm events experienced during the last several years and the amount currently recovered through base distribution rates, it is necessary to adjust the amount of the annual contribution included in rates as a normal course. In order to meet the Department's objectives of maintaining a sufficient reserve in the Storm Fund for the benefit of both customers and the Company, the Company is proposing a new annual base distribution rate allowance of $31 million, or an increase of $21 million effective January 1, 2023.

The Company calculated this increased contribution by eliminating extraordinary storm events greater than $30 million. The Company then calculated the average of the remaining storm costs over the number of months between the effective date of the most recent rate case, February 1, 2018 through the end of the test year ending December 31, 2018.

Q. What is the basis for the Company's request to increase the number of Qualifying Storm 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.

A. Table 2 below shows the Company's computation for the number of Qualifying Storm Fund Thresholds in base distribution rates:

Table 2: Derivation of "Normalized" Amount of Qualifying Storm Fund Threshold

Year	Total Storms > $1.3M	Base Rate Change
(A)	(B)	(C)
2017	5	
2018	2	
2019	7	
2020	10	
Average	6	
Current NSTAR Electric Storm Threshold	$1,200,000	
Cumulative GDP-PI increase since 2016	7.26%	
Revised Storm Threshold (rounded)	$1,300,000	
Annual Storm Costs (Line 31 * Line 25) (rounded)		$ 7,800,000
Amount Recorded in Test Year		$ 12,000,000
Decrease from Test Year (Line 33 - Line 34)		$ (4,200,000)

As shown in Table 2, above, the Company derived the annual amount of $7.8 million by calculating the average of the total number of storms over the updated threshold amount of $1.3 million for the four years, 2017 through 2020. In the test year, 2020, the Company experienced a total of **10** major storm events (as compared to three in rates set in D.P.U. 17-05). The average over the years 2017 through 2020 is six Qualifying Storm Thresholds, or $7.8 million to be included in base rates. As with the rates set in D.P.U. 17-05, the average number of six Qualifying Storm Thresholds is **less** than the test-year number (and less than 2019), indicating that the amount is not necessarily "normalized" or "representative," but can be appropriate where the Department allows for adjustment to meet actual circumstances if the number does not turn out to be "representative."

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

A. In D.P.U. 17-05, the Department found that the $1.2 million threshold for the consolidated storm fund represents an appropriate cost distinction between (1) events that require a response using resources that are contemplated in base rates; and (2) those events that are larger in nature and involve resources beyond the level provided in base rates. D.P.U. 17-05, at 548. Thus, the Qualifying Storm Threshold is expressly intended to serve as the indicator between a normally recurring storm and a large-scale, major storm event. For major storm events, the Qualifying Storm Threshold represents the first $1.3 million in costs incurred to respond to a *major storm event*. Although the Department has noted that it is not possible to discern how many major storms may occur in a year, the Department has never made any finding or decision to *disqualify* or disallow automatically the first $1.3 million of storm costs for those storms that do occur. Therefore, the Department has historically attempted to provide for recovery of the Qualifying Storm Thresholds through base rates.

Q. What was the Department's thought process in D.P.U. 17-05 regarding the recovery of the Qualifying Storm Thresholds?

A. In D.P.U. 17-05, the Department stated that, "given that the frequency of storm events **varies significantly each year**, the test year level of O&M costs associated with storm events were not necessarily representative of … future costs." D.P.U. 17-05, at 549 (emphasis added). Thus, the Department attempted to "normalize" the number of Qualifying Storm Thresholds included in base rates. Id. The Department stated that the purpose of the "normalization" was to "derive a more representative amount of the O&M expense associated with storm events." Id., citing, D.P.U. 15-155, at 80. To derive this normalization, the Department simply relied on the historic average number of qualifying storms over a multi-year period, which was six years for NSTAR Electric. D.P.U. 21-76, at 21, citing, D.P.U. 18-150, at 399, 418-419, 426; D.P.U. 17-05, at 531-532, 549-550, 553. The Department did not discuss whether defined exceptions should occur for recovery of threshold deductible amounts above the normalized amount included in base distribution rates. Id., citing, D.P.U. 18-150, at 399-431; D.P.U. 17-05, at 529-553. Based on that evaluation, the Department determined that three storms represented a normalized number of annual storm-fund eligible events for NSTAR Electric. D.P.U. 17-05, at 549, citing, D.P.U. 15-155, at 80.

Q. Why is the Company proposing to change the practice for accounting for Qualifying Storm Fund Thresholds?

A. As is the case in each jurisdiction in which the Company operates, it makes sense to establish a "significance" threshold to represent an appropriate cost distinction between: (1) events that require a response using resources that are contemplated in base rates; and (2) those events that are larger in nature and involve resources beyond the level provided in base rates, as the Department has previously stated. 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. This concept is not at issue here.

The concept that is at issue is the recovery of Qualifying Storm Fund Thresholds and the logic that the Department has applied in attempting to "normalize" the number of thresholds for inclusion in base rates. On the one hand, the Department has found that "the frequency of storm events **varies significantly each year**" – in fact, the variation is so significant – that the Department is unwilling to use the test year level of Qualifying Storm Fund Thresholds for inclusion in base rates because the test year number of events is "not necessarily representative of … future costs." Conversely, in "normalizing" the number of events to derive a "more representative amount" for inclusion in rates, there is no methodology that has been applied in D.P.U. 15-55, D.P.U. 17-05 or D.P.U. 18-150 that is rationally devised to generate an appropriate proxy for a "representative amount." Nor is there any analysis that has been applied to substantiate the conclusion that the test year number is *not* representative.

In all cases, the Department has established the "normalized" amount at a level *below* the test year number, which has not yielded anything close to a representative number because it is much more likely that Qualifying Storm Fund events will be *more numerous* rather than less. The basic difficulty, as recognized by the Department, is that the frequency of storm events "varies significantly each year" and therefore is actually not susceptible to "normalization," unless the number included in rates is much larger than what the Department has been including in rates. In today's operating environment, the "representative" amount is a much larger number of storms that the Department has been willing to include in rates.

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.

Q. What is the Company’s proposal for addressing the recovery of the Qualifying Storm Fund Thresholds?

A. The Company’s proposal for addressing the recovery of the Qualifying Storm Fund Thresholds is straightforward. There are three steps to the proposal. First, the Department would establish the number of Qualifying Storm Fund Thresholds is base rates by setting the number closer to the actual test year number of storms, which in this case is six storm events (as compared to 10 storm events in the test year). Second, the Department should allow that, 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. Because the number of Qualifying Storm Fund events ""varies significantly each year," the Department should allow a system that is better aligned with the inevitable variability. Also, under the Company's proposal, the mechanism is symmetrical, so that if there is a deviation resulting in a lower number, customers would be credited with the Qualifying Storm Threshold.

C. Deferral of Qualifying Storm Fund Thresholds from 2020 and 2021

Q. Would you summarize the Department's findings in D.P.U. 21-76, regarding the deferral of Qualifying Storm Fund Thresholds?

A. Yes. In the instant proceedings, NSTAR Electric and National Grid each requested approval to defer for Department review and consideration a portion of their storm threshold costs incurred during calendar year 2020 to future storm fund cost recovery proceedings. D.P.U. 21-76, at 19. The Department determined that each company was effectively requesting "an exception from the existing parameters of its storm fund cost recovery requirements, or, at a minimum, the opportunity to request an exception." Id. at 20. The Department permitted the Companies to apply deferred accounting treatment to the excess calendar year 2020 storm threshold amounts, i.e., the threshold amounts that exceed those already recovered in base rates less one, until their next, respective base distribution proceeding. Id. The

Department stated that, at that time, the Department will determine the appropriate level of recovery for these deferred storm threshold amounts, if any. Id.

Q. Should the Department allow recovery of the deferred amounts associated with the 2020 and 2021 Qualifying Storm Thresholds?

