The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 24-10 August 29, 2024

Petition of NSTAR Electric Company d/b/a Eversource Energy for approval by the Department of Public Utilities of its Electric Sector Modernization Plan filed pursuant to G.L. c. 164, § 92B.

D.P.U. 24-11

Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval by the Department of Public Utilities of its Electric Sector Modernization Plan filed pursuant to G.L. c. 164, § 92B.

D.P.U. 24-12

Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval by the Department of Public Utilities of its Electric Sector Modernization Plan filed pursuant to G.L. c. 164, § 92B.

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EXECUTIVE SUMMARY

With this Order, the Department of Public Utilities ("Department") approves the inaugural Electric Sector Modernization Plans ("ESMPs"), which will provide a strategic roadmap to the electric distribution companies' ("utilities" or "Companies") investments in their electric distribution and transmission systems to enable an affordable, equitable clean energy transition. The Legislature directed the ESMP process in Section 53 of An Act Driving Clean Energy and Offshore Wind, enacted in 2022 ("2022 Clean Energy Act"). The utilities filed their ESMPs with the Department after a robust deliberative process with a new stakeholder advisory body, also created by the 2022 Clean Energy Act, known as the Grid Modernization Advisory Council ("GMAC"). The 2022 Clean Energy Act requires each company to develop a plan to proactively upgrade its electric distribution and transmission systems to: (1) improve grid reliability, communications, and resiliency; (2) enable increased, timely adoption of renewable energy and distributed energy resources; (3) promote energy storage and electrification technologies necessary to decarbonize the environment and economy; (4) prepare for future climate-driven impacts on the transmission and distribution systems; (5) accommodate increased transportation electrification, increased building electrification and other potential future demands on distribution and, where applicable, transmission systems; and (6) minimize or mitigate impacts for ratepayers. In this Order, the Department approves NSTAR Electric's, National Grid's, and Unitil's ESMPs, directs certain modifications and next steps, and sets forth criteria for the Companies' biannual reports.

In Section IV.C., the Department establishes the framework for our review of the first ESMPs as long-term, strategic planning documents that endeavor to meet the goals and requirements of the 2022 Clean Energy Act. The Department expects the ESMPs to be each utility's roadmap outlining how the discrete investments proposed will achieve the statutory objectives. The Department declines to make the ESMPs each utility's central distribution system planning document.

The utilities characterize base spending capital investment activities as core investments, i.e., planned investments funded through base distribution rates to maintain the safety and reliability of the electric distribution system in the normal course of business. In contrast, the utilities identify proposed ESMP investments as accelerated, incremental investments that supplement and go beyond existing programs and core investments, and which the utilities deem necessary over the next five years to enable progress towards the Commonwealth's clean energy and decarbonization goals through electrification and distributed energy resources. In Section IV.C., the Department finds this distinction to be reasonable and appropriate. The Department declines to require the Companies to uniformly treat certain investment types as either core or ESMP; rather, we find that a measure of flexibility in ESMP investment planning is appropriate and warranted, consistent with typical distribution system planning practices.

In Section VI.C., the Department determines that each company's ESMP complies with the five- and ten-year forecast and demand assessment statutory requirements. In their biannual reports, the Department requires the utilities to provide a comparison of the forecasted demand and actual demand, separated by categories, for each completed year in the ESMP term. This will allow the Department and stakeholders to assess the reliability of each company's forecast.

In Section VII.A., the Department establishes the first ESMP term for the period July 1, 2025, through June 30, 2030, and the second ESMP term for the period July 1, 2030, through June 30, 2035. Multiple parties identified process constraints with the timeframe for reviewing the draft and final ESMPs established by the Legislature for these inaugural ESMPs. Accordingly, the Department provides the GMAC and the utilities additional time to review the draft plans and prepare the second term ESMP filings with the Department. For the next ESMP term that begins on July 1, 2030: (1) the utilities must submit their draft plans to the GMAC by February 12, 2029; (2) the GMAC must issue its recommendations on the draft ESMPs by June 18, 2029; (3) the utilities must submit their proposed ESMPs for the period July 1, 2030 to June 30, 2035 to the Department on or before September 11, 2029; and (4) the Department shall issue a final Order by April 11, 2030. Pursuant to this schedule, the GMAC is afforded approximately 125 days to submit final recommendations to the Companies, which are afforded approximately 85 days to consider the GMAC's recommendations before submission to the Department.

An important element of each ESMP is the requirement to improve grid resilience and prepare for future climate-driven impacts. As the intensity and frequency of weather-related events due to climate change increase, the Department determines that reliance on system performance beyond those occurring under "blue sky" operating conditions as well as each company's incorporation of a climate vulnerability assessment framework are imperative to accurately assess the resiliency of the system and those locations in need of hardening. An analysis of the potential impacts of climate change across various scenarios is integral to forward-looking distribution system planning and successful pursuit of the statutory objectives. In Section VII.C., however, we find the need for greater consistency in the climate vulnerability assessments prepared by the utilities. In its first biannual ESMP report, each company shall provide a description of its planned targeted resiliency investments.

In Section VII.C., the Department also finds that the proposed electric vehicle program extensions would enable the electrification of transportation across the residential, public, workplace, and fleet electric vehicle charging sectors, leading to reduced emissions. The Department recognizes the potential benefits to ratepayers of a flexible interconnection program that includes electric vehicle infrastructure, particularly if such an offering reduces the need for ratepayer investment.

