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April 15, 2022

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: NSTAR Electric Company d/b/a Eversource Energy-D.P.U. 22-47
Marion-Fairhaven Capital Investment Project Proposal

Dear Secretary Marini:

On behalf of NSTAR Electric Company d/b/a Eversource Energy ("Eversource"), please find enclosed Eversource's capital investment project ("CIP") proposal under the Provisional Program established by the Department in its Order on Provisional System Planning Program, D.P.U. 20-75-B (Nov. 24, 2021). The documents consist of:

(1) Joint Testimony of Digaunto Chatterjee, Lavelle A. Freeman Juan F. Martinez and Gerhard Walker, and supporting exhibits; and

(2) Testimony of Ashley N. Botelho, and supporting exhibits.

Thank you for your attention to this matter. Please contact me if you have any questions regarding this filing.

Sincerely,

John K. Habib

John K. Habib

Enclosures

cc: Katie Zilgme, Hearing Officer

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 22-47

TESTIMONY OF

DIGAUNTO CHATTERJEE, LAVELLE A. FREEMAN, JUAN F. MARTINEZ AND GERHARD WALKER

ON BEHALF OF
NSTAR ELECTRIC COMPANY
d/b/a EVERSOURCE ENERGY

EXHIBIT ES-ENGINEERING PANEL-1

April 15, 2022

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JOINT DIRECT TESTIMONY OF

DIGAUNTO CHATTERJEE, LAVELLE A. FREEMAN, JUAN MARTINEZ AND GERHARD WALKER

I. INTRODUCTION AND QUALIFICATIONS

Digaunto Chatterjee

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

A. My name is Digaunto Chatterjee. I am Vice President of System Planning for Eversource Energy. My business address is 247 Station Drive, Westwood, Massachusetts 02090.

Q. What are your principal responsibilities in this position?

A. As Vice President, System Planning, I am responsible for transmission and distribution planning for NSTAR Electric Company ("NSTAR Electric") in Massachusetts, Connecticut Light and Power Company in Connecticut, and the Public Service Company of New Hampshire in New Hampshire. I oversee and guide the technical studies that serve as the foundation to developing the 10- and 20-year Transmission and Distribution ("T&D") Reliability and Resilience Capital Plan. Our strategic technical studies incorporate scenario-based probabilistic forecasts that include impacts of T&D-related renewable generation, electrification and more recently climate change. I lead a team of approximately 105 employees. In this proceeding, I am testifying on behalf of NSTAR Electric Company ("NSTAR Electric," the "Company" or "Eversource").

Q. Please summarize your professional and educational background.

A. In 1999, I received my Bachelor of Science degree in Power Electronics Engineering from Nagpur University in India. I earned a Master of Science degree in Electric Power Engineering from Rensselaer Polytechnic Institute in 2001, and a Master of Business Administration degree from the University of Chicago-Booth School of Business in 2016. I started my career in 2001 at General Electric Energy Consulting, where I performed engineering studies for US and foreign based utilities. In 2005, I worked for MISO and led Reliability and Economic Transmission Planning as well as Resource Adequacy. While working for MISO, I led the implementation of FERC Orders 890 and 1000; oversaw technical studies in support of Zonal Capacity Market construct; and led the reliability justification of MISO's Multi Value Projects planned and constructed to enable about 21 GW of onshore wind across Midwest. In 2016, I worked for General Electric Energy Financial Services as Vice President, Investment Strategy leading fundamental Energy and Capacity market analysis to inform investment decisions of over 2 GW of renewable generation throughout US. I have also been a member of the Institute of Electrical and Electronics Engineers ("IEEE") since 2001. I joined Eversource in 2019 as Director, System Planning. In 2020, I was named to my current position.

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

A. Yes. I recently testified before the Department in <u>Investigation by the Department of Public Utilities Into Electric Distribution Companies' Distributed Energy Resource</u>

Planning and Assignment and Recovery of Costs for the Interconnection of Distributed Generation, D.P.U. 20-75. I have also sponsored testimony before the Massachusetts Department of Public Utilities (the "Department"), in the NSTAR Electric Company d/b/a Eversource Energy, D.P.U. 22-22 (Petition for Approval of a Performance-Based Ratemaking Plan and Increase in Base Distribution Rates for Electric Service) on Performance-Based Ratemaking Metrics and Major Station Capacity Projects to Support Electrification. In 2021, I provided comments and participation in technical sessions conducted by the Connecticut Public Utilities Regulatory Authority, in Docket No. 17-12-03RE07, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Non-Wires Alternatives, and provided comments and participated in technical sessions in 2021 and 2022, in Docket No. 17-12-03RE08 PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Resilience and Reliability Standards and Programs. I also have testified before the Federal Energy Regulatory Commission, the Minnesota Public Utilities Commission and the Michigan Public Service Commission.

Lavelle A. Freeman

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

A. I am the Director of Distribution System Planning for Eversource Energy. My business address is 247 Station Drive, Westwood, Massachusetts 02090.

Q. What are your principal responsibilities in this position?

A. I am responsible for overseeing system planning and DER interconnection activities in Eversource's services areas in Connecticut, Massachusetts and New Hampshire. In this proceeding, I am testifying on behalf of NSTAR Electric.

Q. Please describe your educational and professional background.

A. I earned a Bachelor of Science degree in Electrical Engineering from the University of Alabama. Subsequently, in 1995, I earned a Master of Science degree in Electrical Engineering with Power Systems concentration from the University of North Carolina at Charlotte and earned a Master of Science degree in Computer Engineering from North Carolina State University in 2000. I joined the IEEE Power Engineering Society while in graduate school and have been on the ANSI C84.1 Standard Committee since 2019.

I started my power systems career in 1997 as an R&D Engineer at ABB Corporate Research in Raleigh, NC, where I devised innovative new products, algorithms and solutions to improve the value and efficiency of transmission and distribution product offerings within ABB Power T&D Inc. In 1999, I became a Senior Consulting Engineer in the ABB Utility Consulting group in Raleigh, NC where I performed system studies in distribution and transmission planning for utility customers, worked with customers to implement changes, and developed and supported power systems software applications that improved the efficiency, marketability and cost-effectiveness of the group.

From 2003 to 2013, I was a Senior Engineer and then a Principal Engineer at General Electric Energy in Schenectady, NY, where I led consulting studies in distribution planning and analysis, power systems engineering, equipment applications, smart grid initiatives, and renewables impact and contributed to development of new products and technology for various General Electric Energy businesses. From 2013 to 2016, I was Manager of Transmission and Distribution at General Electric Energy Consulting where I directed a broad spectrum of client activities in the T&D space, with emphasis on power systems operation and planning, equipment application, renewables impact, and systems analysis. From 2016 through 2020, I was Technical Director at General Electric Energy Consulting in Schenectady, New York. In this position, I led project teams and developed business opportunities in the distribution space with emphasis on DER integration, microgrid design, grid modernization, reliability, power quality and resiliency. I developed and led execution of over $5M in distribution-related projects in New York, New Jersey and Massachusetts. I also successfully completed four ground-breaking New York Prize Stage 2 microgrid design projects and managed the DSTAR consortium (www.dstar.org), working extensively with distribution planners and engineers in investor-owned, municipal and cooperative utilities all across the country. In 2020, I joined Eversource Energy as Director, Distribution System Planning.

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

A. I have not previously testified before the Department. Most recently I sponsored testimony before the Massachusetts Department of Public Utilities (the "Department"), in the NSTAR Electric Company d/b/a Eversource Energy, D.P.U. 22-22 (Petition for Approval of a Performance-Based Ratemaking Plan and Increase in Base Distribution Rates for Electric Service) on Major Station Capacity Projects to Support Electrification. Recently, I provided comments and participated in technical sessions conducted by the Connecticut Public Utilities Regulatory Authority, in Docket No. 17-12-03RE07 PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Non-Wires Alternatives, and Docket No. 17-12-03RE08 PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Resilience and Reliability Standards and Programs, a well as technical sessions conducted by the New Hampshire Public Utilities Commission in Docket No. DE 20-161 Eversource Energy 2020 Least Cost Integrated Resource Plan, and other system planning dockets in Massachusetts, Connecticut and New Hampshire.

Juan F. Martinez

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

A. I am the Distribution System Planning Manager for Eversource Energy. My business address is 247 Station Drive, Westwood, Massachusetts 02090.

Q. What are your principal responsibilities in this position?

A. I am responsible for overseeing electric distribution system planning activities in Eversource's service area in Massachusetts. My department completes the technical studies that serve as the foundation to developing the 10-year Distribution Reliability and Capital Plans. In this proceeding, I am testifying on behalf of NSTAR Electric.

Q. Please describe your educational and professional background.

A. I earned a Bachelor of Science degree in Electrical Engineering from the Grove School of Engineering - City College of New York, in 2009, I earned a Master of Science degree in Electrical Engineering from Manhattan College in 2016.

I started my power systems career in 2004 as Engineering Designer at Consolidated Edison Company of New York (ConEdison), where I planned, designed, and estimated projects for addition of new electric facilities in overhead and underground-residential areas in Staten Island, NY. In 2007, I transferred to the Central Engineering Department of ConEdison as an Analyst. In this role, I developed solutions for improving asset utilization of the substation and transmission electric systems. In this position, I led the development of designs and completion of analysis for new distribution reliability projects approved for $72M under the 2009 Smart Grid Investment and Demonstrating Grants from the Department of Energy implemented in an underground electric distribution network in Queens, NYC.

From 2010 to 2013, I was a Supervisor in ConEdison's Manhattan Distribution Engineering Department. I directed the activities of engineers that developed electrical and civil designs for the electric underground network power system in Manhattan, New York

City. During this role, as a special assignment, I provided technical support to the New York State Energy Research and Development Authority (NYSERDA) in the study of micro-grids for Critical Facility Resiliency in New York State. The Final Report was completed December 2014 for the New York State Legislature. From 2013 to 2019, I was Manager of Distribution Engineering where I led the operations of the section responsible for the performance, integrity, and reliability of the electric underground distribution system in New York City. As a manager, I led the engineering design efforts for risk reduction, asset replacement, and capital expansion projects - ranging from $1M to $20M in scope. In 2019, I joined Eversource Energy as Manager, Distribution System Planning.

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

A. I have not previously testified before the Department. I have supported technical analysis for all technical sessions conducted by the Department of Public Utilities in D.P.U 20-75, Distributed Energy Resource Planning and Cost Assignment, and assisted in other regulatory proceedings relating to distribution system planning.

Gerhard Walker

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

A. My name is Gerhard Walker. I am the Manager for Advanced Forecasting and Modeling for Eversource Energy. My business address is 247 Station Drive, Westwood, Massachusetts 02090.

Q. What are your principal responsibilities in this position?

A. As the Manager for Advanced Forecasting and Modelling, I am responsible for Eversource's advanced forecasting and modeling efforts to transition the Company's distribution planning processes to address the Commonwealth's Net Zero Carbon Objectives. Furthermore, I oversee the non-wires alternative ("NWA") screening and planning process. In this proceeding, I am testifying on behalf of NSTAR Electric.

Q. Please summarize your professional and educational background.

A. I hold a Doctorate in electrical engineering from University of Stuttgart, Germany. I began my career in 2013 at the Netze BW, Germany's third largest distribution system operator. While at Netze BW, I led research and development efforts into probabilistic forecasting, advanced system planning, and electric vehicle grid integration. Additionally, I oversaw efforts with the Association of German Energy and Water Industries to align DSO objectives with the automotive industry on issues regarding charge specifications and load management, as well as ELT coordination across all Netze BW subsidiaries on grid modification topics. In 2016, I joined General Electric Current as the Director for Grid Solutions in Boston, to develop distribution use cases for virtual power plant aggregation of DERs. In 2017, I became the Director for Product Management at Opus One Solutions, a Canadian Utility Software supplier, where I led the scaling up of software solutions and successful customer acquisitions including HECO, SCE, Ameren, as well as expansions into the UK and Germany. I joined Eversource Energy in 2020 as a Principal Engineer in System Planning and transitioned into my current role in 2022.

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

A. I have not previously testified before the Department. Recently, I assisted in technical sessions conducted by the Connecticut Public Utilities Regulatory Authority in Docket No. 17-12-03RE07, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Non-Wires-Alternatives, and assisted in other regulatory proceedings relating to system planning. Most recently, I have sponsored testimony in NSTAR Electric Company d/b/a Eversource Energy, D.P.U. 22-22, regarding the Company's transmission and distribution planning process, including anticipated electrification.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your joint testimony?

A. The purpose of our testimony is to submit Eversource's capital investment project ("CIP") proposal under the Provisional Program established by the Department in its Order on Provisional System Planning Program, D.P.U. 20-75-B (Nov. 24, 2021) (the "Provisional Program Order"). Given that electric power system ("EPS") equipment saturation limits have been reached in certain Affected Group Studies[1] and, as a result, associated network upgrade costs have significantly exceeded past average interconnection costs, the Provisional Program Order established a program to facilitate viable interconnection for distributed generation ("DG") facilities. The Provisional Program established by the Department facilitates DG interconnection through a modified cost allocation and recovery methodology aimed at addressing imminent short-term DG interconnection cost concerns. Our testimony addresses Eversource's first Provisional Program CIP filing for the Marion-Fairhaven Affected Group Study.

Q. Is Eversource offering any additional testimony?

A. In addition to our joint testimony, Eversource is sponsoring testimony from Company Witness Ashley N. Botelho addressing Eversource's proposed CIP Tariff for cost recovery.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes, we are sponsoring the following exhibits, in addition to our Joint Direct Testimony:

Exhibit ES-Engineering Panel 2: Marion-Fairhaven CIP – Need, Benefits, Cost Allocation Analysis.

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[1] Provisional Program Order at 26-27 defines and identifies the Affected Group Studies. Eversource's Affected Group Studies include: (1) Marion-Fairhaven; (2) Plymouth; (3) Cape Cod; (4) Freetown; (5) Dartmouth-Westport; (6) New Bedford; and (7) Plainfield-Blandford.

Q. Please describe how you coordinated with stakeholders in preparation for this proposal.

A. The Company has maintained regular communications with National Grid throughout the D.P.U. 20-75 process and has continued to collaborate during the CIP proposal preparation process. Eversource and National Grid have formed an inter-utility group that meets periodically to discuss the technical and policy issues regarding D.P.U. 20-75 cost allocation. Specifically, we have focused on how to account for differences in planning, design, and operation of the respective electric distribution systems and philosophical approaches to integrated distribution planning. The distribution companies have met several times to discuss components of the CIP proposals, have exchanged drafts, and incorporated mutual feedback.

In addition, the Company met with the Office of the Attorney General ("AGO") earlier this year to review and discuss plans for the CIP proposals, review preliminary input to the proposals, and gather feedback on cost allocation projections. The Company recently had a follow-up discussion with the AGO and incorporated feedback into this proposal. The Company has also shared the CIP proposal with the Department of Energy Resources and the Massachusetts Clean Energy Center, met with representatives to discuss their views, and incorporated feedback into the proposal.

Further, the Company has held regular meetings with the Northeast Clean Energy Council ("NECEC") throughout the Group Study process and has continued to engage with this group of solar and energy storage stakeholders during the CIP proposal preparation process. The Company shared the CIP Proposal with NECEC and has met with this group as well as the Marion-Fairhaven Group Study members to discuss the proposal, receive and incorporate feedback.

III. PROVISIONAL PROGRAM ORDER REQUIREMENTS

Q. Would you please describe the Provisional Program approved by the Department in D.P.U. 20-75-B?

A. The Department's Provisional Program Order is intended to address unique and immediate challenges faced by Eversource and certain DG facilities in the Affected Group Studies, which are will result in significantly higher than average interconnection costs. Under existing cost allocation principles, when major EPS equipment limitations are reached, the costs to interconnect DG to the EPS are borne solely by current interconnecting customers, even if the EPS upgrades necessary to interconnect the DG enables future interconnection of other DG facilities and facilitates operational flexibility[2] and electrification for distribution customers. These costs may be prohibitively high and are likely to be a barrier to interconnect any new DG facilities in the affected geographic areas until the necessary

[2] Per the Eversource Distribution System Planning Guide, to maintain adequate levels of reserve capacity, power quality, and reliability, that meet or exceed our Customer's increased expectations, Bulk Distribution Substations shall be designed to sustain any Single Contingency (N-1) with no Load Loss. Additionally, the transmission system supplying distribution bulk substations shall be designed so that the outcome of any single contingency event does not result in a condition greater than a single contingency at the distribution bulk substations. Operational Flexibility therefore ensures that load and DER customers can remain online under various operating configurations, consistent with the Company's N-1 standard.

EPS upgrades are constructed. If unaddressed, these challenges would limit the Commonwealth's ability to achieve its clean energy goals as set out in the Commonwealth's Interim Clean Energy and Climate Plan ("Interim CECP") for 2030 and under Section 87 of Chapter 8 of the Acts of 2021, An Act Creating a Next Generation Roadmap for Massachusetts Climate Policy (the "Climate Act").[3] To address these challenges in the short term, the Department established the Provisional Program to permit CIP filings based on the cost allocation and cost recovery methodology set forth in the Department's Straw Proposal issued in D.P.U. 20-75, Att. A.

Q. What aspects of the Straw Proposal were adopted in the Provisional Program?

A. The Straw Proposal outlined a modified cost-allocation methodology for interconnecting DG facilities. The Straw Proposal would also require each electric distribution company ("Distribution Company") to perform proactive distribution system planning for the interconnection and integration of DG facilities.[4] The Straw Proposal would have each Distribution Company perform a rolling ten-year assessment of its EPS on an annual basis and would propose CIPs for consideration of cost recovery through a Reconciling Charge[5]

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3 See Provisional Program Order at 27-28.

4 Id. at 6.

5 Reconciling Charge is defined in the Straw Proposal "as the non-bypassable volumetric dollar-per-kilowatt-hour ("kWh") charge assessed to all ratepayers to cover the costs of a Distribution Company's Capital Investment Projects that are preapproved by the Department, and which is offset by the collection of Capital Investment Project Fees from Interconnecting Customers." D.P.U. 20-75, Att. A at 3.

and CIP Fees.[6] The Provisional Program adopted the cost allocation and cost recovery methodology set forth in the Straw Proposal and also identified additional requirements for CIP filings.[7]

Q. Would you please summarize the cost allocation and cost-recovery methodology from the Straw Proposal?

A. Under the Straw Proposal, a Distribution Company would submit a CIP for Department review and approval, and if approved, would construct the CIP and recover the costs of construction from distribution customers via a new Reconciling Charge.[8] Under the Eversource proposal, all incurred costs of Distribution upgrades will initially be included in the reconciling charge. However, based on the Marion-Fairhaven final capacity/cost allocation ratio, a portion of the total costs recovered through the Reconciling Charge would be offset by CIP Fees charged to interconnecting customers. These customers would be able to interconnect to the EPS up to the capacity enabled by a CIP.[9] CIP Fees would

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6 CIP Fee is defined in the Straw Proposal as "a fee that would be assessed by a Distribution Company to an Interconnecting Customer associated with its Facility's pro-rata share of the costs of a Capital Investment Project, which has been approved by the Department and of which the Interconnecting Customer's Facility is a direct beneficiary, as described further in Section II.B." D.P.U. 20-75, Att. A at 1.

7 Provisional Program Order at 29.

8 D.P.U. 20-75, Att. A at 6. The Reconciling Charge would be structured as a non-bypassable volumetric charge, which would be allocated to rate classes by the revenue allocator and would be included as part of the distribution charge. Id. at 6-7. The Straw Proposal, as modified in the Provisional Program Order, also includes an annual rate cap under which the annual change in a Distribution Company's revenue requirement under the Provisional Program would not exceed one-half percent of the Distribution Company's intrastate operating revenues recorded during the calendar year or a greater amount determined by the Department. Id. at 7; Provisional Program Order at 8, n. 16.

9 D.P.U. 20-75, Att. A at 6.

be assessed to an interconnecting customer based on the interconnecting facility's pro-rata share of the cost of the CIP(s) that allows it to interconnect (*i.e.* $/kW).[10] CIP Fees collected over time would offset, or effectively refund distribution customers for a portion of the initial costs associated with the CIPs.[11]

Q. What are the requirements for CIP filings identified in the Provisional Program Order?

A. The following is a summary of the filing requirements and eligibility criteria set out in the Provisional Program Order (at pages 31-39). CIPs must include, at a minimum:

(1) a description of the CIP, including projected cost, equipment, permitting and licensing requirements, and construction timeline;

(2) a demonstration that the CIP meets all eligibility criteria, including the following;

a. Limited to the "Affected Group Studies" in Exh. EDC-1(a) (Eversource).

b. Must enable interconnection of multiple DG facilities.

c. Maximum cost-per-kW for an eligible CIP (meaning the Interconnection Customer portion of the CIP Fee) is $500/kW. A proposal for an amount slightly over $500/kW must include a request for waiver with a justification. Any amount

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10 Id.

11 Id.

allocated to distribution customers and any costs borne only by customers must be clearly justified.

d. Must identify the specific geographic area served by the EPS upgrades constructed as part of a CIP and must be able to demonstrate that the amount of enabled DG likely will be interconnected in that geographic area within the proposed Rate Recovery Period.

e. Demonstrate that the aspects of construction within the Company's control can be completed within a maximum of four years from the conclusion of the adjudication of the CIP. Use commercially reasonable methods to accelerate procurement and construction schedules.

(3) a detailed cost allocation proposal based on the Straw Proposal that includes a proposed rate recovery period for the CIP through the Reconciling Charge;

a. Must include details on the differentiation between distribution and transmission EPS upgrade costs.

b. Propose a time period for rate recovery through the Reconciliation Charge for each CIP proposal ("Rate Recovery Period").

c. Must include justification for any proposal to have CIP costs borne exclusively by distribution customers through a Reconciling Charge and/or transmission rates. Such proposal must provide:

(i) detailed descriptions of each component of a CIP that it proposes to recover solely from customers; and

(ii) a justification for why the costs of the CIP should be recovered from customers and not from Interconnecting Customers.

(4) projected bill impacts that show the flow of reconciliation over the Rate Recovery Period as CIP Fees are collected from new Interconnecting Customers and flowed back to customers.

(5) a description of how the CIP will benefit customers and aligns with cost-efficiently meeting the Commonwealth's clean energy policies; and

(6) an explanation of how the CIP will affect low-income and environmental justice populations, including describing any projects in the CIP that will be constructed in an environmental justice neighborhood.

The Department also noted that it will review each CIP on a case-by-case basis and that the Department may approve, deny or modify any proposal.[12]

IV. DESCRIPTION OF AFFECTED GROUP STUDY AND PROPOSED CIP

Q. Does the CIP proposed in this filing relate to an eligible Affected Group Study?

A. Yes, it does. The CIP we are proposing is intended to interconnect the projects included in the Marion-Fairhaven Group Study. The Marion-Fairhaven Group Study is the first

[12] Provisional Program Order at 29.

Affected Group Study for Eversource identified in the Department's Provisional Program Order at 26-27.

Q. Would you please describe the Marion-Fairhaven Group?

A. The Marion-Fairhaven Group comprises of four substations in Southeastern Massachusetts (SEMA): Arsene Street (Substation #654); Crystal Spring (Substation #646); Rochester (Substation #745); and Wing Lane (Substation #624). These substations collectively serve 57 MVA of customer peak load. There is a total of 60 MW of installed ground mounted (large) DER, in addition to 10 MW rooftop (small) DER on the four stations, and the Group Study will interconnect another 49 MW of large DER, bringing the total DER penetration to 209% of peak load for the group.[13] Figure 1 below shows the approximate geographical location of the group of stations in our East service area, and Table 1 shows the breakdown of existing DER and planned group study DER by station.

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13 The approximately 49MW of DER consists of 17 different facilities from 9 applicants.

Figure 1. Approximate location of Groups Study Substations

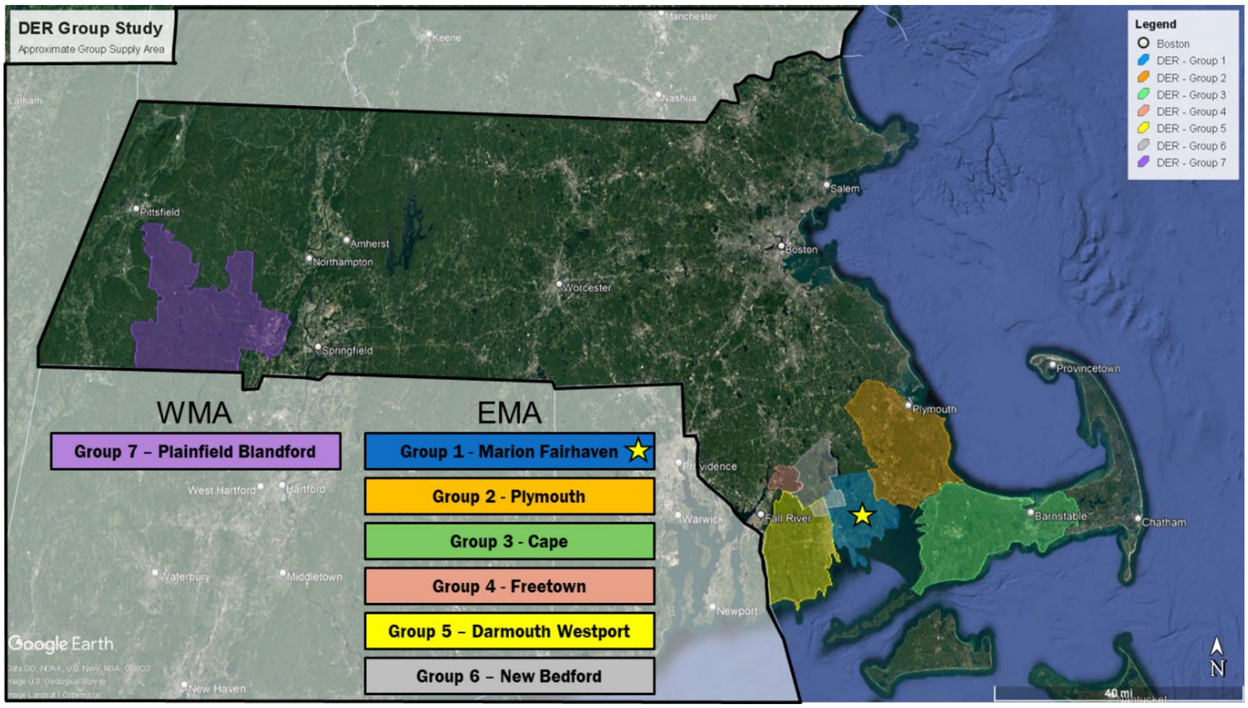


Table 1. Breakdown of Existing and Planned DER by Station

Group Study Station	Existing Ground Mounted DER MW	Group Study DER MW	In-Queue Ground-Mounted DER (after Group Study) MW
Arsene Street 654	12	2.0	3.7
Crystal Spring 646	20	6.7	19.4
Rochester 745	17	19.0	1.0
Wing Lane 624	10	21.0	7.9
Totals	**60**	**48.7**	**32.0**

Q. What is the geographic area served by the Marion-Fairhaven Group and associated substations?

A. Figure 2, below, zooms to the Marion-Fairhaven Group 1 area to map the approximate boundary supplied by Group 1 substations - consisting primarily of zip codes 02770, 02743, 02739, 02719, 02738.

Figure 2 - Marion-Fairhaven (Group 1) Approximate Boundary

Q. Why did Eversource include the four substations noted above in the Marion-Fairhaven Group Study?

A. Due to the interconnected nature of the distribution feeder/line system, the four substations in the Group are interdependent and rely on each other during emergencies as well as day-to-day system operations. For example, Substation 654 has strong distribution ties to both

Substation 646 and Substation 624. Under emergency or scheduled maintenance conditions the load and/or DER customers normally supplied by Substation 654 can be temporarily transferred to Substation 646 and/or Substation 624. Because of the interconnected design of the distribution feeder/line system between these substations, system constraints and corresponding upgrades are coordinated to ensure safety and reliability for all customers served from these four substations. This justifies the four substations being studied as a group and also requires analysis of additional scenarios under N-1 conditions which must be evaluated to ensure safe, reliable operation for all customers, load and DG alike, in alternate configurations.

Q. Is Eversource's approach of considering N-1 conditions in the Group Study consistent with how Eversource conducts other studies?

A. Yes, it is. This approach is consistent with Eversource's Distribution System Planning Guide, including procedures for evaluating N-1 contingencies. See D.P.U. 20-75, Eversource System Planning Analysis Proposal, Attachment 1 (April 23, 2021). Eversource further explained its principles for defining Group areas in response to Information Request EDC-1 in D.P.U. 20-75.

Q. Please describe the N-1 contingency planning standard and why Eversource uses it for distribution system planning?

A. The N-1 contingency planning standard is applied to bulk substation equipment and substation distribution tie-lines as a critical reliability standard assuring that, in the event of the loss of any one of the EPS equipment components, customers would not lose electric service. Bulk distribution transformer outages have the potential to take weeks and/or months to replace. Therefore, application of the N-1 planning standard is operates to make sure that, in the event of loss of an equipment component, current or voltage on all remaining EPS equipment shall not exceed the respective design limitation that would then necessitate customer outages served by that equipment. As discussed in D.P.U. 20-75, EDC-1 (Eversource) at 9, as the EPS becomes more saturated with DG, it becomes increasingly difficult for Eversource to preserve reliability and operational flexibility under all scenarios. In medium-to-high DER saturation areas, substations must be analyzed as a study group to find the most cost-effective solution that integrates new DER while maintaining the current level of reliability and associated operational flexibility for the EPS. This is critical because saturation at connected stations would impact system reconfiguration capability and transfer capability over those substation tie-lines. If Eversource did not address the impacts to interconnected substations in high DER saturated areas, it would result in degradation in service quality for all customers; prolonged outages for DERs in the area; and would undermine the Commonwealth's plans for the short and long-term reduction of greenhouse gas emissions through development of solar capacity.

Q. Has Eversource completed the Marion-Fairhaven Group Study to determine necessary System Modifications to interconnect the DG facilities in the Group?

A. Yes, Eversource has completed System Impact Studies ("SIS") for the Marion-Fairhaven Group. The SIS was completed in accordance with the terms of Eversource's Standards for Interconnection of Distributed Generation, M.D.P.U. No. 55A, including the Group Study Process under Section 3.4. The SIS included the following: steady-state and dynamic analyses to identify thermal loading and voltage regulation issues due to PV output and battery operation; voltage flicker concerns and excessive movements of voltage control equipment due to variable output from PV plants; short circuit current duty that would exceed equipment withstand capability; risk of unintentional islanding due to PV energizing a portion of the EPS; and load rejection overvoltage and ground fault over voltage phenomena leading to transient over-voltages ("TOV") on the system.

The specific planning criteria violations observed from the SIS are documented in detail in the System Impact Study Report summarized in the CIP Proposal Workbook (Exhibit ES-Engineering Panel-2) in the Worksheet titled "3. Project Need". The SIS identified and developed CIP solutions, including equipment upgrades, to allow DER to safely interconnect and operate reliably. These solutions are also documented in the Worksheet titled "2. CIP Facilities" in the CIP Proposal Workbook.

Q. What CIP facilities were identified as being required to interconnect the DER in the Marion-Fairhaven Group?

A. The CIPs for the Marion-Fairhaven Group include the following key projects:

(1) distribution line upgrades (overhead conductors) at the Arsene Street distribution lines;

(2) upgrades to the existing substation transformer and the addition of a second transformer, switchgear duct bank gateway (substation conduit outlet) and cable at the Crystal Spring substation;

(3) distribution feeder upgrades at the Crystal Spring distribution feeders;

(4) an upgrade to one existing substation transformer, switchgear, and duct bank gateway cable at the Rochester substation;

(5) distribution feeder upgrades at the Rochester distribution feeders;

(6) upgrades of two existing substation transformers, a duct bank and gateway cables at the Wing Lane substation; and

(7) distribution feeder upgrades at the Wing Lane distribution feeders.

The required CIP facilities are identified further in Exhibit ES-Engineering Panel-2, Worksheet 1, "Capital Investment Projects (CIP) & Project Need – Group 1." Worksheet 1 of Exhibit ES-Engineering Panel-2 shows a high-level description of the CIP projects (or solutions for SIS violations) for the group, a summary of the project need from the SIS, the major equipment upgrade for each project and the estimated total cost for each CIP as well as other high-level attributes of each CIP. The facilities required for the CIP represent the mitigation measures, solutions and substation and distribution line upgrades required to resolve steady-state and dynamic study violations identified in the SIS, as discussed in Worksheet 1 of Exhibit ES-Engineering Panel-2. The solutions described in the CIP facilities table were developed using Eversource Distribution Planning Criteria, other internal guides and standards for system design and equipment application, and industry standards.

Q. Would you explain how Exhibit ES-Engineering Panel-2 is organized?

A. Yes. As noted above, Exhibit ES-Engineering Panel-2 includes all details regarding the project need and proposed CIPs. The first column of Worksheet 1, "Capital Investment Projects (CIP) & Project Need – Group 1." table, "1. CIP ID", provides a unique identifier for each CIP which can be used as a reference throughout the entire process. The first two characters of the CIP ID are an acronym for the group name ("MF" = Marion-Fairhaven). The third character is either "D" or "S" to identify the CIP as a Distribution project or a Substation project. The final four characters is the unique Eversource substation number. Therefore, the CIP ID "MF-D-0654" is a distribution project in the Marion-Fairhaven group on station 654 (Arsene Street).

The second column "Substation Name" is either Arsene Street 654, Crystal Spring 646, Rochester 745, or Wing Lane 624 in this case. The next two columns, "Project Name" and "Project Description", give a high-level indication of the type of project in the CIP, typically either substation or distribution upgrades. "Project Need Summary" lists the violation from the SIS that led to the project, e.g. "thermal overload of transformer due to DER reverse flow." More detailed information on each violation is provided in Worksheet 3, "Project Need." The "Equipment" column lists the specific asset that is added or upgraded during the project. More detailed information on each piece of equipment or facility upgrade in the project is provided in Worksheet 2 "CIP Facilities."

The next column on the Cost Allocation, Worksheet number 6 table, lists the estimated +/- 25% cost estimate for the CIP, which is the total cost for all the CIP Facilities identified as part of each CIP. These costs were developed as part of Eversource preliminary engineering activities for the station and distribution line scopes.

The Worksheet titled "2. CIP Facilities" in the CIP Proposal Workbook "Capital Investment Projects (CIP) & Project Need - Group 1" lists the CIP facilities for each CIP in the group. The first column in the Worksheet table is the unique CIP ID applicable to each facility. The second column is a CIP Facility identifier within the CIP ID. "Facility Type" identifies the type of distribution asset; "Substation Name" is one of the substations in the group; "From Location" and "To Location" identify where on the system the facility is located; "KV" is the voltage rating; "Facility Nameplate/Type" gives the equipment rating or size, or type; "Project Description" summarizes the mitigation measures, solution or upgrade; and "Existing Feeder Upgrades ft" and "New Feeder ft" give the length of the feeder before and after the upgrade.

Q. What was Eversource's overall approach to determining required CIP facilities?

A. Eversource's objective throughout the study process was to identify the technically optimal and viable solution that, given the applicable standards and criteria, will cost-effectively enable safe, reliable interconnection of the Group Study DER and maintain quality of service for all customers, load and DER alike. Therefore, a range of traditional and emerging solutions were tested and recommended to resolve project needs. It is important to stress that the results of the Marion-Fairhaven Group Study and the proposed CIPs are designed only to interconnect the amount of DER included in the Marion-Fairhaven Group (as stipulated in the Provisional Program Order) taking into account existing and approved DER, load impacts and system constraints.

Q. Does the substation have capacity to interconnect DG not otherwise identified in the Group Study?

A. Yes, as a result of the substation upgrades identified in the Group Study, Eversource identified 136 MVA of Ground Mounted DGs and 11 MVA of Rooftop DGs that could be reliably enabled – 87 MVA above and beyond the current Ground Mounted Group Study projects. However, despite the available substation capacity, additional distribution feeder upgrades are also necessary to accommodate this amount of enabled DG. Specifically, additional distribution feeders would be required to interconnect future DG facilities beyond the Group Study DER (49 MVA) up to the substation enabled capacity (136 MVA).

Eversource determined that in order to ensure that all DG up to 136 MVA who pay a fixed CIP fee can safely and reliably connect to the substations, eight additional distribution feeders are required for the additional 87 MVA of DER. This includes: (3) three new overhead (OH) distribution feeders out of the Crystal Spring Substation; (4) four new OH distribution feeders out of the Rochester Substation; and (1) one new OH distribution feeder out of the Wing Lane Substation.

Q. Was the proposed solution designed to enable accomplishment of the Commonwealth's overall decarbonization goals?

A. Not directly. The proposed solution was designed to address the specific requirements of the D.P.U. 20-75-B decision, to facilitate the interconnection of distributed generation in several areas that are saturated and require significant upgrades to interconnect projects in those areas safely and reliably. However, consistent with the Provisional Program Order requiring utilities to *continue to take a long-term view to ensure long-term reliability for customers,* in developing the proposal, the Company has tried to balance the need for a cost-effective near-term solution for the group with the State's long-term electrification goals. In doing this, the Company reviewed electrification impacts and future DG enablement as part of the design process. However, in keeping with the Provisional Program Order, any benefits of electrification and distributed generation that support the accomplishment of the Commonwealth's overall decarbonization goals are strictly a byproduct of the solution design that facilitates the interconnection of Group Study DG in those areas.

Q. What are the common solutions that Eversource considered?

A. For this Group and others, Eversource considered a number of solutions to resolve the violations observed due to interconnection of the Group Study DER. Solution evaluation involved a combination of engineering judgment, modeling, and simulation to iteratively determine appropriate design changes, technology and equipment application that would enable safe, reliable interconnection. The approaches that were generally considered are described below. During this process, solutions that were more costly, unproven or not technically viable were often rejected in favor of solutions that could be counted on to reliably integrate as much DG as possible in a cost-effective manner

For thermal loading violations on substation transformers and distribution circuits, the most common solution was to upgrade the facility or add new facilities to resolve the violation. The new facilities and upgrades allow the Group Study DER to connect and operate under both normal (N-0) and emergency (N-1) conditions and also create additional headroom for future DER due to the use of standard equipment sizes.

For voltage regulation issues, common solutions included application of voltage control equipment such as capacitor banks and voltage regulators, reconductoring circuit segments, load transfers, and other traditional measures. In some cases, customer-owned inverters were specified to operate at off-unity power factor (pf) in order to mitigate certain voltage quality concerns. Based on the supply substation and location of the DER customers in relation to the substation, high impedance transformers or series reactors may be recommended to lower overall system short-circuit current values. For Battery Energy Storage Systems ("BESS") applications, ramp rate limitation was considered to address flicker concerns. In some cases where traditional measures were insufficient to resolve violation, emerging technology such as dynamic var compensation ("DVAR") devices and STATCOMS helped address some of the voltage and flicker concerns and the Real Time Automation Controller ("RTAC") was used to implement direct transfer trip ("DTT") schemes where needed. These emerging technologies not only helped address multiple steady-state and dynamic analysis violations but will also enable Eversource to mitigate impacts of future DERs on the system.

It should be noted that while these solutions are designed and implemented to safely and reliably interconnect DER to the EPS, in many cases they can also significantly improve capacity, reliability, and voltage quality for load customers on the EPS, as well as enabling future growth.

Q. Did Eversource consider using smaller size equipment to lower the CIP Fees?

A. In designing solutions to resolve violations observed in the SIS due to the Provisional Program DER, Eversource relied on its existing criteria and standards to guide the selection of technically viable solutions. Often, the most technically viable solution was to upgrade distribution lines and transformers to increase system capacity, improve voltage regulation or eliminate power quality/flicker concerns. However, the size of the upgrade was restricted to the standard equipment sizes stocked by Eversource. For distribution bulk transformers, particularly, the Eversource standard size is 62.5 MVA, 75 MVA, and 90 MVA based on system nominal voltage and area load density. This standard has been in place in Eastern Massachusetts for about 20 years. The continued use of standard size of substation transformers, substation equipment and distribution equipment across the Company footprint creates efficiencies for engineering, equipment specification and selection, procurement, spare inventory, repair, replacement and improved performance in day-to-day field operations and maintenance of not just operating the transformers but also all the associated substation equipment. For the Group Study projects as with all ongoing distribution capital projects in Eversource, the use of standard size transformers and associated substation and distribution equipment to resolve capacity violations results in additional headroom at upgraded stations.

Q. Did Eversource reject any solutions that were deemed to be too costly and, if so, was there an impact on the enabled DERs?

A. Yes. During the engineering analysis for this Group Study, consisting of 4 substations, one solution at Wing Lane substation to maximize the enabled DER to the full connected MVA capacity of the substation was rejected due to the high cost of the solution – which entailed addition of series reactors per-phase at each substation transformer. The reactors were needed because the available short circuit current due to upgraded station transformers and additional DERs would increase the fault duty at the secondary bus and distribution feeders above the Eversource standard for distribution equipment. However, due to physical constraints at the substation, the proposed reactors would trigger site expansion and relocation of the upgraded transformers within the new footprint and require relocation of subsurface structures in an already congested site. The incremental cost to install the series reactors (above and beyond the transformer upgrades) was approximately $40M. To reduce the potential for excessively high fault currents and therefore avoid the high-cost reactor solution, the substation Enabled Ground Mounted DER capacity for Wing Lane was reduced by 16 MVA (from 45 MVA to 29 MVA).[14] If this additional 16 MVA were to be included in the Group Study Solution in conjunction with the increased cost of the series reactors, it would increase the CIP fee of the group by $88/kW for a total CIP fee of $473/kW. Due to the high cost to enable this incremental 16 MVA the Company did not consider it prudent to include this solution in the CIP.

Q. What is the estimated total cost of the Group Study interconnection solution for Marion-Fairhaven?

A. The total estimated distribution cost, as shown further in Exhibit ES-Engineering Panel-2, Worksheet 1, is approximately $119.7M.

Q. Does this also represent the total CIP costs?

A. Yes. The total estimated distribution cost of $119.7M above, represents the *estimated* total distribution station and distribution line Group Study Solution cost used to calculate the CIP fee the DER customers will pay. For details of the cost allocation refer to Worksheet 6,

[14] Prior to making the decision to reduce the substation Enabled Ground Mounted DER capacity, Eversource considered a range of additional measures including use of high-impedance transformers, transferring DER to other feeders or stations, and replacing distribution equipment in high-fault current zones with higher duty equipment. However, none of these were deemed to be prudent or feasible due to a number of factors, including physical constraints, safety and reliability considerations.

"Cost Allocation Details".

As noted earlier, this cost is based on Eversource preliminary engineering activities related to the scope as well as schedule requirements, and includes the following assumptions:

- Department Notice to Proceed received no later than December 2022;
- Siting and Permitting approvals are received no later than May 2025;
- Long-lead material procurement to commence in parallel with Siting and Permitting;
- Material lead times include current market delays but do not predict additional supply chain volatility, which could impact cost and schedule;
- Traditional material escalation does not predict future market volatility;
- Market conditions do not impact the availability and cost of construction resources;
- Typical site-specific soil and environmental conditions (site specific studies (e.g. Geotechnical analysis, environmental soil testing, topographical survey, sub grade investigation/digging, soil resistivity measurements, etc.) were not conducted);
- Risk and Contingency from above factors beyond included 20% are not included.

If the conditions for these assumptions are not met, the estimated total CIP costs could be higher.

Q. How does Eversource propose to split the CIP costs between DER developers and retail distribution customers?

A. As shown in Exhibit ES-Engineering Panel-2, Worksheet 6, "Cost Allocation" Eversource has assigned a distribution customer capacity and reliability benefit of $66.4M and a DER customer benefit of $53.3M. Eversource's cost allocation methodology is described further in Section ## of our testimony and in Exhibit ES-Engineering Panel-2, Worksheet 8, "Cost Allocation Details."

Q. Has Eversource evaluated the permitting requirements for the proposed CIP facilities?

A. Yes. The upgrades at the Crystal Spring Substation will require approval to construct an approximately three-mile transmission line extension to the proposed new substation transformer T2 and the granting of zoning exemptions to construct the substation upgrades from the Department. The substation upgrades at the Rochester and Wing Lane substations will also require the granting of zoning exemptions from the Department, unless the upgrades are able to be permitted locally.

There will also be environmental permitting required at the state and local levels. For all station work, Stormwater Pollution Protection Plans will need to be approved by the Massachusetts Department of Environmental Protection ("MassDEP"). For the Rochester station, a wetlands permit will also be required from MassDEP. Local conservation commission review will also be required.

The transmission line extension to the proposed new transformer T2 at Crystal Spring Substation may require these and other MassDEP permits as well as additional environmental permitting and reviews, including filings with the Massachusetts Environmental Policy Act Office, Army Corps of Engineers, Massachusetts Historical Commission, and Natural Heritage and Endangered Species.

Q. Does Eversource have an estimate of how long it will take to construct the CIP facilities?

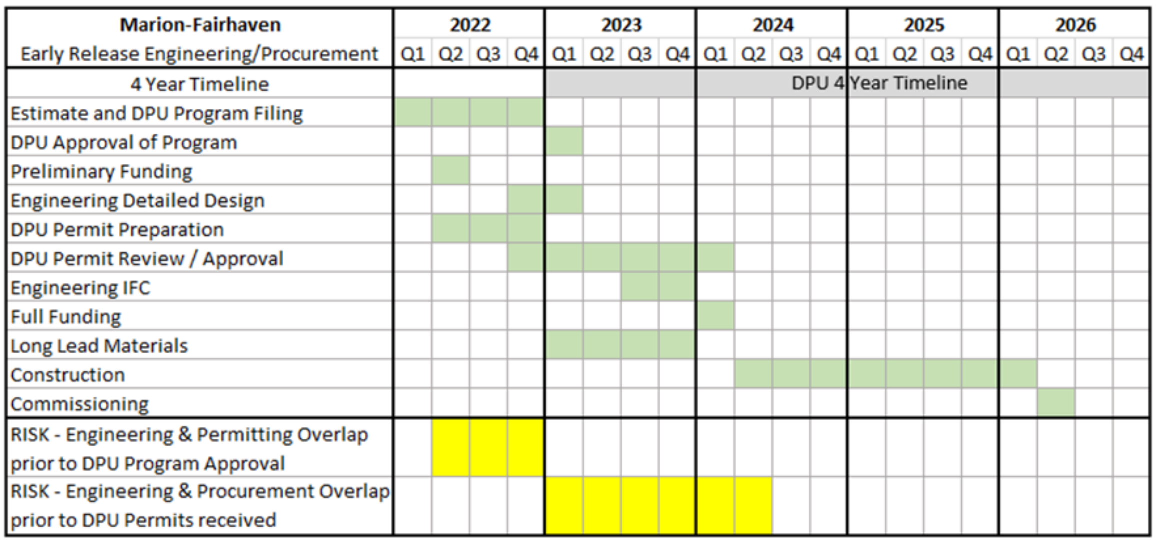
A The Marion-Fairhaven Group of projects is comprised of distribution line and/or substation upgrade projects at all four substations. These projects can be constructed within 4 years. Specifically, the construction period is a nominal two-year period for these projects. This assumes no delays in permitting as well as approval of transmission outage permits from system operators necessary to facilitate construction.

Q. In establishing the construction schedule, has Eversource made reasonable efforts to accelerate procurement and construction schedules?

A Yes. The four-year schedule of the proposed CIPs is based on accelerated procurement of long lead materials conducted in parallel. Specifically, as can be seen in the project milestones and schedules in Figure 3 below, the Company is incorporating the following risks – a) conducting detailed engineering and preparation of permitting application in 2022 in conjunction with the adjudicatory process schedule as well as completing detailed engineering and purchasing long lead materials prior to the approval of appliable permits.

Without conducting these activities in parallel, Eversource's ability to bring all CIPs into service within the four-year timeframe would be limited.

Figure 3



V. CIP ELIGIBILITY AND DER ENABLED

Q. Will the proposed CIP facilitate the interconnection of multiple DG facilities?

A. Yes, it will. As noted above, there are approximately 49 MW of Large Ground-mounted DER included in the current Marion-Fairhaven Group. The capacity included in the Group represents 17 unique DG facilities. Assuming all or most customers in the Group Study move forward with their projects, the CIP will facilitate the interconnection of multiple DG facilities.

Q. Is the proposed CIP Fee within the $500 per kW cap set by the Department in the Provisional Program Order?

A. Yes, it is $385/kW.

Q. Has Eversource evaluated the amount of DER that may be enabled for future interconnection as a result of the CIP?

A. Yes. As noted above, the CIP is designed to interconnect the 49 MW of DER included in the current Marion-Fairhaven Group Study. However, due to the upgrades needed for reliable integration of DERs in the Group Study and the use of Eversource standard size equipment, Eversource has determined that the proposed CIPs will enable an additional 87 MVA of DER above and beyond the Group Study DER.

Q. Would you please describe how Eversource evaluated the DER enabled by the proposed CIP?

A. Eversource is proposing a Comprehensive DER Capacity Allocation Structure adjusted for load, in-queue and future DER facilities, and operational requirements. This capacity allocation structure is the basis for Eversource's CIP proposal, including customer benefit allocation. Further details of Eversource's DER Capacity Allocation Structure are discussed in Exhibit ES-Engineering-2. Under this proposed structure, capacity allocation is prioritized as follows:

a) The "Reserved Operational Capacity[15]" is subtracted from the "Installed Capacity - Group Solution." This remaining Capacity is the "Reserved DER Capacity".

b) "Existing Ground Mounted DER", "Existing Rooftop DER", "Enabled Rooftop DER Capacity[16]" are then netted out of "Existing Minimum Gross Load[17]" and then subtracted from "Reserved DER Capacity" to derive "Enabled Ground Mounted DER Capacity".

c) Lastly, the "Provisional Program DER Group Study" DERs are subtracted from the "Enabled Ground Mounted DER Capacity" to derive the "Enabled Ground Mounted DER Capacity - Post Group Study" or the DERs that would be enabled after the Group Study and continue to pay the Group CIP Fee.

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15 At the substation level, Reserved Operational Capacity is driven by the Operational Capacity of the substation based on the MVA capacity of the remaining transformer(s) assuming the largest transformers is off service. For example, for a substation with two equal sized transformers, the Reserved Operational capacity is 50% of the total connected MVA capacity. For a one-transformer substation(s) the Reserved Operational Capacity is zero, but 5% of the connected MVA capacity is used for capacity planning purposes.

16 To forecast the Enabled Rooftop DER AC capacity value, the historical adoption rate per station, as well as distribution sizing were considered as inputs into a probabilistic model. The results of the analysis are in line with the MA decarbonization roadmap projections from 2030, doubling the installed capacity to 2030.

17 For planning purpose, when analyzing DER, Eversource considers periods of light distribution load and high DER penetration. Distribution customer load, to a limit, acts as an offset to DER because it helps reduce the system capacity constraints created by high DER output. Because of this, the Existing Minimum Gross Load is considered an offset to DER and used in the calculation of additional Enabled DER capacity.

Q. What are the amounts of enabled DER in each category as a result of the Marion-Fairhaven CIP proposal?

A. The tables below show the capacity allocation breakdown, in the context of the Eversource Capacity Allocation methodology, when examining the CIP as proposed. The Enabled Rooftop DER Capacity column is the capacity reserved for future growth of small (rooftop) DER, and the Enabled Ground Mounted DER Capacity is the capacity reserved for all Large (ground mounted) DER. The result is a total enabled DER substation capacity of 152 MVA in Group 1, comprised of 141 MW as DER Customer Benefit (Enabled Large DER Capacity) and 11 MVA as Distribution Customer Benefit (Enabled Small DER Capacity). Reserved Operational Capacity and Enabled Electrification are considered a mutually inclusive Distribution Customer Benefit. At the substation level, 189 MVA of capacity is Reserved for Operational Capacity[18] of which up to 137 MVA of incremental capacity would be utilized to reliably enable electrification.