A. Yes. In granting the deferral in D.P.U. 21-76, the Department stated that:

> Reliance on the historic average of qualifying storms over a multi-year period was intended to account for the variability in the number of major storm events that occur each year. The **repeated deviations**, however, from the representative level of major storm events used to calculate the normalized level of storm threshold costs and storm fund contributions included in base distribution rates at the levels that have occurred in a relatively short time span **is not consistent with the variability we envisioned and accounted for** in the current parameters established for storm cost recovery.

D.P.U. 21-76, at 23 (emphasis added).

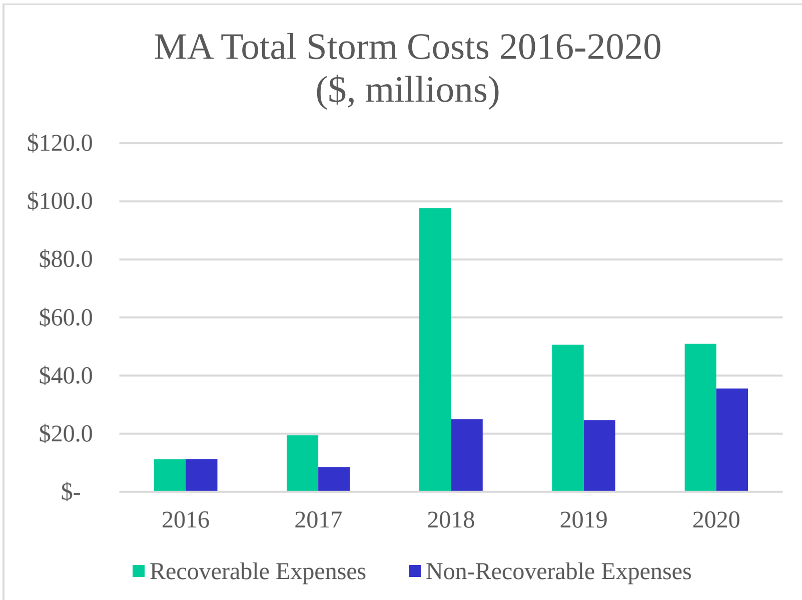
The Department stated that, in considering recovery in this case, the "underlying question at issue … is whether an exception to storm cost recovery would be appropriate, specifically, whether exceptions for excess storm threshold cost recovery should be allowed for calendar year 2020 and, if so, the parameters of that recovery. D.P.U. 21-76, at 26-27.

In this proceeding, the Department should allow for recovery of the Qualifying Storm Thresholds for 2020 and 2021 on the basis that the simple averaging method used in D.P.U. 17-05 to "normalize" the number of Qualifying Storm Thresholds did not act as an effective approach for determining the representative number of events in an environment where the frequency and intensity of storms is increasing, as recognized by the Department in D.P.U. 17-05 and D.P.U. 21-76. D.P.U. 17-06, at 546; D.P.U. 21-76, at 22. In fact, given the "significant variability" in storms – and the increasing frequency and severity -- the simple averaging approach is highly unlikely to be effective in generating the "representative" number because history is not an indicator of the future or present experience.

Q. How does the Company's proposal address the Department's concern that there needs to be a balancing of risk and cost recovery to protect the interests of customers?

A. There is no imbalance in allowing the Company to recover the Qualifying Storm Thresholds subject to deferral and likewise occurring in 2021 over the "representative number in rates set in D.P.U. 17-05. A point is significance is that the changing weather patterns are also affecting storm costs *that do not rise to the level of a major event*. These costs are recovered through base rates and are having a significant impact on the Company's ability to manage costs through the work year. The Company's cost experience is changing drastically in relation to these medium-size storms with relatively severe impact, as shown in Figure 2, below:

Figure 2 Total Storm Costs for Eversource Massachusetts



As shown in Figure 2, the Company's "non-recoverable expenses," or expenses recovered through base rates and not eligible for Storm Fund treatment are rising significantly year to year, from approximately $10 million annually to almost $40 million annually. This cost impact was absorbed by the Company during the term of the PBR Plan. Therefore, the fact that the Company is requesting recovery of the first $1.2 million for storms that, in fact, were major storm events triggering Storm Fund recovery (i.e., six events in 2020 or $7.2 million; 11 events in 2021, or $13.2 million), is not shifting the balance in any manner given that the same weather patterns that are prohibiting the "normalization" of Qualifying Storm Thresholds is also affecting the Company's O&M expense during gray sky operations.

Given the acknowledged circumstances of increasing frequency and severity of storm events, the Company's proposed method of a sliding scale that is symmetrical and is only triggered after there is deviation from the "normalized" level is the most appropriate method. This method assures that customers do not pay for Qualifying Storm Thresholds that do not occur and that the Company has a path for recovery costs associated with major events, while it is absorbing the greater costs associated with the same weather pattern at all other times.

D. Recovery of Existing Storm Costs

Q. Please provide a brief description of the Company's Storm Fund as authorized in D.P.U. 17-05.

A. In D.P.U. 17-05, the Company proposed, and the Department approved, certain modifications to the Storm Fund. As a result of the Department's decision in D.P.U. 17-05 and the legal consolidation of the Company and WMECO, the Department authorized the Company's Storm Fund to operate on a consolidated basis and approved the Company's proposal to apply a $1.2 million threshold to determine eligibility for Storm Fund recovery. D.P.U. 17-05, at 547, 549. If a storm's incremental costs exceed $1.2 million, then the Company can defer the costs into the Storm Fund, while incremental expense falling below $1.2 million is not eligible for recovery through the Fund. Id. at 548-549. Additionally, the Department authorized an annual contribution amount through base distribution rates of $10 million to support the Storm Fund. Id. at 551-553. The Company is authorized to accrue carrying charges at the prime rate for Storm Fund-eligible events when it is billed for storm cost recovery. Id. at 556.

In an effort to prevent the Storm Fund from falling into a significant deficit as a result of a single major storm event, the Department found it appropriate to exclude from Storm Fund eligibility any single storm event that exceeds $30 million in incremental costs (exclusive of costs for which Verizon is responsible under a joint operating agreement). Id. at 554-555. Eversource has the option to seek a deferral of storm costs that exceed $75 million until its next base distribution rate case or, alternatively, the Company is authorized to seek cost recovery for storms in excess of $30 million through the exogenous cost provision of the Performance Based Ratemaking mechanism ("PBRM"). Id. at 554-555, 558-559. The Company will only implement a rate change to the Storm Reserve Adjustment Mechanism ("SRAM") if the Storm Fund is in a surplus or deficit of $75 million.

Q. Since D.P.U. 17-05, had the Company proposed any modifications to the Storm Fund?

A. Yes. On December 2, 2019 and December 1, 2020, the Company filed it 2019 and 2020 Storm Cost Rate Adjustment Factor ("SCRAF") filings including its storm fund qualifying events cost reports and documentation of its storm preparation and response costs associated with: (1) three storm events that occurred in the period February 2018 through January 2019 ("2018-2019 Storm Events"); and (2) six storm events that occurred in the period February 2019 through January 2020 ("2019-2020 Storm Events"). The Department docketed this matter as D.P.U. 20-29. D.P.U. 20-29, at 1.

As part of its filings in D.P.U. 20-29, the Company filed a motion proposing that the Department adopt a storm cost review process that would shift the prudence review of the costs associated with the 2018-2019 Storm Events and the 2019-2020 Storm Events to the Company's next base distribution rate proceeding, i.e., this proceeding. Id., at 3. Specifically, the Company proposed that the Department adopt a storm cost review process whereby: (1) consistent with D.P.U. 17-05, the Company would submit a petition for storm cost recovery that would include complete and final documentation and supporting testimony; (2) the Department and other stakeholders would affirmatively request review of the costs addressed in the filing at the time of the filing; (3) if no affirmative request for review was made, the Department's prudency review for storm fund-eligible events would be delayed until the Company's next base distribution rate proceeding; and (4) if the storm fund fell into a deficit position, the Company would file for an adjustment to the SRAF to replenish the fund with the associated cost review to take place at the time of the SRAF adjustment is requested, or delayed until the Company's next base distribution rate proceeding. Id. at 3-4.