In Section VII.D., the Department finds that the utilities have complied with the statutory requirements applicable to alternatives to investments. It is reasonable and appropriate for summaries and discussions of alternative investments in the ESMPs: (1) for both ESMP and non-ESMP investments, to address a company's distribution system planning framework process and policies (e.g., distribution system planning, capital authorization, and non-wires alternatives policies), including discussions of how alternatives are considered in that framework and, if applicable, how and why the process(es) for developing proposed ESMP investments differ for non-ESMP investments; and (2) for proposed ESMP investments only, to describe ESMP proposals for nontraditional utility investments or foundational investments to enable nontraditional investments (e.g., virtual power plants, energy storage systems, etc.), as well as any specific alternatives, if applicable, that the company considered in the development of its ESMP investment proposals.

The utilities each identify several projects to update their distribution systems through projects classified as capital investment projects and network investments, including new substation projects. The projects as described comply with the statutory requirements. In Section VII.F., the Department directs the Companies to coordinate a long-term system planning process stakeholder group no later than October 1, 2024. The Department directs the Companies to organize a six-month stakeholder process (i.e., beginning in October 2024 and concluding in March 2025).

The Department is committed to an equitable clean energy transition. The Department's approval of the ESMPs is based on the understanding that the Companies will aggressively seek to minimize ESMP costs through grants, tax incentives, and low-cost financing programs. As electrification efforts expand, ensuring affordability and equity, including the equitable distribution of the extensive benefits from a clean energy economy, is of particular importance to avoid overburdening customers financially, particularly those who already bear higher burdens in terms of not only costs but also other cumulative impacts. In Section VII.H., the Department approves the utilities' equity framework, with modification. The Companies must coordinate with the Community Engagement Stakeholder Advisory Group to develop clear and cohesive equity policies and practices, including policies and practices related to language access, environmental justice, and the siting of electric distribution system infrastructure.

For purposes of the ESMP net benefits analysis, the Department reviews the costs and benefits of the proposed planning solutions in the context of strategic planning documents only, i.e., not for purposes of cost recovery. In Section VII.I., the Department finds that the utilities have each established net benefits for their ESMPs using a reasonable method and inputs. We find reasonable and appropriate the Companies' omission of non-ESMP investments from their net benefits analyses; they do not need to each propose ESMP investments for every investment category identified as part of the net benefits analysis and within the ESMPs. Each distribution system has unique characteristics and system needs, and their proposals are tailored to the present state of each system. We direct the Companies to better coordinate to ensure consistent groupings of substantially similar investments in future ESMP filings.

The Department intends to investigate how innovative approaches to cost recovery through base distribution rates can further the purpose of the 2022 Clean Energy Act, optimally balance our priorities, and promote administrative efficiency, but an investigation of that scale will likely require a lengthy inquiry to identify, analyze, and resolve many complex ratemaking issues, as discussed in Section VIII.D. Therefore, the Department will allow a short-term, targeted cost recovery framework for ESMP costs for NSTAR Electric and Unitil while our investigation into a long-term cost recovery framework proceeds; cost recovery determinations applicable to National Grid require resolution of matters pending in its current base distribution rate proceeding, D.P.U. 23-150. The Department finds that it is appropriate to allow short-term, targeted cost recovery for ESMP costs and will determine the parameters of a new ESMP cost recovery mechanism in a subsequent phase of these proceedings.

In Section IX.D., the Department finds that the utilities correctly calculated their estimated bill impacts and that the estimated bill impacts resulting from the proposed ESMP costs are within the range of reasonableness in light of the anticipated benefits that the proposed ESMPs may provide. When the Companies propose to include ESMP costs in rates, the Department will consider the actual proposed bill impacts in our decision on whether to allow the proposed rate changes consistent with statutory requirements, the Department's authority to regulate rates, and well-established precedent.

The Companies must file two biannual reports, one on March 31 and one on September 30, respectively, with the first biannual reports due on September 30, 2025, as discussed in Section XI.D.

I. INTRODUCTION AND PROCEDURAL HISTORY

On January 29, 2024, NSTAR Electric Company d/b/a Eversource Energy ("NSTAR Electric"), Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid ("National Grid"), and Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil") (collectively, "the Companies"; individually, "company") each filed for approval by the Department a proposed electric sector modernization plan ("ESMP") for the period January 1, 2025, through December 31, 2029.[1] Each company submitted its filing pursuant to G.L. c. 164, § 92B. The Department docketed these matters as D.P.U. 24-10, D.P.U. 24-11, and D.P.U. 24-12, respectively.[2]

In anticipation of these filings, on August 7, 2023, and November 14, 2023, the Department provided procedural guidance, including pre-assigning docket numbers, and establishing intervention requirements and the initial procedural schedule for the proceedings. In particular, the Department established two procedural tracks for the proceedings, a

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1 On January 31, 2024, and April 4, 2024, National Grid submitted revisions to its initial filing bill impacts exhibits and corrections to its initial filing exhibits, respectively. On April 2, 2024, NSTAR Electric and Unitil each submitted corrections to their initial filing exhibits.

2 For administrative efficiency, the Department adjudicated the three dockets simultaneously and issues a single Order. These cases have not been consolidated, however, and remain separate proceedings.

General Track and an Alternate Track,[3] with separate intervention and discovery deadlines for each track.