Table 2- Group 1 Substation Capacity Allocation

Stations	Reserved Operational Capacity (MVA)	Enabled Electrification (MVA)	Enabled Rooftop DER Capacity (MVA)	Enabled Ground Mounted DER Capacity - Group Study (MVA)
Arsene St 654	2	0	3	19
Crystal Springs 646	63	44	3	40
Rochester 745	63	50	2	52
Wing Lane 624	63	43	4	29
	189	**137**	**11**	**141**

A similar Capacity Allocation methodology was applied at the distribution line level[19]. The result is a total Enabled DER line Capacity of 314 MVA in Group 1, comprised of 303

MVA as DER Customer Benefit (Enabled Large DER Capacity) and 11 MVA as Distribution Customer Benefit (Enabled Small DER Capacity). It is important to note that DERs enabled are always limited by the substation limit of 147 MVA. At the Distribution Line level, 206 MVA of capacity is Enabled Line Electrification with the 114 MVA of that Reserved Operational capacity as a sub-set of the 206 MVA.

Table 3 – Group 1 Distribution Line Capacity Allocation

Stations	Reserved Operational Capacity (MVA)	Enabled Electrification (MVA)	Enabled Rooftop DER Capacity (MVA)	Enabled Ground Mounted DER Capacity - Group Study (MVA)
Arsene St 654	20	6	3	28
Crystal Springs 646	37	62	3	101
Rochester 745	34	90	2	101
Wing Lane 624	24	48	4	73
	114	**206**	**11**	**303**

To help differentiate the Substation Enabled Capacity from the Distribution Line Enabled Capacity, it should be noted that the Substation Capacity is the total MVA limit of the system, while the distribution line capacity is the total MVA locational limit of the system. Therefore, the Enabled Ground Mounted DER Line capacity provides DER developers the

18 At the substation level, the Reserved Operational Capacity is the main driver for Distribution Customer benefit, so the total amount of capacity allocated to Distribution Customer Benefits is the Reserved Operational Capacity. Nevertheless, to recognize the future Electrification benefits that the Group Study Solution provide to Distribution Customers, the Reserved Operational Capacity is allocated between Reliability benefit and Load Allocation benefit.

19 One key difference between Distribution Line Capacity and Substation Capacity is that Distribution Line capacity is more spread out along the service territory – because there is inherently more geographic diversity in location of load and DERs across distribution feeders compared to substation. Distribution Line capacity is greater than substation capacity because feeder capacity needs to be available where customers area regardless of their location.

ability to interconnect in a wider geographic area along the distribution line system. At the distribution feeder level, the DER customers capacity allocation is for the ability to use the Distribution System regardless of location and not due to the capacity limit when compared to the substation.

Q. Has Eversource conducted any analysis to assess the potential for the DER enabled to be constructed within the geographic area served by the Marion-Fairhaven substations?

A. Yes. Eversource has contracted Gridtwin, a Cambridge-based clean tech startup, to support the analysis of all the parcels within the Eversource service territory, specifically the areas serviced by the Affected Group Studies. This effort was made possible through a partnership with the MassCEC Net Zero Grid Planning Project which funded this engagement. The Gridtwin software tools provide advanced analytics for parcels across the nation using cutting edge cloud-based GIS solutions that allow for a highly granular, parcel by parcel analysis. These software tools evaluate multiple types of land-use and restrictions and are used by solar developers for identifying suitable parcels for development.

Q. What was the framework of Gridtwin's parcel analysis?

A. Eversource and Gridtwin considered "Technically Qualified Land" for DER development. This includes all land that can be developed for solar[20] without limiting factors related to

[20] The Company worked with Gridtwin and data sets provided by MassGIS, which include a wide array of land use and classification layers. https://maps.massgis.digital.mass.gov/MassMapper/MassMapper.html.

project economics under current DER incentive programs. Specifically, Eversource did not consider current regulations under the Solar Massachusetts Renewable Target Program (SMART), 225 C.M.R. § 20.00 *et seq*. to be a long-term limiting factor in this analysis. With the Commonwealth's objective outlined in the 2050 Decarbonization Roadmap, as well as the Department of Energy Resources' recent Request for Quote to conduct a "technical potential of solar study"[21] Eversource expects a revision of current funding programs within the construction period of the CIP projects.

Q. How did Eversource and Gridtwin identify available land for DER development?

A. Eversource and Gridtwin focused on identifying what we refer to as "Technically Qualified Land" within the Marion-Fairhaven service area. Technically Qualified Land includes parcels that can potentially be developed based on certain criteria and classifications as discussed below but does not disqualify land parcels based on current incentive programs or local zoning limitations. Land was then identified using the Gridtwin tool and data layer imports from MassMapper,[22] which provide information on a wide variety of land classifications within the state as outlined in the following Table 4.

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[21] https://www.mass.gov/doc/doer-rfq-ene-2022-008-consulting-servicES-Engineering Panel for-the-technical-potential-of-solar-study/download

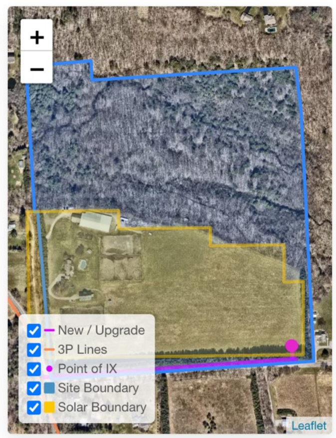
[22] https://maps.massgis.digital.mass.gov/MassMapper/MassMapper.html

Table 4: Data Sources

Data Name	Source
Parcel Boundaries, Assessed Cost	MassGIS Data: Property Tax Parcels
Elevation, Slope, Aspect	National Elevation Dataset (NED) 1 arc-second
Land-use	NLCD 2016 CONUS Land Cover
Wetland Resource Area	MassGIS Data: MassDEP Wetlands (2005)
Priority Habitat	MassGIS Data: BioMap2
Core Habitat	MassGIS Data: BioMap2
Critical Natural Landscape	MassGIS Data: BioMap2
Article 97 Land	MassGIS Data: Protected and Recreational OpenSpace
Prime Farmland	MassGIS Data: Soils SSURGO-Certified NRCS
Farmland of Unique Importance	MassGIS Data: Soils SSURGO-Certified NRCS
Farmland of Statewide Importance	MassGIS Data: Soils SSURGO-Certified NRCS
Agricultural Preservation Restriction	MassGIS Data: Protected and Recreational OpenSpace
State Register (2)	MassGIS Data: MHC Historic Inventory
Brownfield	MassGIS Data: MassDEP Tier Classified Oil and/or Hazardous Material Sites (MGL c. 21E)
Landfill	MassGIS Data: MassDEP Solid Waste Diversion and Disposal
Nearest Electric Infrastructure	Eversource Distribution System

Within the Gridtwin Solution, each parcel is mapped out based on its boundaries, how much of it is covered by various land classifications, as well as setbacks and existing structures. The remaining land is identified as developable land. Each parcel is tracked individually by the solution and a consolidated report provided.

Figure 4: Sample Visualization of Gridtwin's Parcel Analysis



The Company then post-processed the results to remove existing solar sites, as well as sites that are part of the current group or have a place in the queue. These are considered spoken-for, as site control is in place for applications.

Q. What types of land classifications did Eversource and Gridtwin consider as limiting factors for development?

A. Every parcel within Eversource's service territory was analyzed based on certain characteristics to identify its technical potential for solar development. The analysis allowed a subdivision of parcels based on land restrictions, eliminating the need to disqualify entire parcels. Table 5 below lists all layers applied as part of the analysis.

Table 5: Developable Land Limitations

Characteristics	Limited	Description
Land-use	X	Open Water
	X	Perennial Ice/Snow
		Developed, Open Space
	X	Developed, Low Intensity
	X	Developed, Medium Intensity
	X	Developed, High Intensity
		Barren Land (Rock/Sand/Clay)
		Deciduous Forest
		Evergreen Forest
		Mixed Forest
		Dwarf Scrub
		Shrub/Scrub
		Grassland/Herbaceous
		Sedge/Herbaceous
		Lichens
		Moss
		Pasture/Hay
		Cultivated Crops
	X	Woody Wetlands
	X	Emergent Herbaceous Wetlands
Wetland Resource Area	*X*	MassDEP Wetlands (2005)
Priority Habitat		See the MassGIS BM2_CORE_HABITAT Layer.
Core Habitat		MassGIS Data - NHESP Priority Habitats of Rare Species
Critical Natural Landscape		See the MassGIS BM2_CRITICAL_NATURAL_LANDSCAPE Layer
Existing Solar Installations	*X*	Parcels associated with existing sites
Minimum Feasible Size[23]	*X*	A minimum economic project size of 1 MW
Location Relative to Infrastructure[24]		Distance to 3-phase and substation infrastructure

23 No upper boundaries for parcel sizes were imposed.

24 The proposed CIP fees include a build out of distribution infrastructure to site, therefore, no distance limitations to the distribution infrastructure were imposed when evaluating parcels.

Line items marked “X” in the table are used to filter out available land parcels, while items with no marker do not filter out available land. Land availability is calculated precisely, meaning that within a parcel, suitable land can be identified for development, rather than disqualifying an entire parcel. A 25-foot setback is applied at every border of a parcel or to a use limitation within a parcel.[25]

Q. What did the results of your analysis show for the Marion-Fairhaven Group Study area?

A. The resulting analysis verified that there is sufficient Technically Qualified Land to fully utilize the enabled DER capacity under the proposed CIP filing. The results are summarized in the following table. The “Incremental Enabled Above Queued” represents the enabled DER capacity under the assumption that all group study and queued DERs are constructed. This compares with the “Incremental Available Above Queued”, which represents the available Technically Qualified Land with the existing, group study, and queued DER subtracted. As seen in the table below, there is sufficient Technically Qualified Land. The analysis demonstrates that there is significantly more available land in the region (3,411 MVA Incremental Developable above existing, group, and queued) to develop the post-Group Study solar projects enabled by the distribution upgrades (87 MVA post-Group Study and 55.9 MVA post-queue).

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[25] As part of the proposed CIP fee structure, distribution feeder infrastructure build out is covered. As a result, the Company has not limited Technically Qualified Parcels by their distance to existing 3-phase infrastructure.

Table 6: Potential Analysis Results for Parcels within Studied Group

Substation Name	Group Study DER Application after Provisional Program (MVA)	Enabled Ground Mounted DER Capacity Group Study (MVA)	Incremental Enabled post queued (MVA)	Technically Devolopable Solar (MVA)	Incremental Developable above Existing, Group, and Queued (MVA)
Arsene Street 654	3.7	19.4	13.7	314.8	296.9
Crystal Spring 646	19.4	40.0	13.9	843.6	797.5
Rochester 745	1.0	52.2	32.2	1653.0	1615.7
Wing Lane 624	7.9	29.0	0.1	739.6	700.7
Totals	**32.0**	**140.5**	**55.9**	**3550.9**	**3410.2**

Q. Has Eversource also considered when enabled DER may be interconnected, and how that time period relates to the proposed Rate Recovery Period?

A. Yes. Four scenarios for solar development were used to demonstrate how different rates of solar development impact recovery. In Scenario 1, it was assumed that all DERs in the group study, as well as all currently queued DER can interconnect in year 4. The remaining enabled capacity is assumed equally distributed across the 15-year recovery period with DERs from year 1-5 being interconnected in year 5. Scenario 1 reaches 100% of enabled in year 15. As shown, below, a major jump in solar DG is observable in year 4 and 5, with a linear trend from there on until year 15. For all stations, more than 50% of enabled DG were achieved at year 5.

Table 7: Scenario 1 Progression

	Cummulative															
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Enabled Ground Mounted
Group 1	0.0	0.0	0.0	80.7	100.6	104.6	108.6	112.6	116.6	120.6	124.6	128.6	132.6	136.5	140.5	140.5
ARSENE STREET 654	0.0	0.0	0.0	5.7	10.3	11.2	12.1	13.0	13.9	14.8	15.7	16.7	17.6	18.5	19.4	19.4
CRYSTAL SPRING 646	0.0	0.0	0.0	26.1	30.7	31.7	32.6	33.5	34.4	35.4	36.3	37.2	38.1	39.1	40.0	40.0
ROCHESTER 745	0.0	0.0	0.0	20.0	30.7	32.9	35.0	37.2	39.3	41.5	43.6	45.8	47.9	50.0	52.2	52.2
WING LANE 624	0.0	0.0	0.0	28.9	28.9	28.9	28.9	28.9	28.9	28.9	28.9	28.9	28.9	28.9	29.0	29.0

Scenario 2 is similar to Scenario 1 with the only difference being that the remaining enabled capacity is not equally split in the 15-year recovery period, but rather front loaded with deployment simulating a slow down towards the end of the recovery period. It also achieves 100% of enabled capacity at the end of the 15-year recovery period. As shown, below, Scenario 2 hits higher DER numbers earlier after the first 5 years.

Table 8: Scenario 2 Progression

	Cummulative															
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Enabled Ground Mounted
Group 1	0.0	0.0	0.0	80.7	113.1	118.1	122.6	126.6	130.1	133.0	135.5	137.5	139.0	140.0	140.5	140.5
ARSENE STREET 654	0.0	0.0	0.0	5.7	13.1	14.3	15.3	16.2	17.0	17.7	18.3	18.7	19.0	19.3	19.4	19.4
CRYSTAL SPRING 646	0.0	0.0	0.0	26.1	33.6	34.8	35.8	36.8	37.6	38.3	38.8	39.3	39.6	39.9	40.0	40.0
ROCHESTER 745	0.0	0.0	0.0	20.0	37.4	40.1	42.5	44.7	46.6	48.2	49.5	50.6	51.4	51.9	52.2	52.2
WING LANE 624	0.0	0.0	0.0	28.9	28.9	28.9	28.9	28.9	28.9	28.9	28.9	29.0	29.0	29.0	29.0	29.0

Scenario 3 is identical to Scenario 1, with the exception that Scenario 3 achieves 120% of enabled by year 15 of the recovery period, simulating an early subscription of the enabled capacity. As shown, below, Wing Lane 624 reaches its enabled capacity by Year 5 with all other stations following until Year 12 at which point the stations are fully subscribed and can no longer accommodate additional DG.

Table 9: Scenario 3 Progression

	Cummulative															
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Enabled Ground Mounted
Group 1	0.0	0.0	0.0	80.7	110.0	115.8	121.7	127.6	133.4	139.3	140.5	140.5	140.5	140.5	140.5	140.5
ARSENE STREET 654	0.0	0.0	0.0	5.7	11.6	12.7	13.9	15.1	16.2	17.4	18.6	19.4	19.4	19.4	19.4	19.4
CRYSTAL SPRING 646	0.0	0.0	0.0	26.1	33.4	34.9	36.3	37.8	39.2	40.0	40.0	40.0	40.0	40.0	40.0	40.0
ROCHESTER 745	0.0	0.0	0.0	20.0	34.2	37.1	39.9	42.7	45.6	48.4	51.3	52.2	52.2	52.2	52.2	52.2
WING LANE 624	0.0	0.0	0.0	28.9	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0

Lastly, Scenario 4 is the same as Scenario 3 with the difference that it provides a scenario for underachieving the enabled ground mounted DG by 20%. As a result, at the end of year 15 only 80% of the enabled DG will have been subscribed to.

Table 10: Scenario 4 Progression

	Cummulative															
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Enabled Ground Mounted
Group 1	0.0	0.0	0.0	80.7	91.2	93.4	95.5	97.6	99.7	101.8	104.0	106.1	108.2	110.3	112.4	140.5
ARSENE STREET 654	0.0	0.0	0.0	5.7	9.0	9.6	10.3	10.9	11.6	12.2	12.9	13.6	14.2	14.9	15.5	19.4
CRYSTAL SPRING 646	0.0	0.0	0.0	26.1	28.1	28.5	28.9	29.2	29.6	30.0	30.4	30.8	31.2	31.6	32.0	40.0
ROCHESTER 745	0.0	0.0	0.0	20.0	27.3	28.7	30.2	31.6	33.1	34.5	36.0	37.4	38.9	40.3	41.8	52.2
WING LANE 624	0.0	0.0	0.0	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.2	23.2	23.2	29.0

Q. Has Eversource considered current state incentives in the presented solar scenarios?

A. No, the Company has not considered current state incentives in the presented solar scenarios. The Company acknowledges that funding, regulations, local zoning, and cost development of solar components will play an important role in the speed of the DER rollout, both at a state and local level. However, it is not possible for the Company to reliably predict these impacts, especially factors such as how a fixed interconnection fee offsets project risks for local adoption which is a non-quantifiable parameter. Therefore, the Company is presenting these four scenarios as a sensitivity analysis depending on different solar development volumes and times. Company Witness Ashley N. Botelho presents the associated impacts of the Scenario 1 progression of enabled DER.

Q. Do developers face land use challenges that may ultimately reduce the amount of land they are able to develop?

A. They do. Developers must ultimately navigate various land use restrictions, which while not making development impossible, can certainly make it more difficult. They must also obtain a number of permits to site a DG project, including those listed above, in addition to navigating funding rules and finding landowners willing to part with or lease out their land. Based on information available to the Company, it is impossible to conclude which parcels would present insurmountable obstacles to developers. Furthermore, the scope of work does not include predicting future funding and associated incentives, regulation, and zoning changes that might occur, nor can this be done with any level of accuracy. Accordingly, the Company is proposing CIP fees based, in part, on the Technically Qualified Land the Company has identified based on its proposed Marion-Fairhaven interconnection solution and known land use restrictions that the Company has determined are highly likely to pose obstacles to development of a particular site. Further, the Company is providing solar development scenarios, rather than forecasts, to illustrate impact on customers under different outcomes.

VI. COST ALLOCATION PROPOSAL

Q. What is Eversource's total cost allocation proposal for the Marion-Fairhaven CIP as between CIP Fees to DER customers and the Reconciling Charge to retail distribution customers?

A. Eversource total cost allocation proposal is shown in Table 11 below. This table is shown on Exhibit ES-Engineering Panel-2, Worksheet 6, "Cost Allocation". The cost allocation methodology and calculations to arrive at the cost allocation proposal are detailed on Exhibit ES-Engineering Panel-2, Worksheet 8, "Cost Allocation Details."

The total cost of distribution substation upgrades is estimated to be $92.3 million. The portion of the total distribution substation cost allocated to DER customers via the CIP fee (to safely and reliably interconnect DER) is $38.1 million. The portion of the total distribution substation cost allocated to Distribution customers for common system modifications is $37.1 million for reliability and $17.1 million for distribution substation capacity.

The total cost of distribution line upgrades is estimated to be $27.4 million. The portion of the total distribution line cost allocated to DER customers via the CIP fee (to safely and reliably interconnect DER) is $16 million. The portion of the total distribution line cost allocated to Distribution customers for common system modifications is $4.8 million for reliability and $6.6 million for distribution line capacity.

The CIP Fee is calculated by dividing the $54.1 million ($38.1 million + $16 million) of CIP cost allocated to DER customers by the 141,000 kW of total ground mounted solar enabled by the CIP upgrades, to establish the $385/kW CIP Fee included in Table 7 below.

Table 11

Project Type	DER Customer Benefit	Distribution Customer Reliability Benefit	Distribution Customer Capacity Benefit	Upgrade Cost
Distribution Substation	$38 M	$37 M	$17 M	$92 M
Distribution Line	$16 M	$5 M	$7 M	$27 M
Total:	$54 M			
CIP Fee:	**$385 /KW**			

Q. Do the CIP Fees and Reconciling Charge include any transmission electric power system upgrade costs?

A. No, they do not. Eversource plans to recover the upgrade cost for the approximately three-mile transmission line extension to Crystal Spring Transformer #2 through local transmission rates.

Q. What distribution electric power system upgrades are included in the CIP Fees and Reconciling Charge?

A. The CIP Fees and Reconciling Charge include the costs associated with the distribution substation and feeder level (line) upgrades discussed above and detailed further in Exhibit

ES-Engineering Panel-2, Worksheets 1 and 2.

Q. Are there any costs associated with individual DG facility protection and control measures, point of interconnection upgrades, or customer-side upgrades included in the CIP Fees and Reconciling Charge?

A. No, there are not. Those costs will be assessed directly to the benefiting DG Interconnecting Customer. Costs associated at the local point of interconnection such as any three phase line extension in order to provide service to that individual DER project, metering requirement, site access requirement, any other Distribution Engineering local equipment requirement such as disconnect switches, transformers and/or any other equipment related to the direct transfer trip and/or other overhead SCADA equipment that may be required for safety and reliability purposes were not included in the CIP fees. CIP fees cover the system upgrades – upgrades to the Eversource Distribution Lines and Distribution Stations that serve the broader set of Distribution and DER customers – not an individual customer connection.

Q. Would you please explain how Eversource arrived at its cost allocation proposal?

A. Eversource is building the necessary Transmission and Distribution infrastructure necessary to enable a clean energy future for its customers and communities consistent with leading the industry in sustainability and supporting regional climate change goals. Eversource's overarching objective for this proceeding is to ensure timely and cost-effective infrastructure investment necessary for safe, reliable interconnection of DERs in the queue, as well as DERs projected to be in the queue – upgrades that benefit not just the

DER developers but also distribution (load) customers supplied by these same highly saturated distribution stations and lines. The CIP Facilities proposed by Eversource in Exhibit ES-Engineering Panel-2, Worksheet 2 will produce upgrades to the EPS that will meet the reliability, operational flexibility, and affordability goals of the system to provide service required by all our customers.

One of Eversource's key planning objectives is to provide the same level of safe, reliable service to DER customers that we provide to our distribution customers. This implies that the EPS should preserve safety and reliability under normal conditions, emergency conditions, and scheduled maintenance conditions with the addition of DER. The resulting infrastructure reinforcements would therefore ensure that the EDCs can count on DER availability in real time operations – to provide reliable clean energy peak shaving benefits and therefore enable EDC Planners to effectively account for DERs in long-term planning assessments. More specifically, if the system is not designed to provide N-1 reliability for all customers at the substation level, (which is inconsistent with our planning criteria) the infrastructure will be unable to accommodate DERs under alternate system configurations. DER would trip offline under such scenarios, which are relatively routine in day-to-day system operation. Under this scenario, Eversource planning criteria would therefore limit the amount of these DERs (and their associated energy) that could be incorporated in future Eversource Reliability studies undermining the Commonwealth's overarching goal of full integration and enablement of clean energy.

Eversource's cost allocation methodology is consistent with those overarching goals and is based on an approach Eversource refers to as the "capacity allocation principle." Under this proposed structure, the cost of Distribution Station and Distribution Line upgrades is allocated between Distribution customers and DER customers in proportion to the Load and DER capacity allocation.

Q. How is the capacity under the Marion-Fairhaven CIP allocated?

A. The capacity for the Marion-Fairhaven CIP is allocated across both the substation level and the distribution feeder level, as shown in the following tables:

Table 12– Group 1 Substation Capacity Allocation

Stations	Reserved Operational Capacity (MVA)	Enabled Electrification (MVA)	Enabled Rooftop DER Capacity (MVA)	Enabled Ground Mounted DER Capacity - Group Study (MVA)	Enabled Ground Mounted DER Capacity- Post Group Study (MVA)
Arsene St 654	2	0	3	19	17
Crystal Springs 646	63	44	3	40	33
Rochester 745	63	50	2	52	33
Wing Lane 624	63	43	4	29	8
	189	**137**	**11**	**141**	**92**

Table 13 – Group 1 Distribution Line Capacity Allocation

Stations	Reserved Operational Capacity (MVA)	Enabled Electrification (MVA)	Enabled Rooftop DER Capacity (MVA)	Enabled Ground Mounted DER Capacity - Group Study (MVA)	Enabled Ground Mounted DER Capacity- Post Group Study (MVA)
Arsene St 654	20	6	3	28	26
Crystal Springs 646	37	62	3	101	94
Rochester 745	34	90	2	101	82
Wing Lane 624	24	48	4	73	52
	114	**206**	**11**	**303**	**254**

Q. Please describe this capacity allocation in more detail.?

A. The Company determined Reserved Operational Capacity and Enabled Electrification to calculate the Distribution Customer Capacity associated with the substation upgrades. At two transformer substations in the current configuration, "Available Operational Capacity" is calculated by subtracting the largest transformer from the "Installed Capacity" and "Existing Maximum Gross Load." For single ended substations or substations with a single transformer, due to lack of substation redundant capacity the "Available Operational Capacity" is deemed to be zero. The Operational Capacity for single-ended, or one-transformer substations, is at the nearby substation that will provide backup switching capacity via distribution feeder connections.

Similar to the existing configuration, at two transformer substations in the upgraded configuration, the new Operational Capacity is calculated by subtracting new largest transformer from the "Installed Capacity – Comprehensive Solution." The "Available Operational Capacity[26]" and "Existing Maximum Gross Load" is then subtracted from this operational capacity of the upgraded configuration to establish the incremental capacity -

[26] Available operational Capacity of the existing system is one key indicator used to determine Enabled Electrification; therefore, it is included in the Cost Allocation Details. Available Operational Capacity after the Group Study Solution is not shown in the Cost Allocation Details because it is not used in the calculation, but it can be determined using the same formula and the updated substation capacity values.

"Enabled Electrification."[27] Because capacity enabled for electrification is derived from the Reserved Operational Capacity, it is by definition its subset.

Q. How was Reserved Operational Switching Capacity and Enabled Electrification used to calculate the Distribution Customer Benefit for Distribution Line Upgrades?

A. For distribution lines in the current configuration, "Available Operational Capacity" is calculated by subtracting the "Existing Maximum Gross Load" from the distribution line headroom capacity.[28] Available Operational Capacity for distribution feeders is very locational and reflective of current operational conditions and practices in the respective towns.

The increased in nameplate rating of all distribution lines, resulting from the Comprehensive Solution, are added to the Installed Capacity to calculate the "Installed Capacity - Comprehensive Solution." This reflects the total new thermal capacity of the system accounting for upgraded and additional distribution lines. Similar to the existing system operations, a portion of this capacity is reserved to ensure adequate thermal and switching capability to pick up customers during scheduled outages and maintain the same level of safety and reliability of the distribution system. This is documented as "Reserved Operational Capacity."

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27 This is the Enabled Substation Electrification Capacity (MVA) after Comprehensive Upgrades.

28 Similar concept to Distribution Substation Capacity but applied at the distribution feeder level by reserving a percentage of the feeder nameplate rating as headroom for operational capacity.

In the upgraded configuration, the enabled electrification is calculated by subtracting the existing configuration "Available Operational Capacity" from that new configuration line Operational Capacity.[29] The resulting value is then reduced by the "Existing Maximum Gross Load" to derive the "Enabled Electrification" for distribution lines.

Q. How are substation and distribution line costs allocated between DER customers and distribution customers?

A. For Substations: The costs are allocated between DER customers and distribution customers based on the share of capacity allocation of the upgraded equipment. While "Enabled Ground Mounted DER Capacity" capacity is allocated to DER customers, "Reserved Comprehensive Operational Capacity" and "Enabled Rooftop DER Capacity" capacities are allocated to the distribution customers. The "Reserved Comprehensive Operational Switching Capacity" is further broken down among load allocation (electrification) and reliability allocation.

For Distribution Lines: The costs are allocated between DER customers and distribution customers based on the share of capacity allocation of the upgraded equipment. While "Enabled Ground Mounted DER Capacity" capacity is allocated to DER customers, "Enabled Electrification" and "Enabled Rooftop DER Capacity" capacities are allocated

[29] Similar concept to Distribution Substation Capacity but applied at the distribution feeder level. Therefore, for distribution lines, Operational Capacity is defined as the Installed Capacity minus the headroom capacity.

to the distribution customers. The "Enabled Electrification" is further broken down among load allocation ("Reserved Operational Capacity") and reliability allocation.

Q. Is this method of cost allocation among DER customers and distribution customers appropriate and equitable?

A. Yes. From the standpoint of substation upgrades, to ensure reliable interconnection, no more than 152 MVA of Group Study and future DERs (141MVA of Ground Mounted and 11 MVA Rooftop) will interconnect in Marion-Fairhaven Group study area. Additionally, 189 MVA of distribution customer load would benefit from uninterrupted power supply during N-1 conditions at the substation. This same operational switching capacity will also allow for enablement of Electric Vehicles and Electric Heat Pumps as shown in Section 4 - Clean Energy Enablement.

The anticipated EPS upgrades, in addition to enabling renewable energy to fully support the Commonwealth's climate goals, also allow the Company to preserve and maintain safe, reliable operation of the EPS for all customers with high penetration levels of potentially disruptive DG, particularly solar PV. The key to maintaining safe, reliable operation is preserving operational flexibility under all scenarios for which the system is planned and designed to accommodate. As systems become more saturated with DG, it becomes increasingly difficult for the Company to preserve reliability and operational flexibility under all scenarios.

In addition to the substation reliability benefits to all customers, new distribution lines and line upgrades driven by DER growth are likely to create opportunities to rebalance feeders, reduce exposure and transfer load, which would lead to improved reliability and voltage quality for customers.

Furthermore, distribution customers will be able to install in aggregate 11 MVA additional of rooftop solar. Therefore, this (141/[11+189+141]) or 41% allocation of substation costs to DER customers is appropriate and likewise [(189/[189+11+141]) + (11/[189+11+141])] or 58.6% allocation of substation costs to distribution customers is appropriate.

Table 14 –Substation Capacity/Cost Allocation

Cost Allocation - Substation		
Group Study 1 - Distribution and DER Customer Substation Capacity/Cost Allocation		**$92.3M**
Station	**MVA**	**Investment ($M)**
Enabled Load Allocation - Distribution Customer Benefit	**52.6**	**$14.2**
Enabled Reliability Benefit - Distribution Customer Benefit	**136.7**	**$37.1**
Enabled Future Small DER - Distribution Customer Benefit (Including Future Small DG)	**11**	**$2.9**
Enabled DER by Total Investments - DER Customer Benefit	**141**	**$38.1**
Enabled Queue Large DER (Group Study Large DER)	49	
Enabled Future Large DER (Future Large DERs)	92	

From the standpoint of distribution feeder upgrades, with the significant upgrade of existing distribution feeders and addition of new distribution feeders, the proportionate allocation of electrification enablement capacity of 206 MVA (including a 114 MVA of operational reliability capacity) and 11 MVA of rooftop solar enablement would directly benefit Distribution customers. When compared against the 303 MVA DER enablement at the distribution feeder level, the (303/[206+11+303]) or 58.2% allocation of the distribution feeder costs to DER customers is appropriate while distribution customers should not likewise be allocated any more than (206/[206+11+303]) and (11/[206/11/303) or 41.8%.

Table 15 –Distribution Line Capacity/Cost Allocation

Cost Allocation - Distribution Line		
Group Study 1 - Distribution and DER Customer Distribution Line Capacity/Cost Allocation		$27.4M
Distribution	MVA	Investment ($M)
Enabled Load Allocation - Distribution Customer Benefit	114.4	$6.0
Enabled Reliability Benefit - Distribution Customer Benefit	91.6	$4.8
Enabled Future Small DER - Distribution Customer Benefit (Including Future Small DG)	11	$0.6
Enabled DER by Total Investments - DER Customer Benefit	303	$16.0
Enabled Queue Large DER (Group Study Large DER)	49	
Enabled Future Large DER (Future Large DERs)	254	

Q. Why does Eversource consider operational reserve a significant necessity belonging to distribution customers?

A. As noted above, Operational Reserve is the capacity allocated to operate the distribution system safely and, as such, it cannot be used for additional DER interconnection. As stated previously, Eversource's key planning objectives is to maintain the same level of safe, reliable service for all customers. This means that the EPS should preserve safety and reliability under normal conditions, emergency conditions, and scheduled maintenance conditions. Infrastructure reinforcements proposed as part of the CIP are not to be fully subscribed by DER capacity. By excluding operational capacity from the total Comprehensive Group Solution capacity as a first step in the CIP proposal cost allocation methodology, EDC planners can effectively account for DER in Long-Term system assessments.

Q. Why does Eversource consider capacity reserved for "Future Rooftop DER" a benefit to be maintained for distribution customers?

A. Rooftop solar production is behind the meter and offset the distribution customer load at the point of interconnection. The aggregated sum of all rooftop DER generation, from Distribution Customers, during light load condition limits the amount of ground mounted DER that can be interconnected to the substation. By reserving capacity for distribution customer as rooftop solar capacity, it will not be used by ground mounted solar. Eversource is preserving the ability of distribution customer to install their own rooftop solar systems and participate in the clean energy economy and furthering the Commonwealth's progress towards achieving the 2050 Decarbonization Roadmap. For this reason, capacity reserved for rooftop solar will always be available in the 2050 planning horizon or until fully utilized.

VII. BENEFITS TO DISTRIBUTION CUSTOMERS AND ALIGNMENT WITH ENERGY POLICIES

Q. Would you explain further how capacity enabled by the CIP Facilities will benefit distribution customers?

A. The primary benefit to distribution customers by the upgrades to the distribution EPS under the CIP is improved reliability and an ability to accommodate future electrification that is needed to meet the Commonwealth's 2050 Decarbonization Goals. System upgrades proposed as part of the Group Study Solution include the installation of new substation transformers and distribution lines, upgrade of existing transformers and distribution lines and rearrangement of the distribution feeder/line system. Overall, these changes are expected to improve the reliability of all customers (new and existing). For example, new distribution lines proposed under this solution can be used to create new distribution circuit ties with the overall goal of reducing customer count by zones. This reduces the number of customers affected by feeder or line outages. Furthermore, additional capacity that is needed to accommodate the Group Study DGs also provides additional distribution load capacity for customers.

Q. What are the decarbonization policies that encourage electrification?

A. In its 2050 Decarbonization Roadmap,[30] the Commonwealth has laid out aggressive objectives for decarbonizing all aspects of society with the key element of the strategy revolving around electrification of sectors previously directly consuming primary energy

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[30] https://www.mass.gov/info-details/ma-decarbonization-roadmap

resources such as oil, gas, or gasoline. Although the proposed upgrades to the EPS in this CIP Filing are in accordance with the Provisional Program Order, not driven nor informed by the need for future electrification, the outlined system upgrades provide a quantifiable electrification benefit to distribution customers. By ensuring that throughout the transition to a decarbonized society and the expected associated significant electric load increases further system upgrades are either deferred into the future, minimized, or the need is eliminated entirely. To clearly articulate the extent of this benefit, the Company has conducted analysis on the expected load growth in the region serviced by the Marion-Fairhaven CIP, with a specific focus on the electrification of heating applications, as well as the electrification of transportation.[31,32]

Q. How has Eversource considered the electrification of transportation?

A. One key corner stone of the Commonwealth's decarbonization roadmap is the transition from internal combustion engines ("ICE") to electric vehicles ("EV") wherever possible. This brings several benefits such as the potential of improving air quality in densely populated spaces. Most of all however, it significantly reduces the primary energy need of vehicles while providing the ability for that energy to come from renewable sources. However, this transition creates an entirely new class of mobile electric loads for utilities

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31 This long-range electric demand assessment focuses on the overall potential of electric demand, it does not aim to forecast when certain levels of electrification will be reached, but rather what percentage of electrification will be supported by the proposed investments.

32 At no point was the long-range electric demand assessment used for sizing the proposed system upgrades.

to account for across their system while all the energy typically transported via a well-established gasoline and diesel infrastructure is transferred onto the EPS. The Company has made it one of its key priorities to understand this future impact.

As part of D.P.U. 20-74, the Company was awarded funds to develop advanced forecasting capabilities, which include the modelling of electric vehicles. The Company has utilized initial results from this project to develop electric vehicle charging profiles for the region serviced through the Marion-Fairhaven Group area. The Company uses mobility data sets provided by StreetLight Data as part of this project.[33] These data sets provide the Company visibility into the driving behavior of all light duty vehicles in the Commonwealth at a zip-code aggregated level. Most importantly, when and where vehicles terminate trips and thereby creating the potential for a charging event. This enables capturing charging impacts that occur based on regional travel patterns.

Given that every region has its own mobility needs depending on the customer it services, the residential and commercial infrastructure, or potential tourist destinations, a generic observation was not advisable. Locationally specific data sets were created for each of the bulk stations in each studied group separately. The combination of number of vehicles arriving as well as their average distance driven provides the input to creating charging profiles. Figure 4 shows of the number of vehicles terminating trips in the Marion-

[33] The Company utilizes the same vendor as the MA DOT allowing for uniform data sets.

Fairhaven Group area every 15-minute interval.[34] Clearly visible in the data the different mobility behavior depending on the type of and time of day.

Utilizing this arrival data as well as average distance traveled information provided in the same data sets, charging profiles can be calculated for every 15-min interval. The resulting cumulative profiles for each substation and group region highlight how much charging potential exists. Based on the Commonwealth 2050 Decarbonization Pathway "All Options",[35] expected adoption rates for every 5 years can be concluded.

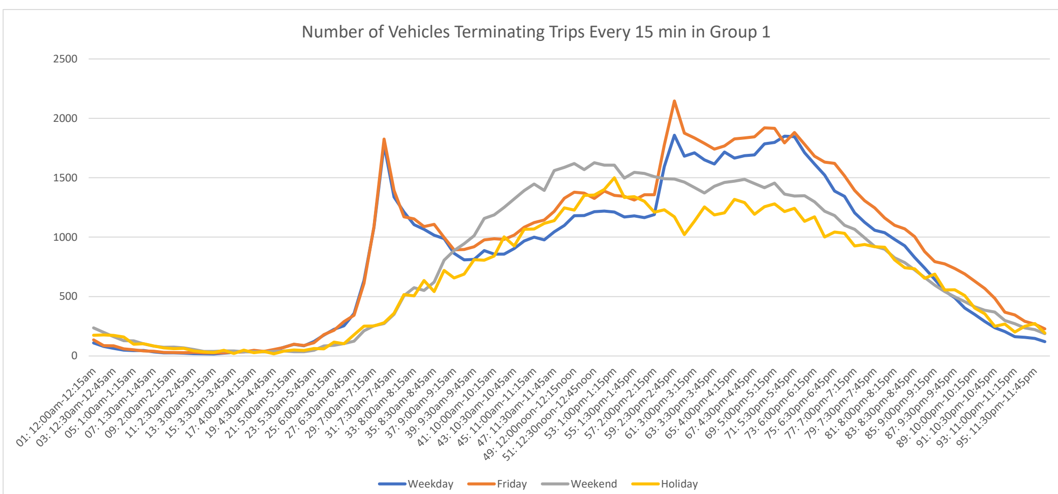

Figure 5: Vehicle Arrival Data Group 1

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[34] The Company utilizes 2019 mobility data sets as the last year prior to pandemic related impacts on mobility behavior.

[35] This is the "benchmark compliant" decarbonization pathway, using midpoint assumptions across most technical parameters.

Table 16 below highlights the overall enabled electrification by bulk station and Group total, as well as how much, time coincident during peak events, would be attributed to electric vehicles if 100%[36] of light duty[37] vehicles converted[38,39,40]. Hereby, the "Total Operational Capacity after Comprehensive Upgrade" represents the sum of existing operational capacity and enabled operational capacity. Using the charging profiles created from the mobility data, the 6pm Peak Contribution of Light Duty EVs was calculated and compared to the "Available Operational Capacity" and the "Total Operation Capacity."

For the entire group, electric vehicles are expected to raise the summer peak load from the 2021 value by a total of 27.2 MVA (Coincident Peak). As shown below, without any upgrades, the existing stations would be able to enable between 0% to 71% of Electric Vehicle charging demand during Summer Peak. After the Group Study upgrades, the *upgraded* stations would be able to enable 100% of Electric Vehicle charging demand.

[36] The presented results assume availability of charging infrastructure to meet demand.

[37] Commercial and heavy-duty vehicles are excluded from this assessment as they provide very localized, high intensity load additions (step loads), which are considered under additional load development.

[38] Specific charging power of each vehicle is not important. In a large observed set, the coincidence factor correlates directly with the charging power of a vehicle leaving any bulk impacts the same.

[39] No considerations for utility charge management programs were made in the evaluation. Any utility owned or incentivized charge management program has the potential of reducing peak load contribution through EVs.

[40] No considerations for potential future third party virtual power plant aggregations under FERC Order 2222 were made as it is to date unclear if these aggregations would increase or decrease potential system peak contributions from EVs.

Because the Group Study did not trigger the need to upgrade Arsene substation, Electric Vehicle charging demand is not enabled at this station.

Table 16: Substation Electric Vehicle Summer Impact

Substation Name	Available Operational Capacity (MVA)	Enabled Operational Capacity (MVA)	Total Operational Capacity (MVA)	Coincident Peak EV Load (MVA)	Available Support of Electrification	Enabled Support of Electrification
Arsene Street 654	0	0	0	8.7	0%	0%
Crystal Spring 646	0	44.2	44.2	5.8	0%	100%
Rochester 745	5.3	50.0	55.3	7.9	67%	100%
Wing Lane 624	3.4	42.5	45.0	4.8	71%	100%
Total	8.7	136.7	145.5	27.2		

Q. How has Eversource considered the electrification of heating?

A. Besides the transition from combustion to electric vehicles, the largest driver of electric load on the system is expected to stem from the proliferation of heat pumps. Electric heat pumps, much like electric vehicles, have the advantage of reducing the primary energy need of buildings significantly through the heat pump's heating coefficient which is >100% with the exception of rare conditions. Aggressive steps have already been taken with the latest funding available to homeowners to deploy heat pumps by providing up to $10,000 in incentives.[41] This transition to electric load for heating is expected to bring a significant increase in electric loads as energy, which has so far been transported via the well-established natural gas, heating oil, and propane infrastructure, is transferred to the electric

41 https://www.masssave.com/en/saving/residential-rebates/heat-pump

power system. However, unlike other load drivers, electric heating occurs, by definition, in winter months. The Company expects to see increasing winter peaks up to and exceeding the current summer peaks.

To understand the total accessible electric heating potential, the Company has utilized the parcel information provided from MassMapper[42] in combination with the Gridtwin Software to identify the total residential[43] building square footage within the service territory of each bulk station[44]. Actual heating load values will vary from the assessment present here depending on: (a) incentives to improve building envelope efficiency; (b) incentives of geothermal vs. air sourced heat pumps; (c) the final percentage of resistive electric heating; (d) the amount of registered square footage actually heated; and (e) the role gas or other combustion heat sources will continue to play.[45] However, a reasonable estimate can be determined. Using the available building square footage and an estimated peak heating demand can be estimated.[46]

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42 https://maps.massgis.digital.mass.gov/MassMapper/MassMapper.html

43 Assumptions were made around what building sqft qualify. The total square footage for buildings identified in the regions varies but is on average 30-40% higher than the numbers presented by the Company.

44 https://www.mass.gov/files/documents/2016/08/wr/classificationcodebook.pdf

45 The Company is evaluating the technical potential for electric heating applications without assumptions on improvements to building envelope efficiency or heat pump efficiencies

46 The Company used a heating coefficient of 2 as well as a peak heat demand of structures at 5.8 Watts/sqft. This results in an electric demand of 2.9 Watts/sqft, or 2.9 kW for every 1000 sqft of building space.

The following tables show the electrification impacts for winter scenarios using both EV and heat pump impacts, as well as the substation and distribution operational capacity. For the Substation Electrification Winter Impact, the existing substation capacity is insufficient. As shown below, without any upgrades, the existing stations would be able to enable between 0% to 47% of transition to electric heat pump winter peak demand coupled with coincident electric vehicle winter morning charging demand. After the Group Study upgrades, the *upgraded* stations would be able to enable 100% of Electrification demand. Because Group Study did not trigger the need to upgrade Arsene substation, electrification demand is not enabled at this station. Once the proposed projects are completed, a broader electrification is supportable.[47]

Table 17: Substation Electrification Winter Impact

Substation Name	Available Operationa l Capacity (MVA)	Enabled Operational Capacity (MVA)	Total Operational Capacity (MVA)	Coincident Peak EV Load (MVA) [Winter am]	Coincident Heat Pump Load (MVA)	Total Coincident Winter Electrification (MVA)	Available Support of Electrification	Enabled Support of Electrification
Arsene Street	0.0	0.0	0.0	5.5	21.9	27.4	0%	0%
Crystal Spring	0.0	44.2	44.2	4.5	30.2	34.7	0%	100%
Rochester	8.2	50.0	58.2	2.8	11.4	14.2	58%	100%
Wing Lane	10.0	42.5	52.5	2.9	26.7	29.6	34%	100%
Totals	**18.2**	**136.7**	**154.9**	**15.7**	**90.2**	**105.9.0**		

[47] Presented numbers are based on an assumed conversion of 100% of square footage to electric heat pumps. Depending on the actual conversion to heat pumps, this number might go down, or up, if electric heating is realized through resistive heating.

Q. Did you consider the electrification forecast as part of the design process to arrive at the proposed solution?

A. No, the electrification assessment was conducted to evaluate additional customer benefits from infrastructure upgrades triggered by the proposed projects under the Provisional Program Order to facilitate safe, reliable interconnection of distributed generation in several areas that are saturated. These electrification assessments were not inputs to the design process that led to the proposed solution but were evaluated post-process.

Q. Did you consider load growth forecasts aside from the electrification components to arrive at the proposed solution?

A. No, the Company did not consider a load growth forecast as part of its analysis. The analysis is conducted based on the most recent load data on the system and shows how much additional load driven by economic development (less the electrification of vehicles and heating) can be added. Table 18 below outlines this remaining operational capacity in both winter and summer scenarios, before and after the proposed project following full electrification assumptions.

Table 18

Substation	Summer Conditions after Electrification		Winter Conditions after Electrification	
	Operational Capacity (MVA)	Operational Capacity after project (MVA)	Operational Capacity (MVA)	Operational Capacity after project (MVA)
ARSENE STREET 654	0.0	0.0	0.0	0.0
CRYSTAL SPRING 646	0.0	38.4	0.0	9.5
ROCHESTER 745	0.0	47.4	0.0	44.0
WING LANE 624	0.0	41.1	0.0	22.9

Q. Would you please summarize the distribution customer benefits from the CIP?

A. The aggressive decarbonization objectives laid out by the Commonwealth will increase electric system demand. The proposed Marion-Fairhaven CIP upgrades do support these electrification goals to some extent, and have the potential to delay, defer, or reduce the need of future system investments. Only Arsene Street 654 is shown to be reaching the limits of enabled capacity because it is a single ended station whose load carrying capability (LCC)[48] is dependent on the ability to transfer load to neighboring stations. Any remaining enabled capacity can be applied to a wide variety of additional step loads, which might be the result of electrification initiatives (fast chargers, fleet chargers, heavy duty vehicle electrification[49]) or commercial development (new factories, offices, lab space, manufacturing).

Based on the Commonwealth's policy goals, these stations would need to be upgraded before 2050 to accommodate electrification growth. Eversource's proposal allows the Provisional Program DER to be interconnected while also reducing the ayerage cost to

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48 LCC is defined as the Firm Capacity plus Distribution Transfer Switching Capacity.

49 The Company does not consider battery storage systems as a driver for peak station load as all future storage systems are expected to be under Distributed Energy Resource Management System (DERMS) control as proposed by the Company in D.P.U. 21-80, which will prevent them from contributing to peak conditions (charge and discharge alike). However, it must be stated that the proposed system upgrades will increase the available system capacity for battery storage projects by an undefined amount pending on the amount of curtailment feasible for battery projects, this number can be larger or smaller. The financial feasibility is highly dependent on state incentives and the development of bulk energy market values. Higher market values or state incentives would allow higher battery curtailment and more resources, vice versa, less funding and markets value would decrease financial feasibility and increase the need for unrestrained market access and less curtailment.

upgrade the stations for future load growth (as a byproduct). The Company does not expect stations upgraded as part of the group study to be upgraded again to accommodate additional solar above the currently enabled capacity. At this point, a new substation would likely be required to accommodate the incremental solar generation.

As noted previously, system upgrades proposed as part of the Group Study Solution include the installation of new substation transformers and distribution lines, upgrade of existing transformers and distribution lines, and rearrangement of the distribution feeder/line system. Overall, these changes will significantly improve reliability for all customers (new and existing). For example, new distribution lines proposed under this solution can be used to create new distribution circuit ties with the overall goal of reducing customer count by zones. This reduces the number of customers affected by feeder or line outages.

VIII. BENEFITS TO LOW-INCOME AND ENVIRONMENTAL JUSTICE POPULATIONS

Q. Would you please explain how the CIP will affect low-income and environmental justice populations?

A. The impacts of the Marion-Fairhaven CIP on low-income and environmental justice populations is identified further in Exhibit ES-Engineering Panel-2, Worksheet 5, "Capital Investment Projects (CIP) & Project Need – Group 1" (Impact on LMI_EJ Population). Worksheet 5 identifies the population served out of the Marion-Fairhaven Study Group

Stations that falls within the EJ population criteria defined for 2020 block groups and census tracts in Bristol and Plymouth counties.[50]

As a result of this provisional CIP Filing, the electric system supplying the 8,722 EJ population customers will see approximately 170% increase in annual energy served from renewable sources. Currently, approximately 83 GWh of energy is supplied from renewable resources in the Marion-Fairhaven Group Study area. The Marion-Fairhaven CIP upgrades proposed in this provisional filing will result in approximately 141 GWh of annual energy being generated from renewable resources.

The CIP upgrades proposed in this provisional filing will also result is significant reliability improvement for the electric system supplying the 8,722 EJ population customers.

Q. Would you please describe any projects in the CIP that will be constructed in an environmental justice neighborhood?

A. The approximate electric boundary supplied by the substations in this group is significant in scope - covering an area in excess of 110 square miles, as shown in Figure 6 below.

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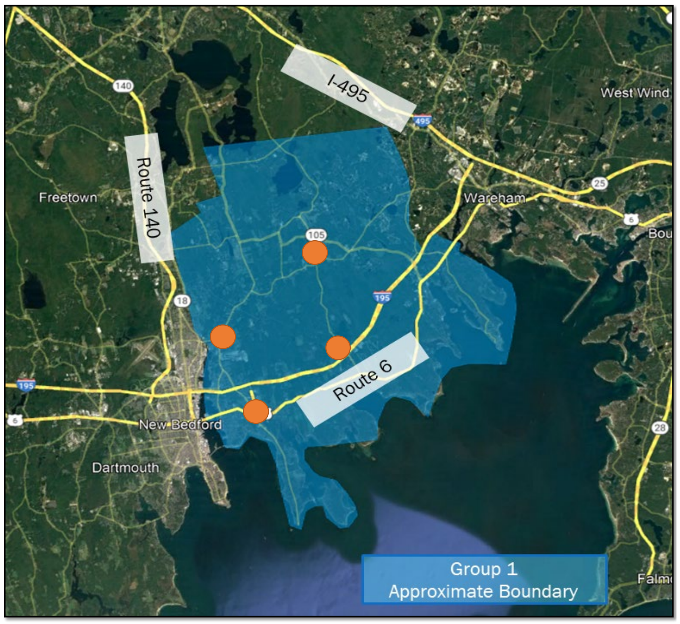
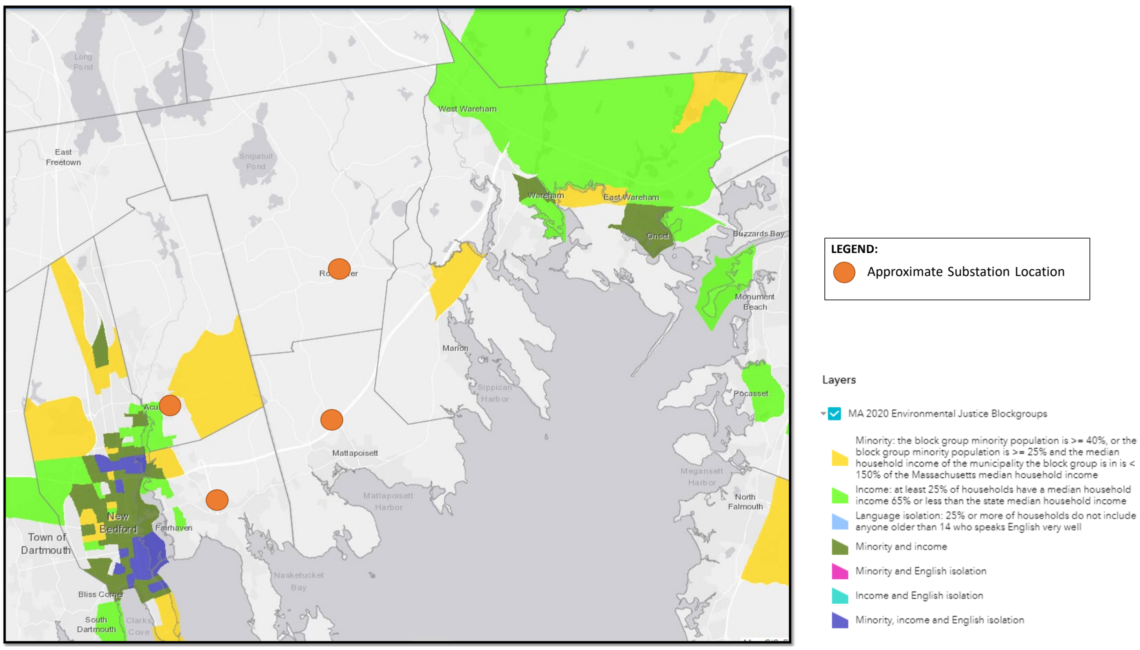
50 Refer to Massachusetts 2020 Environmental Justice Populations: Massachusetts 2020 Environmental Justice Populations (arcgis.com).