On December 21, 2021, the Department issued an Interlocutory Order in D.P.U. 20-29 and declined to adopt the Company's proposed storm cost review schedule. Id. at 6-8. The Department did acknowledge that benefits may be achieved if the current annual storm cost review process is streamlined and determined that there are efficiencies to be gained by consolidating storm cost prudence reviews when circumstances warrant. Id. at 8. Accordingly, the Department directed the

Company to submit its Storm Fund qualifying events cost report and supporting documentation of its storm preparation and response costs associated with Storm Fund qualifying events that have occurred since February 2020 in D.P.U. 20-29. Id. at 8. The Department stated that it will review the Company's annual 2019, 2020, and 2021 SRAF storm cost filings on a consolidated basis in D.P.U. 20-29 and that it may explore other potential adjustments to the storm cost review process to improve the efficiency of the overall review process. Id. at 9, fn. 2.

The Department also reiterated that, consistent with D.P.U. 17-05, when the Storm Fund cap is exceeded as a result of a storm fund balance deficiency, the Company has the option to propose to the Department an alternative method for recovery of incremental costs that exceed the Storm Fund cap. Id. at 9. In D.P.U. 21-133, the Company's 2021 storm cost recovery adjustment factor ("SCRAF"), the Company indicated that the Storm Fund was in a deficit balance of approximately $122 million. Id. at 9-10 citing D.P.U. 21-133, Exhibits ES-ANB/CD at 12 and ES-ANB/CD-4. The Company also indicated that it did not intend to seek an SRAF adjustment for effect January 1, 2022, but that it would propose a method to recover the Storm Fund deficit balance in its forthcoming base distribution rate proceeding. Id. at 10. The Department stated that it will review the proposed method for cost recovery of the Storm Fund deficiency balance in the Company's forthcoming base distribution rate proceeding. Id.

Q. Please describe the Company's proposal to recover the outstanding storm fund deficiency balance.

A. The Company is proposing in this proceeding to maintain the current level of the SCRAF and to begin the recovery of the Company's outstanding storm fund deficiency for rates effective on January 1, 2023 to recover a storm fund deficiency totaling approximately $124 million as shown in Exhibit ES-REVREQ-4, Schedule 11(c). Currently, the Company is recovering a revenue requirement of $28,003,299 associated with storm fund qualifying events occurring prior to February 1, 2018 through the SCRAF.[11] In the Company's most recent rate case, the Department acknowledged that the Company's storm fund mechanism had not provided the desired balance between cost recovery and rate stability. D.P.U. 17-05, at 546. As a result, the Department approved commencing recovery of the storm fund qualifying events, beginning February 1, 2018 to be amortized over five years through the SCRAF, subject to prudence reviews and reconciliation. D.P.U. 17-05, Exh. DPU-50-1, Att. (a) and Att. (c).[12]

On December 31, 2022, the amortization for the storm fund qualifying events prior to February 1, 2018 expires. The Company's proposal is to maintain the current SCRAF rate in effect, subject to a future prudence review of the storm costs and

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[11] Prior to February 1, 2018, the Company was authorized to defer storm costs exceeding $1 million, resulting from the settlements in D.T.E. 96-23 and D.T.E. 05-85.

[12] The Department's approval included the allowance of the accrual of carrying charges on the outstanding storm fun balance at the prime rate from the time NSTAR Electric is billed for storm cost recovery. D.P.U. 17-05, at 561.

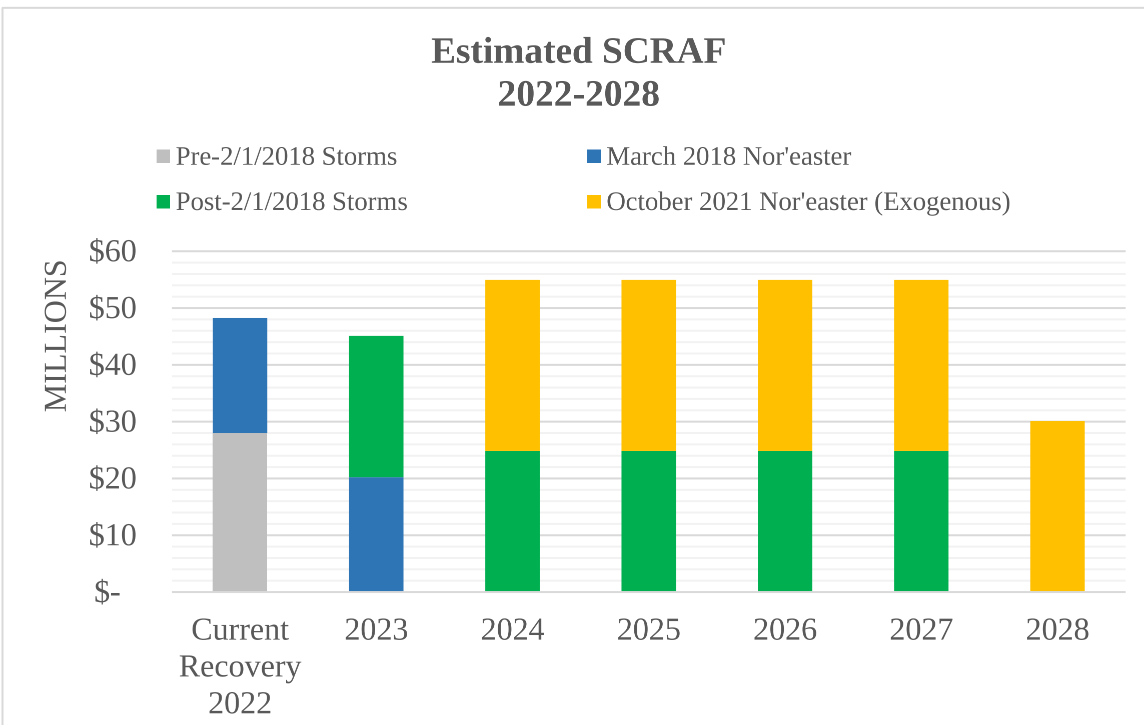
reconciliation through the SCRAF. The Company's proposal to commence recovery is in the best interest of customers as it serves to minimize carrying charges that will ultimately be recovered for the storm fund qualifying events to mitigate bill impacts and maintain stabilized rates.

Q. What are the customer impacts of the Company's proposal in this proceeding?

A. The Company is proposing to maintain the current SCRAF rate for effect on January 1, 2023, subject to a future prudence review of the storm costs and reconciliation through the SCRAF and therefore would not have a bill increase nor decrease associated with the recovery of the outstanding storm fund deficiency on January 1, 2023. It is reasonable to maintain the SCRAF in effect as the Company's storm fund deficiency is currently estimated at $124,273,407, or $24,854,681 amortized over 5 years, for storms that have occurred to date. The Company anticipates additional storm activity to occur in 2022 that would increase the storm fund deficiency. If the Department were to reflect the current storm fund deficit in rates for January 1, 2023, the bill impacts would be relatively small, representing a decrease for Eastern Massachusetts customers of 0.1 percent and an increase for Western Massachusetts customers of 0.6 percent. Separately, the Company's amortization of the exogenous event currently in rates, the March 2018 Nor'easter, is expiring on December 31, 2023 and the Company would propose commencing recovery of the exogenous storm event occurring in October 2021, the October 2021 Nor'easter beginning on January 1, 2024. Figure 3 presents the estimated recovery for all outstanding storm costs resulting from both storm fund qualifying events, as well as, any exogenous events that have occurred demonstrating that the Company's proposal strikes the appropriate balance between cost recovery and rate stability.