On September 15, 2023, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a notice of intervention pursuant to G.L. c. 12, § 11E(a) in each proceeding. Additionally, after the initial filings, the Department granted full intervenor status to each of the following entities for all three proceedings: (1) the Massachusetts Department of Energy Resources ("DOER"); (2) Acadia Center; (3) Conservation Law Foundation ("CLF"); and (4) Northeast Clean Energy Council, Inc., Coalition for Community Solar Access, Inc., Advanced Energy United, Inc., and Solar Energy Industries Association, Inc. ("Clean Energy Coalition" or "the Coalition"). The Department granted full intervenor status to the Cape Light Compact JPE ("Cape Light Compact" or "CLC") for D.P.U. 24-10, to Williams College for D.P.U. 24-11, and to each of the following entities for both D.P.U. 24-10 and D.P.U. 24-11: (1) Green Energy Consumers Alliance ("GECA"); and (2) Direct Energy Business, LLC, Direct Energy Services, LLC, Energy Plus Holdings, LLC, Green Mountain Energy Company, Inc., NRG Home f/k/a Reliant Energy Northeast, LLC, and Xoom Energy Massachusetts, LLC ("NRG Retail Companies" or "NRG"). The Department granted limited participant status to: (1) NSTAR Electric for

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3 For these proceedings, General Track participants are members of the Grid Modernization Advisory Council ("GMAC"), or entities whose interests are represented on the GMAC. Alternate Track participants are any other entity that pursuant to G.L. c. 30A, § 10, the Department finds to be substantially and specifically affected by the proceedings but that did not participate in or whose interests were not adequately represented in the GMAC process.

D.P.U. 24-11 and D.P.U. 24-12; (2) National Grid for D.P.U. 24-10 and D.P.U. 24-12; (3) the Gloucester Economic Development and Industrial Corporation ("Gloucester EDIC") for D.P.U. 24-11; and (4) to Unitil, PowerOptions, Inc., and The Energy Consortium for D.P.U. 24-10 and D.P.U. 24-11. Finally, the Department granted limited intervenor[4] status to EVgo Services LLC ("EVgo") and Tesla, Inc. for D.P.U. 24-10 and D.P.U. 24-11.

On February 20, 2024, the Department issued an interlocutory order addressing the scope of the proceedings. Electric Sector Modernization Plans, D.P.U. 24-10/D.P.U. 24-11/ D.P.U. 24-12, Interlocutory Order on Scope of Proceedings (February 20, 2024) ("Interlocutory Order on Scope"). On February 23, 2024, the Department issued an interlocutory order addressing two intervention requests in D.P.U. 24-11 and clarifying for future ESMP filings the criteria for interested parties to qualify as either General Track or Alternate Track Participants. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 24-11, Interlocutory Order on Petitions to Intervene at 10-17 (February 23, 2024). Pursuant to notices duly issued, the Department conducted joint virtual public hearings for these proceedings on March 7, 2024, and March 12, 2024.[5]

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4 Limited intervention, in contrast to limited participation, allows entities to fully participate in a proceeding on specific topics delineated in their petitions to intervene. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 18-150, at 3 n.7 (2019).

5 The Department received oral and written comments during the public comment period, including from the GMAC and several GMAC members, the City of Boston, the Town of Williamstown, the Gloucester EDIC, the United Way, solar and/or energy storage developers, other business interests, and several members of the public, among others. Many commenters support establishing a long-term planning

Additionally, the Companies jointly conducted a virtual public information session on March 5, 2024, to provide an overview of their ESMPs and respond to questions from the public. The Department held seven days of virtual evidentiary hearings from April 9, 2024, through April 22, 2024. On May 17, 2024, the following intervenors submitted initial briefs in these proceedings: the Attorney General, DOER, Acadia Center, CLC, the Clean Energy Coalition, CLF, EVgo, GECA, NRG, and Williams College. On May 31, 2024, NSTAR Electric, National Grid, and Unitil jointly submitted an initial brief ("Companies' Joint Brief"). On June 21, 2024, the following intervenors submitted reply briefs: Acadia Center, CLF, and GECA jointly ("Joint Intervenor Reply Brief"), the Attorney General, DOER, CLC, the Clean Energy Coalition, NRG, and Williams College. On that same date, the Companies jointly submitted a reply brief ("Companies' Joint Reply Brief").[6]

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process for distributed generation ("DG") interconnection. Other commenters: (1) express concern with capacity constraints, reliability issues, and/or costs; (2) seek more equitable distribution of benefits and burdens and other environmental justice ("EJ") considerations; (3) support the deployment of particular technologies and solutions; (4) recommend separate proceedings on various topics; (5) seek more integrated and transparent coordination between the local gas distribution companies and electric distribution companies; (6) support establishing a Community Engagement Stakeholder Advisory Group ("CESAG"); and/or (7) criticize the Companies' rejection of various GMAC recommendations. The GMAC requests that the Department define the future role of the GMAC and delineate future ESMP filings requirements.