Figure 6



Substation construction work proposed in this CIP filing will be concentrated on upgrades that are <u>outside</u> of the environmental justice neighborhoods. Substation upgrades would be followed by associated distribution feeder/line upgrades. Based on the location of existing and future ground mounted DER installations, existing distribution lines in EJ communities could become candidates for upgrades. This could result in overhead and underground utility construction work impacting EJ communities. Additionally, based on the capacity and reach of the existing distribution system, new distribution lines may be required. This work could result in new overhead pole lines or underground cable-in-conduit infrastructure. These substation and distribution upgrades will result in electric system reliability improvements for the EJ communities shown in Figure 7 below.

Figure 7



Q. When will the Company know specific impacts to EJ Communities?

A. The Company plans to complete permit applications for submittal to the Department by 2023 unless it is possible to obtain the permits locally. The Company will include a description of its community outreach, including to EJ communities, in such applications.

Q. Please describe Eversource's plan to engage stakeholders in environmental justice communities?

A. Eversource is committed to being a strong environmental partner and a responsible steward in the communities it serves. This commitment requires the Company to provide meaningful opportunities for members of EJ communities to be informed about and participate in community discussions of Company projects, especially where those members are burdened with existing negative environmental circumstances and justice disparities. The Company also understands that reliable electric service is vital to public safety, the health and welfare of the Commonwealth's citizens, and sustainable economic development opportunities. These justice and reliability goals can be accomplished simultaneously. To promote a more robust system and to properly plan for and address the Commonwealth's energy needs, including further integration of clean energy supply sources, in a timely way, the Company is developing and implementing these CIPs consistent with the Commonwealth's environmental and resource use laws and policies, including recent Commonwealth enactments of laws and regulations aimed at supporting EJ communities. The Company plans to take proactive steps to promote community involvement during the planning and execution of the CIP, including:

- Inclusive outreach expanded to specifically provide information to and gather feedback from EJ communities affected by major CIP upgrades, including through translated materials to ensure non-English speaking populations have access to relevant project information;
- Appropriate mitigation planning; and
- Detailed analyses and action plans to ensure that the proposed major CIP upgrades appropriately avoids and minimizes impacts.

Q. How does Eversource plan to assess the impact on EJ communities during the CIP planning and execution?

A. The type of utility infrastructure projects, such as the proposed CIPs, are universal throughout the Commonwealth. These kinds of infrastructure facilities exist in essentially every city and town in the state (including specifically within the Marion-Fairhaven group substation project areas) because these are the facilities that are needed to deliver the essential service of electric power to homes and business. Further, the increased capacity and reliable power supply provided by the CIPs is designed to integrate clean energy and support electrification throughout the Group Study area, which will benefit all communities in the Group Study area, including EJ communities. Additionally, the upgraded substation and distribution lines will permit the further integration of clean energy generating sources and support electrification through the Group Study Area, all of which will benefit EJ communities. As the Company continues and broadens its outreach and communications with EJ communities, to the extent those conversations result in new ideas regarding EJ community-specific mitigations, or changes to the Company's approach to mitigation (described below), the Company will respond.

As described, this CIP proposal does not include the build out of substations in EJ communities. Additionally, the CIPs are not generating any energy, nor are the CIPs manufacturing any products or emitting any industrial discharges that could potentially be point sources of pollution. Nonetheless, the Company is mindful of the potential impacts that the CIPs may pose in relation to the concerns of abutters, including EJ populations, particularly during construction of the lines and substation work. Eversource is committed to working with EJ Communities to understand, mitigate or eliminate impacts to the extent possible in conjunction with the obligation to assure that safe and reliable power is available to all customers in all communities.

IX. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 22-47

TESTIMONY OF

ASHLEY N. BOTELHO

ON BEHALF OF
NSTAR ELECTRIC COMPANY
d/b/a EVERSOURCE ENERGY

EXHIBIT ES-ANB-1

April 15, 2022

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<u>EXHIBITS</u>

Exhibit ES-ANB-2	CIP Tariff
Exhibit ES-ANB-3	Illustrative 15-year Revenue Requirement
Exhibit ES-ANB-4	Illustrative Bill Impacts

I. INTRODUCTION

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 Acting Director, 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 and in January 2018, promoted to the role of Manager, Revenue Requirements, Massachusetts. I was named Acting Director for

Revenue Requirements, Massachusetts in March 2022.

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 Electric, D.P.U. 22-22, and NSTAR Gas, D.P.U. 19-120, as well as 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 have sponsored testimony and exhibits in the Company's Performance-Based Rate Adjustment in D.P.U. 21-106 and the Company's filings in D.P.U. 21-80 for its 2022-2025 Grid Modernization Plan and Advanced Metering Infrastructure proposals.

II. OVERVIEW OF FILING

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to submit Eversource's capital investment project ("CIP") proposal under the Provisional Program established by the Department in its

Order on Provisional System Planning Program, D.P.U. 20-75-B (Nov. 24, 2021) (the "Provisional Program Order").[1] Given that electric power system ("EPS") equipment saturation limits have been reached in certain Affected Group Studies,[2] and as a result, associated network upgrade costs have significantly exceeded past average interconnection costs, the Provisional Program Order established a Provisional Program to facilitate viable interconnection for distributed generation ("DG") facilities. The Provisional Program is enabled through implementation of a modified cost allocation and cost-recovery methodology to address imminent short-term DG interconnection cost concerns. Specifically, my testimony:

- Submits for authorization a Capital Investment Project Tariff authorizing cost recovery for CIPs that was prepared jointly with Massachusetts Electric Company d/b/a National Grid ("National Grid") in Exhibit ES-ANB-2;
- Presents an illustration of the Company's revenue-requirement analysis specific to the Marion-Fairhaven CIP in Exhibit ES-ANB-3; and
- Presents an illustrative estimate of the resulting rate and bill impacts based on the above revenue requirement in Exhibit ES-ANB-4.

Q. Please summarize the Company's illustrative revenue requirement analysis.

A. The Company presents an illustrative revenue requirement that considers all currently queued DER can interconnect in year 4 with 100 percent enabled capacity in year 15

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[1] The Department defines a CIP as "a project proposed for cost recovery by a Distribution Company under the proposed distribution system planning process for the assessment of the interconnection and integration of DG…" The Department further clarified that CIPs "may include but are not necessarily limited to: (1) substation transformer replacements; (2) reconductoring of distribution feeders; (3) distribution protection measures; and (4) transmission related upgrades triggered by resources interconnecting to the distribution system." D.P.U. 20-75, Att. A at 6 n.2. see also D.P.U. 20-75-B n.12.

[2] Provisional Program Order at 26-27 defines and identifies the Affected Group Studies. Eversource's Affected Group Studies include: (1) Marion-Fairhaven; (2) Plymouth; (3) Cape Cod; (4) Freetown; (5) Dartmouth-Westport; (6) New Bedford; and (7) Plainfield-Blandford.

("Scenario 1"). For purposes of determining potential rate impacts to customers over the 15-year horizon, the Company calculated a 15-year illustrative revenue requirement based on planned capital spending for the Marion-Fairhaven CIP in calendar years 2023 through 2025, including the associated CIP Fees as described further in this testimony. I calculate the Company's illustrative revenue requirement associated with the Marion-Fairhaven CIP to range between approximately $5 million and $13 million annually over the 15-year timeframe. The Company has also calculated an average levelized revenue requirement in Exhibit ES-ANB-3 over the 15-year horizon of approximately $8 million annually.

Q. Please summarize the bill impacts associated with the construction of the Marion-Fairhaven CIP?

A. Based on the levelized revenue requirement calculated in Exhibit ES-ANB-3, a typical residential customer would experience a monthly bill increase of approximately 0.2 percent associated with the construction of the Marion-Fairhaven CIP on average over the 15-year time horizon. Annual bill impacts will vary based on the actual revenue requirement over time. The Company has presented the estimated bill impacts in Exhibit ES-ANB-4.

Q. Are other witnesses testifying on behalf of the Company in this proceeding?

A. Yes. The Company is submitting its panel of engineering experts supporting the Marion-Fairhaven CIP: (1) Diguanto Chatterjee; (2) Lavelle A. Freeman; (3) Juan F. Martinez and (4) Gerhard Walker (the "Engineering Panel"). The Engineering Panel testimony explains the methodology used by the Company to allocate costs between distributed generation ("DG") projects interconnecting to the Marion-Fairhaven CIP and distribution customers that will benefit from the construction and operation of the Marion-Fairhaven CIP. Their testimony also addresses the potential distributed energy resources ("DER") that the Marion-Fairhaven CIP may enable and the potential benefits to distribution customers in environmental justice communities, and generally, from the Marion-Fairhaven CIP.

III. CIP TARIFF PROVISIONS

Q. Please explain the CIP Tariff and its purpose.

A. The CIP Tariff was developed jointly by Eversource and National Grid to define the cost-recovery parameters that each distribution company will follow to compute recovery of eligible CIP costs.[3]

Q. Please describe Section 1.0 of the CIP Tariff.

A. Section 1.0 addresses the applicability of the Company's CIP Tariff. The CIP Tariff provides for the recovery of costs associated with CIPs approved by the Department to enable the interconnection of distributed generation facilities pursuant to the Provisional System Planning Program authorized under D.P.U. 20-75-B or as otherwise authorized by the Department. To be eligible for recovery, CIP costs must: (1) be preauthorized by the Department; (2) be solely attributable to preauthorized CIPs; and (3) be recorded as in-service by December 31 of each CIP Investment Year.

[3] National Grid is expected to submit CIPs to the Department for approval in the future.

The Company's recovery of costs for CIPs shall be through a combination of CIP Fees charged to Interconnecting Customers and a CIP Factor to be charged to distribution customers to recover the CIP Revenue Requirement. These terms are described below and defined in the CIP Tariff. The Company's rates for retail Delivery Service will be subject to adjustment to reflect the operation of the CIP Tariff.

Q. What is the purpose of the CIP Fee?

A. The CIP Fee would be assessed by a Distribution Company to an Interconnecting Customer associated with its Facility's pro-rata share of the costs of a CIP, which has been approved by the Department and of which the Interconnecting Customer's Facility is a direct beneficiary."[4] An Interconnecting Customer that proposes to connect in the defined area of a CIP, and will utilize the export capacity of the CIP, will be assessed the CIP Fee along with other Facility specific costs in the Interconnection Service Agreement ("ISA") executed with the Company and all such costs shall be payable in accordance with the terms of the ISA. Facilities seeking to connect to a distribution line connected to the CIP area but outside the system modifications enabled by the CIP Fee will incur additional costs for any system modifications required by the distribution system impact study for that Facility as described in the testimony of the Engineering Panel.

The CIP Fee will be treated as a contribution in aid of construction and therefore be adjusted to include federal and state income taxes. Each CIP Fee shall be available to Interconnecting Customers executing an ISA for a project in the CIP area for a term of 15

[4] D.P.U. 20-75, Att. A at 1. See also D.P.U. 20-75-B n.14.

years beginning with the first day of the month following Department approval of the respective CIP and CIP Fee. The CIP Tariff will contain appendices for each CIP to be approved by the Department including the associated CIP Fee. The Company has outlined information to be included in the CIP Tariff for each authorized CIP as part of Appendix A of the CIP Tariff.

Q. How is CIP Fee defined in the CIP Tariff?

A. The term "CIP Fee" is defined in Section 2.1 consistent with D.P.U. 20-75, Att. A. at 1, as:

> a fee assessed by the Company to an Interconnecting Customer associated with its Facility's pro-rata share of the costs of a CIP as described in Section 3.0, which has been approved by the Department and of which the Interconnecting Customer's Facility is a direct beneficiary. Each CIP shall have a CIP Fee specific to the CIP.

Q. How is the term "CIP Revenue Requirement" defined in the CIP Tariff?

A. CIP Revenue Requirement is defined in Section 2.5 of the CIP Tariff as:

> [T]he revenue requirement associated with CIP Plant Investment and CIP expenditures that have been authorized to be deferred to a regulatory asset for each CIP Investment Year prior to the CIP Recovery Year. The Company will calculate a separate CIP Revenue Requirement for each CIP approved by the Department and recorded as in-service. For the year in which a CIP is placed into service, the CIP Revenue Requirement will be calculated on a monthly basis. The CIP Revenue Requirement for subsequent years shall be calculated based upon the average of the beginning and ending calendar year balances. The CIP Revenue Requirement will be calculated to recover (1) the monthly revenue requirement for the CIP recorded as in-service in the CIP Investment Year immediately prior to the CIP Recovery Year; (2) the average annual revenue requirement for the calendar year ending December 31 of the CIP Investment Year two years prior to the CIP Recovery Year, for cumulative CIP Investment recorded as in-service in CIP Investment Years two years prior to the CIP Recovery Year; and (3) the average annual revenue

> requirement for the calendar year following the most recent CIP Investment Year on cumulative CIP Investment recorded as in-service through the CIP Investment Year immediately prior to the CIP Recovery Year.

Q. Is the Company proposing to limit the annual increase in the total CIP Revenue Requirement?

A. Yes. The annual increase in the total CIP Revenue Requirement for all CIPs to be reflected in the proposed CIP Factors ("CIPFs") shall not exceed one and one-half percent (1½%) of intrastate operating revenue as reported in the Company's Federal Energy Regulatory Commission Form 1, page 300, line 27, for the calendar year prior to the proposed change in CIPFs. Intrastate operating revenue shall also include an adjustment for electric supply for those customers who were with competitive suppliers during the prior calendar year. To the extent that the application of this revenue cap results in an annual increase to be reflected in the CIPFs that is less than that calculated in accordance with Section 4.1 of the CIP Tariff, the difference shall be deferred with interest calculated at the customer deposit rate and included in the determination of the CIPFs in subsequent years, subject to the revenue cap for those years. See D.P.U. 20-75-B at 7.

Q. How is a CIPF defined in the CIP Tariff?

A. The CIPF is a reconciling, non-bypassable, and volumetric dollar-per-kilowatt-hour ("kWh") charge. The CIPF shall be determined in accordance with a formula provided in Section 4.1 of the CIP Tariff. The Company proposes that the CIPF shall be applied to all bills issued by the Company shall be assessed to the billed kWh of all retail delivery service customers, and will be identified as "Capital Investment Project Charge" on customer bills.

Q. How will customers participating in the Company's Solar Massachusetts Renewable Target ("SMART") Program be billed?

A. Customers participating in the Company's SMART Program will be billed the CIPF assessed to the sum of the net kWh recorded on their solar tariff generation unit's production meter and the net kWh recorded on the customer's revenue meter. By doing so, SMART customers will not be able to bypass the CIPF.

Q. How is CIP Plant Investment defined in the CIP Tariff?

A. CIP Plant Investment is defined in Section 2.3 as:

> the capitalized costs of CIPs recorded as in-service on the Company's books, including cost of removal, and is used and useful at the end of the CIP Investment Year that is prior to the CIP Recovery Year. Capitalized cost of CIPs shall include applicable overhead and burden costs subject to the test provided in Section 5.0. CIP Plant Investment shall be reduced by all CIP Fees received by the Company, excluding the amount of federal and state income taxes included in the CIP Fees. For any CIP Fees received after recovery of the CIP Revenue Requirement begins through the CIPF, amounts for CIP Plant Investment, ADIT, ARD, Depreciation Expense, and any other applicable amount associated with each applicable CIP will be adjusted in the year the CIP Fee(s) was received to reflect the impact of the receipt of CIP Fee(s).

Q. What CIP expenditures does the Company propose to be deferred to a regulatory asset?

A. The Company's CIP Fees and Reconciling Charge do not include any transmission electric power system upgrade costs. Any transmission costs association with the CIP are anticipated to be recovered through Local Network transmission service charges under the applicable provisions and schedules of the FERC-approved ISO New England Inc.

Transmission, Markets and Services Tariff, and the applicable Schedule 21-NSTAR and Schedule 21-ES Local Service Schedules. In the event that these transmission costs are not eligible to be included in the Local Network transmission service charges, the Company should be eligible to establish a regulatory asset for those costs.

Q. How does the CIP Tariff address overheads and burdens associated with annual CIP investment?

A. The CIP Tariff states in Section 5.0 that, for purposes of CIPF calculations, the Company will perform an overhead and burdens test to demonstrate that actual overhead and burdens costs charged to CIPs are incremental to amounts recovered in base distribution rates and other reconciling mechanisms. This test will compare the actual O&M overhead and burdens and the amount included in base distribution rates in each year. If the actual O&M overhead and burdens exceed the amount included in base distribution rates, capitalized overheads and burdens recovered through a reconciling rate would be reduced by the amount of the excess. The Company will determine whether such reduction is required for all reconciling mechanisms that require such a determination once each year, and the determination shall be included in the Company's annual CIP cost recovery filing. In addition, the percentage of capitalized overhead and burdens assigned to CIPs is set equal to the ratio of CIP costs to total direct costs in any given year.

Q. Does the CIP Tariff explain how the Company will reconcile CIPF costs?

A. Yes. The Company will reconcile the difference between the amount authorized to be recovered through the prior year's CIPFs as approved by the Department and the actual revenue billed through the applicable CIPFs. Interest is calculated on the average monthly balance using the customer deposit rate. As described above, the CIP Fee will be treated as a contribution in aid of construction, which will offset the distribution system investments that will be recovered from all customers. The Company does not intend for the CIP Fee to be adjusted in the event that project costs are higher or lower than anticipated. Customers would receive the benefit to extent the Company can manage its capital projects at or below the estimated level.

Q. What information is included in Section 6.0 of the CIP Tariff?

A. Section 6.0 of the CIP Tariff addresses information to be filed with the Department to support approval of CIPFs on an annual basis. Proposed CIPFs would be filed with the Department by May 15th each year and would include the reconciliation of the amount recoverable through prior CIPFs, if applicable. The annual CIP cost recovery filing will include full project documentation and supporting information of all CIP expenditures recorded as in-service, with a narrative providing justification that the costs meet the cost recovery eligibility in Section 1.0 of the CIP Tariff, including identifying cost variances from the Company's project authorizations. The Company will also include the calculation of the revenue requirements per the terms of the CIP Tariff and the associated bill impacts.

IV. REVENUE REQUIREMENT

Q. Have you prepared illustrative revenue requirement calculations?

A. Yes. The Company prepared an illustrative revenue requirement that considers all currently queued DER can interconnect in year 4 with 100 percent enabled capacity in year 15. The Engineering Panel identified this as Scenario 1. For purposes of determining potential rate impacts to customers over the 15-year horizon, the Company calculated a 15-year illustrative revenue requirement based on estimated plant in service for the Marion-Fairhaven CIP in calendar years 2023 through 2025, including the associated CIP Fees anticipated to be received over that timeframe. The Company calculated the Net Present Value of the estimated annual revenue requirements from 2023 through 2037 using a discount rate of 6.71 percent and then divided this amount by 15 years to arrive at a levelized annual revenue requirement of $7,768,330 producing an average rate of $0.00034 ($/kWh).

Q. Have you derived the CIPF for effect?

A. No. The Company anticipates filing for its first CIPF following the first year that investments are placed in service and a CIPF is applicable to be recovered from customers for the Marion-Fairhaven CIP consistent with the terms of the CIP Tariff described above.

V. BILL IMPACTS

Q. What are the illustrative bill impacts associated with the proposed CIPF?

A. The Company has presented the estimated bill impacts associated with the construction of the Marion-Fairhaven CIP in Exhibit ES-ANB-4. A typical residential (R-1) customer consuming 516 kWh in a month would, on average, experience a total monthly bill increase of $0.24 or approximately 0.2 percent based on the illustrative levelized annual revenue requirement calculated in Exhibit ES-ANB-3. For NSTAR Electric's commercial and industrial ("C&I") customer classes, average monthly bill impacts would vary across rate classes ranging between 0.1 and 0.2 percent.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

CAPITAL INVESTMENT PROJECT

1.0 APPLICABILITY

This Capital Investment Project tariff provides for the recovery of costs associated with Capital Investment Projects ("CIPs") approved by the Department of Public Utilities (the "Department") to enable the interconnection of distributed generation facilities pursuant to the Provisional System Planning Program authorized under D.P.U. 20-75-B or as otherwise authorized by the Department. To be eligible for recovery, CIP costs must: (1) be preauthorized by the Department; (2) be solely attributable to preauthorized CIPs; and (3) be recorded as in-service by December 31 of each CIP Investment Year.

The Company's recovery of costs for CIPs shall be through a combination of CIP Fees assessed to Interconnecting Customers and a CIP Factor to be applied to the bills of all customers receiving service under the Company's distribution service tariffs, both defined herein. The Company's rates for distribution service are subject to adjustment to reflect the operation of this tariff.

2.0 DEFINITIONS

2.1 Capital Investment Project Fee (CIP Fee) is a fee assessed by the Company to an Interconnecting Customer and is associated with a DG Facility's pro-rata share of the costs of a CIP, which has been approved by the Department and of which the Interconnecting Customer's DG Facility is a direct beneficiary, and as further defined in Section 3.0. Each CIP shall have a CIP Fee specific to the CIP.

2.2 CIP Investment Year is the annual period beginning on January 1 and ending on December 31.

2.3 CIP Plant Investment is the capitalized costs of CIPs recorded as in-service on the Company's books, including cost of removal, and is used and useful at the end of the CIP Investment Year that is prior to the CIP Recovery Year. Capitalized cost of CIPs shall include applicable overhead and burden costs subject to the test provided in Section 5.0. CIP Plant Investment shall be reduced by all CIP Fees received by the Company, excluding the amount of federal and state income taxes included in the CIP Fees. For any CIP Fees received after recovery of the CIP Revenue Requirement begins through the CIPF, amounts for CIP Plant Investment, ADIT, ARD, Depreciation Expense, and any other applicable amount associated with each applicable CIP will be adjusted in the year the CIP Fee(s) was received to reflect the impact of the receipt of CIP Fee(s).

CAPITAL INVESTMENT PROJECT

2.4 CIP Recovery Year is the 12-month period for which the CIPF is in effect beginning on July 1 and ending on June 30 of each year.

2.5 CIP Revenue Requirement is the revenue requirement associated with CIP Plant Investment and CIP expenditures that have been authorized to be deferred to a regulatory asset for each CIP Investment Year prior to the CIP Recovery Year. The Company will calculate a separate CIP Revenue Requirement for each CIP approved by the Department and recorded as in-service. For the year in which a CIP is placed into service, the CIP Revenue Requirement will be calculated on a monthly basis. The CIP Revenue Requirement for subsequent years shall be calculated based upon the average of the beginning and ending calendar year balances. The CIP Revenue Requirement will be calculated to recover (1) the monthly revenue requirement for the CIP recorded as in-service in the CIP Investment Year immediately prior to the CIP Recovery Year; (2) the average annual revenue requirement for the calendar year ending December 31 of the CIP Investment Year two years prior to the CIP Recovery Year, for cumulative CIP Investment recorded as in-service in CIP Investment Years two years prior to the CIP Recovery Year; and (3) the average annual revenue requirement for the calendar year following the most recent CIP Investment Year on cumulative CIP Investment recorded as in-service through the CIP Investment Year immediately prior to the CIP Recovery Year.

2.6 Distributed Generation Facility (DG Facility) means a source of electricity owned and/or operated by the Interconnecting Customer that is located on the Customer's side of the point of common coupling, and all facilities ancillary and appurtenant thereto, including interconnection equipment, which the Interconnecting Customer requests to interconnect to the Company EPS. A DG Facility must submit an application to interconnect under the Company's Interconnection Tariff.

2.7 Electric Power System (EPS) is the electric power system owned, controlled, or operated by the Company to provide distribution service to its customers.

2.8 Interconnection Service Agreement (ISA) is the agreement between the Interconnecting Customer and the Company for interconnection service, as further defined in the Interconnection Tariff.

CAPITAL INVESTMENT PROJECT

2.9 Interconnecting Customer is the entity that owns and/or operates the DG Facility proposing to interconnect or is interconnected to the Company's EPS, with legal authority to enter into agreements regarding the construction or operation of the DG Facility.

2.10 Interconnection Tariff refers to M.D.P.U. No. 55, Standards for Interconnection of Distributed Generation, as amended from time to time.

2.11 Property Tax Rate is the Company's composite property tax rate determined in the Company's most recent base distribution rate case, calculated as the ratio of total annual property taxes paid to total taxable net plant in service.

3.0 CIP FEE

An Interconnecting Customer that proposes to connect in the defined area of a CIP, and will utilize the export capacity of the CIP, will be assessed the CIP Fee along with other DG Facility specific costs in the ISA executed with the Company and all such costs shall be payable in accordance with the terms of the ISA. DG Facilities seeking to connect to a distribution line connected to the CIP area but outside the system modifications enabled by the CIP Fee will incur additional costs for any system modifications required by the distribution system impact study for that DG Facility.

The CIP Fee will be treated as a contribution in aid of construction and therefore be adjusted to include federal and state income taxes. Each CIP Fee shall be available to Interconnecting Customers executing an ISA for a project in the CIP area for a term of 15 years beginning with the first day of the month following Department approval of the respective CIP and CIP Fee. This tariff contains appendices for each CIP and CIP Fee approved by the Department.

4.0 CIP FACTOR

The CIPF, as defined herein, is a non-bypassable, reconciling charge to be determined in accordance with Section 4.1 below, subject to the Department’s review and approval. The CIPF shall be identified as “Capital Investment Project Chg” on customer bills. Customers participating in the Company’s Solar Massachusetts Renewable Target Program will be billed the CIPF assessed

CAPITAL INVESTMENT PROJECT

to the sum of the net kWh recorded on their solar tariff generation unit's production meter and the net kWh recorded on the customer's revenue meter.

The annual increase in the total CIP Revenue Requirement for all CIPs to be reflected in the proposed CIPFs shall not exceed one and one-half percent (1½%) of intrastate operating revenue as reported in the Company's Federal Energy Regulatory Commission Form 1, page 300, line 27, for the calendar year prior to the proposed change in CIPFs. Intrastate operating revenue shall also include an adjustment for electric supply for those customers who were with competitive suppliers during the prior calendar year. To the extent that the application of this revenue cap results in an annual increase to be reflected in the CIPFs that is less than that calculated in accordance with Section 4.1, the difference shall be deferred with interest calculated at the customer deposit rate and included in the determination of the CIPFs in subsequent years, subject to the revenue cap for those years.

4.1 Rate Formula

$$CIPF_r = \frac{(CIPRR + PPRA) \times DRA_r}{FkWh_r}$$

And:

$$CIPRR = (RB \times PTRR) + DEPR + AMT + PTE$$

And:

$$RB = [(GP_P + ARD_P + ADIT_P) + (GP_C + ARD_C + ADIT_C)] \div 2$$

Where:

r	Designates a separate factor for each rate class.
p	The prior year.
c	The current year.
$CIPF_r$	The Capital Investment Project Factor, by rate class.
CIPRR	The CIP Revenue Requirement as defined in Section 2.5.
PPRA	The Past Period Reconciliation Amount defined as the difference between (a)

CAPITAL INVESTMENT PROJECT

the amount authorized to be recovered through the prior year's CIPFs as approved by the Department and (b) the actual revenue billed through the applicable CIPFs. Interest calculated on the average monthly balance using the customer deposit rate, as outlined in 220 CMR 26.09, shall also be included in the PPRA.

DRA_r The Distribution Revenue Allocator representing the percentage of final revenue requirement allocated to each rate class as determined in the Company's most recent base distribution rate case as follows:

Service Territory/Area	Rate Classes	Distribution Revenue Allocator
All	R-1/R-2	41.145%
All	R-2/R-3	4.575%
Greater Boston	G-1/T-1	3.446%
Greater Boston	G-2/T-2	27.907%
Greater Boston	G-3/WR	7.998%
Cambridge	G-0/G-1/G-6	0.829%
Cambridge	G-2	1.329%
Cambridge	G-3/SB1	0.856%
Cambridge	G-4	0.012%
Cambridge	G-5	0.018%
South Shore, Cape Cod, Martha's Vineyard	G-1/G-7	3.930%
South Shore, Cape Cod, Martha's Vineyard	G-2	1.088%
South Shore, Cape Cod, Martha's Vineyard	G-3	0.610%
South Shore, Cape Cod, Martha's Vineyard	G-4	0.008%
South Shore, Cape Cod, Martha's Vineyard	G-5	0.053%
South Shore, Cape Cod, Martha's Vineyard	G-6	0.008%
Western Massachusetts	23/24/G-0/T-0	2.626%
Western Massachusetts	G-2/T-4	1.159%
Western Massachusetts	T-2	1.495%
Western Massachusetts	T-5	0.498%
Eastern Massachusetts	S-1/S-2	0.315%
Western Massachusetts	S-1/S-2	0.095%

CAPITAL INVESTMENT PROJECT

Service Territory/Area	Rate Classes	Distribution Revenue Allocator
Total		100.000%

$FkWh_c$ The forecasted kWh to be delivered to the Company's retail delivery service customers.

RB The average annual Rate Base associated with the cumulative CIP Plant Investment, as defined in Section 2.3, based upon the beginning of the year and end of the year GP, ARD, and ADIT balances of the respective CIP Investment Year. For the year in which CIP Plant Investment is recorded as in-service, Rate Base shall be calculated using actual beginning and end of month balances for GP, ARD, and ADIT balances.

PTRR The pre-tax rate of return shall be the after-tax weighted average cost of capital established by the Department in the Company's most recent base distribution rate case, adjusted to a pre-tax basis by using currently effective federal and state income tax rates applicable to the period for which the CIP Revenue Requirement is calculated.

DEPR The annual depreciation expense associated with the average annual cumulative CIP Plant Investment recorded as in-service through the end of the calendar year prior to the Recovery Year. For the year during which the CIP Plant Investment is recorded as in-service, the Company shall calculate depreciation expense for use in the CIP Revenue Requirement by: (1) dividing the annual depreciation accrual rates, determined in the Company's most recent base distribution rate case by 12; and (2) applying the resulting rate to the average monthly plant balances during the year. Depreciation expense for subsequent years may be calculated based on the average of the beginning and end of year plant balances.

AMT The annual amortization expense associated with CIP expenditures other than CIP Plant Investment that the Department has authorized to be deferred to a regulatory asset.

CAPITAL INVESTMENT PROJECT

PTE The property taxes calculated based on a CIP's net taxable CIP Plant Investment multiplied by the Property Tax Rate defined in Section 2.11. Property taxes will be excluded in the CIP Revenue Requirement in the first Recovery Year following the CIP Investment Year in which the eligible taxable plant went into service. Property taxes will be included in the CIP Revenue Requirement beginning in the second Recovery Year at 50% of the annual property tax amount. In subsequent years, the CIP Revenue Requirement will reflect a full year of property taxes.

GP The cumulative Gross Plant Investments, or capitalized costs of CIP Plant Investments recorded on the Company's books for CIPs. Actual capitalized cost of CIPs shall include applicable overhead and burden costs subject to the test provided in Section 5.0.

ARD The Accumulated Reserve for Depreciation, including cost of removal, associated with cumulative CIPs as of the end of the respective CIP Investment Year. For the year in which the CIP Investment was recorded as in-service, the ARD will be determined on a monthly basis. The ARD for subsequent years shall be calculated based upon the average of the beginning and ending calendar year balances.

ADIT The Accumulated Deferred Income Taxes associated with cumulative CIPs as of the end of the respective CIP Investment Year. For the year in which the CIP was recorded as in-service, the ADIT will be determined on a monthly basis. The ADIT for subsequent years shall be calculated based upon the average of the beginning and ending calendar year balances.

5.0 OVERHEAD AND BURDEN ADJUSTMENTS

The Company will perform an overhead and burdens test to demonstrate that actual overhead and burdens costs charged to CIPs are incremental to amounts recovered in base distribution rates and other reconciling mechanisms. This test shall compare the actual O&M overhead and burdens and the amount included in base distribution rates in each year. If the actual O&M overhead and burdens exceed the amount included in base distribution rates, capitalized overheads and burdens recovered through a reconciling rate shall be reduced by the amount of the excess. The Company shall determine whether such reduction is required for all reconciling mechanisms that require such a determination once each year, and the determination shall be included in the Company's annual CIP cost recovery filing. In addition, the percentage of capitalized overhead and burdens assigned to CIPs shall be set equal to the ratio of CIP costs to total direct costs in any given year.

6.0 FILING OF CIPFs FOR DEPARTMENT APPROVAL

Proposed CIPFs shall be filed with the Department by May 15 and shall include the reconciliation of the amount recoverable through prior CIPFs, as appropriate. The annual CIP cost recovery filing shall include, but not be limited to:

(1) For a filing subsequent to a CIP Investment Year in which CIP Plant Investment was recorded as in-service:

   a. full project documentation of all CIP expenditures recorded as in-service, with narrative providing justification that the costs meet the cost recovery eligibility requirements in Section 1.0;

   b. Supporting information and documentation demonstrating that the costs sought for recovery are preauthorized, incremental, prudently incurred, in service, and used and useful (where applicable); and

   c. Any cost variances as defined in the Company's capital authorization policies;

(2) A demonstration that the revenue requirements are calculated appropriately;

(3) A demonstration that the proposed factors are calculated appropriately; and

(4) Bill impacts.

CAPITAL INVESTMENT PROJECT TARIFF
APPENDIX A
[insert name of CIP]

CIP:	[Name of Group Study]
CIP Station(s):	[insert location of CIP, identified by substation]
CIP Description:	[insert summary description of CIP]
Group Study Size:	[insert count of DG facilities]
CIP Enabled DG:	[insert MW/kW]
CIP Fee:	[insert $/kW, including tax]
CIP Fee Term:	15 Years From: [date] To: [date]
Availability of CIP:	CIP allows interconnection to the Company's EPS for the following type of Interconnecting Customers:
	[list size of DG facilities]
	[list application type]
	[other]

CIP Interconnection Specifications

[A detailed, technical description of the assets/equipment within the CIP available for Interconnecting Customers to connect their DG facilities.]

NSTAR Electric Company d/b/a Eversource Energy
Computation of Capital Investment Project (CIP) Revenue Requirement
Summary
For The Years 2023 through 2037
Group 1, Scenario 1

Line No.			2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
1	Revenue Requirement Calculation:																
2	Return and Taxes	Return and Taxes, Line 41	$ 108,945	$ 2,798,422	$ 7,455,712	$ 9,021,860	$ 6,939,697	$ 6,271,915	$ 5,907,329	$ 5,555,841	$ 5,216,127	$ 4,885,692	$ 4,559,981	$ 4,235,937	$ 3,913,945	$ 3,595,347	$ 3,280,959
3	Book Depreciation	Depreciation Expense, Line 21	144,859	625,218	1,799,094	2,294,388	1,866,389	1,764,490	1,730,523	1,696,557	1,662,590	1,628,624	1,594,657	1,560,691	1,526,724	1,492,758	1,458,791
4	Property Taxes	Property Tax Expense, Line 6	-	1,055,977	2,622,299	1,873,553	1,659,073	1,584,937	1,511,565	1,438,955	1,367,108	1,296,023	1,225,701	1,156,142	1,087,346	1,019,312	952,042
5	Total Revenue Requirement	Sum of Lines 1 through 3	$ 253,803	$ 4,479,617	$ 11,877,106	$ 13,189,800	$ 10,465,159	$ 9,621,342	$ 9,149,417	$ 8,691,353	$ 8,245,825	$ 7,810,339	$ 7,380,340	$ 6,952,770	$ 6,528,015	$ 6,107,417	$ 5,691,792
6		Revenue Requirement NPV @6.71%	$72,067,706														
7		Levelized Annual Revenue Requirement	$7,768,330														
8		Forecasted 2022 kWh	22,364,112,458														
9		Average Rate ($/kWh)	$ 0.00034														

NSTAR Electric Company d/b/a Eversource Energy
Computation of Capital Investment Project (CIP) Revenue Requirement
Return and Taxes
For The Years 2023 through 2037

Line No.			2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
	Depreciable Net Plant Additions																
1	CIP Program - Substation		$ 14,413,800	$ 33,383,100	$ 44,136,800	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	CIP Program - Feeders		-	-	27,416,780	-	-	-	-	-	-	-	-	-	-	-	-
3	CIP Program - CIP Fee Recovery (CIAC)		-	-	-	(31,050,250)	(7,685,242)	(1,537,048)	(1,537,048)	(1,537,048)	(1,537,048)	(1,537,048)	(1,537,048)	(1,537,048)	(1,537,048)	(1,537,048)	(1,537,048)
4	Annual CIP Gross Plant	Sum of Line 1 thru Line 3	$ 14,413,800	$ 33,383,100	$ 71,553,580	$ (31,050,250)	$ (7,685,242)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)
5	Cumulative CIP Gross Plant	CM Line 4 + PM Line 5	$ 14,413,800	$ 47,796,900	$ 119,350,480	$ 88,300,230	$ 80,614,988	$ 79,077,940	$ 77,540,892	$ 76,003,844	$ 74,466,796	$ 72,929,748	$ 71,392,700	$ 69,855,652	$ 68,318,604	$ 66,781,556	$ 65,244,508
6																	
7	Deferred Tax Calculation:																
8	Annual Federal Tax Depreciation	Deferred Taxes	$ 540,518	$ 2,292,398	$ 6,055,595	$ 7,120,399	$ 5,133,453	$ 4,403,148	$ 3,956,983	$ 3,545,319	$ 3,204,032	$ 2,990,323	$ 3,010,122	$ 3,038,863	$ 3,028,125	$ 2,950,452	$ 2,874,958
9	Cumulative Federal Tax Depreciation	CY Line 9 + PY Line 10	$ 540,518	$ 2,832,916	$ 8,888,511	$ 16,008,909	$ 21,142,362	$ 25,545,510	$ 29,502,494	$ 33,047,813	$ 36,251,845	$ 39,242,167	$ 42,252,289	$ 45,291,152	$ 48,319,277	$ 51,269,729	$ 54,144,688
10																	
11	Annual State Tax Depreciation	Deferred Taxes	$ 540,518	$ 2,292,398	$ 6,055,595	$ 7,120,399	$ 5,133,453	$ 4,403,148	$ 3,956,983	$ 3,545,319	$ 3,204,032	$ 2,990,323	$ 3,010,122	$ 3,038,863	$ 3,028,125	$ 2,950,452	$ 2,874,958
12	Cumulative State Tax Depreciation	CY Line 12 + PY Line 13	$ 540,518	$ 2,832,916	$ 8,888,511	$ 16,008,909	$ 21,142,362	$ 25,545,510	$ 29,502,494	$ 33,047,813	$ 36,251,845	$ 39,242,167	$ 42,252,289	$ 45,291,152	$ 48,319,277	$ 51,269,729	$ 54,144,688
13																	
14	Book Deprec - Substation	Depreciation Expense, Line 4	$ 144,859	$ 625,218	$ 1,404,293	$ 1,847,867	$ 1,847,867	$ 1,847,867	$ 1,847,867	$ 1,847,867	$ 1,847,867	$ 1,847,867	$ 1,847,867	$ 1,847,867	$ 1,847,867	$ 1,847,867	$ 1,847,867
15	Book Deprec - Feeders	Depreciation Expense, Line 11	-	-	394,802	789,603	789,603	789,603	789,603	789,603	789,603	789,603	789,603	789,603	789,603	789,603	789,603
16	Book Deprec - CIP Fee Recovery (CIAC)	Depreciation Expense, Line 18	-	-	-	(343,083)	(771,081)	(872,981)	(906,947)	(940,914)	(974,880)	(1,008,847)	(1,042,813)	(1,076,780)	(1,110,746)	(1,144,713)	(1,178,679)
17	Total Book Depreciation	Sum of Line 14 thru Line 17	$144,859	$625,218	$1,799,094	$2,294,388	$1,866,389	$1,764,490	$1,730,523	$1,696,557	$1,662,590	$1,628,624	$1,594,657	$1,560,691	$1,526,724	$1,492,758	$1,458,791
18	Cumulative Book Depreciation	CY Line 19 + PY Line 20	$144,859	$770,076	$2,569,170	$4,863,559	$6,729,948	$8,494,438	$10,224,961	$11,921,518	$13,584,108	$15,212,732	$16,807,389	$18,368,080	$19,894,804	$21,387,562	$22,846,353
19																	
20	Cumulative Book / Tax Timer	Line 9 - Line 18	$395,659	$2,062,840	$6,319,340	$11,145,351	$14,412,414	$17,051,073	$19,277,533	$21,126,295	$22,667,737	$24,029,435	$25,444,900	$26,923,072	$28,424,473	$29,882,168	$31,298,335
21	Effective Federal Tax Rate	Tax Dept	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%
22	Deferred Federal Tax Reserve	Line 20 x Line 21	$83,088	$433,196	$1,327,061	$2,340,524	$3,026,607	$3,580,725	$4,048,282	$4,436,522	$4,760,225	$5,046,181	$5,343,429	$5,653,845	$5,969,139	$6,275,255	$6,572,650
23	Less: Federal Deduction for Deferred State Taxes	Line 28 x -35.00%	($6,647)	($34,656)	($106,165)	($187,242)	($242,129)	($286,458)	($323,863)	($354,922)	($380,818)	($403,695)	($427,474)	($452,308)	($477,531)	($502,020)	($525,812)
24	Net Deferred Federal Tax Reserve	Line 22 + Line 23	$76,441	$398,541	$1,220,897	$2,153,282	$2,784,478	$3,294,267	$3,724,419	$4,081,600	$4,379,407	$4,642,487	$4,915,955	$5,201,538	$5,491,608	$5,773,235	$6,046,838
25																	
26	Cumulative Book / Tax Timer	Line 12 - Line 18	$395,659	$2,062,840	$6,319,340	$11,145,351	$14,412,414	$17,051,073	$19,277,533	$21,126,295	$22,667,737	$24,029,435	$25,444,900	$26,923,072	$28,424,473	$29,882,168	$31,298,335
27	Effective State Tax Rate	Tax Dept	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.000%	8.000%	8.000%	8.000%	8.000%	8.000%
28	Deferred State Tax Reserve	Line 26 x Line 27	$31,653	$165,027	$505,547	$891,628	$1,152,993	$1,364,086	$1,542,203	$1,690,104	$1,813,419	$1,922,355	$2,035,592	$2,153,846	$2,273,958	$2,390,573	$2,503,867
29																	
30	Total Deferred Taxes	Line 24 + Line 28	$108,094	$563,568	$1,726,444	$3,044,910	$3,937,472	$4,658,353	$5,266,622	$5,771,704	$6,192,826	$6,564,842	$6,951,547	$7,355,383	$7,765,566	$8,163,808	$8,550,705
31																	
32	Rate Base Calculation:																
33	Cumulative Incremental Spend	Line 5	$14,413,800	$47,796,900	$119,350,480	$88,300,230	$80,614,988	$79,077,940	$77,540,892	$76,003,844	$74,466,796	$72,929,748	$71,392,700	$69,855,652	$68,318,604	$66,781,556	$65,244,508
34	Accumulated Depreciation	- Line 18	(144,859)	(770,076)	(2,569,170)	(4,863,559)	(6,729,948)	(8,494,438)	(10,224,961)	(11,921,518)	(13,584,108)	(15,212,732)	(16,807,389)	(18,368,080)	(19,894,804)	(21,387,562)	(22,846,353)
35	Deferred Tax Reserve	- Line 30	(108,094)	(563,568)	(1,726,444)	(3,044,910)	(3,937,472)	(4,658,353)	(5,266,622)	(5,771,704)	(6,192,826)	(6,564,842)	(6,951,547)	(7,355,383)	(7,765,566)	(8,163,808)	(8,550,705)
36	Year End Rate Base	Sum Lines 33 thru 35	$14,160,847	$46,463,256	$115,054,866	$80,391,762	$69,947,569	$65,925,149	$62,049,309	$58,310,623	$54,689,862	$51,152,174	$47,633,764	$44,132,189	$40,658,234	$37,230,186	$33,847,450
37																	
38	Revenue Requirement Calculation:																
39	Average Rate Base	Line 36 ÷ 2	$1,180,071	$30,312,052	$80,759,061	$97,723,314	$75,169,665	$67,936,359	$63,987,229	$60,179,966	$56,500,242	$52,921,018	$49,392,969	$45,882,977	$42,395,211	$38,944,210	$35,538,818
40	Pre-Tax Monthly ROR	Capital Structure, Line 8	9.23%	9.23%	9.23%	9.23%	9.23%	9.23%	9.23%	9.23%	9.23%	9.23%	9.23%	9.23%	9.23%	9.23%	9.23%
41	Return and Taxes	Line 39 x Line 40	$108,945	$2,798,422	$7,455,712	$9,021,860	$6,939,697	$6,271,915	$5,907,329	$5,555,841	$5,216,127	$4,885,692	$4,559,981	$4,235,937	$3,913,945	$3,595,347	$3,280,959

Input

	Investments - Substation	Investments - Feeders	CIP Payments	CIP MW
Year 1	$ 14,413,800	$ -	$ -	-
Year 2	$ 33,383,100	$ -	$ -	-
Year 3	$ 44,136,800	$ 27,416,780	$ -	-
Year 4	$ -	$ -	$ (31,050,250)	80.650
Year 5	$ -	$ -	$ (7,685,242)	19.962
Year 6	$ -	$ -	$ (1,537,048)	3.992
Year 7	$ -	$ -	$ (1,537,048)	3.992
Year 8	$ -	$ -	$ (1,537,048)	3.992
Year 9	$ -	$ -	$ (1,537,048)	3.992
Year 10	$ -	$ -	$ (1,537,048)	3.992
Year 11	$ -	$ -	$ (1,537,048)	3.992
Year 12	$ -	$ -	$ (1,537,048)	3.992
Year 13	$ -	$ -	$ (1,537,048)	3.992
Year 14	$ -	$ -	$ (1,537,048)	3.992
Year 15	$ -	$ -	$ (1,537,048)	3.992

NSTAR Electric Company d/b/a Eversource Energy
Computation of Capital Investment Project (CIP) Revenue Requirement
Depreciation Expense
For The Years 2023 through 2037

Line No.	Month		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
	CIP Program - Substations																
1	CIP Program - Substations	Return and Taxes, Line 1	$14,413,800	$33,383,100	$44,136,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Cumulative Capital Investment	CY Line 1 + PY Line 2	$14,413,800	$47,796,900	$91,933,700	$91,933,700	$91,933,700	$91,933,700	$91,933,700	$91,933,700	$91,933,700	$91,933,700	$91,933,700	$91,933,700	$91,933,700	$91,933,700	$91,933,700
3	Annual Depreciation Rate	Annual Depreciation Rate @ 2.01%	2.01%	2.01%	2.01%	2.01%	2.01%	2.01%	2.01%	2.01%	2.01%	2.01%	2.01%	2.01%	2.01%	2.01%	2.01%
4	Annual Book Depreciation	Line 2 x Line 3	$144,859	$625,218	$1,404,293	$1,847,867	$1,847,867	$1,847,867	$1,847,867	$1,847,867	$1,847,867	$1,847,867	$1,847,867	$1,847,867	$1,847,867	$1,847,867	$1,847,867
5	Cumulative Depreciation	CY Line 4 + PY Line 5	$144,859	$770,076	$2,174,369	$4,022,236	$5,870,103	$7,717,971	$9,565,838	$11,413,706	$13,261,573	$15,109,440	$16,957,308	$18,805,175	$20,653,042	$22,500,910	$24,348,777
6																	
7	CIP Program - Feeders																
8	CIP Program - Feeders	Return and Taxes, Line 2	-	-	27,416,780	-	-	-	-	-	-	-	-	-	-	-	-
9	Cumulative Capital Investment	CY Line 8 + PY Line 9	$0	$0	$27,416,780	$27,416,780	$27,416,780	$27,416,780	$27,416,780	$27,416,780	$27,416,780	$27,416,780	$27,416,780	$27,416,780	$27,416,780	$27,416,780	$27,416,780
10	Annual Depreciation Rate	Annual Depreciation Rate @ 2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%
11	Annual Book Depreciation	Line 9 x Line 10	$0	$0	$394,802	$789,603	$789,603	$789,603	$789,603	$789,603	$789,603	$789,603	$789,603	$789,603	$789,603	$789,603	$789,603
12	Cumulative Depreciation	CY Line 11 + PY Line 12	$0	$0	$394,802	$1,184,405	$1,974,008	$2,763,611	$3,553,215	$4,342,818	$5,132,421	$5,922,024	$6,711,628	$7,501,231	$8,290,834	$9,080,438	$9,870,041
13																	
14	CIP Program - CIP Fee Recovery																
15	CIP Program - CIP Fee Recovery	Return and Taxes, Line 3	$0	$0	$0	($31,050,250)	($7,685,242)	($1,537,048)	($1,537,048)	($1,537,048)	($1,537,048)	($1,537,048)	($1,537,048)	($1,537,048)	($1,537,048)	($1,537,048)	($1,537,048)
16	Cumulative Capital Investment	CY Line 15 + PY Line 16	$0	$0	$0	($31,050,250)	($38,735,492)	($40,272,540)	($41,809,588)	($43,346,636)	($44,883,684)	($46,420,732)	($47,957,780)	($49,494,828)	($51,031,876)	($52,568,924)	($54,105,972)
17	Annual Depreciation Rate	Annual Depreciation Rate @ 2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%	2.21%
18	Annual Book Depreciation	Line 16 x Line 17	$0	$0	$0	($343,083)	($771,081)	($872,981)	($906,947)	($940,914)	($974,880)	($1,008,847)	($1,042,813)	($1,076,780)	($1,110,746)	($1,144,713)	($1,178,679)
19	Cumulative Depreciation	CY Line 18 + PY Line 19	$0	$0	$0	($343,083)	($1,114,164)	($1,987,145)	($2,894,092)	($3,835,006)	($4,809,886)	($5,818,733)	($6,861,546)	($7,938,326)	($9,049,073)	($10,193,786)	($11,372,465)
20																	
21	Total Book Depreciation	Line 4 + Line 11 + Line 18	$144,859	$625,218	$1,799,094	$2,294,388	$1,866,389	$1,764,490	$1,730,523	$1,696,557	$1,662,590	$1,628,624	$1,594,657	$1,560,691	$1,526,724	$1,492,758	$1,458,791
22	Total Cumulative Book Depreciation	CY Line 21 + PY Line 22	$144,859	$770,076	$2,569,170	$4,863,559	$6,729,948	$8,494,438	$10,224,961	$11,921,518	$13,584,108	$15,212,732	$16,807,389	$18,368,080	$19,894,804	$21,387,562	$22,846,353