Figure 3:

Estimated SCRAF (2022-2028)



Q. Please describe Company's method with regard establishing the annual level of customer contribution to the Storm Fund that it recovers through base distribution rates.

A. In order to meet the Department's objectives of maintaining a sufficient reserve in the Storm Fund for the benefit of both customers and the Company and given the large disparity between the annual average incremental O&M costs related to qualifying storm events experienced during the last few years, the Company is proposing a new annual base distribution rate allowance of $31 million effective with the start of the rate year. This proposal is reasonable The Company's forecasted storm fund balance as of December 31, 2022 totals $124,273,407 ($24,854,681 amortized over 5 years).

Q. How did the Company determine this amount?

A. The Company used the same methodology approved in D.P.U. 17-05 in order to determine a more appropriate level of base rate contributions. To do so, and in an effort to balance customer rate impact and to normalized for truly extraordinary storm events, the Company eliminated the costs related to one extraordinary storm event from the $244 million of total net incremental O&M costs, representing storms exceeding $30 million. This storm was the 2018 March Nor'easter which had a net incremental O&M costs of $91 million. The Company then took an average of the resulting costs, net of the proposed deductible of $1.3 million per storm, of $122 million over the number of months between February 2017 through the end of the test year of December 31, 2020 or 47 months, to arrive at an annualized amount of $31 million as shown on Exhibit ES-REVREQ-2, Schedule 22, Page 2. The Company is proposing to increase the amount recovered through base rates from $10 million to $31 million.

VII. PROPERTY TAX EXOGENOUS COST RECOVERY

Q. What are the Company's proposals with respect to exogenous cost recovery related to property tax expense?

A. The Company is proposing to recover property taxes that qualify under the exogenous cost provisions established in the following rate plans: (1) the NSTAR/Northeast Utilities merger-related settlement agreement from D.P.U. 10-170 for the period January 1, 2012 through December 31, 2015; and (2) the Company's PBR Plan established in D.P.U. 17-05, beginning on January 1, 2018 and expiring on December 31, 2022.

Q. Is the Company proposing the recovery of property taxes that qualify as an exogenous cost under the NSTAR/Northeast Utilities merger-related settlement agreement from D.P.U. 10-170?

A. Yes. As part of the AGO-DOER Settlement Agreement approved by the Department in D.P.U. 10-170, NSTAR Electric agreed to freeze its base distribution rates for a period of approximately four years (AGO-DOER Merger Settlement at Art. II (3); D.P.U. 10-170-B, at 18, 36). The rate freeze terminated as of December 31, 2015. During the term of the rate freeze, the Company agreed to forgo its right to petition the Department for a change in base distribution rates. As part of the exchange, the AGO-DOER Settlement Agreement contained an exogenous cost recovery provision that permitted NSTAR Electric to obtain recovery of certain unanticipated cost changes beyond its control that would significantly affect the Company's operations (Merger Settlement at Art. II (5); D.P.U. 10-170-B, at 18).

Under that provision, the Company is authorized to recover exogenous costs incurred during the term of the rate freeze if certain conditions are met (Merger Settlement at Art. II (5)). D.P.U. 10-170-B, at 18. In particular, the AGO-DOER Settlement allows the Company to petition for exogenous recovery of incremental property taxes incurred during the rate freeze related to a change in the valuation method for assessing utility property approved by the Massachusetts the Appellate Tax Board ("ATB") (Merger Settlement at Art. II (5)). To qualify for recovery, the incremental cost must meet a minimum annual threshold identified in the settlement (Merger Settlement at Art. II (5)). The settlement provides that the dollar threshold for qualification as an exogenous factor in any calendar year shall be determined by multiplying the total distribution revenues of that year by a factor of 0.003212 (Merger Settlement at Art. II (5)).

In this proceeding, the Company is requesting to recover approximately $8 million associated with property-tax expense incurred in the period 2012-2015, which is associated solely with the new valuation method, causing the increase in costs. The Department previously considered this amount in D.P.U. 17-05 and denied the Company's request for recovery. However, the Company is renewing its request in this case due to certain circumstances arising since D.P.U. 17-05.

Q. What is the original basis for the exogenous cost change?

A. On December 16, 2009, the Appellate Tax Board issued a ruling validating a change made by the City of Boston Board of Assessors in relation to its valuation method for assessing utility property (Boston Gas Company d/b/a KeySpan Energy Delivery New England v. The Board of Assessors of Boston, Docket No. F275055, F275056 (December 16, 2009)). Pursuant to that ruling, the ATB approved the City of Boston's change in method from assessing utility property based on net book value (i.e., original cost less depreciation) to assessing utility property based on weighing net book value equally with "reproduction cost new less depreciation." Boston Gas Company appealed the ruling to the Supreme Judicial Court ("SJC"), which upheld the ATB's decision and determined that the valuation method used by the City of Boston was reasonable. Boston Gas Company v. Board of Assessors, 458 Mass. 715, 729, 739-740 (2011). The SJC then remanded the matter to the Appellate Tax Board for further findings. On April 21, 2011, the Appellate Tax Board issued a final ruling in the matter. Boston Gas Company d/b/a KeySpan Energy Delivery New England v. The Board of Assessors of Boston, Docket No. F275055, F275056 (April 21, 2011).

Following that ruling, Springfield, among other municipalities, adopted the new valuation method for assessing utility property and assessed property taxes using the new valuation method beginning with fiscal year 2012. The new valuation method substantially increases the property tax expense for the Company's customers; therefore, NSTAR Electric took steps to challenge the valuation for the City of Springfield. The Company has deferred approximately $8 million in relation to its tax liability for the City of Springfield. Exhibit ES-RevReq-6(a), Schedule 1 presents the computation of the proposed distribution-related expense recovery amount, which pertains to property tax charges in FY 2012, FY 2013, FY 2014, and FY 2015, totaling $8,314,371.

The Company challenged the new valuation method by filing for tax abatements and withholding payments. The City of Springfield denied the abatement requests and, as a result, the Company filed appeals with the Appellate Tax Board for each of the years 2012 through 2019, which are still pending. Only the incremental property-tax expense incurred in relation to the valuation in 2012 through 2015 is eligible for exogenous cost recovery by NSTAR Electric.

Q. What was the outcome in D.P.U. 17-05 regarding the Company's request to recover amounts recorded on its books for incremental property taxes incurred during the rate-freeze period of the merger settlement?

A. In D.P.U. 17-05, the Department denied the Company's proposal to recover incremental property tax expense incurred as a result of the adoption of the new valuation method by the City of Springfield as an exogenous cost, pending final resolution of the Company's tax appeals.[13] Under the AG-DOER Settlement Agreement, the Company was authorized to seek exogenous recovery of incremental property taxes related to the change in valuation method approved by the AATB, subject to an annual threshold. However, in D.P.U. 17-05, the Department noted that Company's appeals to the ATB of the municipal denials of

[13] Prior to its decision in D.P.U. 17-05, the Department issued the same finding for NSTAR Gas Company in D.P.U. 14-150 for the municipalities of Worcester and Westborough. D.P.U. 14-150, at 281.

its tax abatement requests were pending and the Department was unable to assess whether at the end of the appeals process there will be any incremental taxes and, if there are, whether the amount will be above the annual threshold subject to recovery from ratepayers as exogenous costs. The Department stated that "once all appeals are exhausted, the Company should file a separate petition seeking exogenous cost recovery of any incremental property tax assessed using the new valuation method through the year ending December 31, 2015." D.P.U. 17-05, at 524.