[6] On July 3, 2024, the Companies filed a letter with the Department addressing items discussed by the Attorney General, DOER, and the Coalition on brief. On July 11, 2024, with leave from the Hearing Officer, these three intervenors each submitted responses to the Companies' letter. Because these filings are not necessary for our understanding of the issues in these proceedings and are not a part of the evidentiary

In support of its filing in D.P.U. 24-10, NSTAR Electric sponsored the testimony of the following witnesses, all of whom are employed by Eversource Service Company ("ESC"):[7] (1) Jennifer A. Schilling, vice president of grid modernization; (2) Digaunto Chatterjee, vice president of system planning; (3) Gerhard Walker, manager for advanced forecasting and modeling; (4) Sophia Zhang, lead data scientist for advanced forecasting and modeling; (5) Lavelle A. Freeman, director of distribution system planning; (6) Juan F. Martinez, manager of distribution system planning; (7) Elli Ntakou, manager of system resiliency and reliability; (8) Erin M. Engstrom, director of regulatory affairs and stakeholder engagement; (9) Ashley N. Botelho, director of revenue requirements – Massachusetts; (10) Richard D. Chin, manager of rates – Massachusetts; (11) Andrew Belden, vice president of solar programs; and (12) Christopher Coy, principal analyst for clean transportation.

In support of its filing in D.P.U. 24-11, National Grid sponsored the testimony of the following witnesses, all of whom are employed by National Grid USA Service Company, Inc. ("NGSC"):[8] (1) Shira Horowitz, director of load forecasting and analytics; (2) Elton

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records, the Department will not consider them in making our determinations in this Order.

7 ESC performs functions such as accounting, auditing, communications, rates, legal, regulatory affairs, information technology, and human resources for NSTAR Electric and other Eversource Energy subsidiaries. NSTAR Electric Company, D.P.U. 22-22, at 5 n.8 (2022).

8 NGSC provides management, administrative, accounting, legal, engineering, information systems, and other services to National Grid USA subsidiaries, including Massachusetts Electric Company and Nantucket Electric Company. D.P.U. 18-150, at 2).

Prifti, director of distribution planning and asset management for New England; (3) Jingrui Xie, manager of electric load forecasting; (4) Robert Andrew Schneller, vice president of electric strategy and regulation; (5) William F. Jones, director of ESMP development; (6) Eli H. Shakun, principal analyst for future of electric, utility of the future transformation team; (7) Joshua Tom, director of future of electric for customers; (8) Jonathan Berry, vice president of electric information technology ("IT") delivery; (9) James McGaugh, head of United States ("U.S.") corporate affairs; (10) Meghan McGuinness, director of regulatory strategies; (11) Alisha Collins, director of community impact and engagement in New England; (12) Melissa Lavinson, head of New England corporate affairs; (13) Nicola Medalova, chief operating officer of New England electric; (14) Andrew A. Gumbus, director of Massachusetts revenue requirements for New England regulation and pricing; (15) Melissa A. Little, director of Massachusetts pricing for New England regulation and pricing; (16) Sandy Grace, vice president of U.S. policy and regulatory strategy; (17) Matthew Motley, director of stakeholder engagement and marketing campaigns; and (18) Emily Slack, engineering manager for distribution system planning and asset management.

In support of its filing in D.P.U. 24-12, Unitil sponsored the testimony of the following witnesses, each of whom are employed by Unitil Service Company ("USC"):[9]

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[9] USC performs administrative and professional services for Unitil and its utility affiliates. Fitchburg Gas and Electric Light Company, D.P.U. 23-80/D.P.U. 23-81, at 5 (June 28, 2024).

(1) Kevin E. Sprague, vice president of engineering; (2) Jacob S. Dusling, principal engineer; (3) Daniel T. Nawazelski, manager of revenue requirements; and (4) Katherine Bourque, vice president of policy and corporate relations. Additionally, in support of their filings, the Companies each sponsored the testimony of the following external consultant witnesses, both of whom are employed by West Monroe Partners, LLC ("West Monroe"): (1) Eric Chung, partner for energy and utilities; and (2) Christopher Timberg, senior manager for energy and utilities.

The Attorney General sponsored the testimony of the following witnesses for all three proceedings: (1) Ron Nelson, founder and president at Volt-Watt Consulting, LLC; (2) Nikhil Balakumar, principal at Gaia Energy, LLC; (3) Timothy Cook, distributed energy resource ("DER") integration consultant at Strategen Consulting; (4) Carolyn A. Berry, principal at Bates White, LLC; and (5) Charles A. Fijnvandraat, principal at Fijnvandraat Consulting Group, Inc. DOER sponsored the testimony of two employees from its policy, planning, and analysis division: (1) Aurora Edington, deputy director; and (2) Marian Swain Harkavy, director. CLF sponsored the testimony of John Walkey, director of waterfront and climate justice initiatives at GreenRoots, Inc. The Coalition sponsored the testimony of Marc D. Montalvo, chief executive officer and principal consultant at Daymark Energy Advisors, Inc.

In D.P.U. 24-10 and D.P.U. 24-11, EVgo sponsored the testimony of Lindsey Stegall, senior manager of market development and public policy; GECA sponsored the testimony of Larry Chretien, executive director, and Anna Vanderspek, electric vehicle

("EV") program director; and Tesla sponsored the testimony of William Ehrlich, senior policy advisor for EV charging policy and rates. In D.P.U. 24-11, Williams College sponsored the testimony of the director of its Zilka Center for Environmental Initiatives, Tanja Srebotnjak, and its assistant director for energy and utilities, Jason Moran.