D.P.U. 17-05, Exhibit ES-JJS-4

Plant Account 362 - Substations	$16,680,407	$746,185,586	$83,684,415	$829,870,001	2.01%
Plant Account 364	$13,509,660	$360,418,876	$75,376,605	$435,795,481	
Plant Account 365	$25,096,056	$666,549,305	$145,620,795	$812,170,100	
Plant Account 366	$14,493,203	$616,466,882	$67,174,754	$683,641,636	
Plant Account 367	$44,306,408	$1,362,580,636	$154,762,093	$1,517,342,729	
Plant Account 368	$19,889,439	$540,284,361	$79,324,339	$619,608,700	
Total Feeders	$117,294,766			$4,068,558,646	2.88%
Substation Investment	$91,933,700	77.03%	2.01%	1.55%	
Feeder Investment	$27,416,780	22.97%	2.88%	0.66%	
Total Investment	$119,350,480			2.21%	

NSTAR Electric Company d/b/a Eversource Energy
Computation of Capital Investment Project (CIP) Revenue Requirement
Deferred Taxes - Substations
For The Years 2023 through 2037

Line	Description	Reference	(a) CY - 2023	(b) CY - 2024	(c) CY - 2025	(d) CY - 2026	(e) CY - 2027	(f) CY - 2028	(g) CY - 2029	(h) CY - 2030	(i) CY - 2031	(j) CY - 2032	(k) CY - 2033	(l) CY - 2034	(m) CY - 2035	(n) CY - 2036	(o) CY - 2037
1																	
2	Federal Tax Depreciation																
3	Investments - Substation (2023)	Return and Taxes, Line 2	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800
4	Annual 20 Yr MACRS	MACRS Half Year Depreciation Rates, Line 7	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%
5	Federal Tax Depreciation	Line 3 x Line 4	$540,518	$1,040,532	$962,409	$890,340	$823,460	$761,769	$704,547	$651,792	$643,144	$643,000	$643,144	$643,000	$643,144	$643,000	$643,144
6	Investments - Substation (2024)	Return and Taxes, Line 2	$ -	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100
7	Annual 20 Yr MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%
8	Federal Tax Depreciation	Line 6 x Line 7	$0	$1,251,866	$2,409,926	$2,228,990	$2,062,074	$1,907,177	$1,764,297	$1,631,766	$1,509,584	$1,489,554	$1,489,220	$1,489,554	$1,489,220	$1,489,554	$1,489,220
9	Investments - Substation (2025)	Return and Taxes, Line 2	$ -	$ -	$ 44,136,800	$ 44,136,800	$ 44,136,800	$ 44,136,800	$ 44,136,800	$ 44,136,800	$ 44,136,800	$ 44,136,800	$ 44,136,800	$ 44,136,800	$ 44,136,800	$ 44,136,800	$ 44,136,800
10	Annual 20 Yr MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%
11	Federal Tax Depreciation	Line 9 x Line 10	$0	$0	$1,655,130	$3,186,236	$2,947,014	$2,726,330	$2,521,535	$2,332,630	$2,157,407	$1,995,866	$1,969,384	$1,968,943	$1,969,384	$1,968,943	$1,969,384
12	Total Federal Tax Depreciation		$540,518	$2,292,398	$5,027,465	$6,305,566	$5,832,549	$5,395,276	$4,990,379	$4,616,188	$4,310,134	$4,128,420	$4,101,748	$4,101,496	$4,101,748	$4,101,496	$4,101,748
13	Cumulative Federal Tax Depreciation		$540,518	$2,832,916	$7,860,381	$14,165,947	$19,998,496	$25,393,772	$30,384,150	$35,000,338	$39,310,473	$43,438,892	$47,540,640	$51,642,136	$55,743,884	$59,845,380	$63,947,128
14																	
15																	
16	State Tax Depreciation																
17	Investments - Substation (2023)	Line 3	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800	$ 14,413,800
18	20 Year MACRS	MACRS Half Year Depreciation Rates, Line 7	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%
19	State Tax Depreciation	Line 17 x Line 18	$540,518	$1,040,532	$962,409	$890,340	$823,460	$761,769	$704,547	$651,792	$643,144	$643,000	$643,144	$643,000	$643,144	$643,000	$643,144
20	Investments - Substation (2024)	Line 6	$ -	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100	$ 33,383,100
21	20 Year MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%
22	State Tax Depreciation	Line 20 x Line 21	$0	$1,251,866	$2,409,926	$2,228,990	$2,062,074	$1,907,177	$1,764,297	$1,631,766	$1,509,584	$1,489,554	$1,489,220	$1,489,554	$1,489,220	$1,489,554	$1,489,220
23	Investments - Substation (2025)	Line 9	$ -	$ -	$ 44,136,800	$ 44,136,800	$ 44,136,800	$ 44,136,800	$ 44,136,800	$ 44,136,800	$ 44,136,800	$ 44,136,800	$ 44,136,800	$ 44,136,800	$ 44,136,800	$ 44,136,800	$ 44,136,800
24	20 Year MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%
25	State Tax Depreciation	Line 23 x Line 24	$0	$0	$1,655,130	$3,186,236	$2,947,014	$2,726,330	$2,521,535	$2,332,630	$2,157,407	$1,995,866	$1,969,384	$1,968,943	$1,969,384	$1,968,943	$1,969,384
26	Total State Tax Depreciation		$540,518	$2,292,398	$5,027,465	$6,305,566	$5,832,549	$5,395,276	$4,990,379	$4,616,188	$4,310,134	$4,128,420	$4,101,748	$4,101,496	$4,101,748	$4,101,496	$4,101,748
27	Cumulative State Tax Depreciation		$540,518	$2,832,916	$7,860,381	$14,165,947	$19,998,496	$25,393,772	$30,384,150	$35,000,338	$39,310,473	$43,438,892	$47,540,640	$51,642,136	$55,743,884	$59,845,380	$63,947,128

NSTAR Electric Company d/b/a Eversource Energy
Computation of Capital Investment Project (CIP) Revenue Requirement
Deferred Taxes - Feeders
For The Years 2023 through 2037

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1																	
2	Federal Tax Depreciation		**CY - 2023**	**CY - 2024**	**CY - 2025**	**CY - 2026**	**CY - 2027**	**CY - 2028**	**CY - 2029**	**CY - 2030**	**CY - 2031**	**CY - 2032**	**CY - 2033**	**CY - 2034**	**CY - 2035**	**CY - 2036**	**CY - 2037**
3	Investments - Feeder	Return and Taxes, Line 2	$ -	$ -	$ 27,416,780	$ 27,416,780	$ 27,416,780	$ 27,416,780	$ 27,416,780	$ 27,416,780	$ 27,416,780	$ 27,416,780	$ 27,416,780	$ 27,416,780	$ 27,416,780	$ 27,416,780	$ 27,416,780
4	Annual 20 Yr MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%
5	Federal Tax Depreciation	Line 3 x Line 4	$0	$0	$1,028,129	$1,979,217	$1,830,618	$1,693,535	$1,566,321	$1,448,977	$1,340,132	$1,239,787	$1,223,337	$1,223,063	$1,223,337	$1,223,063	$1,223,337
6	Cumulative Federal Tax Depreciation		$0	$0	$1,028,129	$3,007,347	$4,837,965	$6,531,499	$8,097,820	$9,546,797	$10,886,929	$12,126,716	$13,350,053	$14,573,115	$15,796,452	$17,019,515	$18,242,851
7																	
8																	
9	State Tax Depreciation																
10	Investments - Feeder	Line 3	$ -	$ -	$ 27,416,780	$ 27,416,780	$ 27,416,780	$ 27,416,780	$ 27,416,780	$ 27,416,780	$ 27,416,780	$ 27,416,780	$ 27,416,780	$ 27,416,780	$ 27,416,780	$ 27,416,780	$ 27,416,780
11	20 Year MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%
12	State Tax Depreciation	Line 10 x Line 11	$0	$0	$1,028,129	$1,979,217	$1,830,618	$1,693,535	$1,566,321	$1,448,977	$1,340,132	$1,239,787	$1,223,337	$1,223,063	$1,223,337	$1,223,063	$1,223,337
13	Cumulative State Tax Depreciation		$0	$0	$1,028,129	$3,007,347	$4,837,965	$6,531,499	$8,097,820	$9,546,797	$10,886,929	$12,126,716	$13,350,053	$14,573,115	$15,796,452	$17,019,515	$18,242,851

NSTAR Electric Company d/b/a Eversource Energy
Computation of Capital Investment Project (CIP) Revenue Requirement
Deferred Taxes - CIP Recovery (CIAC)
For The Years 2023 through 2037

1			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
2	Federal Tax Depreciation		CY - 2023	CY - 2024	CY - 2025	CY - 2026	CY - 2027	CY - 2028	CY - 2029	CY - 2030	CY - 2031	CY - 2032	CY - 2033	CY - 2034	CY - 2035	CY - 2036	CY - 2037
3	Investments - CIP Recovery (2026)	Return and Taxes, Line 2	$ -	$ -	$ -	$ (31,050,250)	$ (31,050,250)	$ (31,050,250)	$ (31,050,250)	$ (31,050,250)	$ (31,050,250)	$ (31,050,250)	$ (31,050,250)	$ (31,050,250)	$ (31,050,250)	$ (31,050,250)	$ (31,050,250)
4	Annual 20 Yr MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%
5	Federal Tax Depreciation	Line 3 x Line 4	$0	$0	$0	($1,164,384)	($2,241,518)	($2,073,225)	($1,917,974)	($1,773,901)	($1,641,006)	($1,517,736)	($1,404,092)	($1,385,462)	($1,385,152)	($1,385,462)	($1,385,152)
6	Investments - CIP Recovery (2027)	Return and Taxes, Line 2	$ -	$ -	$ -	$ -	$ (7,685,242)	$ (7,685,242)	$ (7,685,242)	$ (7,685,242)	$ (7,685,242)	$ (7,685,242)	$ (7,685,242)	$ (7,685,242)	$ (7,685,242)	$ (7,685,242)	$ (7,685,242)
7	Annual 20 Yr MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%
8	Federal Tax Depreciation	Line 6 x Line 7	$0	$0	$0	$0	($288,197)	($554,798)	($513,144)	($474,717)	($439,058)	($406,165)	($375,655)	($347,527)	($342,915)	($342,839)	($342,915)
9	Investments - CIP Recovery (2028)	Return and Taxes, Line 2	$ -	$ -	$ -	$ -	$ -	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)
10	Annual 20 Yr MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%
11	Federal Tax Depreciation	Line 9 x Line 10	$0	$0	$0	$0	$0	($57,639)	($110,959)	($102,629)	($94,943)	($87,812)	($81,233)	($75,131)	($69,505)	($68,583)	($68,568)
12	Investments - CIP Recovery (2029)	Return and Taxes, Line 2	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)
13	Annual 20 Yr MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%
14	Federal Tax Depreciation	Line 12 x Line 13	$0	$0	$0	$0	$0	$0	($57,639)	($110,959)	($102,629)	($94,943)	($87,812)	($81,233)	($75,131)	($69,505)	($68,583)
15	Investments - CIP Recovery (2030)	Return and Taxes, Line 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)
16	Annual 20 Yr MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%
17	Federal Tax Depreciation	Line 15 x Line 16	$0	$0	$0	$0	$0	$0	$0	($57,639)	($110,959)	($102,629)	($94,943)	($87,812)	($81,233)	($75,131)	($69,505)
18	Investments - CIP Recovery (2031)	Return and Taxes, Line 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)
19	Annual 20 Yr MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%
20	Federal Tax Depreciation	Line 18 x Line 19	$0	$0	$0	$0	$0	$0	$0	$0	($57,639)	($110,959)	($102,629)	($94,943)	($87,812)	($81,233)	($75,131)
21	Investments - CIP Recovery (2032)	Return and Taxes, Line 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)
22	Annual 20 Yr MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%
23	Federal Tax Depreciation	Line 21 x Line 22	$0	$0	$0	$0	$0	$0	$0	$0	$0	($57,639)	($110,959)	($102,629)	($94,943)	($87,812)	($81,233)
24	Investments - CIP Recovery (2033)	Return and Taxes, Line 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)
25	Annual 20 Yr MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%
26	Federal Tax Depreciation	Line 24 x Line 25	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($57,639)	($110,959)	($102,629)	($94,943)	($87,812)
27	Investments - CIP Recovery (2034)	Return and Taxes, Line 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)
28	Annual 20 Yr MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%
29	Federal Tax Depreciation	Line 27 x Line 28	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($57,639)	($110,959)	($102,629)	($94,943)
30	Investments - CIP Recovery (2035)	Return and Taxes, Line 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)
31	Annual 20 Yr MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%	7.22%	6.68%
32	Federal Tax Depreciation	Line 30 x Line 31	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($57,639)	($110,959)	($102,629)
33	Investments - CIP Recovery (2036)	Return and Taxes, Line 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,537,048)	$ (1,537,048)
34	Annual 20 Yr MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%	7.22%
35	Federal Tax Depreciation	Line 33 x Line 34	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($57,639)	($110,959)
36	Investments - CIP Recovery (2037)	Return and Taxes, Line 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,537,048)
37	Annual 20 Yr MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%
38	Federal Tax Depreciation	Line 36 x Line 37	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($57,639)
39	Total Federal Tax Depreciation		$0	$0	$0	($1,164,384)	($2,529,714)	($2,685,662)	($2,599,716)	($2,519,846)	($2,446,235)	($2,377,884)	($2,314,962)	($2,285,696)	($2,296,959)	($2,374,107)	($2,450,126)
40	Cumulative Federal Tax Depreciation		$0	$0	$0	($1,164,384)	($3,694,098)	($6,379,761)	($8,979,477)	($11,499,323)	($13,945,557)	($16,323,441)	($18,638,403)	($20,924,099)	($23,221,059)	($25,595,165)	($28,045,292)
41																	

42																	
43	State Tax Depreciation																
44	Investments - CIP Recovery (2026)	Line 3	$ -	$ -	$ -	$ (31,050,250)	$ (31,050,250)	$ (31,050,250)	$ (31,050,250)	$ (31,050,250)	$ (31,050,250)	$ (31,050,250)	$ (31,050,250)	$ (31,050,250)	$ (31,050,250)	$ (31,050,250)	$ (31,050,250)
45	20 Year MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%
46	State Tax Depreciation	Line 44 x Line 45	$0	$0	$0	($1,164,384)	($2,241,518)	($2,073,225)	($1,917,974)	($1,773,901)	($1,641,006)	($1,517,736)	($1,404,092)	($1,385,462)	($1,385,152)	($1,385,462)	($1,385,152)
47	Investments - CIP Recovery (2027)	Line 6	$ -	$ -	$ -	$ -	$ (7,685,242)	$ (7,685,242)	$ (7,685,242)	$ (7,685,242)	$ (7,685,242)	$ (7,685,242)	$ (7,685,242)	$ (7,685,242)	$ (7,685,242)	$ (7,685,242)	$ (7,685,242)
48	20 Year MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%
49	State Tax Depreciation	Line 47 x Line 48	$0	$0	$0	$0	($288,197)	($554,798)	($513,144)	($474,717)	($439,058)	($406,165)	($375,655)	($347,527)	($342,915)	($342,839)	($342,915)
50	Investments - CIP Recovery (2028)	Line 9	$ -	$ -	$ -	$ -	$ -	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)
51	20 Year MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%
52	State Tax Depreciation	Line 50 x Line 51	$0	$0	$0	$0	$0	($57,639)	($110,959)	($102,629)	($94,943)	($87,812)	($81,233)	($75,131)	($69,505)	($68,583)	($68,568)
53	Investments - CIP Recovery (2029)	Line 12	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)
54	20 Year MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%
55	State Tax Depreciation	Line 53 x Line 54	$0	$0	$0	$0	$0	$0	($57,639)	($110,959)	($102,629)	($94,943)	($87,812)	($81,233)	($75,131)	($69,505)	($68,583)
56	Investments - CIP Recovery (2030)	Line 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)
57	20 Year MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%
58	State Tax Depreciation	Line 56 x Line 57	$0	$0	$0	$0	$0	$0	$0	($57,639)	($110,959)	($102,629)	($94,943)	($87,812)	($81,233)	($75,131)	($69,505)
59	Investments - CIP Recovery (2031)	Line 18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)
60	20 Year MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%
61	State Tax Depreciation	Line 59 x Line 60	$0	$0	$0	$0	$0	$0	$0	$0	($57,639)	($110,959)	($102,629)	($94,943)	($87,812)	($81,233)	($75,131)
62	Investments - CIP Recovery (2032)	Line 21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)
63	20 Year MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%
64	State Tax Depreciation	Line 62 x Line 63	$0	$0	$0	$0	$0	$0	$0	$0	$0	($57,639)	($110,959)	($102,629)	($94,943)	($87,812)	($81,233)
65	Investments - CIP Recovery (2033)	Line 24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)
66	20 Year MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%	5.71%
67	State Tax Depreciation	Line 65 x Line 66	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($57,639)	($110,959)	($102,629)	($94,943)	($87,812)
68	Investments - CIP Recovery (2034)	Line 27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)
69	20 Year MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%	7.22%	6.68%	6.18%
70	State Tax Depreciation	Line 68 x Line 69	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($57,639)	($110,959)	($102,629)	($94,943)
71	Investments - CIP Recovery (2035)	Line 30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,537,048)	$ (1,537,048)	$ (1,537,048)
72	20 Year MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%	7.22%	6.68%
73	State Tax Depreciation	Line 71 x Line 72	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($57,639)	($110,959)	($102,629)
74	Investments - CIP Recovery (2036)	Line 33	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,537,048)	$ (1,537,048)
75	20 Year MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%	7.22%
76	State Tax Depreciation	Line 74 x Line 75	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($57,639)	($110,959)
77	Investments - CIP Recovery (2037)	Line 36	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,537,048)
78	20 Year MACRS	MACRS Half Year Depreciation Rates, Line 7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.75%
79	State Tax Depreciation	Line 77 x Line 78	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($57,639)
80	Total State Tax Depreciation		$0	$0	$0	($1,164,384)	($2,529,714)	($2,685,662)	($2,599,716)	($2,519,846)	($2,446,235)	($2,377,884)	($2,314,962)	($2,285,696)	($2,296,959)	($2,374,107)	($2,450,126)
81	Cumulative State Tax Depreciation		$0	$0	$0	($1,164,384)	($3,694,098)	($6,379,761)	($8,979,477)	($11,499,323)	($13,945,557)	($16,323,441)	($18,638,403)	($20,924,099)	($23,221,059)	($25,595,165)	($28,045,292)

NSTAR Electric Company d/b/a Eversource Energy
Computation of Capital Investment Project (CIP) Revenue Requirement
Property Tax Expense
For The Years 2023 through 2037

Line No.			2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
1	Property Taxes																
2	Plant in Service	Return and Taxes, Line 35	$0	$47,796,900	$119,350,480	$88,300,230	$80,614,988	$79,077,940	$77,540,892	$76,003,844	$74,466,796	$72,929,748	$71,392,700	$69,855,652	$68,318,604	$66,781,556	$65,244,508
3	Accumulated Depreciation	Return and Taxes, Line 36	0	(770,076)	(2,569,170)	(4,863,559)	(6,729,948)	(8,494,438)	(10,224,961)	(11,921,518)	(13,584,108)	(15,212,732)	(16,807,389)	(18,368,080)	(19,894,804)	(21,387,562)	(22,846,353)
4	Net Plant in Service	Sum Lines 2 thru 3	$0	$47,026,824	$116,781,310	$83,436,671	$73,885,040	$70,583,502	$67,315,931	$64,082,326	$60,882,688	$57,717,016	$54,585,311	$51,487,572	$48,423,800	$45,393,994	$42,398,155
5	Property Tax Rate per $1000	Note 1 & 2	$22.45	$22.45	$22.45	$22.45	$22.45	$22.45	$22.45	$22.45	$22.45	$22.45	$22.45	$22.45	$22.45	$22.45	$22.45
6	Annual Property Tax	(Line 4 ÷ 1000) * Line 5	$0	$1,055,977	$2,622,299	$1,873,553	$1,659,073	$1,584,937	$1,511,565	$1,438,955	$1,367,108	$1,296,023	$1,225,701	$1,156,142	$1,087,346	$1,019,312	$952,042

1) Average Property Tax Rate per 2020 FERC Form 1

Gross Plant (FERC Pg. 204 - 207)	$12,266,302,611
Accumulated Depreciation (FERC Pg. 219)	3,349,848,611
Net Plant	$8,916,454,000
Property Tax Expense (FERC Pg. 262 - 263)	200,217,070
Rate per Thousand	$22.45

NSTAR Electric Company d/b/a Eversource Energy
Computation of Capital Investment Project (CIP) Revenue Requirement
Capital Structure
for the Period Ending December 31, 2020

Line No.			Capital Structure (2) (a)	Cost Rate (b)	Weighted Return (c)= (a) x (b)	Taxes (d)	Pre-tax Return (e)=(c)+(d)	After Tax Discount Rate
1	Long Term Debt	D.P.U. 22-22, Schedule 33 Test Year	44.57%	3.69%	1.64%		1.64%	1.20%
2								
3	Preferred Stock	D.P.U. 22-22, Schedule 33 Test Year	0.52%	4.56%	0.02%	0.01% (1)	0.03%	0.02%
4								
5	Total Common Equity (3)	D.P.U. 22-22, Schedule 33 Test Year	54.91%	10.00%	5.49%	2.06% (1)	7.55%	5.49%
6								
7	Total Capitalization	Line 1 + Line 3 + Line 5	100.00%		7.16%	2.07%	9.23%	6.71%
8	Monthly Capitalization	Line 7 ÷ 12					0.77%	

Line Notes

(1) Tax Gross-up at 27.32%

(2)	Common Equity	D.P.U. 22-22, Schedule 33, Page 1, Line 21	$4,521,109,220	54.91%
	Preferred Stock	D.P.U. 22-22, Schedule 33, Page 1, Line 20	43,000,000	0.52%
	Long Term Debt	D.P.U. 22-22, Schedule 33, Page 1, Line 19	3,670,000,000	44.57%
	Total Capital		$8,234,109,220	

(3) ROE rate per D.P.U. 17-05

NSTAR Electric Company d/b/a Eversource Energy
Computation of Capital Investment Project (CIP) Revenue Requirement
MACRS Half Year Depreciation Rates
For The Years 2023 through 2037

IRS Publication 946 Table A-1
MACRS Half Year Depreciation Rates

1	**Recovery Year**	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
2	3	33.33%	44.45%	14.81%	7.41%																	
3	5	20.00%	32.00%	19.20%	11.52%	11.52%	5.76%															
4	7	14.29%	24.49%	17.49%	12.49%	8.93%	8.92%	8.93%	4.46%													
5	10	10.00%	18.00%	14.40%	11.52%	9.22%	7.37%	6.55%	6.55%	6.56%	6.55%	3.28%										
6	15	5.00%	9.50%	8.55%	7.70%	6.93%	6.23%	5.90%	5.90%	5.91%	5.90%	5.91%	5.90%	5.91%	5.90%	5.91%	2.95%					
7	20	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	2.23%

Eastern Massachusetts
Summary of Bill Impact Analysis
Illustrative January 1, 2023

				Monthly		Month		Annual	
	Service Area	Rate	Season	kWh	kW	Total Change	% Change	Total Change	% Change
1	EMA	R-1		516		$ 0.24	0.2%	$ 2.88	0.2%
2	EMA	R-2		488		$ 0.15	0.2%	$ 1.80	0.2%
3	EMA	R-3		740		$ 0.27	0.1%	$ 3.24	0.1%
4	EMA	R-4		874		$ 0.21	0.1%	$ 2.52	0.1%
5	Boston	G-1ND	Winter	493		$ 0.26	0.2%	$ 3.12	0.2%
6	Boston	G-1ND	Summer	464		$ 0.25	0.2%	$ 3.00	0.2%
7	Boston	G-1DMD	Winter	300	3	$ 0.16	0.2%	$ 1.92	0.2%
8	Boston	G-1DMD	Winter	1,250	5	$ 0.67	0.2%	$ 8.04	0.2%
9	Boston	G-1DMD	Winter	2,000	5	$ 1.08	0.2%	$ 12.96	0.2%
10	Boston	G-1DMD	Summer	300	3	$ 0.16	0.2%	$ 1.92	0.2%
11	Boston	G-1DMD	Summer	1,250	5	$ 0.67	0.2%	$ 8.04	0.2%
12	Boston	G-1DMD	Summer	2,000	5	$ 1.08	0.2%	$ 12.96	0.2%
13	Boston	G-2	Winter	3,400	17	$ 1.19	0.1%	$ 14.28	0.1%
14	Boston	G-2	Winter	7,200	24	$ 2.52	0.1%	$ 30.24	0.1%
15	Boston	G-2	Winter	13,950	31	$ 4.88	0.2%	$ 58.56	0.2%
16	Boston	G-2	Summer	3,600	18	$ 1.26	0.1%	$ 15.12	0.1%
17	Boston	G-2	Summer	7,800	26	$ 2.73	0.1%	$ 32.76	0.1%
18	Boston	G-2	Summer	14,850	33	$ 5.20	0.1%	$ 62.40	0.1%
19	Boston (NEMA)	G-3	Winter	150,500	430	$ 31.61	0.1%	$ 379.32	0.1%
20	Boston (NEMA)	G-3	Winter	360,000	800	$ 75.60	0.1%	$ 907.20	0.1%
21	Boston (NEMA)	G-3	Winter	802,450	1,459	$ 168.51	0.1%	$ 2,022.12	0.1%
22	Boston (NEMA)	G-3	Summer	177,100	506	$ 37.19	0.1%	$ 446.28	0.1%
23	Boston (NEMA)	G-3	Summer	477,000	1,060	$ 100.17	0.1%	$ 1,202.04	0.1%
24	Boston (NEMA)	G-3	Summer	1,155,550	2,101	$ 242.67	0.1%	$ 2,912.04	0.1%
25	Boston (SEMA)	G-3	Winter	150,500	430	$ 31.61	0.1%	$ 379.32	0.1%
26	Boston (SEMA)	G-3	Winter	360,000	800	$ 75.60	0.1%	$ 907.20	0.1%
27	Boston (SEMA)	G-3	Winter	802,450	1,459	$ 168.51	0.1%	$ 2,022.12	0.1%
28	Boston (SEMA)	G-3	Summer	177,100	506	$ 37.19	0.1%	$ 446.28	0.1%
29	Boston (SEMA)	G-3	Summer	477,000	1,060	$ 100.17	0.1%	$ 1,202.04	0.1%
30	Boston (SEMA)	G-3	Summer	1,155,550	2,101	$ 242.67	0.1%	$ 2,912.04	0.1%
31	Boston	T-1	Winter	509		$ 0.28	0.2%	$ 3.36	0.2%
32	Boston	T-1	Summer	287		$ 0.16	0.2%	$ 1.92	0.2%
33	Boston (NEMA)	T-2	Winter	70,350	201	$ 24.62	0.2%	$ 295.44	0.2%
34	Boston (NEMA)	T-2	Winter	126,450	281	$ 44.25	0.2%	$ 531.00	0.2%
35	Boston (NEMA)	T-2	Winter	164,450	299	$ 57.55	0.2%	$ 690.60	0.2%
36	Boston (NEMA)	T-2	Summer	86,100	246	$ 30.13	0.1%	$ 361.56	0.1%
37	Boston (NEMA)	T-2	Summer	143,550	319	$ 50.25	0.2%	$ 603.00	0.2%
38	Boston (NEMA)	T-2	Summer	193,600	352	$ 67.76	0.2%	$ 813.12	0.2%
39	Boston (SEMA)	T-2	Winter	70,350	201	$ 24.62	0.2%	$ 295.44	0.2%
40	Boston (SEMA)	T-2	Winter	126,450	281	$ 44.25	0.2%	$ 531.00	0.2%
41	Boston (SEMA)	T-2	Winter	164,450	299	$ 57.55	0.2%	$ 690.60	0.2%
42	Boston (SEMA)	T-2	Summer	86,100	246	$ 30.13	0.2%	$ 361.56	0.2%
43	Boston (SEMA)	T-2	Summer	143,550	319	$ 50.25	0.2%	$ 603.00	0.2%
44	Boston (SEMA)	T-2	Summer	193,600	352	$ 67.76	0.2%	$ 813.12	0.2%
45	Cambridge	G-0		593		$ 0.17	0.1%	$ 2.04	0.1%

Eastern Massachusetts
Summary of Bill Impact Analysis
Illustrative January 1, 2023

				Monthly		Month			Annual		
	Service Area	Rate	Season	kWh	kW	Total Change		% Change	Total Change		% Change
46	Cambridge	G-1		4,750	19	$	1.33	0.1%	$	15.96	0.1%
47	Cambridge	G-1		9,100	26	$	2.54	0.1%	$	30.48	0.1%
48	Cambridge	G-1		16,000	32	$	4.48	0.1%	$	53.76	0.1%
49	Cambridge	G-2		79,450	227	$	15.10	0.1%	$	181.20	0.1%
50	Cambridge	G-2		140,400	312	$	26.68	0.1%	$	320.16	0.1%
51	Cambridge	G-2		155,650	283	$	29.57	0.1%	$	354.84	0.1%
52	Cambridge	G-3		320,800	802	$	35.29	0.1%	$	423.48	0.1%
53	Cambridge	G-3		585,000	1,170	$	64.35	0.1%	$	772.20	0.1%
54	Cambridge	G-3		715,200	1,192	$	78.67	0.1%	$	944.04	0.1%
55	Cambridge	G-4		14,400	36	$	2.01	0.1%	$	24.12	0.1%
56	Cambridge	G-4		19,000	38	$	2.66	0.1%	$	31.92	0.1%
57	Cambridge	G-4		21,000	35	$	2.94	0.1%	$	35.28	0.1%
58	Cambridge	G-5		4,756		$	1.19	0.1%	$	14.28	0.1%
59	Cambridge	G-6		593		$	0.17	0.1%	$	2.04	0.1%
60	South	G-1		400	2	$	0.13	0.1%	$	1.56	0.1%
61	South	G-1		5,700	19	$	1.76	0.1%	$	21.12	0.1%
62	South	G-1		10,800	27	$	3.35	0.1%	$	40.20	0.1%
63	South	G-1S		450	9	$	0.14	0.1%	$	1.68	0.1%
64	South	G-1S		1,200	8	$	0.37	0.1%	$	4.44	0.1%
65	South	G-1S		2,700	9	$	0.84	0.1%	$	10.08	0.1%
66	South	G-2		61,500	205	$	12.92	0.1%	$	155.04	0.1%
67	South	G-2		85,600	214	$	17.98	0.1%	$	215.76	0.1%
68	South	G-2		126,500	253	$	26.57	0.1%	$	318.84	0.1%
69	South	G-3		373,100	1,066	$	44.78	0.1%	$	537.36	0.1%
70	South	G-3		354,600	788	$	42.55	0.1%	$	510.60	0.1%
71	South	G-3		614,900	1,118	$	73.79	0.1%	$	885.48	0.1%
72	South	G-4		7,800	52	$	2.03	0.1%	$	24.36	0.1%
73	South	G-4		6,750	27	$	1.75	0.1%	$	21.00	0.1%
74	South	G-4		9,450	27	$	2.45	0.1%	$	29.40	0.1%
75	South	G-5		1,472		$	0.61	0.2%	$	7.32	0.2%
76	South	G-6		60,748		$	7.89	0.1%	$	94.68	0.1%
77	South	G-7		7,000	20	$	2.17	0.1%	$	26.04	0.1%
78	South	G-7		15,500	31	$	4.80	0.1%	$	57.60	0.1%
79	South	G-7		11,700	18	$	3.63	0.1%	$	43.56	0.1%
80	South	G-7S		450	9	$	0.14	0.1%	$	1.68	0.1%
81	South	G-7S		1,500	10	$	0.46	0.1%	$	5.52	0.1%
82	South	G-7S		3,900	13	$	1.21	0.1%	$	14.52	0.1%

Western Massachusetts
Summary of Bill Impact Analysis
Illustrative January 1, 2023

			Monthly		Month			Annual		
	Service Ar	Rate	kWh	kW	Total Change		% Change	Total Change		% Change
1	WMA	R-1	516		$	0.24	0.2%	$	2.88	0.2%
2	WMA	R-2	488		$	0.15	0.2%	$	1.80	0.2%
3	WMA	R-3	740		$	0.28	0.1%	$	3.36	0.1%
4	WMA	R-4	874		$	0.21	0.1%	$	2.52	0.1%
5	WMA	23	644		$	0.23	0.1%	$	2.70	0.1%
6	WMA	24	1,300	13	$	0.45	0.1%	$	5.46	0.1%
7	WMA	24	4,200	21	$	1.47	0.2%	$	17.64	0.2%
8	WMA	24	7,200	24	$	2.52	0.2%	$	30.24	0.2%
9	WMA	G-0	900	6	$	0.31	0.1%	$	3.78	0.1%
10	WMA	G-0	3,300	11	$	1.16	0.2%	$	13.86	0.2%
11	WMA	G-0	7,650	17	$	2.68	0.2%	$	32.13	0.2%
12	WMA	T-0	150	1	$	0.05	0.1%	$	0.63	0.1%
13	WMA	T-0	1,200	4	$	0.42	0.2%	$	5.04	0.2%
14	WMA	T-0	4,500	10	$	1.58	0.2%	$	18.90	0.2%
15	WMA	G-2	23,750	95	$	6.18	0.1%	$	74.10	0.1%
16	WMA	G-2	42,000	84	$	10.92	0.2%	$	131.04	0.2%
17	WMA	G-2	42,300	94	$	11.00	0.2%	$	131.98	0.2%
18	WMA	T-4	17,500	70	$	4.55	0.1%	$	54.60	0.1%
19	WMA	T-4	37,100	106	$	9.65	0.1%	$	115.75	0.1%
20	WMA	T-4	53,550	119	$	13.92	0.2%	$	167.08	0.2%
21	WMA	T-2	143,500	410	$	25.83	0.1%	$	309.96	0.1%
22	WMA	T-2	256,950	571	$	46.25	0.1%	$	555.01	0.1%
23	WMA	T-2	319,000	580	$	57.42	0.1%	$	689.04	0.1%
24	WMA	T-5	1,394,050	3,983	$	125.46	0.1%	$	1,505.57	0.1%
25	WMA	T-5	3,084,750	6,855	$	277.63	0.1%	$	3,331.53	0.1%
26	WMA	T-5	2,485,450	4,519	$	223.69	0.1%	$	2,684.29	0.1%

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Rate R-1 Residential

1		Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		100	$20.69	$15.76	$36.45	$20.74	$15.76	$36.50	$0.05	0.1%
4		200	$34.38	$31.53	$65.91	$34.47	$31.53	$66.00	$0.09	0.1%
5		300	$48.06	$47.29	$95.35	$48.21	$47.29	$95.50	$0.15	0.2%
6		400	$61.75	$63.06	$124.81	$61.94	$63.06	$125.00	$0.19	0.2%
7		500	$75.44	$78.82	$154.26	$75.68	$78.82	$154.50	$0.24	0.2%
8		600	$89.13	$94.58	$183.71	$89.41	$94.58	$183.99	$0.28	0.2%
9		700	$102.82	$110.35	$213.17	$103.15	$110.35	$213.50	$0.33	0.2%
10		800	$116.50	$126.11	$242.61	$116.88	$126.11	$242.99	$0.38	0.2%
11		900	$130.19	$141.88	$272.07	$130.62	$141.88	$272.50	$0.43	0.2%
12		1,000	$143.88	$157.64	$301.52	$144.35	$157.64	$301.99	$0.47	0.2%
13		1,250	$178.10	$197.05	$375.15	$178.69	$197.05	$375.74	$0.59	0.2%
14		1,500	$212.32	$236.46	$448.78	$213.03	$236.46	$449.49	$0.71	0.2%
15		2,000	$280.76	$315.28	$596.04	$281.70	$315.28	$596.98	$0.94	0.2%
16	Avg	516	$77.63	$81.34	$158.97	$77.87	$81.34	$159.21	$0.24	0.2%

17		Current	Proposed	
18		Rates	Rates	Change
19	Customer Charge	$7.00	$7.00	$ -
20	Distribution Energy	$0.05165	$0.05165	$ -
21	Revenue Decoupling	$0.00267	$0.00267	$ -
22	Distributed Solar Charge	$0.00341	$0.00341	$ -
23	Residential Assistance Adjustment Factor	$0.00572	$0.00572	$ -
24	Pension Adjustment Factor	$0.00120	$0.00120	$ -
25	Net Metering Recovery Surcharge	$0.00756	$0.00756	$ -
26	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
27	AG Consulting Expense	$0.00000	$0.00000	$ -
28	Storm Cost Recovery Adjustment Factor	$0.00322	$0.00322	$ -
29	Capital Investment Project	$0.00000	$0.00047	$0.00047
30	Basic Service Cost True Up Factor	($0.00011)	($0.00011)	$ -
31	Solar Program Cost Adjustment Factor	($0.00001)	($0.00001)	$ -
32	Solar Expansion Cost Recovery Factor	$0.00101	$0.00101	$ -
33	Vegetation Management	$0.00159	$0.00159	$ -
34	Tax Act Credit Factor	($0.00163)	($0.00163)	$ -
35	Grid Modernization	$0.00081	$0.00081	$ -
36	Transition	($0.00177)	($0.00177)	$ -
37	Transmission Energy	$0.04437	$0.04437	$ -
38	Energy Efficiency Reconciliation Factor	$0.01464	$0.01464	$ -
39	System Benefits Charge	$0.00250	$0.00250	$ -
40	Renewable Energy Charge	$0.00050	$0.00050	$ -
41	Basic Service Charge	$0.15764	$0.15764	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Rate R-2 Residential Assistance

			Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
1		Monthly								
2		kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		100	$12.48	$10.09	$22.57	$12.51	$10.09	$22.60	$0.03	0.1%
4		200	$20.48	$20.18	$40.66	$20.54	$20.18	$40.72	$0.06	0.1%
5		300	$28.48	$30.27	$58.75	$28.57	$30.27	$58.84	$0.09	0.2%
6		400	$36.48	$40.36	$76.84	$36.60	$40.36	$76.96	$0.12	0.2%
7		500	$44.48	$50.44	$94.92	$44.63	$50.44	$95.07	$0.15	0.2%
8		600	$52.48	$60.53	$113.01	$52.66	$60.53	$113.19	$0.18	0.2%
9		700	$60.48	$70.62	$131.10	$60.70	$70.62	$131.32	$0.22	0.2%
10		800	$68.49	$80.71	$149.20	$68.73	$80.71	$149.44	$0.24	0.2%
11		900	$76.49	$90.80	$167.29	$76.76	$90.80	$167.56	$0.27	0.2%
12		1,000	$84.49	$100.89	$185.38	$84.79	$100.89	$185.68	$0.30	0.2%
13		1,250	$104.49	$126.11	$230.60	$104.86	$126.11	$230.97	$0.37	0.2%
14		1,500	$124.49	$151.33	$275.82	$124.94	$151.33	$276.27	$0.45	0.2%
15		2,000	$164.49	$201.78	$366.27	$165.09	$201.78	$366.87	$0.60	0.2%
16	Avg	488	$43.52	$49.23	$92.75	$43.67	$49.23	$92.90	$0.15	0.2%

17		Current	Proposed	
18		Rates	Rates	Change
19	Customer Charge	$7.00	$7.00	$ -
20	Distribution Energy	$0.05165	$0.05165	$ -
21	Revenue Decoupling	$0.00267	$0.00267	$ -
22	Distributed Solar Charge	$0.00341	$0.00341	$ -
23	Residential Assistance Adjustment Factor	$0.00572	$0.00572	$ -
24	Pension Adjustment Factor	$0.00120	$0.00120	$ -
25	Net Metering Recovery Surcharge	$0.00756	$0.00756	$ -
26	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
27	AG Consulting Expense	$0.00000	$0.00000	$ -
28	Storm Cost Recovery Adjustment Factor	$0.00322	$0.00322	$ -
29	Capital Investment Project	$0.00000	$0.00047	$0.00047
30	Basic Service Cost True Up Factor	($0.00011)	($0.00011)	$ -
31	Solar Program Cost Adjustment Factor	($0.00001)	($0.00001)	$ -
32	Solar Expansion Cost Recovery Factor	$0.00101	$0.00101	$ -
33	Vegetation Management	$0.00159	$0.00159	$ -
34	Tax Act Credit Factor	($0.00163)	($0.00163)	$ -
35	Grid Modernization	$0.00081	$0.00081	$ -
36	Transition	($0.00177)	($0.00177)	$ -
37	Transmission Energy	$0.04437	$0.04437	$ -
38	Energy Efficiency Reconciliation Factor	$0.00277	$0.00277	$ -
39	System Benefits Charge	$0.00250	$0.00250	$ -
40	Renewable Energy Charge	$0.00050	$0.00050	$ -
41	Basic Service Charge	$0.15764	$0.15764	$ -
42	Low Income Discount	36%	36%	0%

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Rate R-3 Residential Space Heating

1		Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		100	$19.14	$15.76	$34.90	$19.17	$15.76	$34.93	$0.03	0.1%
4		200	$31.27	$31.53	$62.80	$31.34	$31.53	$62.87	$0.07	0.1%
5		300	$43.41	$47.29	$90.70	$43.52	$47.29	$90.81	$0.11	0.1%
6		400	$55.54	$63.06	$118.60	$55.69	$63.06	$118.75	$0.15	0.1%
7		500	$67.68	$78.82	$146.50	$67.86	$78.82	$146.68	$0.18	0.1%
8		600	$79.81	$94.58	$174.39	$80.03	$94.58	$174.61	$0.22	0.1%
9		700	$91.95	$110.35	$202.30	$92.20	$110.35	$202.55	$0.25	0.1%
10		800	$104.08	$126.11	$230.19	$104.38	$126.11	$230.49	$0.30	0.1%
11		900	$116.22	$141.88	$258.10	$116.55	$141.88	$258.43	$0.33	0.1%
12		1,000	$128.35	$157.64	$285.99	$128.72	$157.64	$286.36	$0.37	0.1%
13		1,250	$158.69	$197.05	$355.74	$159.15	$197.05	$356.20	$0.46	0.1%
14		1,500	$189.03	$236.46	$425.49	$189.58	$236.46	$426.04	$0.55	0.1%
15		2,000	$249.70	$315.28	$564.98	$250.44	$315.28	$565.72	$0.74	0.1%
16	Avg	740	$96.80	$116.65	$213.45	$97.07	$116.65	$213.72	$0.27	0.1%

17		Current	Proposed	
18		Rates	Rates	Change
19	Customer Charge	$7.00	$7.00	$ -
20	Distribution Energy	$0.04494	$0.04494	$ -
21	Revenue Decoupling	$0.00211	$0.00211	$ -
22	Distributed Solar Charge	$0.00270	$0.00270	$ -
23	Residential Assistance Adjustment Factor	$0.00452	$0.00452	$ -
24	Pension Adjustment Factor	$0.00115	$0.00115	$ -
25	Net Metering Recovery Surcharge	$0.00598	$0.00598	$ -
26	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
27	AG Consulting Expense	$0.00000	$0.00000	$ -
28	Storm Cost Recovery Adjustment Factor	$0.00254	$0.00254	$ -
29	Capital Investment Project	$0.00000	$0.00037	$0.00037
30	Basic Service Cost True Up Factor	($0.00008)	($0.00008)	$ -
31	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
32	Solar Expansion Cost Recovery Factor	$0.00080	$0.00080	$ -
33	Vegetation Management	$0.00153	$0.00153	$ -
34	Tax Act Credit Factor	($0.00129)	($0.00129)	$ -
35	Grid Modernization	$0.00064	$0.00064	$ -
36	Transition	($0.00177)	($0.00177)	$ -
37	Transmission Energy	$0.04039	$0.04039	$ -
38	Energy Efficiency Reconciliation Factor	$0.01464	$0.01464	$ -
39	System Benefits Charge	$0.00250	$0.00250	$ -
40	Renewable Energy Charge	$0.00050	$0.00050	$ -
41	Basic Service Charge	$0.15764	$0.15764	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Rate R-4 Residential Assistance Space Heating

1		Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		100	$11.49	$10.09	$21.58	$11.51	$10.09	$21.60	$0.02	0.1%
4		200	$18.49	$20.18	$38.67	$18.54	$20.18	$38.72	$0.05	0.1%
5		300	$25.50	$30.27	$55.77	$25.57	$30.27	$55.84	$0.07	0.1%
6		400	$32.51	$40.36	$72.87	$32.60	$40.36	$72.96	$0.09	0.1%
7		500	$39.51	$50.44	$89.95	$39.63	$50.44	$90.07	$0.12	0.1%
8		600	$46.52	$60.53	$107.05	$46.66	$60.53	$107.19	$0.14	0.1%
9		700	$53.53	$70.62	$124.15	$53.69	$70.62	$124.31	$0.16	0.1%
10		800	$60.53	$80.71	$141.24	$60.72	$80.71	$141.43	$0.19	0.1%
11		900	$67.54	$90.80	$158.34	$67.75	$90.80	$158.55	$0.21	0.1%
12		1,000	$74.55	$100.89	$175.44	$74.78	$100.89	$175.67	$0.23	0.1%
13		1,250	$92.06	$126.11	$218.17	$92.36	$126.11	$218.47	$0.30	0.1%
14		1,500	$109.58	$151.33	$260.91	$109.94	$151.33	$261.27	$0.36	0.1%
15		2,000	$144.61	$201.78	$346.39	$145.09	$201.78	$346.87	$0.48	0.1%
16	Avg	874	$65.72	$88.18	$153.90	$65.93	$88.18	$154.11	$0.21	0.1%

17		Current	Proposed	
18		Rates	Rates	Change
19	Customer Charge	$7.00	$7.00	$ -
20	Distribution Energy	$0.04494	$0.04494	$ -
21	Revenue Decoupling	$0.00211	$0.00211	$ -
22	Distributed Solar Charge	$0.00270	$0.00270	$ -
23	Residential Assistance Adjustment Factor	$0.00452	$0.00452	$ -
24	Pension Adjustment Factor	$0.00115	$0.00115	$ -
25	Net Metering Recovery Surcharge	$0.00598	$0.00598	$ -
26	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
27	AG Consulting Expense	$0.00000	$0.00000	$ -
28	Storm Cost Recovery Adjustment Factor	$0.00254	$0.00254	$ -
29	Capital Investment Project	$0.00000	$0.00037	$0.00037
30	Basic Service Cost True Up Factor	($0.00008)	($0.00008)	$ -
31	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
32	Solar Expansion Cost Recovery Factor	$0.00080	$0.00080	$ -
33	Vegetation Management	$0.00153	$0.00153	$ -
34	Tax Act Credit Factor	($0.00129)	($0.00129)	$ -
35	Grid Modernization	$0.00064	$0.00064	$ -
36	Transition	($0.00177)	($0.00177)	$ -
37	Transmission Energy	$0.04039	$0.04039	$ -
38	Energy Efficiency Reconciliation Factor	$0.00277	$0.00277	$ -
39	System Benefits Charge	$0.00250	$0.00250	$ -
40	Renewable Energy Charge	$0.00050	$0.00050	$ -
41	Basic Service Charge	$0.15764	$0.15764	$ -
42	Low Income Discount	36%	36%	0%

Western Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Rate R-1 Residential

1		Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		100	$20.52	$13.73	$34.25	$20.56	$13.73	$34.29	$0.04	0.1%
4		200	$34.03	$27.46	$61.49	$34.13	$27.46	$61.59	$0.10	0.2%
5		300	$47.55	$41.19	$88.74	$47.69	$41.19	$88.88	$0.14	0.2%
6		400	$61.07	$54.92	$115.99	$61.26	$54.92	$116.18	$0.19	0.2%
7		500	$74.59	$68.66	$143.25	$74.82	$68.66	$143.48	$0.23	0.2%
8		600	$88.10	$82.39	$170.49	$88.38	$82.39	$170.77	$0.28	0.2%
9		700	$101.62	$96.12	$197.74	$101.95	$96.12	$198.07	$0.33	0.2%
10		800	$115.14	$109.85	$224.99	$115.51	$109.85	$225.36	$0.37	0.2%
11		900	$128.65	$123.58	$252.23	$129.08	$123.58	$252.66	$0.43	0.2%
12		1,000	$142.17	$137.31	$279.48	$142.64	$137.31	$279.95	$0.47	0.2%
13		1,250	$175.96	$171.64	$347.60	$176.55	$171.64	$348.19	$0.59	0.2%
14		1,500	$209.76	$205.97	$415.73	$210.46	$205.97	$416.43	$0.70	0.2%
15		2,000	$277.34	$274.62	$551.96	$278.28	$274.62	$552.90	$0.94	0.2%
16	Avg	516	$76.75	$70.85	$147.60	$76.99	$70.85	$147.84	$0.24	0.2%

17		Current	Proposed	
18		Rates	Rates	Change
19	Customer Charge	$7.00	$7.00	$ -
20	Distribution Energy	$0.05165	$0.05165	$ -
21	Revenue Decoupling	$0.00267	$0.00267	$ -
22	Distributed Solar Charge	$0.00341	$0.00341	$ -
23	Residential Assistance Adjustment Factor	$0.00572	$0.00572	$ -
24	Pension Adjustment Factor	$0.00120	$0.00120	$ -
25	Net Metering Recovery Surcharge	$0.00756	$0.00756	$ -
26	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
27	AG Consulting Expense	$0.00000	$0.00000	$ -
28	Storm Cost Recovery Adjustment Factor	$0.00124	$0.00124	$ -
29	Capital Investment Project	$0.00000	$0.00047	$0.00047
30	Basic Service Cost True Up Factor	($0.00011)	($0.00011)	$ -
31	Solar Program Cost Adjustment Factor	($0.00001)	($0.00001)	$ -
32	Solar Expansion Cost Recovery Factor	$0.00101	$0.00101	$ -
33	Vegetation Management	$0.00159	$0.00159	$ -
34	Tax Act Credit Factor	($0.00163)	($0.00163)	$ -
35	Grid Modernization	$0.00081	$0.00081	$ -
36	Transition	($0.00177)	($0.00177)	$ -
37	Transmission Energy	$0.04437	$0.04437	$ -
38	Energy Efficiency Reconciliation Factor	$0.01491	$0.01491	$ -
39	System Benefits Charge	$0.00250	$0.00250	$ -
40	Renewable Energy Charge	$0.00050	$0.00050	$ -
41	Basic Service Charge	$0.13731	$0.13731	$ -

Western Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Rate R-2 Residential Assistance

1		Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		100	$12.43	$8.79	$21.22	$12.46	$8.79	$21.25	$0.03	0.1%
4		200	$20.38	$17.58	$37.96	$20.44	$17.58	$38.02	$0.06	0.2%
5		300	$28.33	$26.36	$54.69	$28.42	$26.36	$54.78	$0.09	0.2%
6		400	$36.28	$35.15	$71.43	$36.40	$35.15	$71.55	$0.12	0.2%
7		500	$44.22	$43.94	$88.16	$44.37	$43.94	$88.31	$0.15	0.2%
8		600	$52.17	$52.73	$104.90	$52.35	$52.73	$105.08	$0.18	0.2%
9		700	$60.12	$61.51	$121.63	$60.33	$61.51	$121.84	$0.21	0.2%
10		800	$68.07	$70.30	$138.37	$68.31	$70.30	$138.61	$0.24	0.2%
11		900	$76.02	$79.09	$155.11	$76.29	$79.09	$155.38	$0.27	0.2%
12		1,000	$83.97	$87.88	$171.85	$84.27	$87.88	$172.15	$0.30	0.2%
13		1,250	$103.84	$109.85	$213.69	$104.22	$109.85	$214.07	$0.38	0.2%
14		1,500	$123.71	$131.82	$255.53	$124.16	$131.82	$255.98	$0.45	0.2%
15		2,000	$163.46	$175.76	$339.22	$164.06	$175.76	$339.82	$0.60	0.2%
16	Avg	488	$43.27	$42.88	$86.15	$43.42	$42.88	$86.30	$0.15	0.2%