Q. What are the developments that have occurred since the time of the Department's decision in D.P.U. 17-05?

A. Since the Department's orders in D.P.U. 14-150 and D.P.U. 17-05, the ATB has addressed appeals of the new valuation method by NSTAR Electric with outcomes that indicate that the ATB process has not changed since D.P.U. 17-05. For example, NSTAR Electric filed petitions at the ATB related to its personal property assessments in the City of Boston for the fiscal years 2012 through 2018. Its petitions for FY2012 and FY2013 were filed at the ATB in June 2012 and May 2013, respectively, and the ATB ultimately found for the appellee (Boston) in a one-line decision in March 2016. The ATB then took over one year, to August 2017, to issue its findings and report (a prerequisite to a court appeal). NSTAR Electric then appealed the matter to the Massachusetts Appeals Court, which issued a decision in favor of the municipality on February 22, 2019. On April 8, 2019, the Appeals Court denied NSTAR Electric's motion for rehearing. NSTAR Electric then petitioned the SJC for a further appeal, but in an order dated May 9, 2019, the SJC declined to take up the matter and thus denied NSTAR Electric's application for further appellate review, thereby allowing the Appeals Court decision to stand. NSTAR Electric's petitions to the ATB for FY2014 – FY2018 remain pending with no action by the ATB.

NSTAR Electric also filed petitions at the ATB related to its personal property assessments in the City of Springfield for the fiscal years 2012 through 2019. The petitions for FY2012 and FY2013 were filed at the ATB in May 2012 and May 2013, respectively, and the ATB ultimately found for the appellee (City of Springfield) in a one-line decision on May 31, 2018. In June 2018, NSTAR Electric filed a request for the ATB to issue its findings and report (a prerequisite to a court appeal) on May 20, 2020, and the City of Springfield filed an opposition to that request. The Company subsequently filed a petition to the Appellate Court. Since that time, the ATB has taken no further action on the FY2012 and FY2013 petitions. The ATB recently scheduled a hearing for December 2019 on the appeals for FY2014, FY2015 and FY2016 the date was in conflict with other ATB matters and rescheduled for March 1, 2022. The appeals for FY2017 – FY2019 remain pending with no action at the ATB.

Similarly, NSTAR Gas also filed petitions at the ATB related to its personal property assessments for Westborough and Worcester for the fiscal years 2012 through 2019 in addition to the petition for the City of Boston. For Westborough, the petitions for FY2012, FY2013, FY2014, FY2015 were filed at the ATB in May 2012, May 2013, April 2014, and May 2015, respectively. ATB set a hearing date of March 3, 2019, rescheduled to September 15, 2020, and postponed the September 15, 2020 hearing. Since that time, the ATB has taken no further action and has not attempted to reschedule the hearing regarding the FY2012 through FY2015 petition. For Worcester, the petitions for FY2012, FY2013, and FY2014 were filed at the ATB in November 2012, May 2013, and July 2014, respectively. ATB set a hearing date of December 18, 2019 and rescheduled to August 3, 2020. On November 9, 2020, NSTAR Gas and the City of Worcester reached a settlement regarding the FY2012 through FY2014 petitions, and the ATB petition is no longer outstanding.

Q. Has the Company been able to complete or progress the process for any of its property tax appeals since the Department's decision in D.P.U. 17-05?

A. No. Despite the Company's best efforts, the matters have been stalled with very little progress at the ATB since the time of the Department's decision in D.P.U. 17-05. The municipalities of Springfield, Boston, Westborough and Worcester all utilized the disputed method to calculate the Company's property taxes for the fiscal years 2012 through 2020. The Company filed timely appeals of all of these assessments at the ATB, and they remain pending at the ATB.

Q. Which of these matters are subject to the exogenous cost provision of the merger settlement?

A. The Company's appeals of the City of Springfield assessments for FY2012 through

FY2015 constitute the incremental property taxes subject to the exogenous cost provision of the merger settlement.

Q. Please explain why the City of Boston is not subject to the Company's exogenous cost provision of the merger settlement.

A. The City of Boston's methodology for calculating the assessments were at a level higher than NBV at the time of the Company's rate settlement in D.T.E 05-85 and prior to D.P.U. 17-05. Therefore, the Company's base distribution rates were set at a level that contemplated the higher rate of property taxes for the City of Boston and not eligible for exogenous cost recovery.

Q. What is the total amount of incremental property tax subject to the exogenous cost provision of the merger settlement?

A. The Company has accrued a deferral of $8,314,371 related to the appeal of the City of Springfield assessments for FY2012 through FY2015. The amounts by year are shown in the table below:

<u>Accrued Amounts</u>

Fiscal Year	Total
2012	$2,358,344
2013	1,976,138
2014	1,933,480
2015	2,046,409
Balances	**$8,314,371**

Q. Why is the Boston Gas case important?

A. Boston Gas took an appeal to the SJC from a December 16, 2009 ruling by the ATB validating the change made by the City of Boston Board of Assessors from assessing utility property based on net book value (i.e., original cost less depreciation) to assessing utility property based on weighing net book value equally with "reproduction cost new less depreciation." On appeal, the SJC upheld the ATB's decision and determined that the valuation method used by the City of Boston was reasonable. Boston Gas Company v. Board of Assessors, 458 Mass. 715, 729, 739-740 (2011). The SJC then remanded the matter to the Appellate Tax Board for further findings. Although there are discrete differences in the methodologies used by the municipalities of Boston, Springfield, Worcester, and Westborough, the Boston Gas case precedent will be difficult to overcome.

Q. In addition to the accrual of interest expense, are there other concerns caused by the passage of time until the appeals process is complete?

A. Yes. The taxes in dispute relate to the fiscal years 2012 through 2015, and it may well be 2025 or later before these matters have concluded with appeals to the SJC. This raises a substantial intergenerational equity issue between customers due to the passage of time. The customers that must ultimately pay these expenses will be different than the customers when the expenses were incurred.

Q. Does the Company have a proposal to address a portion of these costs?

A. Yes. Based on the developments since the Department's decision in D.P.U. 17-05, the Company proposes to recover as an exogenous cost the incremental tax expense for Springfield, equal to $8,314,371. The Company would amortize this amount over five years at an annual amount of $1,662,874. NSTAR Electric will continue to move forward with its appeals before the ATB, but this is a process that will likely take years to reach a conclusion. The Company will evaluate further appeals of any future ATB decisions when the time comes. If the Company prevails on its Springfield appeals, the refunds will be due to customers when and if received. The Company has become more confident on the appeals; however, the long time period and the initiation of a 10-year PBR Plan is causing the Company to seek to resolve recovery of these amounts in this case. The Company has included the recovery of the annual amortization amount of $1,662,874 on line 30 of Exhibit ES-REVREQ-2, Schedule 26.

Q. What are the Company's proposals under the exogenous provision approved in D.P.U. 17-05?

A. The Company is proposing to recover property taxes that qualify under the exogenous cost provisions established in the Company's PBR Plan established in D.P.U. 17-05, beginning on January 1, 2018 and expiring on December 31, 2022, as an adjustment to the PBRAF on January 1, 2023 consistent with the terms of M.D.P.U. No. 59F.

On September 15, 2021, the Company filed its fourth annual PBR adjustment for rate effective on January 1, 2022. As part of that initial filing, the Company requested to commence recovery of the exogenous event associated with increased property tax valuations for FY 2021. In its initial filing, the Company sought to implement a total PBR adjustment of $56,534,312. The proposed adjustment consisted of: (1) a base distribution revenue requirement increase of $44,721,786;

and (2) recovery of $11,812,526 in additional property taxes associated with an exogenous event resulting from a change in the valuation method used by certain municipalities to assess utility property.

On November 10, 2021, NSTAR Electric filed what it refers to as a "rate mitigation proposal". Under that proposal, the Company withdrew from consideration in the instant docket its request to recover costs associated with the purported exogenous event. Instead, the Company proposes to file its request for exogenous cost recovery for Department review in a future proceeding. The Company is filing its request for exogenous cost recovery in this proceeding through the PBRAF in effect on January 1, 2023.

Q. Is the Company proposing the recovery of property taxes that qualify as an exogenous cost under the Company's performance-based rate plan established in its most recent rate case, D.P.U. 17-05?