The evidentiary record for each docket consists of the company's initial filing exhibits and corresponding revisions and corrections to those exhibits, the intervenors' pre-filed testimony and supporting exhibits, responses to information requests, witness testimony from the evidentiary hearings, and responses to record requests.[10] Each evidentiary record also includes the Grid Modernization Advisory Council ("GMAC") November 20, 2023 report and recommendations ("GMAC Report") on the Companies' draft ESMPs submitted to the GMAC on September 1, 2023, as well as the GMAC consultant February 22, 2024 comments ("GMAC Consultant Comments") on the Companies' ESMPs filed with the Department (D.P.U. 24-10/D.P.U. 24-11, Exh. GECA-LC-3;[11] D.P.U. 24-10/D.P.U. 24-11/ D.P.U. 24-12, Tr. at 20; Tr. 7, at 956).[12]

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[10] On the final day of evidentiary hearings, all exhibits filed in each docket were moved into the evidentiary record for that docket (D.P.U. 24-10/D.P.U. 24-11/ D.P.U. 24-12, Tr. 7, at 1056-1057).

[11] Exhibit GECA-LC-3 consists of the GMAC Consultant Comments. In this Order, the Department refers to Exhibit GECA-LC-3 as the GMAC Consultant Comments.

[12] The GMAC is tasked with reviewing and providing input and recommendations on draft ESMPs and related data before they are filed with the Department. G.L. c. 164, § 92B, (c)(iii), (d); G.L. c. 164, § 92C. The Department addresses the role of the GMAC in further detail in Section V.D., below.

In D.P.U. 24-10, NSTAR Electric responded to 399 information requests and nine record requests, the Attorney General responded to seven information requests, DOER responded to seven information requests, and the Coalition responded to two information requests. In D.P.U. 24-11, National Grid responded to 365 information requests and four record requests, the Attorney General responded to seven information requests, DOER responded to seven information requests, and the Clean Energy Coalitions responded to two information requests. In D.P.U. 24-12, Unitil responded to 270 information requests and two record requests, the Attorney General responded to seven information requests, DOER responded to seven information requests, and the Clean Energy Coalition responded to two information requests.

II. STATUTORY REQUIREMENTS

Section 92B(a) of G.L. c. 164 ("Section 92B(a)") requires an electric distribution company to develop a plan to proactively upgrade its distribution and, where applicable, transmission systems to: (1) improve grid reliability, communications, and resiliency; (2) enable increased, timely adoption of renewable energy and DERs;[13] (3) promote energy

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13 Pursuant to G.L. c. 164, § 1, DERs are defined as small-scale power generation or storage technology, not greater than 20 megawatts, including, but not limited to, resources that are in front of or behind the customer meter, electric storage resources, intermittent generation, distributed generation ("DG"), demand response, energy efficiency, thermal storage and EVs and their supply equipment that may provide an alternative to, or an enhancement of, the traditional electric power system and are located on an electric utility's distribution system or on a subsystem of the utility's distribution system. Under that same provision, DG is defined as a generation facility or renewable energy facility connected directly to distribution facilities or to retail

storage and electrification technologies necessary to decarbonize the environment and economy; (4) prepare for future climate-driven impacts on the transmission and distribution systems; (5) accommodate increased transportation electrification, increased building electrification and other potential future demands on distribution and, where applicable, transmission systems; and (6) minimize or mitigate impacts for ratepayers, to help the Commonwealth meet its statewide greenhouse gas ("GHG") emissions limits and sublimits under G.L. c. 21N. G.L. c. 164, § 92B. To be approved by the Department, an ESMP must provide net benefits for customers and meet the criteria enumerated in subsection (a) of Section 92B. G.L. c. 164, § 92B(d).

The ESMP must describe in detail: (1) improvements to the electric distribution system to increase reliability and strengthen system resiliency to address potential weather-related and disaster-related risks; (2) the availability and suitability of new technologies including, but not limited to, smart inverters, advanced metering and telemetry and energy storage technology for meeting forecasted reliability and resiliency needs, as applicable; (3) patterns and forecasts of DER adoption in the company's territory and upgrades that might facilitate or inhibit increased adoption of such technologies; (4) improvements to the distribution system that will enable customers to express preferences for access to renewable energy resources; (5) improvements to the distribution system that will facilitate transportation or building electrification; (6) improvements to the transmission

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customer facilities which alleviate or avoid transmission or distribution constraints or the installation of new transmission facilities or distribution facilities.

or distribution system to facilitate achievement of the statewide GHG emissions limits under G.L. c. 21N; (7) opportunities to deploy energy storage technologies to improve renewable energy utilization and avoid curtailment; (8) alternatives to proposed investments, including changes in rate design, load management and other methods for reducing demand, enabling flexible demand and supporting dispatchable demand response; and (9) alternative approaches to financing proposed investments, including, but not limited to, cost allocation arrangements between developers and ratepayers and, with respect to any proposed investments in transmission systems, cost allocation arrangements and methods that allow for the equitable allocation of costs to, and the equitable sharing of costs with, other states and populations and interests within other states that are likely to benefit from said investments. G.L. c. 164, § 92B(b).