17		Current	Proposed	
18		Rates	Rates	Change
19	Customer Charge	$7.00	$7.00	$ -
20	Distribution Energy	$0.05165	$0.05165	$ -
21	Revenue Decoupling	$0.00267	$0.00267	$ -
22	Distributed Solar Charge	$0.00341	$0.00341	$ -
23	Residential Assistance Adjustment Factor	$0.00572	$0.00572	$ -
24	Pension Adjustment Factor	$0.00120	$0.00120	$ -
25	Net Metering Recovery Surcharge	$0.00756	$0.00756	$ -
26	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
27	AG Consulting Expense	$0.00000	$0.00000	$ -
28	Storm Cost Recovery Adjustment Factor	$0.00124	$0.00124	$ -
29	Capital Investment Project	$0.00000	$0.00047	$0.00047
30	Basic Service Cost True Up Factor	($0.00011)	($0.00011)	$ -
31	Solar Program Cost Adjustment Factor	($0.00001)	($0.00001)	$ -
32	Solar Expansion Cost Recovery Factor	$0.00101	$0.00101	$ -
33	Vegetation Management	$0.00159	$0.00159	$ -
34	Tax Act Credit Factor	($0.00163)	($0.00163)	$ -
35	Grid Modernization	$0.00081	$0.00081	$ -
36	Transition	($0.00177)	($0.00177)	$ -
37	Transmission Energy	$0.04437	$0.04437	$ -
38	Energy Efficiency Reconciliation Factor	$0.00394	$0.00394	$ -
39	System Benefits Charge	$0.00250	$0.00250	$ -
40	Renewable Energy Charge	$0.00050	$0.00050	$ -
41	Basic Service Charge	$0.13731	$0.13731	$ -
42	Low Income Discount	36%	36%	0%

Western Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Rate R-3 Residential Space Heating

1		Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		100	$19.01	$13.73	$32.74	$19.04	$13.73	$32.77	$0.03	0.1%
4		200	$31.01	$27.46	$58.47	$31.09	$27.46	$58.55	$0.08	0.1%
5		300	$43.02	$41.19	$84.21	$43.13	$41.19	$84.32	$0.11	0.1%
6		400	$55.02	$54.92	$109.94	$55.17	$54.92	$110.09	$0.15	0.1%
7		500	$67.03	$68.66	$135.69	$67.22	$68.66	$135.88	$0.19	0.1%
8		600	$79.04	$82.39	$161.43	$79.26	$82.39	$161.65	$0.22	0.1%
9		700	$91.04	$96.12	$187.16	$91.30	$96.12	$187.42	$0.26	0.1%
10		800	$103.05	$109.85	$212.90	$103.34	$109.85	$213.19	$0.29	0.1%
11		900	$115.05	$123.58	$238.63	$115.39	$123.58	$238.97	$0.34	0.1%
12		1,000	$127.06	$137.31	$264.37	$127.43	$137.31	$264.74	$0.37	0.1%
13		1,250	$157.08	$171.64	$328.72	$157.54	$171.64	$329.18	$0.46	0.1%
14		1,500	$187.09	$205.97	$393.06	$187.65	$205.97	$393.62	$0.56	0.1%
15		2,000	$247.12	$274.62	$521.74	$247.86	$274.62	$522.48	$0.74	0.1%
16	Avg	740	$95.84	$101.61	$197.45	$96.12	$101.61	$197.73	$0.28	0.1%

17		Current	Proposed	
18		Rates	Rates	Change
19	Customer Charge	$7.00	$7.00	$ -
20	Distribution Energy	$0.04494	$0.04494	$ -
21	Revenue Decoupling	$0.00211	$0.00211	$ -
22	Distributed Solar Charge	$0.00270	$0.00270	$ -
23	Residential Assistance Adjustment Factor	$0.00452	$0.00452	$ -
24	Pension Adjustment Factor	$0.00115	$0.00115	$ -
25	Net Metering Recovery Surcharge	$0.00598	$0.00598	$ -
26	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
27	AG Consulting Expense	$0.00000	$0.00000	$ -
28	Storm Cost Recovery Adjustment Factor	$0.00098	$0.00098	$ -
29	Capital Investment Project	$0.00000	$0.00037	$0.00037
30	Basic Service Cost True Up Factor	($0.00008)	($0.00008)	$ -
31	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
32	Solar Expansion Cost Recovery Factor	$0.00080	$0.00080	$ -
33	Vegetation Management	$0.00153	$0.00153	$ -
34	Tax Act Credit Factor	($0.00129)	($0.00129)	$ -
35	Grid Modernization	$0.00064	$0.00064	$ -
36	Transition	($0.00177)	($0.00177)	$ -
37	Transmission Energy	$0.04039	$0.04039	$ -
38	Energy Efficiency Reconciliation Factor	$0.01491	$0.01491	$ -
39	System Benefits Charge	$0.00250	$0.00250	$ -
40	Renewable Energy Charge	$0.00050	$0.00050	$ -
41	Basic Service Charge	$0.13731	$0.13731	$ -

Western Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Rate R-4 Residential Assistance Space Heating

1		Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		100	$11.46	$8.79	$20.25	$11.49	$8.79	$20.28	$0.03	0.1%
4		200	$18.44	$17.58	$36.02	$18.49	$17.58	$36.07	$0.05	0.1%
5		300	$25.43	$26.36	$51.79	$25.50	$26.36	$51.86	$0.07	0.1%
6		400	$32.41	$35.15	$67.56	$32.50	$35.15	$67.65	$0.09	0.1%
7		500	$39.39	$43.94	$83.33	$39.51	$43.94	$83.45	$0.12	0.1%
8		600	$46.37	$52.73	$99.10	$46.51	$52.73	$99.24	$0.14	0.1%
9		700	$53.35	$61.51	$114.86	$53.52	$61.51	$115.03	$0.17	0.1%
10		800	$60.33	$70.30	$130.63	$60.52	$70.30	$130.82	$0.19	0.1%
11		900	$67.32	$79.09	$146.41	$67.53	$79.09	$146.62	$0.21	0.1%
12		1,000	$74.30	$87.88	$162.18	$74.53	$87.88	$162.41	$0.23	0.1%
13		1,250	$91.75	$109.85	$201.60	$92.05	$109.85	$201.90	$0.30	0.1%
14		1,500	$109.21	$131.82	$241.03	$109.56	$131.82	$241.38	$0.35	0.1%
15		2,000	$144.12	$175.76	$319.88	$144.59	$175.76	$320.35	$0.47	0.1%
16	Avg	874	$65.50	$76.81	$142.31	$65.71	$76.81	$142.52	$0.21	0.1%

17		Current	Proposed	
18		Rates	Rates	Change
19	Customer Charge	$7.00	$7.00	$ -
20	Distribution Energy	$0.04494	$0.04494	$ -
21	Revenue Decoupling	$0.00211	$0.00211	$ -
22	Distributed Solar Charge	$0.00270	$0.00270	$ -
23	Residential Assistance Adjustment Factor	$0.00452	$0.00452	$ -
24	Pension Adjustment Factor	$0.00115	$0.00115	$ -
25	Net Metering Recovery Surcharge	$0.00598	$0.00598	$ -
26	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
27	AG Consulting Expense	$0.00000	$0.00000	$ -
28	Storm Cost Recovery Adjustment Factor	$0.00098	$0.00098	$ -
29	Capital Investment Project	$0.00000	$0.00037	$0.00037
30	Basic Service Cost True Up Factor	($0.00008)	($0.00008)	$ -
31	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
32	Solar Expansion Cost Recovery Factor	$0.00080	$0.00080	$ -
33	Vegetation Management	$0.00153	$0.00153	$ -
34	Tax Act Credit Factor	($0.00129)	($0.00129)	$ -
35	Grid Modernization	$0.00064	$0.00064	$ -
36	Transition	($0.00177)	($0.00177)	$ -
37	Transmission Energy	$0.04039	$0.04039	$ -
38	Energy Efficiency Reconciliation Factor	$0.00394	$0.00394	$ -
39	System Benefits Charge	$0.00250	$0.00250	$ -
40	Renewable Energy Charge	$0.00050	$0.00050	$ -
41	Basic Service Charge	$0.13731	$0.13731	$ -
42	Low Income Discount	36%	36%	0%

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Greater Boston Service Area
Rate G-1 Small General Service (Non Demand)

1		Monthly	Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
2		kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		20	$10.46	$2.95	$13.41	$10.48	$2.95	$13.43	$0.02	0.1%
4		50	$14.16	$7.38	$21.54	$14.19	$7.38	$21.57	$0.03	0.1%
5		90	$19.09	$13.28	$32.37	$19.14	$13.28	$32.42	$0.05	0.2%
6		150	$26.49	$22.14	$48.63	$26.57	$22.14	$48.71	$0.08	0.2%
7		230	$36.35	$33.95	$70.30	$36.47	$33.95	$70.42	$0.12	0.2%
8		350	$51.13	$51.66	$102.79	$51.32	$51.66	$102.98	$0.19	0.2%
9		500	$69.62	$73.81	$143.43	$69.89	$73.81	$143.70	$0.27	0.2%
10		750	$100.43	$110.71	$211.14	$100.84	$110.71	$211.55	$0.41	0.2%
11		1,300	$168.21	$191.89	$360.10	$168.91	$191.89	$360.80	$0.70	0.2%
12		2,000	$254.48	$295.22	$549.70	$255.56	$295.22	$550.78	$1.08	0.2%
13	Avg	493	$68.76	$72.77	$141.53	$69.02	$72.77	$141.79	$0.26	0.2%

14		Monthly	Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
15		kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
16		20	$11.09	$2.95	$14.04	$11.10	$2.95	$14.05	$0.01	0.1%
17		50	$15.73	$7.38	$23.11	$15.76	$7.38	$23.14	$0.03	0.1%
18		90	$21.91	$13.28	$35.19	$21.96	$13.28	$35.24	$0.05	0.1%
19		150	$31.19	$22.14	$53.33	$31.27	$22.14	$53.41	$0.08	0.2%
20		230	$43.55	$33.95	$77.50	$43.68	$33.95	$77.63	$0.13	0.2%
21		350	$62.10	$51.66	$113.76	$62.29	$51.66	$113.95	$0.19	0.2%
22		500	$85.29	$73.81	$159.10	$85.56	$73.81	$159.37	$0.27	0.2%
23		750	$123.94	$110.71	$234.65	$124.34	$110.71	$235.05	$0.40	0.2%
24		1,300	$208.95	$191.89	$400.84	$209.66	$191.89	$401.55	$0.71	0.2%
25		2,000	$317.16	$295.22	$612.38	$318.24	$295.22	$613.46	$1.08	0.2%
26	Avg	464	$79.73	$68.49	$148.22	$79.98	$68.49	$148.47	$0.25	0.2%

27		Current	Proposed	
28		Rates	Rates	Change
29	Customer Charge	$8.00	$8.00	$ -
30	Distribution Energy - Winter	$0.05133	$0.05133	$ -
31	Distribution Energy - Summer	$0.08267	$0.08267	$ -
32	Revenue Decoupling	$0.00304	$0.00304	$ -
33	Distributed Solar Charge	$0.00388	$0.00388	$ -
34	Residential Assistance Adjustment Factor	$0.00651	$0.00651	$ -
35	Pension Adjustment Factor	$0.00123	$0.00123	$ -
36	Net Metering Recovery Surcharge	$0.00860	$0.00860	$ -
37	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
38	AG Consulting Expense	$0.00000	$0.00000	$ -
39	Storm Cost Recovery Adjustment Factor	$0.00366	$0.00366	$ -
40	Capital Investment Project	$0.00000	$0.00054	$0.00054
41	Basic Service Cost True Up Factor	($0.00012)	($0.00012)	$ -
42	Solar Program Cost Adjustment Factor	($0.00001)	($0.00001)	$ -
43	Solar Expansion Cost Recovery Factor	$0.00115	$0.00115	$ -
44	Vegetation Management	$0.00163	$0.00163	$ -
45	Tax Act Credit Factor	($0.00186)	($0.00186)	$ -
46	Grid Modernization	$0.00094	$0.00094	$ -
47	Transition	($0.00177)	($0.00177)	$ -
48	Transmission Energy	$0.03485	$0.03485	$ -
49	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
50	System Benefits Charge	$0.00250	$0.00250	$ -
51	Renewable Energy Charge	$0.00050	$0.00050	$ -
52	Basic Service Charge	$0.14761	$0.14761	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Greater Boston Service Area
Rate G-1 Small General Service (Demand)

1	Hours Use: 100										
2		Monthly	Monthly	Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
3		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
4		1	100	$22.12	$14.76	$36.88	$22.17	$14.76	$36.93	$0.05	0.1%
5		2	200	$33.23	$29.52	$62.75	$33.34	$29.52	$62.86	$0.11	0.2%
6		3	300	$44.36	$44.28	$88.64	$44.52	$44.28	$88.80	$0.16	0.2%
7		4	400	$55.47	$59.04	$114.51	$55.69	$59.04	$114.73	$0.22	0.2%
8		5	500	$66.59	$73.81	$140.40	$66.86	$73.81	$140.67	$0.27	0.2%
9		6	600	$77.71	$88.57	$166.28	$78.03	$88.57	$166.60	$0.32	0.2%
10		7	700	$88.82	$103.33	$192.15	$89.20	$103.33	$192.53	$0.38	0.2%
11		8	800	$99.95	$118.09	$218.04	$100.38	$118.09	$218.47	$0.43	0.2%
12		10	1,000	$122.18	$147.61	$269.79	$122.72	$147.61	$270.33	$0.54	0.2%
13		12	1,200	$216.05	$177.13	$393.18	$216.70	$177.13	$393.83	$0.65	0.2%
14	Avg	3	300	$44.36	$44.28	$88.64	$44.52	$44.28	$88.80	$0.16	0.2%

15		Monthly	Monthly	Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
16		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
17		1	100	$25.02	$14.76	$39.78	$25.07	$14.76	$39.83	$0.05	0.1%
18		2	200	$39.04	$29.52	$68.56	$39.15	$29.52	$68.67	$0.11	0.2%
19		3	300	$53.06	$44.28	$97.34	$53.22	$44.28	$97.50	$0.16	0.2%
20		4	400	$67.07	$59.04	$126.11	$67.29	$59.04	$126.33	$0.22	0.2%
21		5	500	$81.10	$73.81	$154.91	$81.37	$73.81	$155.18	$0.27	0.2%
22		6	600	$95.12	$88.57	$183.69	$95.44	$88.57	$184.01	$0.32	0.2%
23		7	700	$109.13	$103.33	$212.46	$109.51	$103.33	$212.84	$0.38	0.2%
24		8	800	$123.15	$118.09	$241.24	$123.58	$118.09	$241.67	$0.43	0.2%
25		10	1,000	$151.19	$147.61	$298.80	$151.73	$147.61	$299.34	$0.54	0.2%
26		12	1,200	$392.99	$177.13	$570.12	$393.64	$177.13	$570.77	$0.65	0.1%
27	Avg	3	300	$53.06	$44.28	$97.34	$53.22	$44.28	$97.50	$0.16	0.2%

28		Current	Proposed	
29		Rates	Rates	Change
30	Customer Charge	$11.00	$11.00	$ -
31	Distribution Demand <=10 kW - Winter	$0.00	$0.00	$ -
32	Distribution Demand >10 kW - Winter	$0.31	$0.31	$ -
33	Transmission Demand >10 kW - Winter	$35.51	$35.51	$ -
34	Distribution Demand <=10 kW - Summer	$0.00	$0.00	$ -
35	Distribution Demand >10 kW - Summer	$0.97	$0.97	$ -
36	Transmission Demand >10 kW - Summer	$105.91	$105.91	$ -
37	Distribution Energy - 1st 2000 kWh - Winter	$0.04778	$0.04778	$ -
38	Distribution Energy - next 150 hrs*kW - Winter	$0.04154	$0.04154	$ -
39	Distribution Energy - remainder kWh - Winter	$0.02758	$0.02758	$ -
40	Distribution Energy - 1st 2000 kWh - Summer	$0.07679	$0.07679	$ -
41	Distribution Energy - next 150 hrs*kW - Summer	$0.04660	$0.04660	$ -
42	Distribution Energy - remainder kWh - Summer	$0.02899	$0.02899	$ -
43	Revenue Decoupling	$0.00304	$0.00304	$ -
44	Distributed Solar Charge	$0.00388	$0.00388	$ -
45	Residential Assistance Adjustment Factor	$0.00651	$0.00651	$ -
46	Pension Adjustment Factor	$0.00123	$0.00123	$ -
47	Net Metering Recovery Surcharge	$0.00860	$0.00860	$ -
48	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
49	AG Consulting Expense	$0.00000	$0.00000	$ -
50	Storm Cost Recovery Adjustment Factor	$0.00366	$0.00366	$ -
51	Capital Investment Project	$0.00000	$0.00054	$0.00054
52	Basic Service Cost True Up Factor	($0.00012)	($0.00012)	$ -
53	Solar Program Cost Adjustment Factor	($0.00001)	($0.00001)	$ -
54	Solar Expansion Cost Recovery Factor	$0.00115	$0.00115	$ -
55	Vegetation Management	$0.00163	$0.00163	$ -
56	Tax Act Credit Factor	($0.00186)	($0.00186)	$ -
57	Grid Modernization	$0.00094	$0.00094	$ -
58	Transition	($0.00177)	($0.00177)	$ -
59	Transmission Energy - 1st 2000 kWh	$0.02634	$0.02634	$ -
60	Transmission Energy - next 150 hrs*kW	$0.02634	$0.02634	$ -
61	Transmission Energy - remainder kWh	$0.00000	$0.00000	$ -
62	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
63	System Benefits Charge	$0.00250	$0.00250	$ -
64	Renewable Energy Charge	$0.00050	$0.00050	$ -
65	Basic Service Charge	$0.14761	$0.14761	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Greater Boston Service Area
Rate G-1 Small General Service (Demand)

1	Hours Use: 250										
2		Monthly	Monthly	Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
3		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
4		1	250	$38.80	$36.90	$75.70	$38.93	$36.90	$75.83	$0.13	0.2%
5		2	500	$66.59	$73.81	$140.40	$66.86	$73.81	$140.67	$0.27	0.2%
6		3	750	$94.39	$110.71	$205.10	$94.79	$110.71	$205.50	$0.40	0.2%
7		4	1,000	$122.18	$147.61	$269.79	$122.72	$147.61	$270.33	$0.54	0.2%
8		5	1,250	$149.98	$184.51	$334.49	$150.65	$184.51	$335.16	$0.67	0.2%
9		6	1,500	$177.77	$221.42	$399.19	$178.58	$221.42	$400.00	$0.81	0.2%
10		7	1,750	$205.57	$258.32	$463.89	$206.51	$258.32	$464.83	$0.94	0.2%
11		8	2,000	$233.36	$295.22	$528.58	$234.44	$295.22	$529.66	$1.08	0.2%
12		10	2,500	$285.83	$369.03	$654.86	$287.18	$369.03	$656.21	$1.35	0.2%
13		12	3,000	$409.94	$442.83	$852.77	$411.56	$442.83	$854.39	$1.62	0.2%
14	Avg	5	1,250	$149.98	$184.51	$334.49	$150.65	$184.51	$335.16	$0.67	0.2%
15		Monthly	Monthly	Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
16		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
17		1	250	$46.05	$36.90	$82.95	$46.18	$36.90	$83.08	$0.13	0.2%
18		2	500	$81.10	$73.81	$154.91	$81.37	$73.81	$155.18	$0.27	0.2%
19		3	750	$116.15	$110.71	$226.86	$116.55	$110.71	$227.26	$0.40	0.2%
20		4	1,000	$151.19	$147.61	$298.80	$151.73	$147.61	$299.34	$0.54	0.2%
21		5	1,250	$186.24	$184.51	$370.75	$186.91	$184.51	$371.42	$0.67	0.2%
22		6	1,500	$221.29	$221.42	$442.71	$222.10	$221.42	$443.52	$0.81	0.2%
23		7	1,750	$256.34	$258.32	$514.66	$257.28	$258.32	$515.60	$0.94	0.2%
24		8	2,000	$291.38	$295.22	$586.60	$292.46	$295.22	$587.68	$1.08	0.2%
25		10	2,500	$346.38	$369.03	$715.41	$347.73	$369.03	$716.76	$1.35	0.2%
26		12	3,000	$615.14	$442.83	$1,057.97	$616.76	$442.83	$1,059.59	$1.62	0.2%
27	Avg	5	1,250	$186.24	$184.51	$370.75	$186.91	$184.51	$371.42	$0.67	0.2%

28		Current	Proposed	
29		Rates	Rates	Change
30	Customer Charge	$11.00	$11.00	$ -
31	Distribution Demand <=10 kW - Winter	$0.00	$0.00	$ -
32	Distribution Demand >10 kW - Winter	$0.31	$0.31	$ -
33	Transmission Demand >10 kW - Winter	$35.51	$35.51	$ -
34	Distribution Demand <=10 kW - Summer	$0.00	$0.00	$ -
35	Distribution Demand >10 kW - Summer	$0.97	$0.97	$ -
36	Transmission Demand >10 kW - Summer	$105.91	$105.91	$ -
37	Distribution Energy - 1st 2000 kWh - Winter	$0.04778	$0.04778	$ -
38	Distribution Energy - next 150 hrs*kW - Winter	$0.04154	$0.04154	$ -
39	Distribution Energy - remainder kWh - Winter	$0.02758	$0.02758	$ -
40	Distribution Energy - 1st 2000 kWh - Summer	$0.07679	$0.07679	$ -
41	Distribution Energy - next 150 hrs*kW - Summer	$0.04660	$0.04660	$ -
42	Distribution Energy - remainder kWh - Summer	$0.02899	$0.02899	$ -
43	Revenue Decoupling	$0.00304	$0.00304	$ -
44	Distributed Solar Charge	$0.00388	$0.00388	$ -
45	Residential Assistance Adjustment Factor	$0.00651	$0.00651	$ -
46	Pension Adjustment Factor	$0.00123	$0.00123	$ -
47	Net Metering Recovery Surcharge	$0.00860	$0.00860	$ -
48	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
49	AG Consulting Expense	$0.00000	$0.00000	$ -
50	Storm Cost Recovery Adjustment Factor	$0.00366	$0.00366	$ -
51	Capital Investment Project	$0.00000	$0.00054	$0.00054
52	Basic Service Cost True Up Factor	($0.00012)	($0.00012)	$ -
53	Solar Program Cost Adjustment Factor	($0.00001)	($0.00001)	$ -
54	Solar Expansion Cost Recovery Factor	$0.00115	$0.00115	$ -
55	Vegetation Management	$0.00163	$0.00163	$ -
56	Tax Act Credit Factor	($0.00186)	($0.00186)	$ -
57	Grid Modernization	$0.00094	$0.00094	$ -
58	Transition	($0.00177)	($0.00177)	$ -
59	Transmission Energy - 1st 2000 kWh	$0.02634	$0.02634	$ -
60	Transmission Energy - next 150 hrs*kW	$0.02634	$0.02634	$ -
61	Transmission Energy - remainder kWh	$0.00000	$0.00000	$ -
62	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
63	System Benefits Charge	$0.00250	$0.00250	$ -
64	Renewable Energy Charge	$0.00050	$0.00050	$ -
65	Basic Service Charge	$0.14761	$0.14761	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Greater Boston Service Area
Rate G-1 Small General Service (Demand)

				Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
1	Hours Use: 400										
2		Monthly	Monthly	Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
3		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
4		1	400	$55.47	$59.04	$114.51	$55.69	$59.04	$114.73	$0.22	0.2%
5		2	800	$99.95	$118.09	$218.04	$100.38	$118.09	$218.47	$0.43	0.2%
6		3	1,200	$144.41	$177.13	$321.54	$145.06	$177.13	$322.19	$0.65	0.2%
7		4	1,600	$188.89	$236.18	$425.07	$189.75	$236.18	$425.93	$0.86	0.2%
8		5	2,000	$233.36	$295.22	$528.58	$234.44	$295.22	$529.66	$1.08	0.2%
9		6	2,400	$275.33	$354.26	$629.59	$276.63	$354.26	$630.89	$1.30	0.2%
10		7	2,800	$317.31	$413.31	$730.62	$318.82	$413.31	$732.13	$1.51	0.2%
11		8	3,200	$359.29	$472.35	$831.64	$361.02	$472.35	$833.37	$1.73	0.2%
12		10	4,000	$423.09	$590.44	$1,013.53	$425.25	$590.44	$1,015.69	$2.16	0.2%
13		12	4,800	$558.53	$708.53	$1,267.06	$561.12	$708.53	$1,269.65	$2.59	0.2%
14	Avg	5	2,000	$233.36	$295.22	$528.58	$234.44	$295.22	$529.66	$1.08	0.2%

				Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
15		Monthly	Monthly	Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
16		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
17		1	400	$67.07	$59.04	$126.11	$67.29	$59.04	$126.33	$0.22	0.2%
18		2	800	$123.15	$118.09	$241.24	$123.58	$118.09	$241.67	$0.43	0.2%
19		3	1,200	$179.23	$177.13	$356.36	$179.88	$177.13	$357.01	$0.65	0.2%
20		4	1,600	$235.31	$236.18	$471.49	$236.17	$236.18	$472.35	$0.86	0.2%
21		5	2,000	$291.38	$295.22	$586.60	$292.46	$295.22	$587.68	$1.08	0.2%
22		6	2,400	$335.38	$354.26	$689.64	$336.68	$354.26	$690.94	$1.30	0.2%
23		7	2,800	$379.38	$413.31	$792.69	$380.89	$413.31	$794.20	$1.51	0.2%
24		8	3,200	$423.38	$472.35	$895.73	$425.11	$472.35	$897.46	$1.73	0.2%
25		10	4,000	$489.41	$590.44	$1,079.85	$491.57	$590.44	$1,082.01	$2.16	0.2%
26		12	4,800	$769.19	$708.53	$1,477.72	$771.78	$708.53	$1,480.31	$2.59	0.2%
27	Avg	5	2,000	$291.38	$295.22	$586.60	$292.46	$295.22	$587.68	$1.08	0.2%

28		Current	Proposed	
29		Rates	Rates	Change
30	Customer Charge	$11.00	$11.00	$ -
31	Distribution Demand <=10 kW - Winter	$0.00	$0.00	$ -
32	Distribution Demand >10 kW - Winter	$0.31	$0.31	$ -
33	Transmission Demand >10 kW - Winter	$35.51	$35.51	$ -
34	Distribution Demand <=10 kW - Summer	$0.00	$0.00	$ -
35	Distribution Demand >10 kW - Summer	$0.97	$0.97	$ -
36	Transmission Demand >10 kW - Summer	$105.91	$105.91	$ -
37	Distribution Energy - 1st 2000 kWh - Winter	$0.04778	$0.04778	$ -
38	Distribution Energy - next 150 hrs*kW - Winter	$0.04154	$0.04154	$ -
39	Distribution Energy - remainder kWh - Winter	$0.02758	$0.02758	$ -
40	Distribution Energy - 1st 2000 kWh - Summer	$0.07679	$0.07679	$ -
41	Distribution Energy - next 150 hrs*kW - Summer	$0.04660	$0.04660	$ -
42	Distribution Energy - remainder kWh - Summer	$0.02899	$0.02899	$ -
43	Revenue Decoupling	$0.00304	$0.00304	$ -
44	Distributed Solar Charge	$0.00388	$0.00388	$ -
45	Residential Assistance Adjustment Factor	$0.00651	$0.00651	$ -
46	Pension Adjustment Factor	$0.00123	$0.00123	$ -
47	Net Metering Recovery Surcharge	$0.00860	$0.00860	$ -
48	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
49	AG Consulting Expense	$0.00000	$0.00000	$ -
50	Storm Cost Recovery Adjustment Factor	$0.00366	$0.00366	$ -
51	Capital Investment Project	$0.00000	$0.00054	$0.00054
52	Basic Service Cost True Up Factor	($0.00012)	($0.00012)	$ -
53	Solar Program Cost Adjustment Factor	($0.00001)	($0.00001)	$ -
54	Solar Expansion Cost Recovery Factor	$0.00115	$0.00115	$ -
55	Vegetation Management	$0.00163	$0.00163	$ -
56	Tax Act Credit Factor	($0.00186)	($0.00186)	$ -
57	Grid Modernization	$0.00094	$0.00094	$ -
58	Transition	($0.00177)	($0.00177)	$ -
59	Transmission Energy - 1st 2000 kWh	$0.02634	$0.02634	$ -
60	Transmission Energy - next 150 hrs*kW	$0.02634	$0.02634	$ -
61	Transmission Energy - remainder kWh	$0.00000	$0.00000	$ -
62	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
63	System Benefits Charge	$0.00250	$0.00250	$ -
64	Renewable Energy Charge	$0.00050	$0.00050	$ -
65	Basic Service Charge	$0.14761	$0.14761	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Greater Boston Service Area
Rate G-2 Medium General Service

1	Hours Use: 200										
2		Monthly	Monthly	Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
3		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
4		8	1,600	$92.86	$236.18	$329.04	$93.42	$236.18	$329.60	$0.56	0.2%
5		10	2,000	$111.58	$295.22	$406.80	$112.28	$295.22	$407.50	$0.70	0.2%
6		12	2,400	$172.37	$354.26	$526.63	$173.21	$354.26	$527.47	$0.84	0.2%
7		14	2,800	$233.16	$413.31	$646.47	$234.14	$413.31	$647.45	$0.98	0.2%
8		16	3,200	$293.94	$472.35	$766.29	$295.06	$472.35	$767.41	$1.12	0.1%
9		20	4,000	$415.52	$590.44	$1,005.96	$416.92	$590.44	$1,007.36	$1.40	0.1%
10		24	4,800	$537.10	$708.53	$1,245.63	$538.78	$708.53	$1,247.31	$1.68	0.1%
11		30	6,000	$719.46	$885.66	$1,605.12	$721.56	$885.66	$1,607.22	$2.10	0.1%
12		40	8,000	$1,023.40	$1,180.88	$2,204.28	$1,026.20	$1,180.88	$2,207.08	$2.80	0.1%
13		70	14,000	$1,932.06	$2,066.54	$3,998.60	$1,936.96	$2,066.54	$4,003.50	$4.90	0.1%
14	Avg	17	3,400	$324.34	$501.87	$826.21	$325.53	$501.87	$827.40	$1.19	0.1%
15		Monthly	Monthly	Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
16		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
17		8	1,600	$110.85	$236.18	$347.03	$111.41	$236.18	$347.59	$0.56	0.2%
18		10	2,000	$134.06	$295.22	$429.28	$134.76	$295.22	$429.98	$0.70	0.2%
19		12	2,400	$258.03	$354.26	$612.29	$258.87	$354.26	$613.13	$0.84	0.1%
20		14	2,800	$382.01	$413.31	$795.32	$382.99	$413.31	$796.30	$0.98	0.1%
21		16	3,200	$505.97	$472.35	$978.32	$507.09	$472.35	$979.44	$1.12	0.1%
22		20	4,000	$753.92	$590.44	$1,344.36	$755.32	$590.44	$1,345.76	$1.40	0.1%
23		24	4,800	$1,001.87	$708.53	$1,710.40	$1,003.55	$708.53	$1,712.08	$1.68	0.1%
24		30	6,000	$1,373.78	$885.66	$2,259.44	$1,375.88	$885.66	$2,261.54	$2.10	0.1%
25		40	8,000	$1,993.64	$1,180.88	$3,174.52	$1,996.44	$1,180.88	$3,177.32	$2.80	0.1%
26		70	14,000	$3,847.94	$2,066.54	$5,914.48	$3,852.84	$2,066.54	$5,919.38	$4.90	0.1%
27	Avg	18	3,600	$629.95	$531.40	$1,161.35	$631.21	$531.40	$1,162.61	$1.26	0.1%

28		Current	Proposed	
29		Rates	Rates	Change
30	Customer Charge	$18.00	$18.00	$ -
31	Distribution Demand <=10 kW - Winter	$0.00	$0.00	$ -
32	Distribution Demand >10 kW - Winter	$10.68	$10.68	$ -
33	Transmission Demand >10 kW - Winter	$11.50	$11.50	$ -
34	Distribution Demand <=10 kW - Summer	$0.00	$0.00	$ -
35	Distribution Demand >10 kW - Summer	$22.90	$22.90	$ -
36	Transmission Demand >10 kW - Summer	$30.48	$30.48	$ -
37	Distribution Energy - 1st 2000 kWh - Winter	$0.02022	$0.02022	$ -
38	Distribution Energy - next 150 hrs*kW - Winter	$0.01450	$0.01450	$ -
39	Distribution Energy - remainder kWh - Winter	$0.01239	$0.01239	$ -
40	Distribution Energy - 1st 2000 kWh - Summer	$0.03146	$0.03146	$ -
41	Distribution Energy - next 150 hrs*kW - Summer	$0.01646	$0.01646	$ -
42	Distribution Energy - remainder kWh - Summer	$0.01294	$0.01294	$ -
43	Revenue Decoupling	$0.00197	$0.00197	$ -
44	Distributed Solar Charge	$0.00252	$0.00252	$ -
45	Residential Assistance Adjustment Factor	$0.00423	$0.00423	$ -
46	Pension Adjustment Factor	$0.00061	$0.00061	$ -
47	Net Metering Recovery Surcharge	$0.00558	$0.00558	$ -
48	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
49	AG Consulting Expense	$0.00000	$0.00000	$ -
50	Storm Cost Recovery Adjustment Factor	$0.00237	$0.00237	$ -
51	Capital Investment Project	$0.00000	$0.00035	$0.00035
52	Basic Service Cost True Up Factor	($0.00008)	($0.00008)	$ -
53	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
54	Solar Expansion Cost Recovery Factor	$0.00074	$0.00074	$ -
55	Vegetation Management	$0.00082	$0.00082	$ -
56	Tax Act Credit Factor	($0.00121)	($0.00121)	$ -
57	Grid Modernization	$0.00061	$0.00061	$ -
58	Transition	($0.00177)	($0.00177)	$ -
59	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
60	System Benefits Charge	$0.00250	$0.00250	$ -
61	Renewable Energy Charge	$0.00050	$0.00050	$ -
62	Basic Service Charge	$0.14761	$0.14761	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Greater Boston Service Area
Rate G-2 Medium General Service

1	Hours Use: 300										
2		Monthly	Monthly	Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
3		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
4		8	2,400	$128.01	$354.26	$482.27	$128.85	$354.26	$483.11	$0.84	0.2%
5		10	3,000	$152.65	$442.83	$595.48	$153.70	$442.83	$596.53	$1.05	0.2%
6		12	3,600	$221.65	$531.40	$753.05	$222.91	$531.40	$754.31	$1.26	0.2%
7		14	4,200	$290.44	$619.96	$910.40	$291.91	$619.96	$911.87	$1.47	0.2%
8		16	4,800	$358.82	$708.53	$1,067.35	$360.50	$708.53	$1,069.03	$1.68	0.2%
9		20	6,000	$495.55	$885.66	$1,381.21	$497.65	$885.66	$1,383.31	$2.10	0.2%
10		24	7,200	$632.28	$1,062.79	$1,695.07	$634.80	$1,062.79	$1,697.59	$2.52	0.1%
11		30	9,000	$837.40	$1,328.49	$2,165.89	$840.55	$1,328.49	$2,169.04	$3.15	0.1%
12		40	12,000	$1,179.24	$1,771.32	$2,950.56	$1,183.44	$1,771.32	$2,954.76	$4.20	0.1%
13		70	21,000	$2,204.78	$3,099.81	$5,304.59	$2,212.13	$3,099.81	$5,311.94	$7.35	0.1%
14	Avg	24	7,200	$632.28	$1,062.79	$1,695.07	$634.80	$1,062.79	$1,697.59	$2.52	0.1%

15		Monthly	Monthly	Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
16		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
17		8	2,400	$151.27	$354.26	$505.53	$152.11	$354.26	$506.37	$0.84	0.2%
18		10	3,000	$177.09	$442.83	$619.92	$178.14	$442.83	$620.97	$1.05	0.2%
19		12	3,600	$309.67	$531.40	$841.07	$310.93	$531.40	$842.33	$1.26	0.1%
20		14	4,200	$441.89	$619.96	$1,061.85	$443.36	$619.96	$1,063.32	$1.47	0.1%
21		16	4,800	$573.42	$708.53	$1,281.95	$575.10	$708.53	$1,283.63	$1.68	0.1%
22		20	6,000	$836.46	$885.66	$1,722.12	$838.56	$885.66	$1,724.22	$2.10	0.1%
23		24	7,200	$1,099.50	$1,062.79	$2,162.29	$1,102.02	$1,062.79	$2,164.81	$2.52	0.1%
24		30	9,000	$1,494.07	$1,328.49	$2,822.56	$1,497.22	$1,328.49	$2,825.71	$3.15	0.1%
25		40	12,000	$2,151.68	$1,771.32	$3,923.00	$2,155.88	$1,771.32	$3,927.20	$4.20	0.1%
26		70	21,000	$4,124.51	$3,099.81	$7,224.32	$4,131.86	$3,099.81	$7,231.67	$7.35	0.1%
27	Avg	26	7,800	$1,231.03	$1,151.36	$2,382.39	$1,233.76	$1,151.36	$2,385.12	$2.73	0.1%

28		Current	Proposed	
29		Rates	Rates	Change
30	Customer Charge	$18.00	$18.00	$ -
31	Distribution Demand <=10 kW - Winter	$0.00	$0.00	$ -
32	Distribution Demand >10 kW - Winter	$10.68	$10.68	$ -
33	Transmission Demand >10 kW - Winter	$11.50	$11.50	$ -
34	Distribution Demand <=10 kW - Summer	$0.00	$0.00	$ -
35	Distribution Demand >10 kW - Summer	$22.90	$22.90	$ -
36	Transmission Demand >10 kW - Summer	$30.48	$30.48	$ -
37	Distribution Energy - 1st 2000 kWh - Winter	$0.02022	$0.02022	$ -
38	Distribution Energy - next 150 hrs*kW - Winter	$0.01450	$0.01450	$ -
39	Distribution Energy - remainder kWh - Winter	$0.01239	$0.01239	$ -
40	Distribution Energy - 1st 2000 kWh - Summer	$0.03146	$0.03146	$ -
41	Distribution Energy - next 150 hrs*kW - Summer	$0.01646	$0.01646	$ -
42	Distribution Energy - remainder kWh - Summer	$0.01294	$0.01294	$ -
43	Revenue Decoupling	$0.00197	$0.00197	$ -
44	Distributed Solar Charge	$0.00252	$0.00252	$ -
45	Residential Assistance Adjustment Factor	$0.00423	$0.00423	$ -
46	Pension Adjustment Factor	$0.00061	$0.00061	$ -
47	Net Metering Recovery Surcharge	$0.00558	$0.00558	$ -
48	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
49	AG Consulting Expense	$0.00000	$0.00000	$ -
50	Storm Cost Recovery Adjustment Factor	$0.00237	$0.00237	$ -
51	Capital Investment Project	$0.00000	$0.00035	$0.00035
52	Basic Service Cost True Up Factor	($0.00008)	($0.00008)	$ -
53	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
54	Solar Expansion Cost Recovery Factor	$0.00074	$0.00074	$ -
55	Vegetation Management	$0.00082	$0.00082	$ -
56	Tax Act Credit Factor	($0.00121)	($0.00121)	$ -
57	Grid Modernization	$0.00061	$0.00061	$ -
58	Transition	($0.00177)	($0.00177)	$ -
59	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
60	System Benefits Charge	$0.00250	$0.00250	$ -
61	Renewable Energy Charge	$0.00050	$0.00050	$ -
62	Basic Service Charge	$0.14761	$0.14761	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Greater Boston Service Area
Rate G-2 Medium General Service

1		Hours Use: 450									
2		Monthly	Monthly	Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
3		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
4		8	3,600	$176.45	$531.40	$707.85	$177.71	$531.40	$709.11	$1.26	0.2%
5		10	4,500	$212.15	$664.25	$876.40	$213.72	$664.25	$877.97	$1.57	0.2%
6		12	5,400	$292.20	$797.09	$1,089.29	$294.09	$797.09	$1,091.18	$1.89	0.2%
7		14	6,300	$372.26	$929.94	$1,302.20	$374.47	$929.94	$1,304.41	$2.21	0.2%
8		16	7,200	$452.31	$1,062.79	$1,515.10	$454.83	$1,062.79	$1,517.62	$2.52	0.2%
9		20	9,000	$612.43	$1,328.49	$1,940.92	$615.58	$1,328.49	$1,944.07	$3.15	0.2%
10		24	10,800	$772.55	$1,594.19	$2,366.74	$776.33	$1,594.19	$2,370.52	$3.78	0.2%
11		30	13,500	$1,012.72	$1,992.74	$3,005.46	$1,017.44	$1,992.74	$3,010.18	$4.72	0.2%
12		40	18,000	$1,413.00	$2,656.98	$4,069.98	$1,419.30	$2,656.98	$4,076.28	$6.30	0.2%
13		70	31,500	$2,613.86	$4,649.72	$7,263.58	$2,624.88	$4,649.72	$7,274.60	$11.02	0.2%
14	Avg	31	13,950	$1,052.74	$2,059.16	$3,111.90	$1,057.62	$2,059.16	$3,116.78	$4.88	0.2%
15		Monthly	Monthly	Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
16		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
17		8	3,600	$201.50	$531.40	$732.90	$202.76	$531.40	$734.16	$1.26	0.2%
18		10	4,500	$238.12	$664.25	$902.37	$239.69	$664.25	$903.94	$1.57	0.2%
19		12	5,400	$381.49	$797.09	$1,178.58	$383.38	$797.09	$1,180.47	$1.89	0.2%
20		14	6,300	$524.86	$929.94	$1,454.80	$527.07	$929.94	$1,457.01	$2.21	0.2%
21		16	7,200	$668.24	$1,062.79	$1,731.03	$670.76	$1,062.79	$1,733.55	$2.52	0.1%
22		20	9,000	$954.99	$1,328.49	$2,283.48	$958.14	$1,328.49	$2,286.63	$3.15	0.1%
23		24	10,800	$1,241.74	$1,594.19	$2,835.93	$1,245.52	$1,594.19	$2,839.71	$3.78	0.1%
24		30	13,500	$1,671.87	$1,992.74	$3,664.61	$1,676.59	$1,992.74	$3,669.33	$4.72	0.1%
25		40	18,000	$2,388.74	$2,656.98	$5,045.72	$2,395.04	$2,656.98	$5,052.02	$6.30	0.1%
26		70	31,500	$4,539.37	$4,649.72	$9,189.09	$4,550.39	$4,649.72	$9,200.11	$11.02	0.1%
27	Avg	33	14,850	$1,886.92	$2,192.01	$4,078.93	$1,892.12	$2,192.01	$4,084.13	$5.20	0.1%

28		Current	Proposed	
29		Rates	Rates	Change
30	Customer Charge	$18.00	$18.00	$ -
31	Distribution Demand <=10 kW - Winter	$0.00	$0.00	$ -
32	Distribution Demand >10 kW - Winter	$10.68	$10.68	$ -
33	Transmission Demand >10 kW - Winter	$11.50	$11.50	$ -
34	Distribution Demand <=10 kW - Summer	$0.00	$0.00	$ -
35	Distribution Demand >10 kW - Summer	$22.90	$22.90	$ -
36	Transmission Demand >10 kW - Summer	$30.48	$30.48	$ -
37	Distribution Energy - 1st 2000 kWh - Winter	$0.02022	$0.02022	$ -
38	Distribution Energy - next 150 hrs*kW - Winter	$0.01450	$0.01450	$ -
39	Distribution Energy - remainder kWh - Winter	$0.01239	$0.01239	$ -
40	Distribution Energy - 1st 2000 kWh - Summer	$0.03146	$0.03146	$ -
41	Distribution Energy - next 150 hrs*kW - Summer	$0.01646	$0.01646	$ -
42	Distribution Energy - remainder kWh - Summer	$0.01294	$0.01294	$ -
43	Revenue Decoupling	$0.00197	$0.00197	$ -
44	Distributed Solar Charge	$0.00252	$0.00252	$ -
45	Residential Assistance Adjustment Factor	$0.00423	$0.00423	$ -
46	Pension Adjustment Factor	$0.00061	$0.00061	$ -
47	Net Metering Recovery Surcharge	$0.00558	$0.00558	$ -
48	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
49	AG Consulting Expense	$0.00000	$0.00000	$ -
50	Storm Cost Recovery Adjustment Factor	$0.00237	$0.00237	$ -
51	Capital Investment Project	$0.00000	$0.00035	$0.00035
52	Basic Service Cost True Up Factor	($0.00008)	($0.00008)	$ -
53	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
54	Solar Expansion Cost Recovery Factor	$0.00074	$0.00074	$ -
55	Vegetation Management	$0.00082	$0.00082	$ -
56	Tax Act Credit Factor	($0.00121)	($0.00121)	$ -
57	Grid Modernization	$0.00061	$0.00061	$ -
58	Transition	($0.00177)	($0.00177)	$ -
59	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
60	System Benefits Charge	$0.00250	$0.00250	$ -
61	Renewable Energy Charge	$0.00050	$0.00050	$ -
62	Basic Service Charge	$0.14761	$0.14761	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Greater Boston Service Area
Rate G-3 Large General Service - NEMA

1	Hours Use: 350										
2		Monthly	Monthly	Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
3		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
4		100	35,000	$3,275.00	$3,802.75	$7,077.75	$3,282.35	$3,802.75	$7,085.10	$7.35	0.1%
5		250	87,500	$7,812.50	$9,506.88	$17,319.38	$7,830.88	$9,506.88	$17,337.76	$18.38	0.1%
6		400	140,000	$12,350.00	$15,211.00	$27,561.00	$12,379.40	$15,211.00	$27,590.40	$29.40	0.1%
7		550	192,500	$16,887.50	$20,915.13	$37,802.63	$16,927.93	$20,915.13	$37,843.06	$40.43	0.1%
8		700	245,000	$21,425.00	$26,619.25	$48,044.25	$21,476.45	$26,619.25	$48,095.70	$51.45	0.1%
9		1,000	350,000	$30,500.00	$38,027.50	$68,527.50	$30,573.50	$38,027.50	$68,601.00	$73.50	0.1%
10		1,500	525,000	$45,625.00	$57,041.25	$102,666.25	$45,735.25	$57,041.25	$102,776.50	$110.25	0.1%
11		2,500	875,000	$75,875.00	$95,068.75	$170,943.75	$76,058.75	$95,068.75	$171,127.50	$183.75	0.1%
12		5,000	1,750,000	$151,500.00	$190,137.50	$341,637.50	$151,867.50	$190,137.50	$342,005.00	$367.50	0.1%
13	Avg	430	150,500	$13,257.50	$16,351.83	$29,609.33	$13,289.11	$16,351.83	$29,640.94	$31.61	0.1%
14				Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
15		Monthly	Monthly	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
16		100	35,000	$3,957.00	$3,802.75	$7,759.75	$3,964.35	$3,802.75	$7,767.10	$7.35	0.1%
17		250	87,500	$9,517.50	$9,506.88	$19,024.38	$9,535.88	$9,506.88	$19,042.76	$18.38	0.1%
18		400	140,000	$15,078.00	$15,211.00	$30,289.00	$15,107.40	$15,211.00	$30,318.40	$29.40	0.1%
19		550	192,500	$20,638.50	$20,915.13	$41,553.63	$20,678.93	$20,915.13	$41,594.06	$40.43	0.1%
20		700	245,000	$26,199.00	$26,619.25	$52,818.25	$26,250.45	$26,619.25	$52,869.70	$51.45	0.1%
21		1,000	350,000	$37,320.00	$38,027.50	$75,347.50	$37,393.50	$38,027.50	$75,421.00	$73.50	0.1%
22		1,500	525,000	$55,855.00	$57,041.25	$112,896.25	$55,965.25	$57,041.25	$113,006.50	$110.25	0.1%
23		2,500	875,000	$92,925.00	$95,068.75	$187,993.75	$93,108.75	$95,068.75	$188,177.50	$183.75	0.1%
24		5,000	1,750,000	$185,600.00	$190,137.50	$375,737.50	$185,967.50	$190,137.50	$376,105.00	$367.50	0.1%
25	Avg	506	177,100	$19,007.42	$19,241.92	$38,249.34	$19,044.61	$19,241.92	$38,286.53	$37.19	0.1%

26		Current	Proposed	
27		Rates	Rates	Change
28	Customer Charge	$250.00	$250.00	$ -
29	Distribution Demand - Winter	$9.78	$9.78	$ -
30	Distribution Demand - Summer	$16.60	$16.60	$ -
31	Transmission Demand	$13.61	$13.61	$ -
32	Distribution Energy	$0.00000	$0.00000	$ -
33	Revenue Decoupling	$0.00121	$0.00121	$ -
34	Distributed Solar Charge	$0.00154	$0.00154	$ -
35	Residential Assistance Adjustment Factor	$0.00259	$0.00259	$ -
36	Pension Adjustment Factor	$0.00041	$0.00041	$ -
37	Net Metering Recovery Surcharge	$0.00342	$0.00342	$ -
38	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
39	AG Consulting Expense	$0.00000	$0.00000	$ -
40	Storm Cost Recovery Adjustment Factor	$0.00145	$0.00145	$ -
41	Capital Investment Project	$0.00000	$0.00021	$0.00021
42	Basic Service Cost True Up Factor	($0.00005)	($0.00005)	$ -
43	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
44	Solar Expansion Cost Recovery Factor	$0.00045	$0.00045	$ -
45	Vegetation Management	$0.00054	$0.00054	$ -
46	Tax Act Credit Factor	($0.00074)	($0.00074)	$ -
47	Grid Modernization	$0.00037	$0.00037	$ -
48	Transition	($0.00177)	($0.00177)	$ -
49	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
50	System Benefits Charge	$0.00250	$0.00250	$ -
51	Renewable Energy Charge	$0.00050	$0.00050	$ -
52	Basic Service Charge	$0.10865	$0.10865	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Greater Boston Service Area
Rate G-3 Large General Service - NEMA

1		Hours Use: 450									
2		Monthly	Monthly	Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
3		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
4		100	45,000	$3,471.00	$4,889.25	$8,360.25	$3,480.45	$4,889.25	$8,369.70	$9.45	0.1%
5		250	112,500	$8,302.50	$12,223.13	$20,525.63	$8,326.13	$12,223.13	$20,549.26	$23.63	0.1%
6		400	180,000	$13,134.00	$19,557.00	$32,691.00	$13,171.80	$19,557.00	$32,728.80	$37.80	0.1%
7		550	247,500	$17,965.50	$26,890.88	$44,856.38	$18,017.48	$26,890.88	$44,908.36	$51.98	0.1%
8		700	315,000	$22,797.00	$34,224.75	$57,021.75	$22,863.15	$34,224.75	$57,087.90	$66.15	0.1%
9		1,000	450,000	$32,460.00	$48,892.50	$81,352.50	$32,554.50	$48,892.50	$81,447.00	$94.50	0.1%
10		1,500	675,000	$48,565.00	$73,338.75	$121,903.75	$48,706.75	$73,338.75	$122,045.50	$141.75	0.1%
11		2,500	1,125,000	$80,775.00	$122,231.25	$203,006.25	$81,011.25	$122,231.25	$203,242.50	$236.25	0.1%
12		5,000	2,250,000	$161,300.00	$244,462.50	$405,762.50	$161,772.50	$244,462.50	$406,235.00	$472.50	0.1%
13	Avg	800	360,000	$26,018.00	$39,114.00	$65,132.00	$26,093.60	$39,114.00	$65,207.60	$75.60	0.1%
14		Monthly	Monthly	Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
15		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
16		100	45,000	$4,153.00	$4,889.25	$9,042.25	$4,162.45	$4,889.25	$9,051.70	$9.45	0.1%
17		250	112,500	$10,007.50	$12,223.13	$22,230.63	$10,031.13	$12,223.13	$22,254.26	$23.63	0.1%
18		400	180,000	$15,862.00	$19,557.00	$35,419.00	$15,899.80	$19,557.00	$35,456.80	$37.80	0.1%
19		550	247,500	$21,716.50	$26,890.88	$48,607.38	$21,768.48	$26,890.88	$48,659.36	$51.98	0.1%
20		700	315,000	$27,571.00	$34,224.75	$61,795.75	$27,637.15	$34,224.75	$61,861.90	$66.15	0.1%
21		1,000	450,000	$39,280.00	$48,892.50	$88,172.50	$39,374.50	$48,892.50	$88,267.00	$94.50	0.1%
22		1,500	675,000	$58,795.00	$73,338.75	$132,133.75	$58,936.75	$73,338.75	$132,275.50	$141.75	0.1%
23		2,500	1,125,000	$97,825.00	$122,231.25	$220,056.25	$98,061.25	$122,231.25	$220,292.50	$236.25	0.1%
24		5,000	2,250,000	$195,400.00	$244,462.50	$439,862.50	$195,872.50	$244,462.50	$440,335.00	$472.50	0.1%
25	Avg	1,060	477,000	$41,621.80	$51,826.05	$93,447.85	$41,721.97	$51,826.05	$93,548.02	$100.17	0.1%