A. Yes. The Department approved a PBR plan for the Company with a five-year term subject to a stay-out provision that prevents the Company from filing a base distribution rate case at any time during the five-year term. D.P.U. 17-05, at 282, 395. The Department recognized that during the five-year term there may be exogenous costs, both positive and negative, that are beyond the control of the Company and it may be appropriate to recover (or return) through the PBR. Id. at 395. The Department defined exogenous costs are positive or negative cost changes beyond the Company's control and not reflected in GDPPI, or otherwise in the PBRAF. To qualify for exogenous cost recovery (whether positive or negative), the following criteria must be met: (1) the cost change must be beyond the Company's control; (2) that the cost change arises from a change in accounting requirements or regulatory, judicial, or legislative directives or enactments; (3) that the change is unique to the natural gas distribution industry as opposed to the general economy; and (4) that the change meets a threshold of "significance" for qualification. To qualify for recovery, the incremental cost must meet a minimum annual threshold in any calendar year of $5 million, subject to annual adjustments thereafter based on changes in GDP-PI. Id. at 396-397.

To the extent municipalities billed the Company using an alternative valuation method after the Company determined property tax expense in base distribution rates and the combination of those bills resulted in an incremental impact to expense in excess of the significance threshold annually (i.e. for calendar year 2021, $5,286,214), this qualifies as exogenous event under the Company's proposed definition of exogenous costs in the PBR Plan.

In this proceeding, the Company is requesting to recover approximately $8 million associated with property-tax expense incurred for FY 2021 through the PBRAF, which is associated solely with the new valuation method, causing the increase in costs. The Company is also requesting to recover any exogenous cost increases resulting from the FY 2022 bills to be received by Q2, 2022, which will identify additional towns that have transitioned to the new valuation method. As part of the update to provide the latest FOLs and bills to calculate property tax expense in this case, the Company will provide the FY 2022 amounts, associated solely with the increases in costs resulting from towns transitioning to the new valuation method.

Q. What are the current circumstances the Company is currently facing in relation to property tax valuations?

A. The Massachusetts Department of Revenue has mandated that all municipalities transition the method of valuation of the Company's personal property from using only NBVs which are equal to installed cost less accumulated depreciation, to a hybrid of the NBV approach. Specifically, the mandated approach involves alternative assessments in excess of NBV, with some municipalities adopting an approach that is based on 50% of the NBV valuations and 50% on valuations using reproduction cost new less depreciation. Certain municipalities have already revised the calculation of assessed value to represent the new Hybrid RCNLD/NBV Method. 82 municipalities have started using the Hybrid RCNLD/NBV Method in the FY 2021 tax year. The Bureau of Local Assessment ("BLA") conducts a certification review for each municipality on a five-year cycle where municipalities are expected to substantiate their valuation positions. It is anticipated that all remaining municipalities will transition to the Hybrid RCNLD/NBV Method prior to their next certification review, to occur no later than FY 2025. This methodology was first implemented by the City of Boston. The City of Boston challenged the use of the NBV method for utility property by arguing that this personal property value should be determined using reproduction cost new less depreciation, i.e., the RCNLD methodology. The Company challenged use of the RCNLD method in

2010 and the Massachusetts Appellate Tax Board ("ATB") determined that a compromise was appropriate, resulting in the adoption of the Hybrid RCNLD/NBV Method. Based on the ATB's decision, some municipalities in the Company's service territory have also converted to the Hybrid RCNLD/NBV Method.

Q. What guidance has the DOR issued to the municipalities?

A. On March 26, 2019, the DOR submitted a Local Finance Opinion issuing a change in guidance from the BLA on the appropriate method of valuation for purposes of local property tax assessment. Exhibit ES-REVREQ-6(a), Schedule 4 provides (1) Local Finance Opinion letter from the DOR, dated March 26, 2019; (2) Bulletin from the DOR regarding "New Optional Forms of List for FY2021; and (3) Webinar Presentation from the DOR regarding the New Optional Form of List for Utility Companies dated December 17, 2019. (See also, D.P.U. 19-120, Exhibit DPU-ES-10-21(e)). Additionally, the BLA issued an Informational Guideline Release No. 19-08 in April of 2019 providing the certification standards in which local assessors must meet at the time of their certification review for the Commissioner of Revenue to certify that they are assessing at full and fair cash valuation (Exhibit ES-REVREQ-6(a), Schedule 5). Significant changes for FY 2021 were identified on page 7 beginning with assessments as of January 1, 2020 for utility valuation, which requires municipalities to substantiate their valuation position during their certification year. Further on pages 44 through 45, the assessors are provided guidelines for substantiating a fair market value in excess of NBV citing to the circumstances of the *NSTAR Electric Co. v. Assessors of Boston*, 94 Mass App. Ct. 1129 (February 22, 2019) case. There were 48 municipalities in the Eversource electric and gas service territories that were required to re-certify for the FY 2021 period. Resulting from the guidance described above, 44 of these municipalities adopted the Hybrid RCNLD/NBV Method in their FY 2021 bills issued to NSTAR Gas, NSTAR Electric and Eversource Gas of Massachusetts.

Q. Has the Company estimated the impact of a wholesale transition to the Hybrid RCNLD/NBV method by all municipalities in its service territory?

A. Yes. In this proceeding, the Company will demonstrate that it is experiencing an unprecedented level of property tax expense associated with the widespread transition of municipalities to assessing a fair market value in excess of NBV. During the course of this proceeding, the Company will be able to identify the municipalities that have transitioned to the Hybrid RCNLD/NBV method as of the FY 2022 tax year, representing two full years of actual experience following the DOR's guidance described above. The Company provided an illustrative analysis in Exhibit ES-REVREQ-6(a), Schedule 3 in order to demonstrate the potential impact of a wholesale transition of all municipalities in the Company's service territory to the Hybrid RCNLD/NBV method. When comparing the assessed values on NBV to the assessed values of the 88 municipalities that have transitioned to the new valuation method as of the FY 2021 tax year, the Company sees on average a 35 percent increase in the expense attributed to NSTAR electric distribution. If the Company were to apply this increase to the NBV for the remaining municipalities that have yet to transition to the new valuation method, the annual impact on expense is estimated to be $22 million higher than what the Company is currently proposing to reflect in its rate year effective January 1, 2023. The Company plans to update this analysis upon receipt of the FY 2022 tax bills.

Q. How is the exogenous cost recovered from (or returned to) customers through the PBRAF?

A. Once allowed by the Department, the amount of the cost change occurring in the prior year (2021), or the year prior to the prior year and deferred for recovery or refund, is be recovered or returned in the PBRAF. The factor is in effect until the exogenous cost or credit is recovered or refunded, or until such time that the amounts are appropriately reflected in the PBRAF, as applicable. Beginning in the PBRAF for effect on January 1, 2023, the Company is proposing to recover $8 million in property tax expense for 82 municipalities resulting from higher than NBV property tax valuations submitted in the FY 2021 bills. Any over/under recovery of the prior-period expenses associated with the exogenous event will be reconciled in the next PBRA filing on September 15, 2023 with carrying charges calculated at the prime rate.

Q. How did the Company calculate the exogenous cost requested for recovery through the PBRAF?

A. To determine if the Company triggered the threshold for an exogenous cost, the Company compared what the municipalities would have assessed under a traditional NBV method versus the actual assessed values included on the FY bill. When the actual bill exceeded the amount anticipated under the NBV method, the

Company determined that the municipality was using an alternative valuation methodology. The difference between the assessed values based on FY 2021 bills and the assessed values based on NBV represents the incremental assessed values. The incremental assessed values for each municipality are multiplied by the actual fiscal year 2021 Mill Rate to arrive at the additional property taxes for each town that is solely attributed to their transition to the new method. In the FY 2021 bills, there were 82 municipalities that assessed values in excess of NBV, representing an additional annual expense of $8 million well over the threshold for 2021 of $5,286,214. Exhibit ES-REVREQ-6(a), Schedule 2 provides the calculation of the incremental assessed values for each of the 82 towns. Exhibit ES-REVREQ-6(b), Schedule 6 provides the FY 2021 bills for each town in support of that calculation.