The ESMP must also propose discrete, specific, enumerated investments to the distribution and, where applicable, transmission systems, alternatives to such investments and alternative approaches to financing such investments, that facilitate grid modernization, greater reliability, communications and resiliency, increased enablement of DERs, increased transportation electrification, increased building electrification and the minimization or mitigation of ratepayer impacts, to meet the statewide GHG limits and sublimits under G.L. c. 21N. G.L. c. 164, § 92B(e). For all proposed investments and alternative approaches, each electric distribution company shall identify customer benefits associated with the investments and alternatives including, but not limited to, safety, grid reliability and resiliency, facilitation of the electrification of buildings and transportation, integration of

DERs, avoided renewable energy curtailment, reduced GHG emissions and air pollutants, avoided land use impacts and minimization or mitigation of impacts on the ratepayers of the Commonwealth. G.L. c. 164, § 92B(b).

Additionally, in developing its plan, the electric distribution company must: (1) prepare and use three planning horizons for electric demand, including five- and ten-year forecasts and a demand assessment through 2050 to account for future trends in the adoption of renewable energy, DERs, and energy storage and electrification technologies necessary to achieve the Commonwealth's GHG emission limits; (2) consider and include a summary of all proposed and related investments, alternatives to these investments and alternative approaches to financing these investments that have been reviewed, are under consideration, or have been previously approved by the Department; (3) solicit input and report on recommendations from the GMAC established pursuant to G.L. c. 164, § 92C ("Section 92C"); and (4) conduct technical conferences and a minimum of two stakeholder meetings to inform the public and others in developing its ESMP. G.L. c. 164, § 92B(c)-(d).

Each electric distribution company must submit two reports per year to the Department and the Joint Committee on Telecommunications, Utilities, and Energy ("Joint TUE Committee") on the deployment of approved investments in accordance with performance metrics included in the approved plan. G.L. c. 164, § 92B(e). After the initial ESMP filing, each electric distribution company must submit an ESMP once every five years in accordance with a schedule determined by the Department, provided that the plan is submitted to the GMAC no later than 150 days before the company files the plan with the

Department and the GMAC returns the plan to the company with recommendations no later than 70 days before the company files the plan with the Department. G.L. c. 164, § 92B(d).

III. DESCRIPTION OF COMPANIES AND CURRENT STATE OF DISTRIBUTION SYSTEMS

A. NSTAR Electric

NSTAR Electric is the primary electric distribution company for 140 cities and towns across the Commonwealth (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 91; ES-Policy/Solutions-1, at 39). The company provides service to approximately 1.47 million customer accounts, including approximately 1.27 million residential households and 200,000 commercial and industrial ("C&I") customers, to an aggregate area of approximately 3,200 square miles (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 64, 91; ES-Policy/Solutions-1, at 14, 39). The company segments its distribution system into four planning sub-regions: (1) Eastern Massachusetts ("EMA") North Metro Boston ("Metro Boston"), with approximately 383,000 customer accounts, peak electric demand of approximately 2.0 gigawatts ("GW"), total DER of approximately 265 megawatts ("MW"), and 60 MW of DER in queue; (2) EMA-North Metro West ("Metro West"), with approximately 417,000 customer accounts, peak electric demand of 1.9 GW, total DER of approximately 338 MW, and 198 MW of DER in queue; (3) Southeastern Massachusetts ("SEMA"), with approximately 385,000 customer accounts, peak electric demand of approximately 1.2 GW, total DER of approximately 659 MW, and 704 MW of DER in queue; and (4) Western Massachusetts ("WMA"), with approximately 212,000 customer accounts, peak electric demand of approximately 0.9 GW, total DER of approximately

569 MW, and 429 MW of DER in queue (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 63, 91-92, 95, 124, 143, 170-171; ES-Policy/Solutions-1, at 14, 92-94). Sub-regions are defined based the following factors: historical NSTAR Electric predecessor company services areas, service area geography, customer demographics, operating voltage and substation and distribution system design characteristics, historical and forecasted load growth characteristics, load density, and DER penetration levels (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 91-92; ES-Policy/Solutions-1, at 92).

The major assets on the company's distribution system include: (1) 172 substations, including 101 bulk distribution substations,[14] with approximately 7.9 GW of installed substation capacity to supply approximately 6.1 GW of summer peak hour customer demand in 2023; (2) approximately 11,500 circuit miles of overhead lines; (3) approximately 9,200 circuit miles of underground lines; (4) approximately 315,000 utility poles; and (5) 172,900 service transformers (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 14, 64, 115, 136, 163, 188; ES-Policy/Solutions-1, at 38-39). The average headroom[15] of bulk distribution substations ranges between eight to 23 MW: (1) for Metro Boston, 21 bulk distribution substations with 3.0 GW of firm capacity and an average substation headroom of

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14 Bulk distribution substations convert power from transmission-level voltages to distribution-level voltage (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 59).

15 Headroom is the available capacity of equipment to accommodate additional load without violating equipment specifications (D.P.U. 24-10, ES-ESMP-1 (Corrected) at 678; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) Glossary at 5; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at xiv).

23 Megavolt-amperes ("MVA"); (2) for Metro West, 23 bulk distribution substations with 2.2 GW of firm capacity and an average substation headroom of 14 MVA; (3) for SEMA, 29 bulk substations with 1.4 GW of firm capacity and an average substation headroom of about 8 MVA; and (4) for WMA, 28 bulk substations with about 1.3 GW of firm capacity and an average substation headroom of 17 MVA (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 94; ES-Policy/Solutions-1, at 39).