26		Current	Proposed	
27		Rates	Rates	Change
28	Customer Charge	$250.00	$250.00	$ -
29	Distribution Demand - Winter	$9.78	$9.78	$ -
30	Distribution Demand - Summer	$16.60	$16.60	$ -
31	Transmission Demand	$13.61	$13.61	$ -
32	Distribution Energy	$0.00000	$0.00000	$ -
33	Revenue Decoupling	$0.00121	$0.00121	$ -
34	Distributed Solar Charge	$0.00154	$0.00154	$ -
35	Residential Assistance Adjustment Factor	$0.00259	$0.00259	$ -
36	Pension Adjustment Factor	$0.00041	$0.00041	$ -
37	Net Metering Recovery Surcharge	$0.00342	$0.00342	$ -
38	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
39	AG Consulting Expense	$0.00000	$0.00000	$ -
40	Storm Cost Recovery Adjustment Factor	$0.00145	$0.00145	$ -
41	Capital Investment Project	$0.00000	$0.00021	$0.00021
42	Basic Service Cost True Up Factor	($0.00005)	($0.00005)	$ -
43	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
44	Solar Expansion Cost Recovery Factor	$0.00045	$0.00045	$ -
45	Vegetation Management	$0.00054	$0.00054	$ -
46	Tax Act Credit Factor	($0.00074)	($0.00074)	$ -
47	Grid Modernization	$0.00037	$0.00037	$ -
48	Transition	($0.00177)	($0.00177)	$ -
49	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
50	System Benefits Charge	$0.00250	$0.00250	$ -
51	Renewable Energy Charge	$0.00050	$0.00050	$ -
52	Basic Service Charge	$0.10865	$0.10865	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Greater Boston Service Area
Rate G-3 Large General Service - NEMA

1		Hours Use: 550									
2		Monthly	Monthly	Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
3		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
4		100	55,000	$3,667.00	$5,975.75	$9,642.75	$3,678.55	$5,975.75	$9,654.30	$11.55	0.1%
5		250	137,500	$8,792.50	$14,939.38	$23,731.88	$8,821.38	$14,939.38	$23,760.76	$28.88	0.1%
6		400	220,000	$13,918.00	$23,903.00	$37,821.00	$13,964.20	$23,903.00	$37,867.20	$46.20	0.1%
7		550	302,500	$19,043.50	$32,866.63	$51,910.13	$19,107.03	$32,866.63	$51,973.66	$63.53	0.1%
8		700	385,000	$24,169.00	$41,830.25	$65,999.25	$24,249.85	$41,830.25	$66,080.10	$80.85	0.1%
9		1,000	550,000	$34,420.00	$59,757.50	$94,177.50	$34,535.50	$59,757.50	$94,293.00	$115.50	0.1%
10		1,500	825,000	$51,505.00	$89,636.25	$141,141.25	$51,678.25	$89,636.25	$141,314.50	$173.25	0.1%
11		2,500	1,375,000	$85,675.00	$149,393.75	$235,068.75	$85,963.75	$149,393.75	$235,357.50	$288.75	0.1%
12		5,000	2,750,000	$171,100.00	$298,787.50	$469,887.50	$171,677.50	$298,787.50	$470,465.00	$577.50	0.1%
13	Avg	1,459	802,450	$50,104.03	$87,186.19	$137,290.22	$50,272.54	$87,186.19	$137,458.73	$168.51	0.1%

14		Monthly	Monthly	Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
15		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
16		100	55,000	$4,349.00	$5,975.75	$10,324.75	$4,360.55	$5,975.75	$10,336.30	$11.55	0.1%
17		250	137,500	$10,497.50	$14,939.38	$25,436.88	$10,526.38	$14,939.38	$25,465.76	$28.88	0.1%
18		400	220,000	$16,646.00	$23,903.00	$40,549.00	$16,692.20	$23,903.00	$40,595.20	$46.20	0.1%
19		550	302,500	$22,794.50	$32,866.63	$55,661.13	$22,858.03	$32,866.63	$55,724.66	$63.53	0.1%
20		700	385,000	$28,943.00	$41,830.25	$70,773.25	$29,023.85	$41,830.25	$70,854.10	$80.85	0.1%
21		1,000	550,000	$41,240.00	$59,757.50	$100,997.50	$41,355.50	$59,757.50	$101,113.00	$115.50	0.1%
22		1,500	825,000	$61,735.00	$89,636.25	$151,371.25	$61,908.25	$89,636.25	$151,544.50	$173.25	0.1%
23		2,500	1,375,000	$102,725.00	$149,393.75	$252,118.75	$103,013.75	$149,393.75	$252,407.50	$288.75	0.1%
24		5,000	2,750,000	$205,200.00	$298,787.50	$503,987.50	$205,777.50	$298,787.50	$504,565.00	$577.50	0.1%
25	Avg	2,101	1,155,550	$86,369.99	$125,550.51	$211,920.50	$86,612.66	$125,550.51	$212,163.17	$242.67	0.1%

26		Current	Proposed	
27		Rates	Rates	Change
28	Customer Charge	$250.00	$250.00	$ -
29	Distribution Demand - Winter	$9.78	$9.78	$ -
30	Distribution Demand - Summer	$16.60	$16.60	$ -
31	Transmission Demand	$13.61	$13.61	$ -
32	Distribution Energy	$0.00000	$0.00000	$ -
33	Revenue Decoupling	$0.00121	$0.00121	$ -
34	Distributed Solar Charge	$0.00154	$0.00154	$ -
35	Residential Assistance Adjustment Factor	$0.00259	$0.00259	$ -
36	Pension Adjustment Factor	$0.00041	$0.00041	$ -
37	Net Metering Recovery Surcharge	$0.00342	$0.00342	$ -
38	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
39	AG Consulting Expense	$0.00000	$0.00000	$ -
40	Storm Cost Recovery Adjustment Factor	$0.00145	$0.00145	$ -
41	Capital Investment Project	$0.00000	$0.00021	$0.00021
42	Basic Service Cost True Up Factor	($0.00005)	($0.00005)	$ -
43	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
44	Solar Expansion Cost Recovery Factor	$0.00045	$0.00045	$ -
45	Vegetation Management	$0.00054	$0.00054	$ -
46	Tax Act Credit Factor	($0.00074)	($0.00074)	$ -
47	Grid Modernization	$0.00037	$0.00037	$ -
48	Transition	($0.00177)	($0.00177)	$ -
49	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
50	System Benefits Charge	$0.00250	$0.00250	$ -
51	Renewable Energy Charge	$0.00050	$0.00050	$ -
52	Basic Service Charge	$0.10865	$0.10865	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Greater Boston Service Area
Rate G-3 Large General Service - SEMA

1		Hours Use: 350									
2		Monthly	Monthly	Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
3		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
4		100	35,000	$3,275.00	$3,664.50	$6,939.50	$3,282.35	$3,664.50	$6,946.85	$7.35	0.1%
5		250	87,500	$7,812.50	$9,161.25	$16,973.75	$7,830.88	$9,161.25	$16,992.13	$18.38	0.1%
6		400	140,000	$12,350.00	$14,658.00	$27,008.00	$12,379.40	$14,658.00	$27,037.40	$29.40	0.1%
7		550	192,500	$16,887.50	$20,154.75	$37,042.25	$16,927.93	$20,154.75	$37,082.68	$40.43	0.1%
8		700	245,000	$21,425.00	$25,651.50	$47,076.50	$21,476.45	$25,651.50	$47,127.95	$51.45	0.1%
9		1,000	350,000	$30,500.00	$36,645.00	$67,145.00	$30,573.50	$36,645.00	$67,218.50	$73.50	0.1%
10		1,500	525,000	$45,625.00	$54,967.50	$100,592.50	$45,735.25	$54,967.50	$100,702.75	$110.25	0.1%
11		2,500	875,000	$75,875.00	$91,612.50	$167,487.50	$76,058.75	$91,612.50	$167,671.25	$183.75	0.1%
12		5,000	1,750,000	$151,500.00	$183,225.00	$334,725.00	$151,867.50	$183,225.00	$335,092.50	$367.50	0.1%
13	Avg	430	150,500	$13,257.50	$15,757.35	$29,014.85	$13,289.11	$15,757.35	$29,046.46	$31.61	0.1%

14		Monthly	Monthly	Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
15		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
16		100	35,000	$3,957.00	$3,664.50	$7,621.50	$3,964.35	$3,664.50	$7,628.85	$7.35	0.1%
17		250	87,500	$9,517.50	$9,161.25	$18,678.75	$9,535.88	$9,161.25	$18,697.13	$18.38	0.1%
18		400	140,000	$15,078.00	$14,658.00	$29,736.00	$15,107.40	$14,658.00	$29,765.40	$29.40	0.1%
19		550	192,500	$20,638.50	$20,154.75	$40,793.25	$20,678.93	$20,154.75	$40,833.68	$40.43	0.1%
20		700	245,000	$26,199.00	$25,651.50	$51,850.50	$26,250.45	$25,651.50	$51,901.95	$51.45	0.1%
21		1,000	350,000	$37,320.00	$36,645.00	$73,965.00	$37,393.50	$36,645.00	$74,038.50	$73.50	0.1%
22		1,500	525,000	$55,855.00	$54,967.50	$110,822.50	$55,965.25	$54,967.50	$110,932.75	$110.25	0.1%
23		2,500	875,000	$92,925.00	$91,612.50	$184,537.50	$93,108.75	$91,612.50	$184,721.25	$183.75	0.1%
24		5,000	1,750,000	$185,600.00	$183,225.00	$368,825.00	$185,967.50	$183,225.00	$369,192.50	$367.50	0.1%
25	Avg	506	177,100	$19,007.42	$18,542.37	$37,549.79	$19,044.61	$18,542.37	$37,586.98	$37.19	0.1%

26		Current	Proposed	
27		Rates	Rates	Change
28	Customer Charge	$250.00	$250.00	$ -
29	Distribution Demand - Winter	$9.78	$9.78	$ -
30	Distribution Demand - Summer	$16.60	$16.60	$ -
31	Transmission Demand	$13.61	$13.61	$ -
32	Distribution Energy	$0.00000	$0.00000	$ -
33	Revenue Decoupling	$0.00121	$0.00121	$ -
34	Distributed Solar Charge	$0.00154	$0.00154	$ -
35	Residential Assistance Adjustment Factor	$0.00259	$0.00259	$ -
36	Pension Adjustment Factor	$0.00041	$0.00041	$ -
37	Net Metering Recovery Surcharge	$0.00342	$0.00342	$ -
38	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
39	AG Consulting Expense	$0.00000	$0.00000	$ -
40	Storm Cost Recovery Adjustment Factor	$0.00145	$0.00145	$ -
41	Capital Investment Project	$0.00000	$0.00021	$0.00021
42	Basic Service Cost True Up Factor	($0.00005)	($0.00005)	$ -
43	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
44	Solar Expansion Cost Recovery Factor	$0.00045	$0.00045	$ -
45	Vegetation Management	$0.00054	$0.00054	$ -
46	Tax Act Credit Factor	($0.00074)	($0.00074)	$ -
47	Grid Modernization	$0.00037	$0.00037	$ -
48	Transition	($0.00177)	($0.00177)	$ -
49	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
50	System Benefits Charge	$0.00250	$0.00250	$ -
51	Renewable Energy Charge	$0.00050	$0.00050	$ -
52	Basic Service Charge	$0.10470	$0.10470	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Greater Boston Service Area
Rate G-3 Large General Service - SEMA

1 Hours Use: 450

				Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
2		Monthly	Monthly								
3		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
4		100	45,000	$3,471.00	$4,711.50	$8,182.50	$3,480.45	$4,711.50	$8,191.95	$9.45	0.1%
5		250	112,500	$8,302.50	$11,778.75	$20,081.25	$8,326.13	$11,778.75	$20,104.88	$23.63	0.1%
6		400	180,000	$13,134.00	$18,846.00	$31,980.00	$13,171.80	$18,846.00	$32,017.80	$37.80	0.1%
7		550	247,500	$17,965.50	$25,913.25	$43,878.75	$18,017.48	$25,913.25	$43,930.73	$51.98	0.1%
8		700	315,000	$22,797.00	$32,980.50	$55,777.50	$22,863.15	$32,980.50	$55,843.65	$66.15	0.1%
9		1,000	450,000	$32,460.00	$47,115.00	$79,575.00	$32,554.50	$47,115.00	$79,669.50	$94.50	0.1%
10		1,500	675,000	$48,565.00	$70,672.50	$119,237.50	$48,706.75	$70,672.50	$119,379.25	$141.75	0.1%
11		2,500	1,125,000	$80,775.00	$117,787.50	$198,562.50	$81,011.25	$117,787.50	$198,798.75	$236.25	0.1%
12		5,000	2,250,000	$161,300.00	$235,575.00	$396,875.00	$161,772.50	$235,575.00	$397,347.50	$472.50	0.1%
13	Avg	800	360,000	$26,018.00	$37,692.00	$63,710.00	$26,093.60	$37,692.00	$63,785.60	$75.60	0.1%

				Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
14		Monthly	Monthly								
15		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
16		100	45,000	$4,153.00	$4,711.50	$8,864.50	$4,162.45	$4,711.50	$8,873.95	$9.45	0.1%
17		250	112,500	$10,007.50	$11,778.75	$21,786.25	$10,031.13	$11,778.75	$21,809.88	$23.63	0.1%
18		400	180,000	$15,862.00	$18,846.00	$34,708.00	$15,899.80	$18,846.00	$34,745.80	$37.80	0.1%
19		550	247,500	$21,716.50	$25,913.25	$47,629.75	$21,768.48	$25,913.25	$47,681.73	$51.98	0.1%
20		700	315,000	$27,571.00	$32,980.50	$60,551.50	$27,637.15	$32,980.50	$60,617.65	$66.15	0.1%
21		1,000	450,000	$39,280.00	$47,115.00	$86,395.00	$39,374.50	$47,115.00	$86,489.50	$94.50	0.1%
22		1,500	675,000	$58,795.00	$70,672.50	$129,467.50	$58,936.75	$70,672.50	$129,609.25	$141.75	0.1%
23		2,500	1,125,000	$97,825.00	$117,787.50	$215,612.50	$98,061.25	$117,787.50	$215,848.75	$236.25	0.1%
24		5,000	2,250,000	$195,400.00	$235,575.00	$430,975.00	$195,872.50	$235,575.00	$431,447.50	$472.50	0.1%
25	Avg	1,060	477,000	$41,621.80	$49,941.90	$91,563.70	$41,721.97	$49,941.90	$91,663.87	$100.17	0.1%

26		Current	Proposed	
27		Rates	Rates	Change
28	Customer Charge	$250.00	$250.00	$ -
29	Distribution Demand - Winter	$9.78	$9.78	$ -
30	Distribution Demand - Summer	$16.60	$16.60	$ -
31	Transmission Demand	$13.61	$13.61	$ -
32	Distribution Energy	$0.00000	$0.00000	$ -
33	Revenue Decoupling	$0.00121	$0.00121	$ -
34	Distributed Solar Charge	$0.00154	$0.00154	$ -
35	Residential Assistance Adjustment Factor	$0.00259	$0.00259	$ -
36	Pension Adjustment Factor	$0.00041	$0.00041	$ -
37	Net Metering Recovery Surcharge	$0.00342	$0.00342	$ -
38	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
39	AG Consulting Expense	$0.00000	$0.00000	$ -
40	Storm Cost Recovery Adjustment Factor	$0.00145	$0.00145	$ -
41	Capital Investment Project	$0.00000	$0.00021	$0.00021
42	Basic Service Cost True Up Factor	($0.00005)	($0.00005)	$ -
43	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
44	Solar Expansion Cost Recovery Factor	$0.00045	$0.00045	$ -
45	Vegetation Management	$0.00054	$0.00054	$ -
46	Tax Act Credit Factor	($0.00074)	($0.00074)	$ -
47	Grid Modernization	$0.00037	$0.00037	$ -
48	Transition	($0.00177)	($0.00177)	$ -
49	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
50	System Benefits Charge	$0.00250	$0.00250	$ -
51	Renewable Energy Charge	$0.00050	$0.00050	$ -
52	Basic Service Charge	$0.10470	$0.10470	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Greater Boston Service Area
Rate G-3 Large General Service - SEMA

				Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
1		Hours Use: 550									
2		Monthly	Monthly								
3		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
4		100	55,000	$3,667.00	$5,758.50	$9,425.50	$3,678.55	$5,758.50	$9,437.05	$11.55	0.1%
5		250	137,500	$8,792.50	$14,396.25	$23,188.75	$8,821.38	$14,396.25	$23,217.63	$28.88	0.1%
6		400	220,000	$13,918.00	$23,034.00	$36,952.00	$13,964.20	$23,034.00	$36,998.20	$46.20	0.1%
7		550	302,500	$19,043.50	$31,671.75	$50,715.25	$19,107.03	$31,671.75	$50,778.78	$63.53	0.1%
8		700	385,000	$24,169.00	$40,309.50	$64,478.50	$24,249.85	$40,309.50	$64,559.35	$80.85	0.1%
9		1,000	550,000	$34,420.00	$57,585.00	$92,005.00	$34,535.50	$57,585.00	$92,120.50	$115.50	0.1%
10		1,500	825,000	$51,505.00	$86,377.50	$137,882.50	$51,678.25	$86,377.50	$138,055.75	$173.25	0.1%
11		2,500	1,375,000	$85,675.00	$143,962.50	$229,637.50	$85,963.75	$143,962.50	$229,926.25	$288.75	0.1%
12		5,000	2,750,000	$171,100.00	$287,925.00	$459,025.00	$171,677.50	$287,925.00	$459,602.50	$577.50	0.1%
13	Avg	1,459	802,450	$50,104.03	$84,016.52	$134,120.55	$50,272.54	$84,016.52	$134,289.06	$168.51	0.1%

				Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
14		Monthly	Monthly								
15		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
16		100	55,000	$4,349.00	$5,758.50	$10,107.50	$4,360.55	$5,758.50	$10,119.05	$11.55	0.1%
17		250	137,500	$10,497.50	$14,396.25	$24,893.75	$10,526.38	$14,396.25	$24,922.63	$28.88	0.1%
18		400	220,000	$16,646.00	$23,034.00	$39,680.00	$16,692.20	$23,034.00	$39,726.20	$46.20	0.1%
19		550	302,500	$22,794.50	$31,671.75	$54,466.25	$22,858.03	$31,671.75	$54,529.78	$63.53	0.1%
20		700	385,000	$28,943.00	$40,309.50	$69,252.50	$29,023.85	$40,309.50	$69,333.35	$80.85	0.1%
21		1,000	550,000	$41,240.00	$57,585.00	$98,825.00	$41,355.50	$57,585.00	$98,940.50	$115.50	0.1%
22		1,500	825,000	$61,735.00	$86,377.50	$148,112.50	$61,908.25	$86,377.50	$148,285.75	$173.25	0.1%
23		2,500	1,375,000	$102,725.00	$143,962.50	$246,687.50	$103,013.75	$143,962.50	$246,976.25	$288.75	0.1%
24		5,000	2,750,000	$205,200.00	$287,925.00	$493,125.00	$205,777.50	$287,925.00	$493,702.50	$577.50	0.1%
25	Avg	2,101	1,155,550	$86,369.99	$120,986.09	$207,356.08	$86,612.66	$120,986.09	$207,598.75	$242.67	0.1%

26		Current	Proposed	
27		Rates	Rates	Change
28	Customer Charge	$250.00	$250.00	$ -
29	Distribution Demand - Winter	$9.78	$9.78	$ -
30	Distribution Demand - Summer	$16.60	$16.60	$ -
31	Transmission Demand	$13.61	$13.61	$ -
32	Distribution Energy	$0.00000	$0.00000	$ -
33	Revenue Decoupling	$0.00121	$0.00121	$ -
34	Distributed Solar Charge	$0.00154	$0.00154	$ -
35	Residential Assistance Adjustment Factor	$0.00259	$0.00259	$ -
36	Pension Adjustment Factor	$0.00041	$0.00041	$ -
37	Net Metering Recovery Surcharge	$0.00342	$0.00342	$ -
38	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
39	AG Consulting Expense	$0.00000	$0.00000	$ -
40	Storm Cost Recovery Adjustment Factor	$0.00145	$0.00145	$ -
41	Capital Investment Project	$0.00000	$0.00021	$0.00021
42	Basic Service Cost True Up Factor	($0.00005)	($0.00005)	$ -
43	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
44	Solar Expansion Cost Recovery Factor	$0.00045	$0.00045	$ -
45	Vegetation Management	$0.00054	$0.00054	$ -
46	Tax Act Credit Factor	($0.00074)	($0.00074)	$ -
47	Grid Modernization	$0.00037	$0.00037	$ -
48	Transition	($0.00177)	($0.00177)	$ -
49	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
50	System Benefits Charge	$0.00250	$0.00250	$ -
51	Renewable Energy Charge	$0.00050	$0.00050	$ -
52	Basic Service Charge	$0.10470	$0.10470	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Greater Boston Service Area
Rate T-1 Optional Time-of-Use

1		Monthly	Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
2		kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		1	$10.12	$0.15	$10.27	$10.12	$0.15	$10.27	$0.00	0.0%
4		75	$18.78	$11.07	$29.85	$18.82	$11.07	$29.89	$0.04	0.1%
5		100	$21.71	$14.76	$36.47	$21.76	$14.76	$36.52	$0.05	0.1%
6		200	$33.41	$29.52	$62.93	$33.52	$29.52	$63.04	$0.11	0.2%
7		500	$68.53	$73.81	$142.34	$68.80	$73.81	$142.61	$0.27	0.2%
8		1,000	$127.06	$147.61	$274.67	$127.60	$147.61	$275.21	$0.54	0.2%
9	Avg	509	$69.58	$75.13	$144.71	$69.86	$75.13	$144.99	$0.28	0.2%
10		Monthly	Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
11		kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
12		1	$10.13	$0.15	$10.28	$10.14	$0.15	$10.29	$0.01	0.1%
13		75	$20.09	$11.07	$31.16	$20.13	$11.07	$31.20	$0.04	0.1%
14		100	$23.45	$14.76	$38.21	$23.50	$14.76	$38.26	$0.05	0.1%
15		200	$36.90	$29.52	$66.42	$37.01	$29.52	$66.53	$0.11	0.2%
16		500	$77.25	$73.81	$151.06	$77.52	$73.81	$151.33	$0.27	0.2%
17		1,000	$144.51	$147.61	$292.12	$145.05	$147.61	$292.66	$0.54	0.2%
18	Avg	287	$48.60	$42.36	$90.96	$48.76	$42.36	$91.12	$0.16	0.2%

19		Current	Proposed	
20		Rates	Rates	Change
21	Customer Charge	$10.00	$10.00	$ -
22	Distribution Energy Peak - Winter	$0.08369	$0.08369	$ -
23	Distribution Energy Off Peak - Winter	$0.02133	$0.02133	$ -
24	Distribution Energy Peak - Summer	$0.17851	$0.17851	$ -
25	Distribution Energy Off Peak - Summer	$0.02353	$0.02353	$ -
26	Revenue Decoupling	$0.00304	$0.00304	$ -
27	Distributed Solar Charge	$0.00388	$0.00388	$ -
28	Residential Assistance Adjustment Factor	$0.00651	$0.00651	$ -
29	Pension Adjustment Factor	$0.00123	$0.00123	$ -
30	Net Metering Recovery Surcharge	$0.00860	$0.00860	$ -
31	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
32	AG Consulting Expense	$0.00000	$0.00000	$ -
33	Storm Cost Recovery Adjustment Factor	$0.00366	$0.00366	$ -
34	Capital Investment Project	$0.00000	$0.00054	$0.00054
35	Basic Service Cost True Up Factor	($0.00012)	($0.00012)	$ -
36	Solar Program Cost Adjustment Factor	($0.00001)	($0.00001)	$ -
37	Solar Expansion Cost Recovery Factor	$0.00115	$0.00115	$ -
38	Vegetation Management	$0.00163	$0.00163	$ -
39	Tax Act Credit Factor	($0.00186)	($0.00186)	$ -
40	Grid Modernization	$0.00094	$0.00094	$ -
41	Transition	($0.00177)	($0.00177)	$ -
42	Transmission Energy Peak - Winter	$0.10526	$0.10526	$ -
43	Transmission Energy Off Peak - Winter	$0.00000	$0.00000	$ -
44	Transmission Energy Peak - Summer	$0.09990	$0.09990	$ -
45	Transmission Energy Off Peak - Summer	$0.00000	$0.00000	$ -
46	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
47	System Benefits Charge	$0.00250	$0.00250	$ -
48	Renewable Energy Charge	$0.00050	$0.00050	$ -
49	Basic Service Charge	$0.14761	$0.14761	$ -

50		Winter	Summer
51	On-Peak Use:	35%	29%
52	Off-Peak Use:	65%	71%

Eastern Massachusetts
Calculation of Monthly Typical Bill
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Greater Boston Service Area
Rate T-2 Time-of-Use - NEMA

1	Hours Use: 350										
2		Monthly	Monthly	Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
3		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
4		50	17,500	$1,713.98	$1,901.38	$3,615.36	$1,720.10	$1,901.38	$3,621.48	$6.12	0.2%
5		100	35,000	$3,400.95	$3,802.75	$7,203.70	$3,413.20	$3,802.75	$7,215.95	$12.25	0.2%
6		150	52,500	$5,087.93	$5,704.13	$10,792.06	$5,106.30	$5,704.13	$10,810.43	$18.37	0.2%
7		200	70,000	$6,857.90	$7,605.50	$14,463.40	$6,882.40	$7,605.50	$14,487.90	$24.50	0.2%
8		250	87,500	$8,544.88	$9,506.88	$18,051.76	$8,575.50	$9,506.88	$18,082.38	$30.62	0.2%
9		300	105,000	$10,231.85	$11,408.25	$21,640.10	$10,268.60	$11,408.25	$21,676.85	$36.75	0.2%
10		500	175,000	$17,029.75	$19,013.75	$36,043.50	$17,091.00	$19,013.75	$36,104.75	$61.25	0.2%
11		1,000	350,000	$33,899.50	$38,027.50	$71,927.00	$34,022.00	$38,027.50	$72,049.50	$122.50	0.2%
12	Avg	201	70,350	$6,891.64	$7,643.53	$14,535.17	$6,916.26	$7,643.53	$14,559.79	$24.62	0.2%

13		Monthly	Monthly	Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
14		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
15		50	17,500	$2,191.48	$1,901.38	$4,092.86	$2,197.60	$1,901.38	$4,098.98	$6.12	0.1%
16		100	35,000	$4,355.95	$3,802.75	$8,158.70	$4,368.20	$3,802.75	$8,170.95	$12.25	0.2%
17		150	52,500	$6,520.43	$5,704.13	$12,224.56	$6,538.80	$5,704.13	$12,242.93	$18.37	0.2%
18		200	70,000	$8,767.90	$7,605.50	$16,373.40	$8,792.40	$7,605.50	$16,397.90	$24.50	0.1%
19		250	87,500	$10,932.38	$9,506.88	$20,439.26	$10,963.00	$9,506.88	$20,469.88	$30.62	0.1%
20		300	105,000	$13,096.85	$11,408.25	$24,505.10	$13,133.60	$11,408.25	$24,541.85	$36.75	0.1%
21		500	175,000	$21,804.75	$19,013.75	$40,818.50	$21,866.00	$19,013.75	$40,879.75	$61.25	0.2%
22		1,000	350,000	$43,449.50	$38,027.50	$81,477.00	$43,572.00	$38,027.50	$81,599.50	$122.50	0.2%
23	Avg	246	86,100	$10,759.22	$9,354.77	$20,113.99	$10,789.35	$9,354.77	$20,144.12	$30.13	0.1%

24		Current	Proposed	
25		Rates	Rates	Change
26	Customer Charge kW <=150	$27.00	$27.00	$ -
27	Customer Charge 150 < kW <= 300	$110.00	$110.00	$ -
28	Customer Charge 300 < kW <= 1000	$160.00	$160.00	$ -
29	Customer Charge kW > 1000	$360.00	$360.00	$ -
30	Distribution Demand - Winter	$12.66	$12.66	$ -
31	Distribution Demand - Summer	$22.21	$22.21	$ -
32	Transmission Demand	$11.78	$11.78	$ -
33	Distribution Energy	$0.00000	$0.00000	$ -
34	Revenue Decoupling	$0.00197	$0.00197	$ -
35	Distributed Solar Charge	$0.00252	$0.00252	$ -
36	Residential Assistance Adjustment Factor	$0.00423	$0.00423	$ -
37	Pension Adjustment Factor	$0.00061	$0.00061	$ -
38	Net Metering Recovery Surcharge	$0.00558	$0.00558	$ -
39	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
40	AG Consulting Expense	$0.00000	$0.00000	$ -
41	Storm Cost Recovery Adjustment Factor	$0.00237	$0.00237	$ -
42	Capital Investment Project	$0.00000	$0.00035	$0.00035
43	Basic Service Cost True Up Factor	($0.00008)	($0.00008)	$ -
44	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
45	Solar Expansion Cost Recovery Factor	$0.00074	$0.00074	$ -
46	Vegetation Management	$0.00082	$0.00082	$ -
47	Tax Act Credit Factor	($0.00121)	($0.00121)	$ -
48	Grid Modernization	$0.00061	$0.00061	$ -
49	Transition	($0.00177)	($0.00177)	$ -
50	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
51	System Benefits Charge	$0.00250	$0.00250	$ -
52	Renewable Energy Charge	$0.00050	$0.00050	$ -
53	Basic Service Charge	$0.10865	$0.10865	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
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Greater Boston Service Area
Rate T-2 Time-of-Use - NEMA

				Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
1	Hours Use: 450										
2		Monthly	Monthly								
3		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
4		50	22,500	$1,846.83	$2,444.63	$4,291.46	$1,854.70	$2,444.63	$4,299.33	$7.87	0.2%
5		100	45,000	$3,666.65	$4,889.25	$8,555.90	$3,682.40	$4,889.25	$8,571.65	$15.75	0.2%
6		150	67,500	$5,486.48	$7,333.88	$12,820.36	$5,510.10	$7,333.88	$12,843.98	$23.62	0.2%
7		200	90,000	$7,389.30	$9,778.50	$17,167.80	$7,420.80	$9,778.50	$17,199.30	$31.50	0.2%
8		250	112,500	$9,209.13	$12,223.13	$21,432.26	$9,248.50	$12,223.13	$21,471.63	$39.37	0.2%
9		300	135,000	$11,028.95	$14,667.75	$25,696.70	$11,076.20	$14,667.75	$25,743.95	$47.25	0.2%
10		500	225,000	$18,358.25	$24,446.25	$42,804.50	$18,437.00	$24,446.25	$42,883.25	$78.75	0.2%
11		1,000	450,000	$36,556.50	$48,892.50	$85,449.00	$36,714.00	$48,892.50	$85,606.50	$157.50	0.2%
12	Avg	281	126,450	$10,337.42	$13,738.79	$24,076.21	$10,381.67	$13,738.79	$24,120.46	$44.25	0.2%

				Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
13		Monthly	Monthly								
14		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
15		50	22,500	$2,324.33	$2,444.63	$4,768.96	$2,332.20	$2,444.63	$4,776.83	$7.87	0.2%
16		100	45,000	$4,621.65	$4,889.25	$9,510.90	$4,637.40	$4,889.25	$9,526.65	$15.75	0.2%
17		150	67,500	$6,918.98	$7,333.88	$14,252.86	$6,942.60	$7,333.88	$14,276.48	$23.62	0.2%
18		200	90,000	$9,299.30	$9,778.50	$19,077.80	$9,330.80	$9,778.50	$19,109.30	$31.50	0.2%
19		250	112,500	$11,596.63	$12,223.13	$23,819.76	$11,636.00	$12,223.13	$23,859.13	$39.37	0.2%
20		300	135,000	$13,893.95	$14,667.75	$28,561.70	$13,941.20	$14,667.75	$28,608.95	$47.25	0.2%
21		500	225,000	$23,133.25	$24,446.25	$47,579.50	$23,212.00	$24,446.25	$47,658.25	$78.75	0.2%
22		1,000	450,000	$46,106.50	$48,892.50	$94,999.00	$46,264.00	$48,892.50	$95,156.50	$157.50	0.2%
23	Avg	319	143,550	$14,816.93	$15,596.71	$30,413.64	$14,867.18	$15,596.71	$30,463.89	$50.25	0.2%

24		Current	Proposed	
25		Rates	Rates	Change
26	Customer Charge kW <=150	$27.00	$27.00	$ -
27	Customer Charge 150 < kW <= 300	$110.00	$110.00	$ -
28	Customer Charge 300 < kW <= 1000	$160.00	$160.00	$ -
29	Customer Charge kW > 1000	$360.00	$360.00	$ -
30	Distribution Demand - Winter	$12.66	$12.66	$ -
31	Distribution Demand - Summer	$22.21	$22.21	$ -
32	Transmission Demand	$11.78	$11.78	$ -
33	Distribution Energy	$0.00000	$0.00000	$ -
34	Revenue Decoupling	$0.00197	$0.00197	$ -
35	Distributed Solar Charge	$0.00252	$0.00252	$ -
36	Residential Assistance Adjustment Factor	$0.00423	$0.00423	$ -
37	Pension Adjustment Factor	$0.00061	$0.00061	$ -
38	Net Metering Recovery Surcharge	$0.00558	$0.00558	$ -
39	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
40	AG Consulting Expense	$0.00000	$0.00000	$ -
41	Storm Cost Recovery Adjustment Factor	$0.00237	$0.00237	$ -
42	Capital Investment Project	$0.00000	$0.00035	$0.00035
43	Basic Service Cost True Up Factor	($0.00008)	($0.00008)	$ -
44	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
45	Solar Expansion Cost Recovery Factor	$0.00074	$0.00074	$ -
46	Vegetation Management	$0.00082	$0.00082	$ -
47	Tax Act Credit Factor	($0.00121)	($0.00121)	$ -
48	Grid Modernization	$0.00061	$0.00061	$ -
49	Transition	($0.00177)	($0.00177)	$ -
50	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
51	System Benefits Charge	$0.00250	$0.00250	$ -
52	Renewable Energy Charge	$0.00050	$0.00050	$ -
53	Basic Service Charge	$0.10865	$0.10865	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Greater Boston Service Area
Rate T-2 Time-of-Use - NEMA

1	Hours Use: 550										
2		Monthly	Monthly	Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
3		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
4		50	27,500	$1,979.68	$2,987.88	$4,967.56	$1,989.30	$2,987.88	$4,977.18	$9.62	0.2%
5		100	55,000	$3,932.35	$5,975.75	$9,908.10	$3,951.60	$5,975.75	$9,927.35	$19.25	0.2%
6		150	82,500	$5,885.03	$8,963.63	$14,848.66	$5,913.90	$8,963.63	$14,877.53	$28.87	0.2%
7		200	110,000	$7,920.70	$11,951.50	$19,872.20	$7,959.20	$11,951.50	$19,910.70	$38.50	0.2%
8		250	137,500	$9,873.38	$14,939.38	$24,812.76	$9,921.50	$14,939.38	$24,860.88	$48.12	0.2%
9		300	165,000	$11,826.05	$17,927.25	$29,753.30	$11,883.80	$17,927.25	$29,811.05	$57.75	0.2%
10		500	275,000	$19,686.75	$29,878.75	$49,565.50	$19,783.00	$29,878.75	$49,661.75	$96.25	0.2%
11		1,000	550,000	$39,213.50	$59,757.50	$98,971.00	$39,406.00	$59,757.50	$99,163.50	$192.50	0.2%
12	Avg	299	164,450	$11,787.00	$17,867.49	$29,654.49	$11,844.55	$17,867.49	$29,712.04	$57.55	0.2%

13		Monthly	Monthly	Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
14		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
15		50	27,500	$2,457.18	$2,987.88	$5,445.06	$2,466.80	$2,987.88	$5,454.68	$9.62	0.2%
16		100	55,000	$4,887.35	$5,975.75	$10,863.10	$4,906.60	$5,975.75	$10,882.35	$19.25	0.2%
17		150	82,500	$7,317.53	$8,963.63	$16,281.16	$7,346.40	$8,963.63	$16,310.03	$28.87	0.2%
18		200	110,000	$9,830.70	$11,951.50	$21,782.20	$9,869.20	$11,951.50	$21,820.70	$38.50	0.2%
19		250	137,500	$12,260.88	$14,939.38	$27,200.26	$12,309.00	$14,939.38	$27,248.38	$48.12	0.2%
20		300	165,000	$14,691.05	$17,927.25	$32,618.30	$14,748.80	$17,927.25	$32,676.05	$57.75	0.2%
21		500	275,000	$24,461.75	$29,878.75	$54,340.50	$24,558.00	$29,878.75	$54,436.75	$96.25	0.2%
22		1,000	550,000	$48,763.50	$59,757.50	$108,521.00	$48,956.00	$59,757.50	$108,713.50	$192.50	0.2%
23	Avg	352	193,600	$17,268.43	$21,034.64	$38,303.07	$17,336.19	$21,034.64	$38,370.83	$67.76	0.2%

24		Current	Proposed	
25		Rates	Rates	Change
26	Customer Charge kW <=150	$27.00	$27.00	$ -
27	Customer Charge 150 < kW <= 300	$110.00	$110.00	$ -
28	Customer Charge 300 < kW <= 1000	$160.00	$160.00	$ -
29	Customer Charge kW > 1000	$360.00	$360.00	$ -
30	Distribution Demand - Winter	$12.66	$12.66	$ -
31	Distribution Demand - Summer	$22.21	$22.21	$ -
32	Transmission Demand	$11.78	$11.78	$ -
33	Distribution Energy	$0.00000	$0.00000	$ -
34	Revenue Decoupling	$0.00197	$0.00197	$ -
35	Distributed Solar Charge	$0.00252	$0.00252	$ -
36	Residential Assistance Adjustment Factor	$0.00423	$0.00423	$ -
37	Pension Adjustment Factor	$0.00061	$0.00061	$ -
38	Net Metering Recovery Surcharge	$0.00558	$0.00558	$ -
39	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
40	AG Consulting Expense	$0.00000	$0.00000	$ -
41	Storm Cost Recovery Adjustment Factor	$0.00237	$0.00237	$ -
42	Capital Investment Project	$0.00000	$0.00035	$0.00035
43	Basic Service Cost True Up Factor	($0.00008)	($0.00008)	$ -
44	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
45	Solar Expansion Cost Recovery Factor	$0.00074	$0.00074	$ -
46	Vegetation Management	$0.00082	$0.00082	$ -
47	Tax Act Credit Factor	($0.00121)	($0.00121)	$ -
48	Grid Modernization	$0.00061	$0.00061	$ -
49	Transition	($0.00177)	($0.00177)	$ -
50	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
51	System Benefits Charge	$0.00250	$0.00250	$ -
52	Renewable Energy Charge	$0.00050	$0.00050	$ -
53	Basic Service Charge	$0.10865	$0.10865	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Greater Boston Service Area
Rate T-2 Time-of-Use - SEMA

1	Hours Use: 350										
2		Monthly	Monthly	Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
3		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
4		50	17,500	$1,713.98	$1,832.25	$3,546.23	$1,720.10	$1,832.25	$3,552.35	$6.12	0.2%
5		100	35,000	$3,400.95	$3,664.50	$7,065.45	$3,413.20	$3,664.50	$7,077.70	$12.25	0.2%
6		150	52,500	$5,087.93	$5,496.75	$10,584.68	$5,106.30	$5,496.75	$10,603.05	$18.37	0.2%
7		200	70,000	$6,857.90	$7,329.00	$14,186.90	$6,882.40	$7,329.00	$14,211.40	$24.50	0.2%
8		250	87,500	$8,544.88	$9,161.25	$17,706.13	$8,575.50	$9,161.25	$17,736.75	$30.62	0.2%
9		300	105,000	$10,231.85	$10,993.50	$21,225.35	$10,268.60	$10,993.50	$21,262.10	$36.75	0.2%
10		500	175,000	$17,029.75	$18,322.50	$35,352.25	$17,091.00	$18,322.50	$35,413.50	$61.25	0.2%
11		1,000	350,000	$33,899.50	$36,645.00	$70,544.50	$34,022.00	$36,645.00	$70,667.00	$122.50	0.2%
12	Avg	201	70,350	$6,891.64	$7,365.65	$14,257.29	$6,916.26	$7,365.65	$14,281.91	$24.62	0.2%
13		Monthly	Monthly	Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
14		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
15		50	17,500	$2,191.48	$1,832.25	$4,023.73	$2,197.60	$1,832.25	$4,029.85	$6.12	0.2%
16		100	35,000	$4,355.95	$3,664.50	$8,020.45	$4,368.20	$3,664.50	$8,032.70	$12.25	0.2%
17		150	52,500	$6,520.43	$5,496.75	$12,017.18	$6,538.80	$5,496.75	$12,035.55	$18.37	0.2%
18		200	70,000	$8,767.90	$7,329.00	$16,096.90	$8,792.40	$7,329.00	$16,121.40	$24.50	0.2%
19		250	87,500	$10,932.38	$9,161.25	$20,093.63	$10,963.00	$9,161.25	$20,124.25	$30.62	0.2%
20		300	105,000	$13,096.85	$10,993.50	$24,090.35	$13,133.60	$10,993.50	$24,127.10	$36.75	0.2%
21		500	175,000	$21,804.75	$18,322.50	$40,127.25	$21,866.00	$18,322.50	$40,188.50	$61.25	0.2%
22		1,000	350,000	$43,449.50	$36,645.00	$80,094.50	$43,572.00	$36,645.00	$80,217.00	$122.50	0.2%
23	Avg	246	86,100	$10,759.22	$9,014.67	$19,773.89	$10,789.35	$9,014.67	$19,804.02	$30.13	0.2%

24		Current	Proposed	
25		Rates	Rates	Change
26	Customer Charge kW <=150	$27.00	$27.00	$ -
27	Customer Charge 150 < kW <= 300	$110.00	$110.00	$ -
28	Customer Charge 300 < kW <= 1000	$160.00	$160.00	$ -
29	Customer Charge kW > 1000	$360.00	$360.00	$ -
30	Distribution Demand - Winter	$12.66	$12.66	$ -
31	Distribution Demand - Summer	$22.21	$22.21	$ -
32	Transmission Demand	$11.78	$11.78	$ -
33	Distribution Energy	$0.00000	$0.00000	$ -
34	Revenue Decoupling	$0.00197	$0.00197	$ -
35	Distributed Solar Charge	$0.00252	$0.00252	$ -
36	Residential Assistance Adjustment Factor	$0.00423	$0.00423	$ -
37	Pension Adjustment Factor	$0.00061	$0.00061	$ -
38	Net Metering Recovery Surcharge	$0.00558	$0.00558	$ -
39	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
40	AG Consulting Expense	$0.00000	$0.00000	$ -
41	Storm Cost Recovery Adjustment Factor	$0.00237	$0.00237	$ -
42	Capital Investment Project	$0.00000	$0.00035	$0.00035
43	Basic Service Cost True Up Factor	($0.00008)	($0.00008)	$ -
44	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
45	Solar Expansion Cost Recovery Factor	$0.00074	$0.00074	$ -
46	Vegetation Management	$0.00082	$0.00082	$ -
47	Tax Act Credit Factor	($0.00121)	($0.00121)	$ -
48	Grid Modernization	$0.00061	$0.00061	$ -
49	Transition	($0.00177)	($0.00177)	$ -
50	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
51	System Benefits Charge	$0.00250	$0.00250	$ -
52	Renewable Energy Charge	$0.00050	$0.00050	$ -
53	Basic Service Charge	$0.10470	$0.10470	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Greater Boston Service Area
Rate T-2 Time-of-Use - SEMA

1	Hours Use: 450										
2		Monthly	Monthly	Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
3		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
4		50	22,500	$1,846.83	$2,355.75	$4,202.58	$1,854.70	$2,355.75	$4,210.45	$7.87	0.2%
5		100	45,000	$3,666.65	$4,711.50	$8,378.15	$3,682.40	$4,711.50	$8,393.90	$15.75	0.2%
6		150	67,500	$5,486.48	$7,067.25	$12,553.73	$5,510.10	$7,067.25	$12,577.35	$23.62	0.2%
7		200	90,000	$7,389.30	$9,423.00	$16,812.30	$7,420.80	$9,423.00	$16,843.80	$31.50	0.2%
8		250	112,500	$9,209.13	$11,778.75	$20,987.88	$9,248.50	$11,778.75	$21,027.25	$39.37	0.2%
9		300	135,000	$11,028.95	$14,134.50	$25,163.45	$11,076.20	$14,134.50	$25,210.70	$47.25	0.2%
10		500	225,000	$18,358.25	$23,557.50	$41,915.75	$18,437.00	$23,557.50	$41,994.50	$78.75	0.2%
11		1,000	450,000	$36,556.50	$47,115.00	$83,671.50	$36,714.00	$47,115.00	$83,829.00	$157.50	0.2%
12	Avg	281	126,450	$10,337.42	$13,239.32	$23,576.74	$10,381.67	$13,239.32	$23,620.99	$44.25	0.2%
13		Monthly	Monthly	Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
14		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
15		50	22,500	$2,324.33	$2,355.75	$4,680.08	$2,332.20	$2,355.75	$4,687.95	$7.87	0.2%
16		100	45,000	$4,621.65	$4,711.50	$9,333.15	$4,637.40	$4,711.50	$9,348.90	$15.75	0.2%
17		150	67,500	$6,918.98	$7,067.25	$13,986.23	$6,942.60	$7,067.25	$14,009.85	$23.62	0.2%
18		200	90,000	$9,299.30	$9,423.00	$18,722.30	$9,330.80	$9,423.00	$18,753.80	$31.50	0.2%
19		250	112,500	$11,596.63	$11,778.75	$23,375.38	$11,636.00	$11,778.75	$23,414.75	$39.37	0.2%
20		300	135,000	$13,893.95	$14,134.50	$28,028.45	$13,941.20	$14,134.50	$28,075.70	$47.25	0.2%
21		500	225,000	$23,133.25	$23,557.50	$46,690.75	$23,212.00	$23,557.50	$46,769.50	$78.75	0.2%
22		1,000	450,000	$46,106.50	$47,115.00	$93,221.50	$46,264.00	$47,115.00	$93,379.00	$157.50	0.2%
23	Avg	319	143,550	$14,816.93	$15,029.69	$29,846.62	$14,867.18	$15,029.69	$29,896.87	$50.25	0.2%

24		Current	Proposed	
25		Rates	Rates	Change
26	Customer Charge kW <=150	$27.00	$27.00	$ -
27	Customer Charge 150 < kW <= 300	$110.00	$110.00	$ -
28	Customer Charge 300 < kW <= 1000	$160.00	$160.00	$ -
29	Customer Charge kW > 1000	$360.00	$360.00	$ -
30	Distribution Demand - Winter	$12.66	$12.66	$ -
31	Distribution Demand - Summer	$22.21	$22.21	$ -
32	Transmission Demand	$11.78	$11.78	$ -
33	Distribution Energy	$0.00000	$0.00000	$ -
34	Revenue Decoupling	$0.00197	$0.00197	$ -
35	Distributed Solar Charge	$0.00252	$0.00252	$ -
36	Residential Assistance Adjustment Factor	$0.00423	$0.00423	$ -
37	Pension Adjustment Factor	$0.00061	$0.00061	$ -
38	Net Metering Recovery Surcharge	$0.00558	$0.00558	$ -
39	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
40	AG Consulting Expense	$0.00000	$0.00000	$ -
41	Storm Cost Recovery Adjustment Factor	$0.00237	$0.00237	$ -
42	Capital Investment Project	$0.00000	$0.00035	$0.00035
43	Basic Service Cost True Up Factor	($0.00008)	($0.00008)	$ -
44	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
45	Solar Expansion Cost Recovery Factor	$0.00074	$0.00074	$ -
46	Vegetation Management	$0.00082	$0.00082	$ -
47	Tax Act Credit Factor	($0.00121)	($0.00121)	$ -
48	Grid Modernization	$0.00061	$0.00061	$ -
49	Transition	($0.00177)	($0.00177)	$ -
50	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
51	System Benefits Charge	$0.00250	$0.00250	$ -
52	Renewable Energy Charge	$0.00050	$0.00050	$ -
53	Basic Service Charge	$0.10470	$0.10470	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Greater Boston Service Area
Rate T-2 Time-of-Use - SEMA

1	Hours Use: 550										
2		Monthly	Monthly	Current Monthly Bill (Winter)			Proposed Monthly Bill (Winter)			Total Bill Impact	
3		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
4		50	27,500	$1,979.68	$2,879.25	$4,858.93	$1,989.30	$2,879.25	$4,868.55	$9.62	0.2%
5		100	55,000	$3,932.35	$5,758.50	$9,690.85	$3,951.60	$5,758.50	$9,710.10	$19.25	0.2%
6		150	82,500	$5,885.03	$8,637.75	$14,522.78	$5,913.90	$8,637.75	$14,551.65	$28.87	0.2%
7		200	110,000	$7,920.70	$11,517.00	$19,437.70	$7,959.20	$11,517.00	$19,476.20	$38.50	0.2%
8		250	137,500	$9,873.38	$14,396.25	$24,269.63	$9,921.50	$14,396.25	$24,317.75	$48.12	0.2%
9		300	165,000	$11,826.05	$17,275.50	$29,101.55	$11,883.80	$17,275.50	$29,159.30	$57.75	0.2%
10		500	275,000	$19,686.75	$28,792.50	$48,479.25	$19,783.00	$28,792.50	$48,575.50	$96.25	0.2%
11		1,000	550,000	$39,213.50	$57,585.00	$96,798.50	$39,406.00	$57,585.00	$96,991.00	$192.50	0.2%
12	Avg	299	164,450	$11,787.00	$17,217.92	$29,004.92	$11,844.55	$17,217.92	$29,062.47	$57.55	0.2%
13		Monthly	Monthly	Current Monthly Bill (Summer)			Proposed Monthly Bill (Summer)			Total Bill Impact	
14		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
15		50	27,500	$2,457.18	$2,879.25	$5,336.43	$2,466.80	$2,879.25	$5,346.05	$9.62	0.2%
16		100	55,000	$4,887.35	$5,758.50	$10,645.85	$4,906.60	$5,758.50	$10,665.10	$19.25	0.2%
17		150	82,500	$7,317.53	$8,637.75	$15,955.28	$7,346.40	$8,637.75	$15,984.15	$28.87	0.2%
18		200	110,000	$9,830.70	$11,517.00	$21,347.70	$9,869.20	$11,517.00	$21,386.20	$38.50	0.2%
19		250	137,500	$12,260.88	$14,396.25	$26,657.13	$12,309.00	$14,396.25	$26,705.25	$48.12	0.2%
20		300	165,000	$14,691.05	$17,275.50	$31,966.55	$14,748.80	$17,275.50	$32,024.30	$57.75	0.2%
21		500	275,000	$24,461.75	$28,792.50	$53,254.25	$24,558.00	$28,792.50	$53,350.50	$96.25	0.2%
22		1,000	550,000	$48,763.50	$57,585.00	$106,348.50	$48,956.00	$57,585.00	$106,541.00	$192.50	0.2%
23	Avg	352	193,600	$17,268.43	$20,269.92	$37,538.35	$17,336.19	$20,269.92	$37,606.11	$67.76	0.2%