Q. What is included in the Company's base distribution rates related to property tax expense?

A. The latest FOL available in the Company's last base distribution rate case (i.e., the FOLs issued to the towns in the first quarter of 2017, reflecting NBV through the end of the prior calendar year 2016), was used to establish the personal property tax expense in base distribution rates for those towns who, at the time as of their FY 2017 bill, were relying on the FOL to determine property tax expense. For the municipalities using an alternative valuation methodology, the Company's base rates reflect the latest property tax bills provided by each municipality in FY 2017. Therefore, in this proceeding, the Company has calculated the incremental property tax expense for purposes of evaluating the potential for exogenous cost treatment by calculating the incremental property tax expense for only those municipalities that adopted the Hybrid RCNLD/NBV method in the FY 2021 bill issued to the Company, since, for those municipalities, their property tax expense was determined based on NBV in the Company's last base distribution rate proceeding.

Q. Were there any towns that adopted the new methodology as of the Company's last base distribution rate case?

A. Yes. There were six municipalities that did not utilize the FOL method to produce the most recent bill at the time of our last rate case. For the municipalities of Boston, Brookline, Everett, Medway, Newton and Springfield, the Company reflected the amounts provided in the most recent property tax bill for FY 2017. Since the property tax expense for these six municipalities were based on the most recent property tax bills that did not rely on the FOL method, base rates already reflect property tax expense based on the Hybrid RCNLD/NBV Method. Therefore, these 6 municipalities are not eligible for exogenous cost recovery and are not included in the request for exogenous cost recovery. See D.P.U. 17-05, Exhibit ES-DPH-3 (East), WP DPH-25 and D.P.U. 17-05, Exhibit ES-DPH-3 (West), WP DPH-25.

VIII. AMI COST RECOVERY

Q. Please describe the Company's cost-recovery proposal that accompanied the July 1, 2021 AMI Implementation Plan in D.P.U. 21-80.

A. Consistent with the Department's directives in D.P.U. 20-69-A, and in conjunction with National Grid, the Company developed the Model AMI Tariff for the proposed ratemaking mechanism. The Model AMI Tariff was submitted in D.P.U. 21-80 as Exhibit ES-AMI-5 and establishes an annual reconciling mechanism allowing the Company to recover an annual AMI revenue requirement, which is defined as the revenue requirement associated with the Company's AMI-related plant-in-service for each AMI Investment Year prior to the Recovery Year, plus Recoverable operations and maintenance ("O&M") Expense.

By the term of the Model AMI Tariff, the AMI Revenue Requirement will be calculated to recover: (1) the monthly revenue requirement for eligible AMI investments recorded as in-service in the AMI Investment Year immediately prior to the Recovery Year; (2) the average annual revenue requirement for the calendar year ending December 31 of the AMI Investment Year two years prior to the Recovery Year, for cumulative Eligible Investments placed into service in the AMI Investment Years two years prior to the Recovery Year; (3) the annual revenue requirement for the Recovery Year on Eligible Investments recorded as in-service in the AMI Investment Year immediately prior to the Recovery Year; and (4) Recoverable O&M Expense.

Eligible AMI investments are defined as the cumulative capitalized costs directly attributable to implementation of AMI recorded as in-service, including net salvage, and are used and useful at the end of the AMI Investment Year that is prior to the Recovery Year. Recoverable O&M expense is defined as the incremental O&M expense that is incurred by the Company as a result of implementing AMI (either incurred directly by the Company or charged to the Company by ESC), including the amortization of capitalized information systems costs billed to the Company by its affiliate and recorded by the Company as expense, the cost of which is not being recovered through base distribution rates or another cost recovery mechanism. Recoverable O&M expense is the actual monthly AMI-related O&M expenses incurred in the AMI Investment Year prior to the Recovery Year.

Similar to other reconciling mechanisms, the Company will submit to the Department an annual AMI cost recovery filing that will include, but not be limited to:

- Project documentation of all eligible AMI investment recorded as in-service by the Company [or its affiliate] during the Prior AMI Investment Year;
- Documentation supporting non-recurring O&M expense as part of Recoverable O&M Expense;
- The AMI Reconciliation; and
- Bill impacts.

Q. What has the Department directed in terms of the recovery of legacy meter infrastructure?

A. As noted above, this testimony establishes a cost-of-service baseline for the recovery of incremental meter costs associated with AMI implementation. The Department's decision in Modernization of the Electric Grid – Phase II, D.P.U. 20-69 (May 21, 2021) provided the following:

> [I]n support of its strategy to achieve advanced metering functionality, each company shall propose a detailed end-of-life meter replacement plan. The Companies' end-of-life meter replacement plan proposals must be designed to minimize any potential for stranded costs as the Companies transition to a full deployment of AMI meters.

D.P.U. 20-69-A at 29 (citing, D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, at 121-122, 133-134).

Because this proceeding is a base-rate proceeding, the Company is proposing to establish a cost-of-service benchmark for metering infrastructure to use in applying the AMI tariff.

Q. How has the Company addressed the issue of costs related to current AMR meter replacements that are included in the cost of service?

A. Consistent with the Department's directives in D.P.U. 20-69-A, the Company has conducted a review of the meter-related costs that are included in the cost of service proposed in this case for new base distribution rates effective on January 1, 2023. As part of that review the Company has addressed the remaining depreciable life of AMR meters and the depreciation of the remaining AMR assets to align with the

Company's AMI deployment plan; depreciation expense related to existing IT infrastructure; and the costs related to AMR meter O&M expense included in the cost of service and how incremental O&M expense related to AMI will be calculated.

Q. Describe how the Company will account for the depreciation of remaining AMR assets to align with AMI deployment?

A. As discussed in the testimony of Company Witness John Spanos, the Company has proposed an accelerated depreciation rate of 8.62% for Account 370.10 Meters – AMR. Utilization of an accelerated depreciation rate will allow for the retirement of the existing population of AMR meters in the test year with the remaining book value recovered through depreciation by year end, 2028.

The Company anticipates that AMR meters would continue to be purchased and installed at historical levels prior to the approval of an AMI Implementation Plan by the Department. Once an AMI Implementation Plan is approved, the Company would reduce its investment in AMR meters to a level required to maintain service to customers.

Q. How does the Company propose to account for undepreciated meter plant for AMR investments made after the test year and prior to full AMI implementation?

A. Even though the Company anticipates making a reduced level of AMR investments to limit the possibility of costs associated with AMR meters, there is no guarantee that these required AMR investments will be fully depreciated by the time AMI is deployed. In addition, there is the possibility that the timeline for AMI deployment could change as future regulatory proceedings refine the scope and cost of the plan. Therefore, the Company is proposing that any remaining book value of AMR meters at the time of full AMI implementation be treated as a regulatory asset for future recovery. The amortization period for the regulatory asset would be based on the period of recovery of investment through depreciation of AMR meters approved in the rate case cost of service. The Company's proposal in this regard is described more fully in the testimony of Company Witnesses Ms. Conner, Mr. Horton, and Ms. Schilling, covering the topic of AMI. In Exhibit, ES-AMI-3, page 3 the Company has calculated the recovery of AMR meter investment to be $18 million. Assuming, for the sake of illustration, an unrecovered AMR balance of $40 million at the end of AMI deployment, the Company would create a regulatory asset of $40 million and using the $18 million in base rates for AMR depreciation as the amortization amount, the regulatory asset would be fully amortized over 2.2 years. After the regulatory asset is fully amortized, the Company would then apply the recovery of the $18 million of deprecation in base rates against recovery of the AMI cost recovery mechanism.

Q. Has the Company reviewed whether the test-year cost of service includes recovery of IT Infrastructure that would be replaced as part of the AMI Plan?