NSTAR Electric identifies wide variations in load growth, system planning challenges, and needs at the sub-region level due to unique physical, economic, demographic, and historical characteristics of each sub-region (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 19, 59-61, 91-193; ES-Policy/Solutions-1, at 92). The company explains that the Metro Boston and Metro West sub-regions are load centers with the highest customer density per substation and space constraints that limit locally installed generation resources (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 70; ES-Policy/Solutions-1, at 39). The company notes the significant economic growth in the Metro Boston and Metro West sub-regions over the past five years which has contributed to a substantial increase in electric demand (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 59-60). The Metro Boston sub-region serves many large commercial customers and is at an elevated risk of coastal flooding due to climate change (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 20, 59; ES-Policy/Solutions-1, at 92-93). The Metro West sub-region includes heavy commercial and residential areas along the Route 128/Interstate 95 beltway (D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 93).

In the SEMA sub-region, NSTAR Electric identifies significant DER growth in solar photovoltaic ("PV") generation and PV combined with battery energy storage systems ("ESS") that accounts for most substation upgrades in the area (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 20, 60; ES-Policy/Solutions-1, at 93). This sub-region includes areas with rural areas comprising agricultural and conservation lands with low customer density, as well as industrial and heavy commercial load in New Bedford (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 380; ES-Policy/Solutions-1, at 93). Additionally, the Cape Cod region is uniquely exposed to high wind speeds during storms, and parts of Plymouth, most of the Cape Cod district, and Martha's Vineyard historically have summer peaking load due to tourist-based economies (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 20, 60, 143; ES-Policy/Solutions-1, at 93-94).

The WMA sub-region is a more sparsely populated area with significant growth in solar PV and PV combined with ESS (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 20, 60-61, 170; ES-Policy/Solutions-1, at 94). Greater issues with reliability and power outages in this sub-region manifest due to long, overhead, radial distribution lines (i.e., three-phase backbone lines emanating directly from substations) running through heavily treed areas (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 20, 60-61). There are also localized high and moderate load density areas, including Springfield, which has industrial and a heavy commercial load (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 171).

Across the four sub-regions, the company projects that by 2033 electric demand will increase from a baseline summer peak demand of 6.1 GW to 7.4 GW, after accounting for load reductions from energy efficiency ("EE"), demand response, and distributed renewable generation, and transitioning the territory to a winter peaking system by 2035 (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 12, 205; ES-Policy/Solutions-1, at 41, 58). The company's preliminary projections show that new customer load will be the primary driver in an expected increase to the current baseline summer evening peak of 6.1 GW to a winter morning peak of 15.3 GW by 2050, more than doubling the existing peak demand (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 14; ES-Policy/Solutions-1, at 41, 58).[16]

B. National Grid

National Grid is the primary electric distribution company for more than 172 cities and towns across the Commonwealth (D.P.U. 2411, Exhs. NG-ESMP-1 (Corrected) at 15, 48, 62; NG-Policy/Solutions-1 (Corrected) at 31). The company provides service to approximately 1.3 million customer accounts, including approximately 1.14 residential households and 126,250 C&I customers, in an aggregate area of approximately 4,625 square miles (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 15, 62; NG-Policy/Solutions-1 (Corrected) at 31). The company segments its distribution system into six planning sub-regions: (1) North Shore, with approximately 255,067 customers, peak electric demand of 1.1 GW, total DER of approximately 152.2 MW, and 77.5 MW of DER in queue;

16 The Companies each observe that much uncertainty exists at this time involving what electric demand will look like in 2050, given the range of potential economic, technological, market, and policy drivers at play (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 480; ES-Policy/Solutions-1, at 118; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 389, 391; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 194).

(2) South Shore, including Nantucket, with approximately 239,140 customers, peak electric demand of 938 MW, total DER of approximately 218.6 MW, and 255.4 MW of DER in queue; (3) Merrimack Valley, with approximately 263,871 customers, peak electric demand of 1.2 GW, total DER of approximately 266.6 MW, and 256.2 MW of DER in queue; (4) Southeast with approximately 231,799 customers, peak electric demand of 1.0 GW, total DER of approximately 425.6 MW, and 440.8 MW of DER in queue; (5) Central, with approximately 241,061 customers, peak electric demand of 943 MW, total DER of approximately 631.5 MW, and 542.6 MW of DER in queue; and (6) Western, with approximately 121,606 customers, peak electric demand of 418 MW, total DER of approximately 521.2 MW, and 431.2 MW of DER in queue (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 16-17, 75; NG-Policy/Solutions-1 (Corrected) at 61-62). Sub-regions are grouped based on geographic proximity and electric system characteristics, e.g., distribution design elements such as operating voltages and substations (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 16, 73; NG-Policy/Solutions-1 (Corrected) at 61). For distribution system planning and engineering, the company further divides its distribution system into 46 study areas based on electrical interdependencies (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 73-74).

The company identifies the following major assets on its distribution system: (1) 264 substations, which supplied approximately 4.9 GW of summer peak hour customer demand in 2023; (2) approximately 13,500 miles of overhead lines; (3) approximately 5,000 miles of underground lines; (4) approximately 720,000 utility poles;

(5) 1,318 distribution feeder circuits; and (6) 183,600 service transformers (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 9, 20, 62-63; NG-Policy/Solutions-1 (Corrected) at 32). The median headroom of company substations by sub-region ranges between eight and 19 MW: (1) 11.0 MW for North Shore; (2) 8.0 MW for South Shore; (3) 19 MW for Merrimack Valley; (4) 13 MW for Southeast; (5) 19 MW for Central; and (6) 10 MW for Western (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 17, 75).