24		Current	Proposed	
25		Rates	Rates	Change
26	Customer Charge kW <=150	$27.00	$27.00	$ -
27	Customer Charge 150 < kW <= 300	$110.00	$110.00	$ -
28	Customer Charge 300 < kW <= 1000	$160.00	$160.00	$ -
29	Customer Charge kW > 1000	$360.00	$360.00	$ -
30	Distribution Demand - Winter	$12.66	$12.66	$ -
31	Distribution Demand - Summer	$22.21	$22.21	$ -
32	Transmission Demand	$11.78	$11.78	$ -
33	Distribution Energy	$0.00000	$0.00000	$ -
34	Revenue Decoupling	$0.00197	$0.00197	$ -
35	Distributed Solar Charge	$0.00252	$0.00252	$ -
36	Residential Assistance Adjustment Factor	$0.00423	$0.00423	$ -
37	Pension Adjustment Factor	$0.00061	$0.00061	$ -
38	Net Metering Recovery Surcharge	$0.00558	$0.00558	$ -
39	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
40	AG Consulting Expense	$0.00000	$0.00000	$ -
41	Storm Cost Recovery Adjustment Factor	$0.00237	$0.00237	$ -
42	Capital Investment Project	$0.00000	$0.00035	$0.00035
43	Basic Service Cost True Up Factor	($0.00008)	($0.00008)	$ -
44	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
45	Solar Expansion Cost Recovery Factor	$0.00074	$0.00074	$ -
46	Vegetation Management	$0.00082	$0.00082	$ -
47	Tax Act Credit Factor	($0.00121)	($0.00121)	$ -
48	Grid Modernization	$0.00061	$0.00061	$ -
49	Transition	($0.00177)	($0.00177)	$ -
50	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
51	System Benefits Charge	$0.00250	$0.00250	$ -
52	Renewable Energy Charge	$0.00050	$0.00050	$ -
53	Basic Service Charge	$0.10470	$0.10470	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Cambridge Service Area
Rate G-0 Small General Service (Non-Demand)

1		Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		25	$7.39	$3.69	$11.08	$7.40	$3.69	$11.09	$0.01	0.1%
4		50	$9.79	$7.38	$17.17	$9.80	$7.38	$17.18	$0.01	0.1%
5		100	$14.57	$14.76	$29.33	$14.60	$14.76	$29.36	$0.03	0.1%
6		150	$19.36	$22.14	$41.50	$19.40	$22.14	$41.54	$0.04	0.1%
7		250	$28.93	$36.90	$65.83	$29.00	$36.90	$65.90	$0.07	0.1%
8		400	$43.29	$59.04	$102.33	$43.40	$59.04	$102.44	$0.11	0.1%
9		600	$62.43	$88.57	$151.00	$62.60	$88.57	$151.17	$0.17	0.1%
10		900	$91.15	$132.85	$224.00	$91.40	$132.85	$224.25	$0.25	0.1%
11		1,500	$148.58	$221.42	$370.00	$149.00	$221.42	$370.42	$0.42	0.1%
12		2,500	$244.30	$369.03	$613.33	$245.00	$369.03	$614.03	$0.70	0.1%
13	Avg	593	$61.76	$87.53	$149.29	$61.93	$87.53	$149.46	$0.17	0.1%

14		Current	Proposed	
15		Rates	Rates	Change
16	Customer Charge	$5.00	$5.00	$ -
17	Distribution Energy	$0.03870	$0.03870	$ -
18	Revenue Decoupling	$0.00159	$0.00159	$ -
19	Distributed Solar Charge	$0.00204	$0.00204	$ -
20	Residential Assistance Adjustment Factor	$0.00342	$0.00342	$ -
21	Pension Adjustment Factor	$0.00073	$0.00073	$ -
22	Net Metering Recovery Surcharge	$0.00452	$0.00452	$ -
23	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
24	AG Consulting Expense	$0.00000	$0.00000	$ -
25	Storm Cost Recovery Adjustment Factor	$0.00192	$0.00192	$ -
26	Capital Investment Project	$0.00000	$0.00028	$0.00028
27	Basic Service Cost True Up Factor	($0.00006)	($0.00006)	$ -
28	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
29	Solar Expansion Cost Recovery Factor	$0.00060	$0.00060	$ -
30	Vegetation Management	$0.00098	$0.00098	$ -
31	Tax Act Credit Factor	($0.00097)	($0.00097)	$ -
32	Grid Modernization	$0.00049	$0.00049	$ -
33	Transition	($0.00177)	($0.00177)	$ -
34	Transmission Energy	$0.03335	$0.03335	$ -
35	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
36	System Benefits Charge	$0.00250	$0.00250	$ -
37	Renewable Energy Charge	$0.00050	$0.00050	$ -
38	Basic Service Charge	$0.14761	$0.14761	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Cambridge Service Area
Rate G-1 Small General Service (Demand)

1		Monthly	Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		Hours Use: 250									
4		5	1,250	$127.84	$184.51	$312.35	$128.19	$184.51	$312.70	$0.35	0.1%
5		10	2,500	$247.68	$369.03	$616.71	$248.38	$369.03	$617.41	$0.70	0.1%
6		15	3,750	$386.01	$553.54	$939.55	$387.06	$553.54	$940.60	$1.05	0.1%
7		20	5,000	$524.35	$738.05	$1,262.40	$525.75	$738.05	$1,263.80	$1.40	0.1%
8		30	7,500	$801.03	$1,107.08	$1,908.11	$803.13	$1,107.08	$1,910.21	$2.10	0.1%
9		50	12,500	$1,354.38	$1,845.13	$3,199.51	$1,357.88	$1,845.13	$3,203.01	$3.50	0.1%
10		75	18,750	$2,046.06	$2,767.69	$4,813.75	$2,051.31	$2,767.69	$4,819.00	$5.25	0.1%
11		100	25,000	$2,737.75	$3,690.25	$6,428.00	$2,744.75	$3,690.25	$6,435.00	$7.00	0.1%
12	Avg	19	4,750	$496.68	$701.15	$1,197.83	$498.01	$701.15	$1,199.16	$1.33	0.1%
13		Hours Use: 350									
14		5	1,750	$146.11	$258.32	$404.43	$146.60	$258.32	$404.92	$0.49	0.1%
15		10	3,500	$284.23	$516.64	$800.87	$285.21	$516.64	$801.85	$0.98	0.1%
16		15	5,250	$440.84	$774.95	$1,215.79	$442.31	$774.95	$1,217.26	$1.47	0.1%
17		20	7,000	$597.45	$1,033.27	$1,630.72	$599.41	$1,033.27	$1,632.68	$1.96	0.1%
18		30	10,500	$910.68	$1,549.91	$2,460.59	$913.62	$1,549.91	$2,463.53	$2.94	0.1%
19		50	17,500	$1,537.13	$2,583.18	$4,120.31	$1,542.03	$2,583.18	$4,125.21	$4.90	0.1%
20		75	26,250	$2,320.19	$3,874.76	$6,194.95	$2,327.54	$3,874.76	$6,202.30	$7.35	0.1%
21		100	35,000	$3,103.25	$5,166.35	$8,269.60	$3,113.05	$5,166.35	$8,279.40	$9.80	0.1%
22	Avg	26	9,100	$785.39	$1,343.25	$2,128.64	$787.93	$1,343.25	$2,131.18	$2.54	0.1%
23		Hours Use: 500									
24		5	2,500	$173.53	$369.03	$542.56	$174.23	$369.03	$543.26	$0.70	0.1%
25		10	5,000	$339.05	$738.05	$1,077.10	$340.45	$738.05	$1,078.50	$1.40	0.1%
26		15	7,500	$523.08	$1,107.08	$1,630.16	$525.18	$1,107.08	$1,632.26	$2.10	0.1%
27		20	10,000	$707.10	$1,476.10	$2,183.20	$709.90	$1,476.10	$2,186.00	$2.80	0.1%
28		30	15,000	$1,075.15	$2,214.15	$3,289.30	$1,079.35	$2,214.15	$3,293.50	$4.20	0.1%
29		50	25,000	$1,811.25	$3,690.25	$5,501.50	$1,818.25	$3,690.25	$5,508.50	$7.00	0.1%
30		75	37,500	$2,731.38	$5,535.38	$8,266.76	$2,741.88	$5,535.38	$8,277.26	$10.50	0.1%
31		100	50,000	$3,651.50	$7,380.50	$11,032.00	$3,665.50	$7,380.50	$11,046.00	$14.00	0.1%
32	Avg	32	16,000	$1,148.76	$2,361.76	$3,510.52	$1,153.24	$2,361.76	$3,515.00	$4.48	0.1%

33		Current	Proposed	
34		Rates	Rates	Change
35	Customer Charge	$8.00	$8.00	$ -
36	Distribution Demand <=10 kW	$4.28	$4.28	$ -
37	Distribution Demand >10 kW	$7.98	$7.98	$ -
38	Transmission Demand	$10.55	$10.55	$ -
39	Distribution Energy	$0.01288	$0.01288	$ -
40	Revenue Decoupling	$0.00159	$0.00159	$ -
41	Distributed Solar Charge	$0.00204	$0.00204	$ -
42	Residential Assistance Adjustment Factor	$0.00342	$0.00342	$ -
43	Pension Adjustment Factor	$0.00073	$0.00073	$ -
44	Net Metering Recovery Surcharge	$0.00452	$0.00452	$ -
45	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
46	AG Consulting Expense	$0.00000	$0.00000	$ -
47	Storm Cost Recovery Adjustment Factor	$0.00192	$0.00192	$ -
48	Capital Investment Project	$0.00000	$0.00028	$0.00028
49	Basic Service Cost True Up Factor	($0.00006)	($0.00006)	$ -
50	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
51	Solar Expansion Cost Recovery Factor	$0.00060	$0.00060	$ -
52	Vegetation Management	$0.00098	$0.00098	$ -
53	Tax Act Credit Factor	($0.00097)	($0.00097)	$ -
54	Grid Modernization	$0.00049	$0.00049	$ -
55	Transition	($0.00177)	($0.00177)	$ -
56	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
57	System Benefits Charge	$0.00250	$0.00250	$ -
58	Renewable Energy Charge	$0.00050	$0.00050	$ -
59	Basic Service Charge	$0.14761	$0.14761	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Cambridge Service Area
Rate G-2 Large General Time-of-Use - Secondary Service

1		Monthly	Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kVA	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		Hours Use: 350									
4		100	35,000	$2,309.35	$3,802.75	$6,112.10	$2,316.00	$3,802.75	$6,118.75	$6.65	0.1%
5		150	52,500	$3,904.03	$5,704.13	$9,608.16	$3,914.00	$5,704.13	$9,618.13	$9.97	0.1%
6		200	70,000	$5,498.70	$7,605.50	$13,104.20	$5,512.00	$7,605.50	$13,117.50	$13.30	0.1%
7		300	105,000	$8,688.05	$11,408.25	$20,096.30	$8,708.00	$11,408.25	$20,116.25	$19.95	0.1%
8		500	175,000	$15,066.75	$19,013.75	$34,080.50	$15,100.00	$19,013.75	$34,113.75	$33.25	0.1%
9		750	262,500	$23,040.13	$28,520.63	$51,560.76	$23,090.00	$28,520.63	$51,610.63	$49.87	0.1%
10		1,000	350,000	$31,013.50	$38,027.50	$69,041.00	$31,080.00	$38,027.50	$69,107.50	$66.50	0.1%
11	Avg	227	79,450	$6,359.82	$8,632.24	$14,992.06	$6,374.92	$8,632.24	$15,007.16	$15.10	0.1%
12		Hours Use: 450									
13		100	45,000	$2,607.45	$4,889.25	$7,496.70	$2,616.00	$4,889.25	$7,505.25	$8.55	0.1%
14		150	67,500	$4,351.18	$7,333.88	$11,685.06	$4,364.00	$7,333.88	$11,697.88	$12.82	0.1%
15		200	90,000	$6,094.90	$9,778.50	$15,873.40	$6,112.00	$9,778.50	$15,890.50	$17.10	0.1%
16		300	135,000	$9,582.35	$14,667.75	$24,250.10	$9,608.00	$14,667.75	$24,275.75	$25.65	0.1%
17		500	225,000	$16,557.25	$24,446.25	$41,003.50	$16,600.00	$24,446.25	$41,046.25	$42.75	0.1%
18		750	337,500	$25,275.88	$36,669.38	$61,945.26	$25,340.00	$36,669.38	$62,009.38	$64.12	0.1%
19		1,000	450,000	$33,994.50	$48,892.50	$82,887.00	$34,080.00	$48,892.50	$82,972.50	$85.50	0.1%
20	Avg	312	140,400	$10,000.84	$15,254.46	$25,255.30	$10,027.52	$15,254.46	$25,281.98	$26.68	0.1%
21		Hours Use: 550									
22		100	55,000	$2,905.55	$5,975.75	$8,881.30	$2,916.00	$5,975.75	$8,891.75	$10.45	0.1%
23		150	82,500	$4,798.33	$8,963.63	$13,761.96	$4,814.00	$8,963.63	$13,777.63	$15.67	0.1%
24		200	110,000	$6,691.10	$11,951.50	$18,642.60	$6,712.00	$11,951.50	$18,663.50	$20.90	0.1%
25		300	165,000	$10,476.65	$17,927.25	$28,403.90	$10,508.00	$17,927.25	$28,435.25	$31.35	0.1%
26		500	275,000	$18,047.75	$29,878.75	$47,926.50	$18,100.00	$29,878.75	$47,978.75	$52.25	0.1%
27		750	412,500	$27,511.63	$44,818.13	$72,329.76	$27,590.00	$44,818.13	$72,408.13	$78.37	0.1%
28		1,000	550,000	$36,975.50	$59,757.50	$96,733.00	$37,080.00	$59,757.50	$96,837.50	$104.50	0.1%
29	Avg	283	155,650	$9,833.11	$16,911.37	$26,744.48	$9,862.68	$16,911.37	$26,774.05	$29.57	0.1%

30		Current	Proposed	
31		Rates	Rates	Change
32	Customer Charge	$97.00	$97.00	$ -
33	Distribution Demand <=100 kVA	$4.63	$4.63	$ -
34	Distribution Demand >100 kVA	$5.73	$5.73	$ -
35	Transmission Demand <=100 kVA	$7.06	$7.06	$ -
36	Transmission Demand >100 kVA	$15.73	$15.73	$ -
37	Distribution Energy	$0.01085	$0.01085	$ -
38	Revenue Decoupling	$0.00109	$0.00109	$ -
39	Distributed Solar Charge	$0.00139	$0.00139	$ -
40	Residential Assistance Adjustment Factor	$0.00234	$0.00234	$ -
41	Pension Adjustment Factor	$0.00055	$0.00055	$ -
42	Net Metering Recovery Surcharge	$0.00309	$0.00309	$ -
43	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
44	AG Consulting Expense	$0.00000	$0.00000	$ -
45	Storm Cost Recovery Adjustment Factor	$0.00131	$0.00131	$ -
46	Capital Investment Project	$0.00000	$0.00019	$0.00019
47	Basic Service Cost True Up Factor	($0.00004)	($0.00004)	$ -
48	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
49	Solar Expansion Cost Recovery Factor	$0.00041	$0.00041	$ -
50	Vegetation Management	$0.00074	$0.00074	$ -
51	Tax Act Credit Factor	($0.00067)	($0.00067)	$ -
52	Grid Modernization	$0.00034	$0.00034	$ -
53	Transition	($0.00177)	($0.00177)	$ -
54	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
55	System Benefits Charge	$0.00250	$0.00250	$ -
56	Renewable Energy Charge	$0.00050	$0.00050	$ -
57	Basic Service Charge	$0.10865	$0.10865	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Cambridge Service Area
Rate G-3 Large General Time-Of-Use - 13.8kV Service

1		Monthly	Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kVA	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3	Hours Use: 400										
4		300	120,000	$6,799.02	$13,038.00	$19,837.02	$6,812.22	$13,038.00	$19,850.22	$13.20	0.1%
5		500	200,000	$11,983.42	$21,730.00	$33,713.42	$12,005.42	$21,730.00	$33,735.42	$22.00	0.1%
6		1,000	400,000	$24,944.42	$43,460.00	$68,404.42	$24,988.42	$43,460.00	$68,448.42	$44.00	0.1%
7		2,000	800,000	$50,866.42	$86,920.00	$137,786.42	$50,954.42	$86,920.00	$137,874.42	$88.00	0.1%
8		3,000	1,200,000	$76,788.42	$130,380.00	$207,168.42	$76,920.42	$130,380.00	$207,300.42	$132.00	0.1%
9		5,000	2,000,000	$128,632.42	$217,300.00	$345,932.42	$128,852.42	$217,300.00	$346,152.42	$220.00	0.1%
10	Avg	802	320,800	$19,811.86	$34,854.92	$54,666.78	$19,847.15	$34,854.92	$54,702.07	$35.29	0.1%
11	Hours Use: 500										
12		300	150,000	$7,356.42	$16,297.50	$23,653.92	$7,372.92	$16,297.50	$23,670.42	$16.50	0.1%
13		500	250,000	$12,912.42	$27,162.50	$40,074.92	$12,939.92	$27,162.50	$40,102.42	$27.50	0.1%
14		1,000	500,000	$26,802.42	$54,325.00	$81,127.42	$26,857.42	$54,325.00	$81,182.42	$55.00	0.1%
15		2,000	1,000,000	$54,582.42	$108,650.00	$163,232.42	$54,692.42	$108,650.00	$163,342.42	$110.00	0.1%
16		3,000	1,500,000	$82,362.42	$162,975.00	$245,337.42	$82,527.42	$162,975.00	$245,502.42	$165.00	0.1%
17		5,000	2,500,000	$137,922.42	$271,625.00	$409,547.42	$138,197.42	$271,625.00	$409,822.42	$275.00	0.1%
18	Avg	1,170	585,000	$31,525.02	$63,560.25	$95,085.27	$31,589.37	$63,560.25	$95,149.62	$64.35	0.1%
19	Hours Use: 600										
20		300	180,000	$7,913.82	$19,557.00	$27,470.82	$7,933.62	$19,557.00	$27,490.62	$19.80	0.1%
21		500	300,000	$13,841.42	$32,595.00	$46,436.42	$13,874.42	$32,595.00	$46,469.42	$33.00	0.1%
22		1,000	600,000	$28,660.42	$65,190.00	$93,850.42	$28,726.42	$65,190.00	$93,916.42	$66.00	0.1%
23		2,000	1,200,000	$58,298.42	$130,380.00	$188,678.42	$58,430.42	$130,380.00	$188,810.42	$132.00	0.1%
24		3,000	1,800,000	$87,936.42	$195,570.00	$283,506.42	$88,134.42	$195,570.00	$283,704.42	$198.00	0.1%
25		5,000	3,000,000	$147,212.42	$325,950.00	$473,162.42	$147,542.42	$325,950.00	$473,492.42	$330.00	0.1%
26	Avg	1,192	715,200	$34,350.92	$77,706.48	$112,057.40	$34,429.59	$77,706.48	$112,136.07	$78.67	0.1%

27		Current	Proposed	
28		Rates	Rates	Change
29	Customer Charge	$97.00	$97.00	$ -
30	Distribution Demand <=100 kVA	$0.00	$0.00	$ -
31	Distribution Demand >100 kVA	$4.74	$4.74	$ -
32	Transmission Demand <=100 kVA	$774.42	$774.42	$ -
33	Transmission Demand >100 kVA	$13.75	$13.75	$ -
34	Distribution Energy	$0.00381	$0.00381	$ -
35	Revenue Decoupling	$0.00063	$0.00063	$ -
36	Distributed Solar Charge	$0.00080	$0.00080	$ -
37	Residential Assistance Adjustment Factor	$0.00135	$0.00135	$ -
38	Pension Adjustment Factor	$0.00044	$0.00044	$ -
39	Net Metering Recovery Surcharge	$0.00179	$0.00179	$ -
40	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
41	AG Consulting Expense	$0.00000	$0.00000	$ -
42	Storm Cost Recovery Adjustment Factor	$0.00075	$0.00075	$ -
43	Capital Investment Project	$0.00000	$0.00011	$0.00011
44	Basic Service Cost True Up Factor	($0.00002)	($0.00002)	$ -
45	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
46	Solar Expansion Cost Recovery Factor	$0.00023	$0.00023	$ -
47	Vegetation Management	$0.00058	$0.00058	$ -
48	Tax Act Credit Factor	($0.00038)	($0.00038)	$ -
49	Grid Modernization	$0.00019	$0.00019	$ -
50	Transition	($0.00177)	($0.00177)	$ -
51	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
52	System Benefits Charge	$0.00250	$0.00250	$ -
53	Renewable Energy Charge	$0.00050	$0.00050	$ -
54	Basic Service Charge	$0.10865	$0.10865	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Cambridge Service Area
Rate G-4 Optional Time-of-Use

1		Monthly	Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		Hours Use: 400									
4		5	2,000	$160.53	$295.22	$455.75	$160.81	$295.22	$456.03	$0.28	0.1%
5		15	6,000	$457.59	$885.66	$1,343.25	$458.43	$885.66	$1,344.09	$0.84	0.1%
6		25	10,000	$754.65	$1,476.10	$2,230.75	$756.05	$1,476.10	$2,232.15	$1.40	0.1%
7		50	20,000	$1,497.30	$2,952.20	$4,449.50	$1,500.10	$2,952.20	$4,452.30	$2.80	0.1%
8		75	30,000	$2,239.95	$4,428.30	$6,668.25	$2,244.15	$4,428.30	$6,672.45	$4.20	0.1%
9	Avg	36	14,400	$1,081.42	$2,125.58	$3,207.00	$1,083.43	$2,125.58	$3,209.01	$2.01	0.1%
10		Hours Use: 500									
11		5	2,500	$175.10	$369.03	$544.13	$175.45	$369.03	$544.48	$0.35	0.1%
12		15	7,500	$501.30	$1,107.08	$1,608.38	$502.35	$1,107.08	$1,609.43	$1.05	0.1%
13		25	12,500	$827.50	$1,845.13	$2,672.63	$829.25	$1,845.13	$2,674.38	$1.75	0.1%
14		50	25,000	$1,643.00	$3,690.25	$5,333.25	$1,646.50	$3,690.25	$5,336.75	$3.50	0.1%
15		75	37,500	$2,458.50	$5,535.38	$7,993.88	$2,463.75	$5,535.38	$7,999.13	$5.25	0.1%
16	Avg	38	19,000	$1,251.56	$2,804.59	$4,056.15	$1,254.22	$2,804.59	$4,058.81	$2.66	0.1%
17		Hours Use: 600									
18		5	3,000	$189.67	$442.83	$632.50	$190.09	$442.83	$632.92	$0.42	0.1%
19		15	9,000	$545.01	$1,328.49	$1,873.50	$546.27	$1,328.49	$1,874.76	$1.26	0.1%
20		25	15,000	$900.35	$2,214.15	$3,114.50	$902.45	$2,214.15	$3,116.60	$2.10	0.1%
21		50	30,000	$1,788.70	$4,428.30	$6,217.00	$1,792.90	$4,428.30	$6,221.20	$4.20	0.1%
22		75	45,000	$2,677.05	$6,642.45	$9,319.50	$2,683.35	$6,642.45	$9,325.80	$6.30	0.1%
23	Avg	35	21,000	$1,255.69	$3,099.81	$4,355.50	$1,258.63	$3,099.81	$4,358.44	$2.94	0.1%

24		Current	Proposed	
25		Rates	Rates	Change
26	Customer Charge	$12.00	$12.00	$ -
27	Distribution Demand	$4.74	$4.74	$ -
28	Transmission Demand	$13.31	$13.31	$ -
29	Distribution Energy	$0.01188	$0.01188	$ -
30	Revenue Decoupling	$0.00082	$0.00082	$ -
31	Distributed Solar Charge	$0.00105	$0.00105	$ -
32	Residential Assistance Adjustment Factor	$0.00176	$0.00176	$ -
33	Pension Adjustment Factor	$0.00080	$0.00080	$ -
34	Net Metering Recovery Surcharge	$0.00233	$0.00233	$ -
35	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
36	AG Consulting Expense	$0.00000	$0.00000	$ -
37	Storm Cost Recovery Adjustment Factor	$0.00099	$0.00099	$ -
38	Capital Investment Project	$0.00000	$0.00014	$0.00014
39	Basic Service Cost True Up Factor	($0.00003)	($0.00003)	$ -
40	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
41	Solar Expansion Cost Recovery Factor	$0.00031	$0.00031	$ -
42	Vegetation Management	$0.00107	$0.00107	$ -
43	Tax Act Credit Factor	($0.00050)	($0.00050)	$ -
44	Grid Modernization	$0.00025	$0.00025	$ -
45	Transition	($0.00177)	($0.00177)	$ -
46	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
47	System Benefits Charge	$0.00250	$0.00250	$ -
48	Renewable Energy Charge	$0.00050	$0.00050	$ -
49	Basic Service Charge	$0.14761	$0.14761	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Cambridge Service Area
Rate G-5 Commercial Space Heating

		Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
1		Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		500	$43.84	$73.81	$117.65	$43.96	$73.81	$117.77	$0.12	0.1%
4		750	$61.75	$110.71	$172.46	$61.94	$110.71	$172.65	$0.19	0.1%
5		1,000	$79.67	$147.61	$227.28	$79.92	$147.61	$227.53	$0.25	0.1%
6		1,500	$115.51	$221.42	$336.93	$115.88	$221.42	$337.30	$0.37	0.1%
7		2,000	$151.34	$295.22	$446.56	$151.84	$295.22	$447.06	$0.50	0.1%
8		2,500	$187.18	$369.03	$556.21	$187.80	$369.03	$556.83	$0.62	0.1%
9		3,000	$223.01	$442.83	$665.84	$223.76	$442.83	$666.59	$0.75	0.1%
10		5,000	$366.35	$738.05	$1,104.40	$367.60	$738.05	$1,105.65	$1.25	0.1%
11		10,000	$803.25	$1,476.10	$2,279.35	$805.75	$1,476.10	$2,281.85	$2.50	0.1%
12		35,000	$2,987.75	$5,166.35	$8,154.10	$2,996.50	$5,166.35	$8,162.85	$8.75	0.1%
13	Avg	4,756	$348.86	$702.03	$1,050.89	$350.05	$702.03	$1,052.08	$1.19	0.1%

14		Current	Proposed	
15		Rates	Rates	Change
16	Customer Charge	$8.00	$8.00	$ -
17	Distribution Energy <=5,000 kWh	$0.02024	$0.02024	$ -
18	Distribution Energy >5,000 kWh	$0.02659	$0.02659	$ -
19	Revenue Decoupling	$0.00144	$0.00144	$ -
20	Distributed Solar Charge	$0.00183	$0.00183	$ -
21	Residential Assistance Adjustment Factor	$0.00308	$0.00308	$ -
22	Pension Adjustment Factor	$0.00147	$0.00147	$ -
23	Net Metering Recovery Surcharge	$0.00407	$0.00407	$ -
24	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
25	AG Consulting Expense	$0.00000	$0.00000	$ -
26	Storm Cost Recovery Adjustment Factor	$0.00168	$0.00168	$ -
27	Capital Investment Project	$0.00000	$0.00025	$0.00025
28	Basic Service Cost True Up Factor	($0.00006)	($0.00006)	$ -
29	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
30	Solar Expansion Cost Recovery Factor	$0.00054	$0.00054	$ -
31	Vegetation Management	$0.00195	$0.00195	$ -
32	Tax Act Credit Factor	($0.00088)	($0.00088)	$ -
33	Grid Modernization	$0.00044	$0.00044	$ -
34	Transition	($0.00177)	($0.00177)	$ -
35	Transmission Energy <=5,000 kWh	$0.02746	$0.02746	$ -
36	Transmission Energy >5,000 kWh	$0.03682	$0.03682	$ -
37	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
38	System Benefits Charge	$0.00250	$0.00250	$ -
39	Renewable Energy Charge	$0.00050	$0.00050	$ -
40	Basic Service Charge	$0.14761	$0.14761	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Cambridge Service Area
Rate G-6 General Non-Demand Time-of-Use

1		Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		25	$10.62	$3.69	$14.31	$10.62	$3.69	$14.31	$0.00	0.0%
4		50	$12.23	$7.38	$19.61	$12.25	$7.38	$19.63	$0.02	0.1%
5		100	$15.47	$14.76	$30.23	$15.50	$14.76	$30.26	$0.03	0.1%
6		150	$18.70	$22.14	$40.84	$18.74	$22.14	$40.88	$0.04	0.1%
7		250	$25.17	$36.90	$62.07	$25.24	$36.90	$62.14	$0.07	0.1%
8		400	$34.87	$59.04	$93.91	$34.98	$59.04	$94.02	$0.11	0.1%
9		600	$47.80	$88.57	$136.37	$47.97	$88.57	$136.54	$0.17	0.1%
10		900	$67.21	$132.85	$200.06	$67.46	$132.85	$200.31	$0.25	0.1%
11		1,500	$106.01	$221.42	$327.43	$106.43	$221.42	$327.85	$0.42	0.1%
12		2,500	$170.68	$369.03	$539.71	$171.38	$369.03	$540.41	$0.70	0.1%
13	Avg	593	$47.35	$87.53	$134.88	$47.52	$87.53	$135.05	$0.17	0.1%

14		Current	Proposed	
15		Rates	Rates	Change
16	Customer Charge	$9.00	$9.00	$ -
17	Distribution Energy - Peak	$0.06346	$0.06346	$ -
18	Distribution Energy - Low Load	$0.02338	$0.02338	$ -
19	Revenue Decoupling	$0.00159	$0.00159	$ -
20	Distributed Solar Charge	$0.00204	$0.00204	$ -
21	Residential Assistance Adjustment Factor	$0.00342	$0.00342	$ -
22	Pension Adjustment Factor	$0.00073	$0.00073	$ -
23	Net Metering Recovery Surcharge	$0.00452	$0.00452	$ -
24	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
25	AG Consulting Expense	$0.00000	$0.00000	$ -
26	Storm Cost Recovery Adjustment Factor	$0.00192	$0.00192	$ -
27	Capital Investment Project	$0.00000	$0.00028	$0.00028
28	Basic Service Cost True Up Factor	($0.00006)	($0.00006)	$ -
29	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
30	Solar Expansion Cost Recovery Factor	$0.00060	$0.00060	$ -
31	Vegetation Management	$0.00098	$0.00098	$ -
32	Tax Act Credit Factor	($0.00097)	($0.00097)	$ -
33	Grid Modernization	$0.00049	$0.00049	$ -
34	Transition	($0.00177)	($0.00177)	$ -
35	Transmission Energy - Peak	$0.03335	$0.03335	$ -
36	Transmission Energy - Low Load	$0.00000	$0.00000	$ -
37	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
38	System Benefits Charge	$0.00250	$0.00250	$ -
39	Renewable Energy Charge	$0.00050	$0.00050	$ -
40	Basic Service Charge	$0.14761	$0.14761	$ -

41	On-Peak Use:	24%
42	Off-Peak Use:	76%

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

South Shore, Cape Cod, and Martha's Vineyard Service Area
Rate G-1 Small General Service

1		Monthly	Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3	Hours Use: 200										
4		5	1,000	$114.41	$147.61	$262.02	$114.72	$147.61	$262.33	$0.31	0.1%
5		10	2,000	$222.82	$295.22	$518.04	$223.44	$295.22	$518.66	$0.62	0.1%
6		15	3,000	$335.28	$442.83	$778.11	$336.21	$442.83	$779.04	$0.93	0.1%
7		25	5,000	$539.70	$738.05	$1,277.75	$541.25	$738.05	$1,279.30	$1.55	0.1%
8		50	10,000	$1,050.75	$1,476.10	$2,526.85	$1,053.85	$1,476.10	$2,529.95	$3.10	0.1%
9		100	20,000	$2,072.85	$2,952.20	$5,025.05	$2,079.05	$2,952.20	$5,031.25	$6.20	0.1%
10	Avg	2	400	$49.36	$59.04	$108.40	$49.49	$59.04	$108.53	$0.13	0.1%
11	Hours Use: 300										
12		5	1,500	$168.62	$221.42	$390.04	$169.08	$221.42	$390.50	$0.46	0.1%
13		10	3,000	$307.33	$442.83	$750.16	$308.26	$442.83	$751.09	$0.93	0.1%
14		15	4,500	$446.67	$664.25	$1,110.92	$448.06	$664.25	$1,112.31	$1.39	0.1%
15		25	7,500	$725.35	$1,107.08	$1,832.43	$727.67	$1,107.08	$1,834.75	$2.32	0.1%
16		50	15,000	$1,422.05	$2,214.15	$3,636.20	$1,426.70	$2,214.15	$3,640.85	$4.65	0.1%
17		100	30,000	$2,815.45	$4,428.30	$7,243.75	$2,824.75	$4,428.30	$7,253.05	$9.30	0.1%
18	Avg	19	5,700	$558.14	$841.38	$1,399.52	$559.90	$841.38	$1,401.28	$1.76	0.1%
19	Hours Use: 400										
20		5	2,000	$222.82	$295.22	$518.04	$223.44	$295.22	$518.66	$0.62	0.1%
21		10	4,000	$381.59	$590.44	$972.03	$382.83	$590.44	$973.27	$1.24	0.1%
22		15	6,000	$558.06	$885.66	$1,443.72	$559.92	$885.66	$1,445.58	$1.86	0.1%
23		25	10,000	$911.00	$1,476.10	$2,387.10	$914.10	$1,476.10	$2,390.20	$3.10	0.1%
24		50	20,000	$1,793.35	$2,952.20	$4,745.55	$1,799.55	$2,952.20	$4,751.75	$6.20	0.1%
25		100	40,000	$3,558.05	$5,904.40	$9,462.45	$3,570.45	$5,904.40	$9,474.85	$12.40	0.1%
26	Avg	27	10,800	$981.58	$1,594.19	$2,575.77	$984.93	$1,594.19	$2,579.12	$3.35	0.1%

27		Current	Proposed	
28		Rates	Rates	Change
29	Customer Charge	$6.00	$6.00	$ -
30	Distribution Demand <=10 kW	$0.00	$0.00	$ -
31	Distribution Demand >10 kW	$5.59	$5.59	$ -
32	Distribution Energy <=2,300 kWh	$0.04684	$0.04684	$ -
33	Distribution Energy >2,300 kWh	$0.01269	$0.01269	$ -
34	Revenue Decoupling	$0.00179	$0.00179	$ -
35	Distributed Solar Charge	$0.00228	$0.00228	$ -
36	Residential Assistance Adjustment Factor	$0.00383	$0.00383	$ -
37	Pension Adjustment Factor	$0.00097	$0.00097	$ -
38	Net Metering Recovery Surcharge	$0.00507	$0.00507	$ -
39	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
40	AG Consulting Expense	$0.00000	$0.00000	$ -
41	Storm Cost Recovery Adjustment Factor	$0.00215	$0.00215	$ -
42	Capital Investment Project	$0.00000	$0.00031	$0.00031
43	Basic Service Cost True Up Factor	($0.00007)	($0.00007)	$ -
44	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
45	Solar Expansion Cost Recovery Factor	$0.00067	$0.00067	$ -
46	Vegetation Management	$0.00129	$0.00129	$ -
47	Tax Act Credit Factor	($0.00109)	($0.00109)	$ -
48	Grid Modernization	$0.00055	$0.00055	$ -
49	Transition	($0.00177)	($0.00177)	$ -
50	Transmission Energy	$0.03572	$0.03572	$ -
51	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
52	System Benefits Charge	$0.00250	$0.00250	$ -
53	Renewable Energy Charge	$0.00050	$0.00050	$ -
54	Basic Service Charge	$0.14761	$0.14761	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

South Shore, Cape Cod, and Martha's Vineyard Service Area
Rate G-1 Seasonal Small General Service

1		Monthly	Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3	Hours Use: 50										
4		5	250	$43.14	$36.90	$80.04	$43.21	$36.90	$80.11	$0.07	0.1%
5		10	500	$80.27	$73.81	$154.08	$80.43	$73.81	$154.24	$0.16	0.1%
6		20	1,000	$203.84	$147.61	$351.45	$204.15	$147.61	$351.76	$0.31	0.1%
7		50	2,500	$533.01	$369.03	$902.04	$533.79	$369.03	$902.82	$0.78	0.1%
8	Avg	9	450	$72.84	$66.42	$139.26	$72.98	$66.42	$139.40	$0.14	0.1%
9	Hours Use: 150										
10		5	750	$117.41	$110.71	$228.12	$117.64	$110.71	$228.35	$0.23	0.1%
11		10	1,500	$228.81	$221.42	$450.23	$229.28	$221.42	$450.70	$0.47	0.1%
12		20	3,000	$429.71	$442.83	$872.54	$430.64	$442.83	$873.47	$0.93	0.1%
13		50	7,500	$979.01	$1,107.08	$2,086.09	$981.34	$1,107.08	$2,088.42	$2.33	0.1%
14	Avg	8	1,200	$184.25	$177.13	$361.38	$184.62	$177.13	$361.75	$0.37	0.1%
15	Hours Use: 300										
16		5	1,500	$228.81	$221.42	$450.23	$229.28	$221.42	$450.70	$0.47	0.1%
17		10	3,000	$380.41	$442.83	$823.24	$381.34	$442.83	$824.17	$0.93	0.1%
18		20	6,000	$697.31	$885.66	$1,582.97	$699.17	$885.66	$1,584.83	$1.86	0.1%
19		50	15,000	$1,648.01	$2,214.15	$3,862.16	$1,652.66	$2,214.15	$3,866.81	$4.65	0.1%
20	Avg	9	2,700	$353.65	$398.55	$752.20	$354.49	$398.55	$753.04	$0.84	0.1%

21		Current	Proposed	
22		Rates	Rates	Change
23	Customer Charge	$6.00	$6.00	$ -
24	Distribution Demand <=10 kW	$0.00	$0.00	$ -
25	Distribution Demand >10 kW	$4.93	$4.93	$ -
26	Distribution Energy <=1,800 kWh	$0.08697	$0.08697	$ -
27	Distribution Energy >1,800 kWh	$0.02763	$0.02763	$ -
28	Revenue Decoupling	$0.00179	$0.00179	$ -
29	Distributed Solar Charge	$0.00228	$0.00228	$ -
30	Residential Assistance Adjustment Factor	$0.00383	$0.00383	$ -
31	Pension Adjustment Factor	$0.00097	$0.00097	$ -
32	Net Metering Recovery Surcharge	$0.00507	$0.00507	$ -
33	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
34	AG Consulting Expense	$0.00000	$0.00000	$ -
35	Storm Cost Recovery Adjustment Factor	$0.00215	$0.00215	$ -
36	Capital Investment Project	$0.00000	$0.00031	$0.00031
37	Basic Service Cost True Up Factor	($0.00007)	($0.00007)	$ -
38	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
39	Solar Expansion Cost Recovery Factor	$0.00067	$0.00067	$ -
40	Vegetation Management	$0.00129	$0.00129	$ -
41	Tax Act Credit Factor	($0.00109)	($0.00109)	$ -
42	Grid Modernization	$0.00055	$0.00055	$ -
43	Transition	($0.00177)	($0.00177)	$ -
44	Transmission Energy	$0.03572	$0.03572	$ -
45	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
46	System Benefits Charge	$0.00250	$0.00250	$ -
47	Renewable Energy Charge	$0.00050	$0.00050	$ -
48	Basic Service Charge	$0.14761	$0.14761	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

South Shore, Cape Cod, and Martha's Vineyard Service Area
Rate G-2 Medium General Time-of-Use

1		Monthly	Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kVA	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		Hours Use: 300									
4		100	30,000	$2,688.56	$3,141.00	$5,829.56	$2,694.86	$3,141.00	$5,835.86	$6.30	0.1%
5		150	45,000	$3,847.84	$4,711.50	$8,559.34	$3,857.29	$4,711.50	$8,568.79	$9.45	0.1%
6		200	60,000	$5,007.12	$6,282.00	$11,289.12	$5,019.72	$6,282.00	$11,301.72	$12.60	0.1%
7		300	90,000	$7,325.69	$9,423.00	$16,748.69	$7,344.59	$9,423.00	$16,767.59	$18.90	0.1%
8		500	150,000	$11,962.81	$15,705.00	$27,667.81	$11,994.31	$15,705.00	$27,699.31	$31.50	0.1%
9	Avg	205	61,500	$5,123.05	$6,439.05	$11,562.10	$5,135.97	$6,439.05	$11,575.02	$12.92	0.1%
10		Hours Use: 400									
11		100	40,000	$3,078.42	$4,188.00	$7,266.42	$3,086.82	$4,188.00	$7,274.82	$8.40	0.1%
12		150	60,000	$4,432.62	$6,282.00	$10,714.62	$4,445.22	$6,282.00	$10,727.22	$12.60	0.1%
13		200	80,000	$5,786.83	$8,376.00	$14,162.83	$5,803.63	$8,376.00	$14,179.63	$16.80	0.1%
14		300	120,000	$8,495.25	$12,564.00	$21,059.25	$8,520.45	$12,564.00	$21,084.45	$25.20	0.1%
15		500	200,000	$13,912.08	$20,940.00	$34,852.08	$13,954.08	$20,940.00	$34,894.08	$42.00	0.1%
16	Avg	214	85,600	$6,166.01	$8,962.32	$15,128.33	$6,183.99	$8,962.32	$15,146.31	$17.98	0.1%
17		Hours Use: 500									
18		100	50,000	$3,468.27	$5,235.00	$8,703.27	$3,478.77	$5,235.00	$8,713.77	$10.50	0.1%
19		150	75,000	$5,017.41	$7,852.50	$12,869.91	$5,033.16	$7,852.50	$12,885.66	$15.75	0.1%
20		200	100,000	$6,566.54	$10,470.00	$17,036.54	$6,587.54	$10,470.00	$17,057.54	$21.00	0.1%
21		300	150,000	$9,664.81	$15,705.00	$25,369.81	$9,696.31	$15,705.00	$25,401.31	$31.50	0.1%
22		500	250,000	$15,861.35	$26,175.00	$42,036.35	$15,913.85	$26,175.00	$42,088.85	$52.50	0.1%
23	Avg	253	126,500	$8,208.62	$13,244.55	$21,453.17	$8,235.19	$13,244.55	$21,479.74	$26.57	0.1%

24		Current	Proposed	
25		Rates	Rates	Change
26	Customer Charge	$370.00	$370.00	$ -
27	Distribution Demand	$1.78	$1.78	$ -
28	Transmission Demand	$9.71	$9.71	$ -
29	Distribution Energy - Peak	$0.02076	$0.02076	$ -
30	Distribution Energy - Low A	$0.01747	$0.01747	$ -
31	Distribution Energy - Low B	$0.01133	$0.01133	$ -
32	Revenue Decoupling	$0.00118	$0.00118	$ -
33	Distributed Solar Charge	$0.00150	$0.00150	$ -
34	Residential Assistance Adjustment Factor	$0.00252	$0.00252	$ -
35	Pension Adjustment Factor	$0.00065	$0.00065	$ -
36	Net Metering Recovery Surcharge	$0.00333	$0.00333	$ -
37	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
38	AG Consulting Expense	$0.00000	$0.00000	$ -
39	Storm Cost Recovery Adjustment Factor	$0.00141	$0.00141	$ -
40	Capital Investment Project	$0.00000	$0.00021	$0.00021
41	Basic Service Cost True Up Factor	($0.00004)	($0.00004)	$ -
42	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
43	Solar Expansion Cost Recovery Factor	$0.00044	$0.00044	$ -
44	Vegetation Management	$0.00087	$0.00087	$ -
45	Tax Act Credit Factor	($0.00072)	($0.00072)	$ -
46	Grid Modernization	$0.00036	$0.00036	$ -
47	Transition	($0.00177)	($0.00177)	$ -
48	Transmission Energy	$0.00357	$0.00357	$ -
49	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
50	System Benefits Charge	$0.00250	$0.00250	$ -
51	Renewable Energy	$0.00050	$0.00050	$ -
52	Basic Service	$0.10470	$0.10470	$ -

53	Peak Use:	28%
54	Low A Use:	25%
55	Low B Use:	47%

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

South Shore, Cape Cod, and Martha's Vineyard Service Area
Rate G-3 Large General Time-Of-Use

1		Monthly	Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kVA	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3	Hours Use: 350										
4		500	175,000	$11,923.78	$18,322.50	$30,246.28	$11,944.78	$18,322.50	$30,267.28	$21.00	0.1%
5		750	262,500	$17,420.67	$27,483.75	$44,904.42	$17,452.17	$27,483.75	$44,935.92	$31.50	0.1%
6		1,000	350,000	$22,917.56	$36,645.00	$59,562.56	$22,959.56	$36,645.00	$59,604.56	$42.00	0.1%
7		2,000	700,000	$44,905.11	$73,290.00	$118,195.11	$44,989.11	$73,290.00	$118,279.11	$84.00	0.1%
8		3,000	1,050,000	$66,892.67	$109,935.00	$176,827.67	$67,018.67	$109,935.00	$176,953.67	$126.00	0.1%
9	Avg	1,066	373,100	$24,368.73	$39,063.57	$63,432.30	$24,413.51	$39,063.57	$63,477.08	$44.78	0.1%
10	Hours Use: 450										
11		500	225,000	$13,259.14	$23,557.50	$36,816.64	$13,286.14	$23,557.50	$36,843.64	$27.00	0.1%
12		750	337,500	$19,423.71	$35,336.25	$54,759.96	$19,464.21	$35,336.25	$54,800.46	$40.50	0.1%
13		1,000	450,000	$25,588.29	$47,115.00	$72,703.29	$25,642.29	$47,115.00	$72,757.29	$54.00	0.1%
14		2,000	900,000	$50,246.57	$94,230.00	$144,476.57	$50,354.57	$94,230.00	$144,584.57	$108.00	0.1%
15		3,000	1,350,000	$74,904.86	$141,345.00	$216,249.86	$75,066.86	$141,345.00	$216,411.86	$162.00	0.1%
16	Avg	788	354,600	$20,360.73	$37,126.62	$57,487.35	$20,403.28	$37,126.62	$57,529.90	$42.55	0.1%
17	Hours Use: 550										
18		500	275,000	$14,594.51	$28,792.50	$43,387.01	$14,627.51	$28,792.50	$43,420.01	$33.00	0.1%
19		750	412,500	$21,426.76	$43,188.75	$64,615.51	$21,476.26	$43,188.75	$64,665.01	$49.50	0.1%
20		1,000	550,000	$28,259.02	$57,585.00	$85,844.02	$28,325.02	$57,585.00	$85,910.02	$66.00	0.1%
21		2,000	1,100,000	$55,588.03	$115,170.00	$170,758.03	$55,720.03	$115,170.00	$170,890.03	$132.00	0.1%
22		3,000	1,650,000	$82,917.05	$172,755.00	$255,672.05	$83,115.05	$172,755.00	$255,870.05	$198.00	0.1%
23	Avg	1,118	614,900	$31,483.84	$64,380.03	$95,863.87	$31,557.63	$64,380.03	$95,937.66	$73.79	0.1%

24		Current	Proposed	
25		Rates	Rates	Change
26	Customer Charge	$930.00	$930.00	$ -
27	Distribution Demand	$1.01	$1.01	$ -
28	Transmission Demand	$11.63	$11.63	$ -
29	Distribution Energy - Peak	$0.01443	$0.01443	$ -
30	Distribution Energy - Low A	$0.01328	$0.01328	$ -
31	Distribution Energy - Low B	$0.00919	$0.00919	$ -
32	Revenue Decoupling	$0.00067	$0.00067	$ -
33	Distributed Solar Charge	$0.00086	$0.00086	$ -
34	Residential Assistance Adjustment Factor	$0.00144	$0.00144	$ -
35	Pension Adjustment Factor	$0.00041	$0.00041	$ -
36	Net Metering Recovery Surcharge	$0.00191	$0.00191	$ -
37	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
38	AG Consulting Expense	$0.00000	$0.00000	$ -
39	Storm Cost Recovery Adjustment Factor	$0.00081	$0.00081	$ -
40	Capital Investment Project	$0.00000	$0.00012	$0.00012
41	Basic Service Cost True Up Factor	($0.00002)	($0.00002)	$ -
42	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
43	Solar Expansion Cost Recovery Factor	$0.00025	$0.00025	$ -
44	Vegetation Management	$0.00055	$0.00055	$ -
45	Tax Act Credit Factor	($0.00041)	($0.00041)	$ -
46	Grid Modernization	$0.00020	$0.00020	$ -
47	Transition	($0.00177)	($0.00177)	$ -
48	Transmission Energy	$0.00000	$0.00000	$ -
49	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
50	System Benefits Charge	$0.00250	$0.00250	$ -
51	Renewable Energy	$0.00050	$0.00050	$ -
52	Basic Service	$0.10470	$0.10470	$ -

53	Peak Use:	27%
54	Low A Use:	25%
55	Low B Use:	48%

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

South Shore, Cape Cod, and Martha's Vineyard Service Area
Rate G-4 General Power

1		Monthly	Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3	Hours Use: 150										
4		20	3,000	$277.70	$442.83	$720.53	$278.48	$442.83	$721.31	$0.78	0.1%
5		30	4,500	$413.55	$664.25	$1,077.80	$414.72	$664.25	$1,078.97	$1.17	0.1%
6		40	6,000	$549.40	$885.66	$1,435.06	$550.96	$885.66	$1,436.62	$1.56	0.1%
7		70	10,500	$956.95	$1,549.91	$2,506.86	$959.68	$1,549.91	$2,509.59	$2.73	0.1%
8		100	15,000	$1,364.50	$2,214.15	$3,578.65	$1,368.40	$2,214.15	$3,582.55	$3.90	0.1%
9	Avg	52	7,800	$712.42	$1,151.36	$1,863.78	$714.45	$1,151.36	$1,865.81	$2.03	0.1%
10	Hours Use: 250										
11		20	5,000	$379.90	$738.05	$1,117.95	$381.20	$738.05	$1,119.25	$1.30	0.1%
12		30	7,500	$566.85	$1,107.08	$1,673.93	$568.80	$1,107.08	$1,675.88	$1.95	0.1%
13		40	10,000	$753.80	$1,476.10	$2,229.90	$756.40	$1,476.10	$2,232.50	$2.60	0.1%
14		70	17,500	$1,314.65	$2,583.18	$3,897.83	$1,319.20	$2,583.18	$3,902.38	$4.55	0.1%
15		100	25,000	$1,875.50	$3,690.25	$5,565.75	$1,882.00	$3,690.25	$5,572.25	$6.50	0.1%
16	Avg	27	6,750	$510.77	$996.37	$1,507.14	$512.52	$996.37	$1,508.89	$1.75	0.1%
17	Hours Use: 350										
18		20	7,000	$482.10	$1,033.27	$1,515.37	$483.92	$1,033.27	$1,517.19	$1.82	0.1%
19		30	10,500	$720.15	$1,549.91	$2,270.06	$722.88	$1,549.91	$2,272.79	$2.73	0.1%
20		40	14,000	$958.20	$2,066.54	$3,024.74	$961.84	$2,066.54	$3,028.38	$3.64	0.1%
21		70	24,500	$1,672.35	$3,616.45	$5,288.80	$1,678.72	$3,616.45	$5,295.17	$6.37	0.1%
22		100	35,000	$2,386.50	$5,166.35	$7,552.85	$2,395.60	$5,166.35	$7,561.95	$9.10	0.1%
23	Avg	27	9,450	$648.74	$1,394.91	$2,043.65	$651.19	$1,394.91	$2,046.10	$2.45	0.1%