A. Yes. The Company has reviewed the systems that will be replaced as part of the AMI deployment and determined that they are or will be fully depreciated prior to AMI deployment and therefore the cost of new IT Infrastructure related to AMI will be wholly incremental.

Q. How does the Company propose to measure incremental O&M expense related to AMI?

A. The transition from AMR metering to AMI metering represents more than a replacement of assets. Moving to AMI will restructure how meter operations function, what work is performed and how we interact with customers. In addition, much of the increased O&M cost is non-recurring such as the utilization of additional resources for Customer Engagement and Education and Project Management. As outlined in the AMI Business Case Analysis Summary Report included as Exhibit ES-AMI-3, there will be both O&M costs and savings occurring during the implementation period. As it relates to cost recovery of incremental O&M, the Company expects that it will offset its request for incremental cost recovery by any AMI-related cost savings realized in the deployment of AMI. In this way, the Company will ensure it does not double recover costs associated with AMI by collecting incremental AMI-related O&M through the AMI cost recovery mechanism and realizing cost reductions for costs collected through base rates that are avoided as a result of the AMI deployment. For this reason, the Company is proposing a straight-forward measurement of incremental costs based on the test year level of costs for Meter Expenses, Maintenance of Meters, Meter Reading Expenses and Miscellaneous Customer Accounts Expenses as measured by FERC Account.

Q. Has the Company provided an analysis of the test year level of these costs?

A. Yes. In Exhibit ES-AMI-3 page 1 of 3 the Company has calculated the test year cost for metering and miscellaneous customer account expenses to be $9.7 million. The analysis takes metering and customers costs from FERC Accounts 586, 597, 902 and 905. This table represents the level of expenses the Company has incurred in the test year for meter related services, and thus the level of meter-related expenses that will be established in base distribution rates as a result of this proceeding. This amount ($9.7 million), therefore represents the baseline amount of meter-related expenses the Company will compare against in order to determine incremental cost recovery for AMI-meter related O&M. In Exhibit ES-AMI-3, page 2 of 3, the Company has provided a schedule showing the estimated AMI related O&M expenses that will be incurred as it moves to AMI (lines 1 through 11), as well as the areas of expected O&M savings (lines 15-18), and the corresponding FERC account that will be used to track them.

Q. How will the Company determine whether cost increases in the FERC accounts for metering and miscellaneous customer accounts expense represent actual incremental costs related to AMI deployment?

A. The Company will track and provide documentation for the O&M costs required for the AMI Plan categories of work and look to recover as incremental costs the lesser of these costs or the net change to FERC Accounts 586, 597, 902 and 905 from the test year amount of $9.7 million, adjusted each year for the annual change in GDP-PI (representing the amount collected in base rates for these costs). In this way the Company will account for savings that offset the cost of AMI implementation and ensure that costs outside of AMI implementation are not recovered as incremental.

Q. What cost categories identified in the AMI Business Case Analysis are expected to require increased O&M costs?

A. The AMI Business Case Analysis identified 11 cost categories, of which 10 included O&M costs. The cost categories include the following:

1. **Communication Network Costs**: The network consists of end points on the meters that transmit the meter reads through a wireless network where the data is eventually received by the AMI Headend.

2. **Headend and Meter Data Management System (MDMS)**: The Headend software decrypts the meter read data so it can be retrieved by the MDMS, the MDMS then serves as the data repository of all granular meter data.

3. **Customer System Replacement**: The current customer billing system is not capable of billing time varying rates at a scale required to support an AMI deployment. The new customer information system will also offer additional non-AMI benefits such as streamlined billing, fewer exceptions, and faster error and issue resolution.

4. **Customer Enablement**: Customer Enablement products and services will enable new customer tools, usage insights & alerts, and EE/DR program

information.

5. **Analytics**: With data received through AMI the Company will have the ability to perform descriptive and predictive analytics to enhance internal decision making and provide customers with additional insights and alerts. This initiative covers the development of Power BI based reporting and machine learning solutions.

6. **Operational System Integrations & Enhancements**: AMI modules will allow for integration and enhancement of the Company's Outage Management System, and the Volt-Var Optimization System.

7. **Cybersecurity**: Cybersecurity is a foundational aspect of the AMI program ensuring standards for systems and integrations. Added layers of security will ensure that customer data is kept secure.

8. **Customer Engagement and Education**: This initiative involves educating and informing customers on the benefits AMI enables in addition to answering common questions that customers may have regarding AMI technology.

9. **Project Management**: This initiative involves both project management and change management. It provides for the resources and tools required to manage risks, ensure adherence to budgets and timelines, and to ensure alignment within the Company with the overall program vision.

10. **Contact Center and Theft Costs**: This initiative includes costs associated with impacts to the Contact Center for increased calls during AMI implementation, the duration of calls following the new CIS implementation and customer calls pertaining to the new energy insights and rate options.

Q. What cost categories identified in the AMI Business Case Analysis are expected to provide O&M cost savings?

A. The AMI Business Case Analysis identified 11 benefit categories, of which three included O&M cost savings. The benefit cost savings categories include the following:

1. **Metering and Billing System Benefits**: The Company expects to have savings on avoided costs to maintain older meter data systems, costs for field collection system equipment and survey meter cellular costs.

2. **No Trouble Founds and Connectivity Survey**: The Company expects to have savings by eliminating the need to send labor resources and truck rolls to address NTF calls and no longer having to conduct Connectivity Surveys once every 10 years across the service territory.

3. **Meter Reading and Field Operations Benefits**: The Company expects labor savings through staffing attrition for these functions as a result of remote meter reading.

IX. PENSION AND POST-RETIREMENT BENEFITS OTHER THAN PENSION

Q. Are there any other issues that need to be addressed in this proceeding?

A. Yes. Currently, the Company's has eight annual Pension/PBOP Adjustment Factors ("PAF") filings from 2011 through 2018 currently pending before the Department of Public Utilities ('Department'). The dockets in which these filings were made are as follows: D.P.U. 11-91, D.P.U. 12-113, D.P.U. 13-84, D.P.U. 14-145, D.P.U. 15-147, D.P.U. 16-182, D.P.U. 17-159, and D.P.U. 18-121. The PAF filings made in 2011 through 2013, which were docketed as D.P.U. 11-91, D.P.U. 12-113, and D.P.U. 13-84, were consolidated by the Department into one docket. In that docket, the Attorney General filed pre-filed testimony and briefs were filed. The PAF filing for 2014 was docketed as D.P.U. 14-145, and the PAF filing for 2015 was docketed as D.P.U. 15-147. In both these cases, the Attorney General submitted pre-filed testimony. However, no schedule was established for the filing of rebuttal testimony or a hearing. The PAF filing made in 2016 was docketed as D.P.U. 16-182; the PAF filing made in 2017 was docketed as D.P.U. 17-159; and the PAF filing made in 2018 was docketed as D.P.U. 18-121. In all three of these dockets, the Attorney General submitted pre-filed testimony and the Company submitted rebuttal testimony. However, a hearing has not been conducted and briefs have not been filed in any of these three proceedings. In a procedural memorandum, the Department indicated that it intends to consolidate the dockets in which PAF filings were made from 2014 through 2018 and conduct a hearing at some date in the future. The Company is requesting resolution on the impasse relating to prior period pension recovery, which has been pending for many years and needs to be addressed prior to the implementation of a 10-year performance-based ratemaking ("PBR") Plan as supported in the Appendix to this testimony by Company Witnesses Horton, Frank and Botelho in Exhibit ES-REVREQ-7.

X. CONCLUSION

Q. Do you plan to continue to monitor and update items noted within this testimony?

A. Yes. Within this testimony, several adjustments were made based on estimates of O&M expenses and capital additions through December 31, 2021. These cost categories will be monitored and updated throughout this proceeding.

Q. Does this conclude your testimony?

A. Yes, subject to reserving the Company's right to respond to additional issues raised in discovery or at hearings.