24		Current	Proposed	
25		Rates	Rates	Change
26	Customer Charge	$6.00	$6.00	$ -
27	Distribution Demand	$1.99	$1.99	$ -
28	Transmission Demand	$3.93	$3.93	$ -
29	Distribution Energy	$0.02282	$0.02282	$ -
30	Revenue Decoupling	$0.00151	$0.00151	$ -
31	Distributed Solar Charge	$0.00193	$0.00193	$ -
32	Residential Assistance Adjustment Factor	$0.00323	$0.00323	$ -
33	Pension Adjustment Factor	$0.00094	$0.00094	$ -
34	Net Metering Recovery Surcharge	$0.00427	$0.00427	$ -
35	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
36	AG Consulting Expense	$0.00000	$0.00000	$ -
37	Storm Cost Recovery Adjustment Factor	$0.00179	$0.00179	$ -
38	Capital Investment Project	$0.00000	$0.00026	$0.00026
39	Basic Service Cost True Up Factor	($0.00006)	($0.00006)	$ -
40	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
41	Solar Expansion Cost Recovery Factor	$0.00057	$0.00057	$ -
42	Vegetation Management	$0.00126	$0.00126	$ -
43	Tax Act Credit Factor	($0.00092)	($0.00092)	$ -
44	Grid Modernization	$0.00046	$0.00046	$ -
45	Transition	($0.00177)	($0.00177)	$ -
46	Transmission Energy	$0.00489	$0.00489	$ -
47	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
48	System Benefits Charge	$0.00250	$0.00250	$ -
49	Renewable Energy	$0.00050	$0.00050	$ -
50	Basic Service	$0.14761	$0.14761	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

South Shore, Cape Cod, and Martha's Vineyard Service Area
Rate G-5 Commercial Space Heating

1		Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		100	$17.16	$14.76	$31.92	$17.21	$14.76	$31.97	$0.05	0.2%
4		200	$28.33	$29.52	$57.85	$28.41	$29.52	$57.93	$0.08	0.1%
5		300	$39.49	$44.28	$83.77	$39.62	$44.28	$83.90	$0.13	0.2%
6		500	$61.82	$73.81	$135.63	$62.03	$73.81	$135.84	$0.21	0.2%
7		750	$89.73	$110.71	$200.44	$90.04	$110.71	$200.75	$0.31	0.2%
8		1,000	$117.64	$147.61	$265.25	$118.05	$147.61	$265.66	$0.41	0.2%
9		1,500	$173.46	$221.42	$394.88	$174.08	$221.42	$395.50	$0.62	0.2%
10		3,000	$340.92	$442.83	$783.75	$342.15	$442.83	$784.98	$1.23	0.2%
11		5,000	$564.20	$738.05	$1,302.25	$566.25	$738.05	$1,304.30	$2.05	0.2%
12	Avg	1,472	$170.33	$217.28	$387.61	$170.94	$217.28	$388.22	$0.61	0.2%

13		Current	Proposed	
14		Rates	Rates	Change
15	Customer Charge	$6.00	$6.00	$ -
16	Distribution Energy	$0.04120	$0.04120	$ -
17	Revenue Decoupling	$0.00231	$0.00231	$ -
18	Distributed Solar Charge	$0.00295	$0.00295	$ -
19	Residential Assistance Adjustment Factor	$0.00495	$0.00495	$ -
20	Pension Adjustment Factor	$0.00206	$0.00206	$ -
21	Net Metering Recovery Surcharge	$0.00654	$0.00654	$ -
22	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
23	AG Consulting Expense	$0.00000	$0.00000	$ -
24	Storm Cost Recovery Adjustment Factor	$0.00277	$0.00277	$ -
25	Capital Investment Project	$0.00000	$0.00041	$0.00041
26	Basic Service Cost True Up Factor	($0.00009)	($0.00009)	$ -
27	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
28	Solar Expansion Cost Recovery Factor	$0.00087	$0.00087	$ -
29	Vegetation Management	$0.00274	$0.00274	$ -
30	Tax Act Credit Factor	($0.00141)	($0.00141)	$ -
31	Grid Modernization	$0.00071	$0.00071	$ -
32	Transition	($0.00177)	($0.00177)	$ -
33	Transmission Energy	$0.03763	$0.03763	$ -
34	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
35	System Benefits Charge	$0.00250	$0.00250	$ -
36	Renewable Energy Charge	$0.00050	$0.00050	$ -
37	Basic Service Charge	$0.14761	$0.14761	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

South Shore, Cape Cod, and Martha's Vineyard Service Area
Rate G-6 All Electric Schools

1		Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		25,000	$1,763.50	$3,690.25	$5,453.75	$1,766.75	$3,690.25	$5,457.00	$3.25	0.1%
4		40,000	$2,803.60	$5,904.40	$8,708.00	$2,808.80	$5,904.40	$8,713.20	$5.20	0.1%
5		50,000	$3,497.00	$7,380.50	$10,877.50	$3,503.50	$7,380.50	$10,884.00	$6.50	0.1%
6		60,000	$4,190.40	$8,856.60	$13,047.00	$4,198.20	$8,856.60	$13,054.80	$7.80	0.1%
7		150,000	$10,431.00	$22,141.50	$32,572.50	$10,450.50	$22,141.50	$32,592.00	$19.50	0.1%
8	Avg	60,748	$4,242.27	$8,967.01	$13,209.28	$4,250.16	$8,967.01	$13,217.17	$7.89	0.1%

9		Current	Proposed	
10		Rates	Rates	Change
11	Customer Charge	$30.00	$30.00	$ -
12	Distribution Energy	$0.01867	$0.01867	$ -
13	Revenue Decoupling	$0.00076	$0.00076	$ -
14	Distributed Solar Charge	$0.00097	$0.00097	$ -
15	Residential Assistance Adjustment Factor	$0.00163	$0.00163	$ -
16	Pension Adjustment Factor	$0.00075	$0.00075	$ -
17	Net Metering Recovery Surcharge	$0.00216	$0.00216	$ -
18	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
19	AG Consulting Expense	$0.00000	$0.00000	$ -
20	Storm Cost Recovery Adjustment Factor	$0.00090	$0.00090	$ -
21	Capital Investment Project	$0.00000	$0.00013	$0.00013
22	Basic Service Cost True Up Factor	($0.00003)	($0.00003)	$ -
23	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
24	Solar Expansion Cost Recovery Factor	$0.00028	$0.00028	$ -
25	Vegetation Management	$0.00100	$0.00100	$ -
26	Tax Act Credit Factor	($0.00046)	($0.00046)	$ -
27	Grid Modernization	$0.00023	$0.00023	$ -
28	Transition	($0.00177)	($0.00177)	$ -
29	Transmission Energy	$0.03407	$0.03407	$ -
30	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
31	System Benefits Charge	$0.00250	$0.00250	$ -
32	Renewable Energy Charge	$0.00050	$0.00050	$ -
33	Basic Service Charge	$0.14761	$0.14761	$ -

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

South Shore, Cape Cod, and Martha's Vineyard Service Area
Rate G-7 Optional General Time-of-Use

				Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
1		Monthly	Monthly								
2		kVA	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3	Hours Use: 350										
4		5	1,750	$175.61	$258.32	$433.93	$176.16	$258.32	$434.48	$0.55	0.1%
5		10	3,500	$341.23	$516.64	$857.87	$342.31	$516.64	$858.95	$1.08	0.1%
6		20	7,000	$672.46	$1,033.27	$1,705.73	$674.63	$1,033.27	$1,707.90	$2.17	0.1%
7		50	17,500	$1,666.15	$2,583.18	$4,249.33	$1,671.57	$2,583.18	$4,254.75	$5.42	0.1%
8		75	26,250	$2,494.22	$3,874.76	$6,368.98	$2,502.36	$3,874.76	$6,377.12	$8.14	0.1%
9	Avg	20	7,000	$672.46	$1,033.27	$1,705.73	$674.63	$1,033.27	$1,707.90	$2.17	0.1%
10	Hours Use: 500										
11		5	2,500	$210.19	$369.03	$579.22	$210.96	$369.03	$579.99	$0.77	0.1%
12		10	5,000	$410.37	$738.05	$1,148.42	$411.92	$738.05	$1,149.97	$1.55	0.1%
13		20	10,000	$810.74	$1,476.10	$2,286.84	$813.84	$1,476.10	$2,289.94	$3.10	0.1%
14		50	25,000	$2,011.85	$3,690.25	$5,702.10	$2,019.60	$3,690.25	$5,709.85	$7.75	0.1%
15		75	37,500	$3,012.78	$5,535.38	$8,548.16	$3,024.40	$5,535.38	$8,559.78	$11.62	0.1%
16	Avg	31	15,500	$1,251.15	$2,287.96	$3,539.11	$1,255.95	$2,287.96	$3,543.91	$4.80	0.1%
17	Hours Use: 650										
18		5	3,250	$244.76	$479.73	$724.49	$245.76	$479.73	$725.49	$1.00	0.1%
19		10	6,500	$479.51	$959.47	$1,438.98	$481.53	$959.47	$1,441.00	$2.02	0.1%
20		20	13,000	$949.02	$1,918.93	$2,867.95	$953.05	$1,918.93	$2,871.98	$4.03	0.1%
21		50	32,500	$2,357.56	$4,797.33	$7,154.89	$2,367.63	$4,797.33	$7,164.96	$10.07	0.1%
22		75	48,750	$3,531.33	$7,195.99	$10,727.32	$3,546.45	$7,195.99	$10,742.44	$15.12	0.1%
23	Avg	18	11,700	$855.12	$1,727.04	$2,582.16	$858.75	$1,727.04	$2,585.79	$3.63	0.1%

24		Current	Proposed	
25		Rates	Rates	Change
26	Customer Charge	$10.00	$10.00	$ -
27	Distribution Demand	$3.81	$3.81	$ -
28	Transmission Demand	$13.18	$13.18	$ -
29	Distribution Energy - Peak	$0.02621	$0.02621	$ -
30	Distribution Energy - Low Load	$0.01836	$0.01836	$ -
31	Revenue Decoupling	$0.00179	$0.00179	$ -
32	Distributed Solar Charge	$0.00228	$0.00228	$ -
33	Residential Assistance Adjustment Factor	$0.00383	$0.00383	$ -
34	Pension Adjustment Factor	$0.00097	$0.00097	$ -
35	Net Metering Recovery Surcharge	$0.00507	$0.00507	$ -
36	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
37	AG Consulting Expense	$0.00000	$0.00000	$ -
38	Storm Cost Recovery Adjustment Factor	$0.00215	$0.00215	$ -
39	Capital Investment Project	$0.00000	$0.00031	$0.00031
40	Basic Service Cost True Up Factor	($0.00007)	($0.00007)	$ -
41	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
42	Solar Expansion Cost Recovery Factor	$0.00067	$0.00067	$ -
43	Vegetation Management	$0.00129	$0.00129	$ -
44	Tax Act Credit Factor	($0.00109)	($0.00109)	$ -
45	Grid Modernization	$0.00055	$0.00055	$ -
46	Transition	($0.00177)	($0.00177)	$ -
47	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
48	System Benefits Charge	$0.00250	$0.00250	$ -
49	Renewable Energy Charge	$0.00050	$0.00050	$ -
50	Basic Service Charge	$0.14761	$0.14761	$ -

51	Peak Use:	24%
52	Low A Use:	76%

Eastern Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

South Shore, Cape Cod, and Martha's Vineyard Service Area
Rate G-7 Optional Seasonal General Time-of-Use

1		Monthly	Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kVA	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3	Hours Use: 50										
4		5	250	$73.68	$36.90	$110.58	$73.76	$36.90	$110.66	$0.08	0.1%
5		10	500	$137.36	$73.81	$211.17	$137.51	$73.81	$211.32	$0.15	0.1%
6		20	1,000	$264.72	$147.61	$412.33	$265.03	$147.61	$412.64	$0.31	0.1%
7		50	2,500	$646.80	$369.03	$1,015.83	$647.57	$369.03	$1,016.60	$0.77	0.1%
8		75	3,750	$965.20	$553.54	$1,518.74	$966.36	$553.54	$1,519.90	$1.16	0.1%
	Avg	9	450	$124.62	$66.42	$191.04	$124.76	$66.42	$191.18	$0.14	0.1%
10	Hours Use: 150										
11		5	750	$109.04	$110.71	$219.75	$109.27	$110.71	$219.98	$0.23	0.1%
12		10	1,500	$208.08	$221.42	$429.50	$208.54	$221.42	$429.96	$0.46	0.1%
13		20	3,000	$406.16	$442.83	$848.99	$407.09	$442.83	$849.92	$0.93	0.1%
14		50	7,500	$1,000.40	$1,107.08	$2,107.48	$1,002.72	$1,107.08	$2,109.80	$2.32	0.1%
15		75	11,250	$1,495.60	$1,660.61	$3,156.21	$1,499.09	$1,660.61	$3,159.70	$3.49	0.1%
	Avg	10	1,500	$208.08	$221.42	$429.50	$208.54	$221.42	$429.96	$0.46	0.1%
17	Hours Use: 300										
18		5	1,500	$162.08	$221.42	$383.50	$162.54	$221.42	$383.96	$0.46	0.1%
19		10	3,000	$314.16	$442.83	$756.99	$315.09	$442.83	$757.92	$0.93	0.1%
20		20	6,000	$618.32	$885.66	$1,503.98	$620.18	$885.66	$1,505.84	$1.86	0.1%
21		50	15,000	$1,530.80	$2,214.15	$3,744.95	$1,535.45	$2,214.15	$3,749.60	$4.65	0.1%
22		75	22,500	$2,291.20	$3,321.23	$5,612.43	$2,298.17	$3,321.23	$5,619.40	$6.97	0.1%
	Avg	13	3,900	$405.41	$575.68	$981.09	$406.62	$575.68	$982.30	$1.21	0.1%

24		Current	Proposed	
25		Rates	Rates	Change
26	Customer Charge	$10.00	$10.00	$ -
27	Distribution Demand	$3.86	$3.86	$ -
28	Transmission Demand	$5.34	$5.34	$ -
29	Distribution Energy - Peak	$0.05113	$0.05113	$ -
30	Distribution Energy - Low Load	$0.04300	$0.04300	$ -
31	Revenue Decoupling	$0.00179	$0.00179	$ -
32	Distributed Solar Charge	$0.00228	$0.00228	$ -
33	Residential Assistance Adjustment Factor	$0.00383	$0.00383	$ -
34	Pension Adjustment Factor	$0.00097	$0.00097	$ -
35	Net Metering Recovery Surcharge	$0.00507	$0.00507	$ -
36	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
37	AG Consulting Expense	$0.00000	$0.00000	$ -
38	Storm Cost Recovery Adjustment Factor	$0.00215	$0.00215	$ -
39	Capital Investment Project	$0.00000	$0.00031	$0.00031
40	Basic Service Cost True Up Factor	($0.00007)	($0.00007)	$ -
41	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
42	Solar Expansion Cost Recovery Factor	$0.00067	$0.00067	$ -
43	Vegetation Management	$0.00129	$0.00129	$ -
44	Tax Act Credit Factor	($0.00109)	($0.00109)	$ -
45	Grid Modernization	$0.00055	$0.00055	$ -
46	Transition	($0.00177)	($0.00177)	$ -
47	Energy Efficiency Reconciliation Factor	$0.00763	$0.00763	$ -
48	System Benefits Charge	$0.00250	$0.00250	$ -
49	Renewable Energy Charge	$0.00050	$0.00050	$ -
50	Basic Service Charge	$0.14761	$0.14761	$ -

51	Peak Use:	23%
52	Low A Use:	77%

Western Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Schedule 23 Optional Water Heating

1		Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		50	$21.17	$6.52	$27.69	$21.19	$6.52	$27.71	$0.02	0.1%
4		100	$25.34	$13.04	$38.38	$25.38	$13.04	$38.41	$0.03	0.1%
5		150	$29.51	$19.55	$49.06	$29.56	$19.55	$49.12	$0.05	0.1%
6		300	$42.02	$39.11	$81.13	$42.13	$39.11	$81.23	$0.11	0.1%
7		500	$58.71	$65.18	$123.88	$58.88	$65.18	$124.06	$0.18	0.1%
8		1,000	$100.41	$130.35	$230.76	$100.76	$130.35	$231.11	$0.35	0.2%
9		2,000	$183.82	$260.70	$444.52	$184.52	$260.70	$445.22	$0.70	0.2%
10	Avg	644	$70.72	$83.95	$154.66	$70.94	$83.95	$154.89	$0.23	0.1%

11		Current	Proposed	
12		Rates	Rates	Change
13	Customer Charge	$17.00	$17.00	$ -
14	Distribution Energy	$0.03125	$0.03125	$ -
15	Revenue Decoupling	$0.00201	$0.00201	$ -
16	Distributed Solar Charge	$0.00257	$0.00257	$ -
17	Residential Assistance Adjustment Factor	$0.00431	$0.00431	$ -
18	Pension Adjustment Factor	$0.00081	$0.00081	$ -
19	Net Metering Recovery Surcharge	$0.00569	$0.00569	$ -
20	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
21	AG Consulting Expense	$0.00000	$0.00000	$ -
22	Storm Cost Recovery Adjustment Factor	$0.00093	$0.00093	$ -
23	Capital Investment Project	$0.00000	$0.00035	$0.00035
24	Basic Service Cost True Up Factor	($0.00008)	($0.00008)	$ -
25	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
26	Solar Expansion Cost Recovery Factor	$0.00076	$0.00076	$ -
27	Vegetation Management	$0.00108	$0.00108	$ -
28	Tax Act Credit Factor	($0.00123)	($0.00123)	$ -
29	Grid Modernization	$0.00062	$0.00062	$ -
30	Transition	($0.00177)	($0.00177)	$ -
31	Transmission Energy	$0.02588	$0.02588	$ -
32	Energy Efficiency Reconciliation Factor	$0.00803	$0.00803	$ -
33	System Benefits Charge	$0.00250	$0.00250	$ -
34	Renewable Energy Charge	$0.00050	$0.00050	$ -
35	Basic Service Charge	$0.13035	$0.13035	$ -

Western Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Rate 24 Optional Church Service

1		Monthly	Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3		Hours Use: 100									
4		5	500	$110.78	$65.18	$175.95	$110.95	$65.18	$176.13	$0.18	0.1%
5		10	1,000	$176.25	$130.35	$306.60	$176.60	$130.35	$306.95	$0.35	0.1%
6		15	1,500	$241.73	$195.53	$437.25	$242.25	$195.53	$437.78	$0.52	0.1%
7		30	3,000	$438.15	$391.05	$829.20	$439.20	$391.05	$830.25	$1.05	0.1%
8		60	6,000	$831.00	$782.10	$1,613.10	$833.10	$782.10	$1,615.20	$2.10	0.1%
9		100	10,000	$1,354.80	$1,303.50	$2,658.30	$1,358.30	$1,303.50	$2,661.80	$3.50	0.1%
10	Avg	13	1,300	$215.54	$169.46	$384.99	$215.99	$169.46	$385.45	$0.45	0.1%
11		Hours Use: 200									
12		5	1,000	$127.00	$130.35	$257.35	$127.35	$130.35	$257.70	$0.35	0.1%
13		10	2,000	$208.70	$260.70	$469.40	$209.40	$260.70	$470.10	$0.70	0.1%
14		15	3,000	$290.40	$391.05	$681.45	$291.45	$391.05	$682.50	$1.05	0.2%
15		30	6,000	$535.50	$782.10	$1,317.60	$537.60	$782.10	$1,319.70	$2.10	0.2%
16		60	12,000	$1,025.70	$1,564.20	$2,589.90	$1,029.90	$1,564.20	$2,594.10	$4.20	0.2%
17		100	20,000	$1,679.30	$2,607.00	$4,286.30	$1,686.30	$2,607.00	$4,293.30	$7.00	0.2%
18	Avg	21	4,200	$388.44	$547.47	$935.91	$389.91	$547.47	$937.38	$1.47	0.2%
19		Hours Use: 300									
20		5	1,500	$143.23	$195.53	$338.75	$143.75	$195.53	$339.28	$0.52	0.2%
21		10	3,000	$241.15	$391.05	$632.20	$242.20	$391.05	$633.25	$1.05	0.2%
22		15	4,500	$339.08	$586.58	$925.65	$340.65	$586.58	$927.23	$1.57	0.2%
23		30	9,000	$632.85	$1,173.15	$1,806.00	$636.00	$1,173.15	$1,809.15	$3.15	0.2%
24		60	18,000	$1,220.40	$2,346.30	$3,566.70	$1,226.70	$2,346.30	$3,573.00	$6.30	0.2%
25		100	30,000	$2,003.80	$3,910.50	$5,914.30	$2,014.30	$3,910.50	$5,924.80	$10.50	0.2%
26	Avg	24	7,200	$515.34	$938.52	$1,453.86	$517.86	$938.52	$1,456.38	$2.52	0.2%

27		Current	Proposed	
28		Rates	Rates	Change
29	Customer Charge	$65.00	$65.00	$ -
30	Distribution Demand >2 KW	$4.84	$4.84	$ -
31	Transmission Demand >2 KW	$5.01	$5.01	$ -
32	Distribution Energy	$0.00617	$0.00617	$ -
33	Revenue Decoupling	$0.00201	$0.00201	$ -
34	Distributed Solar Charge	$0.00257	$0.00257	$ -
35	Residential Assistance Adjustment Factor	$0.00431	$0.00431	$ -
36	Pension Adjustment Factor	$0.00081	$0.00081	$ -
37	Net Metering Recovery Surcharge	$0.00569	$0.00569	$ -
38	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
39	AG Consulting Expense	$0.00000	$0.00000	$ -
40	Storm Cost Recovery Adjustment Factor	$0.00093	$0.00093	$ -
41	Capital Investment Project	$0.00000	$0.00035	$0.00035
42	Basic Service Cost True Up Factor	($0.00008)	($0.00008)	$ -
43	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
44	Solar Expansion Cost Recovery Factor	$0.00076	$0.00076	$ -
45	Vegetation Management	$0.00108	$0.00108	$ -
46	Tax Act Credit Factor	($0.00123)	($0.00123)	$ -
47	Grid Modernization	$0.00062	$0.00062	$ -
48	Transition	($0.00177)	($0.00177)	$ -
49	Transmission Energy	$0.00000	$0.00000	$ -
50	Energy Efficiency Reconciliation Factor	$0.00803	$0.00803	$ -
51	System Benefits Charge	$0.00250	$0.00250	$ -
52	Renewable Energy Charge	$0.00050	$0.00050	$ -
53	Basic Service Charge	$0.13035	$0.13035	$ -

Western Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Rate G-0 Small General Service

1		Monthly	Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3	Hours Use: 150										
4		5	750	$99.73	$97.76	$197.49	$99.99	$97.76	$197.75	$0.26	0.1%
5		10	1,500	$226.74	$195.53	$422.26	$227.26	$195.53	$422.79	$0.52	0.1%
6		15	2,250	$353.74	$293.29	$647.03	$354.53	$293.29	$647.82	$0.79	0.1%
7		20	3,000	$480.75	$391.05	$871.80	$481.80	$391.05	$872.85	$1.05	0.1%
8		50	7,500	$1,242.80	$977.63	$2,220.42	$1,245.42	$977.63	$2,223.05	$2.63	0.1%
9	Avg	6	900	$125.13	$117.32	$242.44	$125.44	$117.32	$242.76	$0.31	0.1%
10	Hours Use: 300										
11		5	1,500	$121.04	$195.53	$316.56	$121.56	$195.53	$317.09	$0.53	0.2%
12		10	3,000	$269.35	$391.05	$660.40	$270.40	$391.05	$661.45	$1.05	0.2%
13		15	4,500	$417.67	$586.58	$1,004.24	$419.24	$586.58	$1,005.82	$1.58	0.2%
14		20	6,000	$565.98	$782.10	$1,348.08	$568.08	$782.10	$1,350.18	$2.10	0.2%
15		50	15,000	$1,455.87	$1,955.25	$3,411.12	$1,461.12	$1,955.25	$3,416.37	$5.25	0.2%
16	Avg	11	3,300	$299.01	$430.16	$729.17	$300.17	$430.16	$730.32	$1.16	0.2%
17	Hours Use: 450										
18		5	2,250	$142.34	$293.29	$435.63	$143.13	$293.29	$436.42	$0.79	0.2%
19		10	4,500	$311.97	$586.58	$898.54	$313.54	$586.58	$900.12	$1.57	0.2%
20		15	6,750	$481.59	$879.86	$1,361.45	$483.95	$879.86	$1,363.81	$2.36	0.2%
21		20	9,000	$651.21	$1,173.15	$1,824.36	$654.36	$1,173.15	$1,827.51	$3.15	0.2%
22		50	22,500	$1,668.95	$2,932.88	$4,601.82	$1,676.82	$2,932.88	$4,609.70	$7.88	0.2%
23	Avg	17	7,650	$549.44	$997.18	$1,546.61	$552.11	$997.18	$1,549.29	$2.68	0.2%

24		Current	Proposed	
25		Rates	Rates	Change
26	Customer Charge	$15.00	$15.00	$ -
27	Distribution Demand >2 KW	$10.83	$10.83	$ -
28	Transmission Demand >2 KW	$10.31	$10.31	$ -
29	Distribution Energy	$0.00213	$0.00213	$ -
30	Revenue Decoupling	$0.00201	$0.00201	$ -
31	Distributed Solar Charge	$0.00257	$0.00257	$ -
32	Residential Assistance Adjustment Factor	$0.00431	$0.00431	$ -
33	Pension Adjustment Factor	$0.00081	$0.00081	$ -
34	Net Metering Recovery Surcharge	$0.00569	$0.00569	$ -
35	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
36	AG Consulting Expense	$0.00000	$0.00000	$ -
37	Storm Cost Recovery Adjustment Factor	$0.00093	$0.00093	$ -
38	Capital Investment Project	$0.00000	$0.00035	$0.00035
39	Basic Service Cost True Up Factor	($0.00008)	($0.00008)	$ -
40	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
41	Solar Expansion Cost Recovery Factor	$0.00076	$0.00076	$ -
42	Vegetation Management	$0.00108	$0.00108	$ -
43	Tax Act Credit Factor	($0.00123)	($0.00123)	$ -
44	Grid Modernization	$0.00062	$0.00062	$ -
45	Transition	($0.00177)	($0.00177)	$ -
46	Transmission Energy	$0.00000	$0.00000	$ -
47	Energy Efficiency Reconciliation Factor	$0.00803	$0.00803	$ -
48	System Benefits Charge	$0.00250	$0.00250	$ -
49	Renewable Energy Charge	$0.00050	$0.00050	$ -
50	Basic Service Charge	$0.13035	$0.13035	$ -

Western Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Rate T-0 Small General Service Time-Of-Use

1		Monthly	Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3	Hours Use: 150										
4		5	750	$113.23	$97.76	$211.00	$113.50	$97.76	$211.26	$0.26	0.1%
5		10	1,500	$238.09	$195.53	$433.61	$238.61	$195.53	$434.14	$0.53	0.1%
6		15	2,250	$362.94	$293.29	$656.23	$363.73	$293.29	$657.02	$0.79	0.1%
7		20	3,000	$487.80	$391.05	$878.85	$488.85	$391.05	$879.90	$1.05	0.1%
8		50	7,500	$1,236.92	$977.63	$2,214.54	$1,239.54	$977.63	$2,217.17	$2.63	0.1%
	Avg	1	150	$34.16	$19.55	$53.71	$34.21	$19.55	$53.77	$0.05	0.1%
10	Hours Use: 300										
11		5	1,500	$134.04	$195.53	$329.56	$134.56	$195.53	$330.09	$0.52	0.2%
12		10	3,000	$279.70	$391.05	$670.75	$280.75	$391.05	$671.80	$1.05	0.2%
13		15	4,500	$425.35	$586.58	$1,011.93	$426.93	$586.58	$1,013.50	$1.58	0.2%
14		20	6,000	$571.01	$782.10	$1,353.11	$573.11	$782.10	$1,355.21	$2.10	0.2%
15		50	15,000	$1,444.96	$1,955.25	$3,400.21	$1,450.21	$1,955.25	$3,405.46	$5.25	0.2%
	Avg	4	1,200	$104.91	$156.42	$261.33	$105.33	$156.42	$261.75	$0.42	0.2%
17	Hours Use: 450										
18		5	2,250	$154.84	$293.29	$448.13	$155.63	$293.29	$448.92	$0.79	0.2%
19		10	4,500	$321.30	$586.58	$907.88	$322.88	$586.58	$909.45	$1.58	0.2%
20		15	6,750	$487.76	$879.86	$1,367.63	$490.13	$879.86	$1,369.99	$2.36	0.2%
21		20	9,000	$654.23	$1,173.15	$1,827.38	$657.38	$1,173.15	$1,830.53	$3.15	0.2%
22		50	22,500	$1,652.99	$2,932.88	$4,585.87	$1,660.87	$2,932.88	$4,593.74	$7.88	0.2%
	Avg	10	4,500	$321.30	$586.58	$907.88	$322.88	$586.58	$909.45	$1.58	0.2%

24		Current	Proposed	
25		Rates	Rates	Change
26	Customer Charge	$30.00	$30.00	$ -
27	Distribution Demand >2 KW	$10.50	$10.50	$ -
28	Transmission Demand >2 KW	$10.31	$10.31	$ -
29	Distribution Energy - Peak	$0.00329	$0.00329	$ -
30	Distribution Energy - Off Peak	$0.00088	$0.00088	$ -
31	Revenue Decoupling	$0.00201	$0.00201	$ -
32	Distributed Solar Charge	$0.00257	$0.00257	$ -
33	Residential Assistance Adjustment Factor	$0.00431	$0.00431	$ -
34	Pension Adjustment Factor	$0.00081	$0.00081	$ -
35	Net Metering Recovery Surcharge	$0.00569	$0.00569	$ -
36	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
37	AG Consulting Expense	$0.00000	$0.00000	$ -
38	Storm Cost Recovery Adjustment Factor	$0.00093	$0.00093	$ -
39	Capital Investment Project	$0.00000	$0.00035	$0.00035
40	Basic Service Cost True Up Factor	($0.00008)	($0.00008)	$ -
41	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
42	Solar Expansion Cost Recovery Factor	$0.00076	$0.00076	$ -
43	Vegetation Management	$0.00108	$0.00108	$ -
44	Tax Act Credit Factor	($0.00123)	($0.00123)	$ -
45	Grid Modernization	$0.00062	$0.00062	$ -
46	Transition	($0.00177)	($0.00177)	$ -
47	Transmission Energy	$0.00000	$0.00000	$ -
48	Energy Efficiency Reconciliation Factor	$0.00803	$0.00803	$ -
49	System Benefits Charge	$0.00250	$0.00250	$ -
50	Renewable Energy Charge	$0.00050	$0.00050	$ -
51	Basic Service Charge	$0.13035	$0.13035	$ -

52	On-Peak Use:	24%
53	Off-Peak Use:	76%

Western Massachusetts
Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Rate G-2 Primary General Service

1		Monthly	Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3	Hours Use: 250										
4		50	12,500	$1,209.38	$1,298.75	$2,508.13	$1,212.63	$1,298.75	$2,511.38	$3.25	0.1%
5		75	18,750	$1,822.06	$1,948.13	$3,770.19	$1,826.94	$1,948.13	$3,775.06	$4.88	0.1%
6		100	25,000	$2,434.75	$2,597.50	$5,032.25	$2,441.25	$2,597.50	$5,038.75	$6.50	0.1%
7		150	37,500	$3,660.13	$3,896.25	$7,556.38	$3,669.88	$3,896.25	$7,566.13	$9.75	0.1%
8		200	50,000	$4,885.50	$5,195.00	$10,080.50	$4,898.50	$5,195.00	$10,093.50	$13.00	0.1%
9		300	75,000	$7,336.25	$7,792.50	$15,128.75	$7,355.75	$7,792.50	$15,148.25	$19.50	0.1%
10	Avg	95	23,750	$2,312.21	$2,467.63	$4,779.84	$2,318.39	$2,467.63	$4,786.01	$6.18	0.1%
11	Hours Use: 350										
12		50	10,000	$1,150.30	$1,039.00	$2,189.30	$1,152.90	$1,039.00	$2,191.90	$2.60	0.1%
13		75	22,500	$1,910.68	$2,337.75	$4,248.43	$1,916.53	$2,337.75	$4,254.28	$5.85	0.1%
14		100	40,000	$2,789.20	$4,156.00	$6,945.20	$2,799.60	$4,156.00	$6,955.60	$10.40	0.1%
15		150	75,000	$4,546.25	$7,792.50	$12,338.75	$4,565.75	$7,792.50	$12,358.25	$19.50	0.2%
16		200	100,000	$6,067.00	$10,390.00	$16,457.00	$6,093.00	$10,390.00	$16,483.00	$26.00	0.2%
17		300	150,000	$9,108.50	$15,585.00	$24,693.50	$9,147.50	$15,585.00	$24,732.50	$39.00	0.2%
18	Avg	84	42,000	$2,538.86	$4,363.80	$6,902.66	$2,549.78	$4,363.80	$6,913.58	$10.92	0.2%
19	Hours Use: 450										
20		50	22,500	$1,445.68	$2,337.75	$3,783.43	$1,451.53	$2,337.75	$3,789.28	$5.85	0.2%
21		75	33,750	$2,176.51	$3,506.63	$5,683.14	$2,185.29	$3,506.63	$5,691.91	$8.78	0.2%
22		100	45,000	$2,907.35	$4,675.50	$7,582.85	$2,919.05	$4,675.50	$7,594.55	$11.70	0.2%
23		150	67,500	$4,369.03	$7,013.25	$11,382.28	$4,386.58	$7,013.25	$11,399.83	$17.55	0.2%
24		200	90,000	$5,830.70	$9,351.00	$15,181.70	$5,854.10	$9,351.00	$15,205.10	$23.40	0.2%
25		300	135,000	$8,754.05	$14,026.50	$22,780.55	$8,789.15	$14,026.50	$22,815.65	$35.10	0.2%
26	Avg	94	42,300	$2,731.95	$4,394.97	$7,126.92	$2,742.95	$4,394.97	$7,137.92	$11.00	0.2%

27		Current	Proposed	
28		Rates	Rates	Change
29	Customer Charge	$353.00	$353.00	$ -
30	Distribution Demand <= 50 kW	$1.99	$1.99	$ -
31	Distribution Demand Charge >50 kW	$9.37	$9.37	$ -
32	Transmission Demand	$9.23	$9.23	$ -
33	Distribution Energy	$0.00210	$0.00210	$ -
34	Revenue Decoupling	$0.00148	$0.00148	$ -
35	Distributed Solar Charge	$0.00189	$0.00189	$ -
36	Residential Assistance Adjustment Factor	$0.00317	$0.00317	$ -
37	Pension Adjustment Factor	$0.00054	$0.00054	$ -
38	Net Metering Recovery Surcharge	$0.00419	$0.00419	$ -
39	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
40	AG Consulting Expense	$0.00000	$0.00000	$ -
41	Storm Cost Recovery Adjustment Factor	$0.00068	$0.00068	$ -
42	Capital Investment Project	$0.00000	$0.00026	$0.00026
43	Basic Service Cost True Up Factor	($0.00006)	($0.00006)	$ -
44	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
45	Solar Expansion Cost Recovery Factor	$0.00056	$0.00056	$ -
46	Vegetation Management	$0.00072	$0.00072	$ -
47	Tax Act Credit Factor	($0.00090)	($0.00090)	$ -
48	Grid Modernization	$0.00045	$0.00045	$ -
49	Transition	($0.00177)	($0.00177)	$ -
50	Transmission Energy	$0.00000	$0.00000	$ -
51	Energy Efficiency Reconciliation Factor	$0.00803	$0.00803	$ -
52	System Benefits Charge	$0.00250	$0.00250	$ -
53	Renewable Energy Charge	$0.00050	$0.00050	$ -
54	Basic Service Charge	$0.10390	$0.10390	$ -

Western Massachusetts
Calculation of Monthly Typical Bill
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Rate T-4 Primary General Service Time-Of-Use

1		Monthly	Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3	Hours Use: 250										
4		50	12,500	$1,201.60	$1,298.75	$2,500.35	$1,204.85	$1,298.75	$2,503.60	$3.25	0.1%
5		75	18,750	$1,810.39	$1,948.13	$3,758.52	$1,815.27	$1,948.13	$3,763.39	$4.88	0.1%
6		100	25,000	$2,419.19	$2,597.50	$5,016.69	$2,425.69	$2,597.50	$5,023.19	$6.50	0.1%
7		150	37,500	$3,636.79	$3,896.25	$7,533.04	$3,646.54	$3,896.25	$7,542.79	$9.75	0.1%
8		200	50,000	$4,854.38	$5,195.00	$10,049.38	$4,867.38	$5,195.00	$10,062.38	$13.00	0.1%
9		300	75,000	$7,289.57	$7,792.50	$15,082.07	$7,309.07	$7,792.50	$15,101.57	$19.50	0.1%
10	Avg	70	17,500	$1,688.63	$1,818.25	$3,506.88	$1,693.18	$1,818.25	$3,511.43	$4.55	0.1%
11	Hours Use: 350										
12		50	17,500	$1,316.63	$1,818.25	$3,134.88	$1,321.18	$1,818.25	$3,139.43	$4.55	0.1%
13		75	26,250	$1,982.95	$2,727.38	$4,710.32	$1,989.77	$2,727.38	$4,717.15	$6.82	0.1%
14		100	35,000	$2,649.27	$3,636.50	$6,285.77	$2,658.37	$3,636.50	$6,294.87	$9.10	0.1%
15		150	52,500	$3,981.90	$5,454.75	$9,436.65	$3,995.55	$5,454.75	$9,450.30	$13.65	0.1%
16		200	70,000	$5,314.53	$7,273.00	$12,587.53	$5,332.73	$7,273.00	$12,605.73	$18.20	0.1%
17		300	105,000	$7,979.80	$10,909.50	$18,889.30	$8,007.10	$10,909.50	$18,916.60	$27.30	0.1%
18	Avg	106	37,100	$2,809.18	$3,854.69	$6,663.87	$2,818.83	$3,854.69	$6,673.52	$9.65	0.1%
19	Hours Use: 450										
20		50	22,500	$1,431.67	$2,337.75	$3,769.42	$1,437.52	$2,337.75	$3,775.27	$5.85	0.2%
21		75	33,750	$2,155.51	$3,506.63	$5,662.13	$2,164.28	$3,506.63	$5,670.91	$8.78	0.2%
22		100	45,000	$2,879.34	$4,675.50	$7,554.84	$2,891.04	$4,675.50	$7,566.54	$11.70	0.2%
23		150	67,500	$4,327.01	$7,013.25	$11,340.26	$4,344.56	$7,013.25	$11,357.81	$17.55	0.2%
24		200	90,000	$5,774.68	$9,351.00	$15,125.68	$5,798.08	$9,351.00	$15,149.08	$23.40	0.2%
25		300	135,000	$8,670.03	$14,026.50	$22,696.53	$8,705.13	$14,026.50	$22,731.63	$35.10	0.2%
26	Avg	119	53,550	$3,429.46	$5,563.85	$8,993.30	$3,443.38	$5,563.85	$9,007.22	$13.92	0.2%

27		Current	Proposed	
28		Rates	Rates	Change
29	Customer Charge	$353.00	$353.00	$ -
30	Distribution Demand <= 50 kW	$1.99	$1.99	$ -
31	Distribution Demand Charge >50 kW	$9.37	$9.37	$ -
32	Transmission Demand	$9.23	$9.23	$ -
33	Distribution Energy - Peak	$0.00315	$0.00315	$ -
34	Distribution Energy - Off Peak	$0.00089	$0.00089	$ -
35	Revenue Decoupling	$0.00148	$0.00148	$ -
36	Distributed Solar Charge	$0.00189	$0.00189	$ -
37	Residential Assistance Adjustment Factor	$0.00317	$0.00317	$ -
38	Pension Adjustment Factor	$0.00054	$0.00054	$ -
39	Net Metering Recovery Surcharge	$0.00419	$0.00419	$ -
40	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
41	AG Consulting Expense	$0.00000	$0.00000	$ -
42	Storm Cost Recovery Adjustment Factor	$0.00068	$0.00068	$ -
43	Capital Investment Project	$0.00000	$0.00026	$0.00026
44	Basic Service Cost True Up Factor	($0.00006)	($0.00006)	$ -
45	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
46	Solar Expansion Cost Recovery Factor	$0.00056	$0.00056	$ -
47	Vegetation Management	$0.00072	$0.00072	$ -
48	Tax Act Credit Factor	($0.00090)	($0.00090)	$ -
49	Grid Modernization	$0.00045	$0.00045	$ -
50	Transition	($0.00177)	($0.00177)	$ -
51	Transmission Energy	$0.00000	$0.00000	$ -
52	Energy Efficiency Reconciliation Factor	$0.00803	$0.00803	$ -
53	System Benefits Charge	$0.00250	$0.00250	$ -
54	Renewable Energy Charge	$0.00050	$0.00050	$ -
55	Basic Service Charge	$0.10390	$0.10390	$ -

56	On-Peak Use:	26%
57	Off-Peak Use:	74%

Western Massachusetts
Calculation of Monthly Typical Bill
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Rate T-2 Large Primary General Service Time-of-Use

1		Monthly	Monthly	Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
2		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3	Hours Use: 350										
4		350	122,500	$9,761.76	$12,727.75	$22,489.51	$9,783.81	$12,727.75	$22,511.56	$22.05	0.1%
5		425	148,750	$11,690.70	$15,455.13	$27,145.83	$11,717.48	$15,455.13	$27,172.60	$26.78	0.1%
6		500	175,000	$13,619.65	$18,182.50	$31,802.15	$13,651.15	$18,182.50	$31,833.65	$31.50	0.1%
7		650	227,500	$17,477.55	$23,637.25	$41,114.80	$17,518.50	$23,637.25	$41,155.75	$40.95	0.1%
8		1,000	350,000	$27,344.30	$36,365.00	$63,709.30	$27,407.30	$36,365.00	$63,772.30	$63.00	0.1%
9		1,500	525,000	$41,278.95	$54,547.50	$95,826.45	$41,373.45	$54,547.50	$95,920.95	$94.50	0.1%
10		2,000	700,000	$54,138.60	$72,730.00	$126,868.60	$54,264.60	$72,730.00	$126,994.60	$126.00	0.1%
11	Avg	410	143,500	$11,304.91	$14,909.65	$26,214.56	$11,330.74	$14,909.65	$26,240.39	$25.83	0.1%
12	Hours Use: 450										
13		350	157,500	$10,433.69	$16,364.25	$26,797.94	$10,462.04	$16,364.25	$26,826.29	$28.35	0.1%
14		425	191,250	$12,506.62	$19,870.88	$32,377.49	$12,541.04	$19,870.88	$32,411.92	$34.42	0.1%
15		500	225,000	$14,579.55	$23,377.50	$37,957.05	$14,620.05	$23,377.50	$37,997.55	$40.50	0.1%
16		650	292,500	$18,725.42	$30,390.75	$49,116.17	$18,778.07	$30,390.75	$49,168.82	$52.65	0.1%
17		1,000	450,000	$29,264.10	$46,755.00	$76,019.10	$29,345.10	$46,755.00	$76,100.10	$81.00	0.1%
18		1,500	675,000	$44,158.65	$70,132.50	$114,291.15	$44,280.15	$70,132.50	$114,412.65	$121.50	0.1%
19		2,000	900,000	$57,978.20	$93,510.00	$151,488.20	$58,140.20	$93,510.00	$151,650.20	$162.00	0.1%
20	Avg	571	256,950	$16,541.93	$26,697.11	$43,239.03	$16,588.18	$26,697.11	$43,285.28	$46.25	0.1%
21	Hours Use: 550										
22		350	192,500	$11,105.62	$20,000.75	$31,106.37	$11,140.27	$20,000.75	$31,141.02	$34.65	0.1%
23		425	233,750	$13,322.53	$24,286.63	$37,609.16	$13,364.61	$24,286.63	$37,651.23	$42.07	0.1%
24		500	275,000	$15,539.45	$28,572.50	$44,111.95	$15,588.95	$28,572.50	$44,161.45	$49.50	0.1%
25		650	357,500	$19,973.29	$37,144.25	$57,117.54	$20,037.64	$37,144.25	$57,181.89	$64.35	0.1%
26		1,000	550,000	$31,183.90	$57,145.00	$88,328.90	$31,282.90	$57,145.00	$88,427.90	$99.00	0.1%
27		1,500	825,000	$47,038.35	$85,717.50	$132,755.85	$47,186.85	$85,717.50	$132,904.35	$148.50	0.1%
28		2,000	1,100,000	$61,817.80	$114,290.00	$176,107.80	$62,015.80	$114,290.00	$176,305.80	$198.00	0.1%
29	Avg	580	319,000	$17,904.16	$33,144.10	$51,048.26	$17,961.58	$33,144.10	$51,105.68	$57.42	0.1%

30		Current	Proposed	
31		Rates	Rates	Change
32	Customer Charge <1000 kW	$760.00	$760.00	$ -
33	Customer Charge 1000 <= kW <1500kW	$1,625.00	$1,625.00	$ -
34	Customer Charge 1500 <= kW <2500kW	$2,700.00	$2,700.00	$ -
35	Distribution Demand - Peak	$7.29	$7.29	$ -
36	Transmission Demand - Peak	$11.71	$11.71	$ -
37	Distribution Energy - Peak	$0.00297	$0.00297	$ -
38	Distribution Energy - Off Peak	$0.00087	$0.00087	$ -
39	Revenue Decoupling	$0.00103	$0.00103	$ -
40	Distributed Solar Charge	$0.00131	$0.00131	$ -
41	Residential Assistance Adjustment Factor	$0.00220	$0.00220	$ -
42	Pension Adjustment Factor	$0.00042	$0.00042	$ -
43	Net Metering Recovery Surcharge	$0.00291	$0.00291	$ -
44	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
45	AG Consulting Expense	$0.00000	$0.00000	$ -
46	Storm Cost Recovery Adjustment Factor	$0.00047	$0.00047	$ -
47	Capital Investment Project	$0.00000	$0.00018	$0.00018
48	Basic Service Cost True Up Factor	($0.00004)	($0.00004)	$ -
49	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
50	Solar Expansion Cost Recovery Factor	$0.00039	$0.00039	$ -
51	Vegetation Management	$0.00056	$0.00056	$ -
52	Tax Act Credit Factor	($0.00063)	($0.00063)	$ -
53	Grid Modernization	$0.00031	$0.00031	$ -
54	Transition	($0.00177)	($0.00177)	$ -
55	Transmission Energy	$0.00000	$0.00000	$ -
56	Energy Efficiency Reconciliation Factor	$0.00803	$0.00803	$ -
57	System Benefits Charge	$0.00250	$0.00250	$ -
58	Renewable Energy Charge	$0.00050	$0.00050	$ -
59	Basic Service Charge	$0.10390	$0.10390	$ -

60	On-Peak Use:	28%
61	Off-Peak Use:	72%

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Calculation of Monthly Typical Bill
Illustrative January 1, 2023

Rate T-5 Extra Large Primary General Service Time-of-Use

				Current Monthly Bill			Proposed Monthly Bill			Total Bill Impact	
1		Monthly	Monthly								
2		kW	kWh	Delivery	Supplier	Total	Delivery	Supplier	Total	Change	% Change
3	Hours Use: 350										
4		2,500	875,000	$63,348.76	$90,912.50	$154,261.26	$63,427.51	$90,912.50	$154,340.01	$78.75	0.1%
5		3,000	1,050,000	$75,258.52	$109,095.00	$184,353.52	$75,353.02	$109,095.00	$184,448.02	$94.50	0.1%
6		5,000	1,750,000	$122,897.53	$181,825.00	$304,722.53	$123,055.03	$181,825.00	$304,880.03	$157.50	0.1%
7		10,000	3,500,000	$241,995.05	$363,650.00	$605,645.05	$242,310.05	$363,650.00	$605,960.05	$315.00	0.1%
8	Avg	3,983	1,394,050	$98,673.09	$144,841.80	$243,514.88	$98,798.55	$144,841.80	$243,640.35	$125.46	0.1%
9	Hours Use: 450										
10		2,500	1,125,000	$67,119.84	$116,887.50	$184,007.34	$67,221.09	$116,887.50	$184,108.59	$101.25	0.1%
11		3,000	1,350,000	$79,783.81	$140,265.00	$220,048.81	$79,905.31	$140,265.00	$220,170.31	$121.50	0.1%
12		5,000	2,250,000	$130,439.68	$233,775.00	$364,214.68	$130,642.18	$233,775.00	$364,417.18	$202.50	0.1%
13		10,000	4,500,000	$257,079.35	$467,550.00	$724,629.35	$257,484.35	$467,550.00	$725,034.35	$405.00	0.1%
14	Avg	6,855	3,084,750	$177,422.99	$320,505.53	$497,928.52	$177,700.62	$320,505.53	$498,206.15	$277.63	0.1%
15	Hours Use: 550										
16		2,500	1,375,000	$70,890.91	$142,862.50	$213,753.41	$71,014.66	$142,862.50	$213,877.16	$123.75	0.1%
17		3,000	1,650,000	$84,309.10	$171,435.00	$255,744.10	$84,457.60	$171,435.00	$255,892.60	$148.50	0.1%
18		5,000	2,750,000	$137,981.83	$285,725.00	$423,706.83	$138,229.33	$285,725.00	$423,954.33	$247.50	0.1%
19		10,000	5,500,000	$272,163.65	$571,450.00	$843,613.65	$272,658.65	$571,450.00	$844,108.65	$495.00	0.1%
20	Avg	4,519	2,485,450	$125,073.53	$258,238.26	$383,311.79	$125,297.22	$258,238.26	$383,535.48	$223.69	0.1%

21		Current	Proposed	
22		Rates	Rates	Change
23	Customer Charge	$3,800.00	$3,800.00	$ -
24	Distribution Demand - Peak	$5.18	$5.18	$ -
25	Transmission Demand - Peak	$13.36	$13.36	$ -
26	Distribution Energy - Peak	$0.00296	$0.00296	$ -
27	Distribution Energy - Off Peak	$0.00087	$0.00087	$ -
28	Revenue Decoupling	$0.00055	$0.00055	$ -
29	Distributed Solar Charge	$0.00070	$0.00070	$ -
30	Residential Assistance Adjustment Factor	$0.00118	$0.00118	$ -
31	Pension Adjustment Factor	$0.00025	$0.00025	$ -
32	Net Metering Recovery Surcharge	$0.00156	$0.00156	$ -
33	Long Term Renewable Contract Adjustment	($0.00045)	($0.00045)	$ -
34	AG Consulting Expense	$0.00000	$0.00000	$ -
35	Storm Cost Recovery Adjustment Factor	$0.00025	$0.00025	$ -
36	Capital Investment Project	$0.00000	$0.00009	$0.00009
37	Basic Service Cost True Up Factor	($0.00002)	($0.00002)	$ -
38	Solar Program Cost Adjustment Factor	$0.00000	$0.00000	$ -
39	Solar Expansion Cost Recovery Factor	$0.00020	$0.00020	$ -
40	Vegetation Management	$0.00034	$0.00034	$ -
41	Tax Act Credit Factor	($0.00033)	($0.00033)	$ -
42	Grid Modernization	$0.00016	$0.00016	$ -
43	Transition	($0.00177)	($0.00177)	$ -
44	Transmission Energy	$0.00000	$0.00000	$ -
45	Energy Efficiency Reconciliation Factor	$0.00803	$0.00803	$ -
46	System Benefits Charge	$0.00250	$0.00250	$ -
47	Renewable Energy Charge	$0.00050	$0.00050	$ -
48	Basic Service Charge	$0.10390	$0.10390	$ -

49 On-Peak Use: 27%
50 Off-Peak Use: 73%

NOTE: Transmission On Peak Demand Charge is being used to calculate bill impacts as Coincident Peak data is not available based on range of kWh shown