National Grid identifies wide variations in load growth, system planning challenges, and needs at the sub-region level, with each sub-region having unique physical, economic, demographic, and historical characteristics (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 72-203; NG-Policy/Solutions-1 (Corrected) at 61). The company's territories include predominantly rural, suburban, and urban areas, with urban areas often relying on highly integrated networks to serve densely populated areas while rural areas predominantly use radial networks (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 75).

National Grid describes the characteristics of its six sub-regions as follows. First, the North Shore sub-region is primarily coastal and predominately urban with metropolitan core communities near Boston and other urban centers, including Beverly, Gloucester, Lynn, Peabody, and Salem (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 76, 122). These North Shore communities are at a high risk of coastal flooding with low DER penetration due to limited capacity or open space (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 76, 123, 445-446). The company's second sub-region, the South Shore sub-region, also includes coastal communities at high risk of coastal flooding but is predominately suburban with a few urban centers like Brockton and Quincy (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 76, 162-163, 445-446). The South Shore has a moderate level of DER penetration attributed to somewhat limited open space and limited network capacity (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 76, 163). The third sub-region, the Merrimack Valley sub-region, is predominantly suburban with a few urban centers, such as Lowell and Lawrence, and an average DER penetration attributed to limited open space and a comparatively robust distribution infrastructure (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 72-73, 76, 102). The fourth sub-region, the Southeast sub-region, is predominately suburban with urban centers in Milford, Attleboro, Fall River, and Somerset, but with some rural areas with radial networks (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 76, 144). This sub-region has high DER penetration attributed to the large amount of open space and comparatively robust distribution infrastructure (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 76, 144). Fifth, the Central sub-region is predominately suburban with the largest regional urban centers in the company's territory, including Worcester, but also with a substantial number of rural areas with radial networks (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 75, 77-78). The Central sub-region has the highest level of DER penetration attributed to the large amount of open space and comparatively robust distribution infrastructure as compared to western Massachusetts (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 75, 77-78). Finally, the Western sub-region is overwhelmingly rural and mountainous but with regional urban centers in North Adams and Northampton with high DER penetration attributed to the large amount of open space available and limited distribution capacity (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 73, 76, 182-183). The company notes that the network in the Western sub-region is constrained and requires significant investment to meet the expected load growth (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 183).

Across the six sub-regions, the company projects that by 2034 electric demand will increase from a baseline summer peak demand of 4.9 GW to 6.3 GW, after accounting for load reductions from EE, demand response, and solar, as well as load impacts from EVs, electric heating, and ESS, and that the peak will transition to winter by 2036 (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 13, 215). The company projects that new customer load will be the primary driver in an expected increase to the current baseline summer evening peak of 4.9 GW to a winter morning peak of 10.7 GW by 2050, more than doubling the existing peak demand (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 13, 20).

C. Unitil

Unitil is the primary electric distribution company for the towns of Lunenburg, Townsend, and Ashby, and the City of Fitchburg, and also provides individual service in Leominster, Shirley, and Westminster (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 5, 52; UN-Policy/Solutions-1, at 5). The company provides electric service to approximately 26,500 residential customers and approximately 4,000 C&I customers (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 5; UN-Policy/Solutions-1, at 5). The company's major electric distribution assets include: (1) 15 substations; (2) approximately 454 miles of overhead lines; (3) approximately 68 miles of underground lines; (4) approximately 19,100 utility poles; and (5) 6,500 service transformers (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 12). The company designs headroom into its electric system for unexpected customer loads to connect to the system in the short-term and identifies approximately 46,300 kilo-volt-amperes of available hosting capacity on its substations as of June 2023 (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 59; UN-Policy/Solutions-1, at 16). The company identifies total DER of approximately 71.6 MW, and 26.57 MW of DER in queue (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 57-58). The company projects that electric demand will increase by 2034 from a baseline summer peak of 105.3 MW to 118.5 MW, after accounting for EE load reductions, demand response, and distributed renewable generation (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 135). The company projects peak load to increase from the current baseline summer peak of 105.3 MW to a winter peak of 382.5 MW in 2050 (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 135, 193, 211-212).

D. Challenges Identified

The Companies explain that their system investments and operations change to reflect changing customer needs (D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 43; D.P.U. 24-11, Exh. NG-Policy/Solutions-1 (Corrected) at 44; D.P.U. 24-12, Exh. UN-Policy/Solutions-1, at 36). With these changing needs, the Companies identify multiple challenges for their service territories, including: (1) aging infrastructure leading to decreased reliability, safety risks, reduced capacity, and lower system efficiency; (2) voltage and power quality control issues due to bi-directional power flow needs from incorporation of solar and wind generation facilities on their distribution systems; (3) distribution infrastructure investments to ensure that more renewables can be safely and reliably connected in densely populated metropolitan regions where most electric loads are concentrated; (4) significant economic development resulting in increased step loads that requires a rapid buildout of infrastructure; (5) increasing load from electrifying heat and transportation and the pace of investments necessary to meet those loads; (6) accelerating timely adoption of customer clean energy technologies and coordinating the delivery of customer-driven programs related to EE, heat pumps, EVs, and demand response, with the system planning; (7) maintaining reliability and increasing resiliency in response to climate change; (8) siting and permitting delays impacting the electric system's ability to maintain pace with increased loads in support of the Commonwealth's climate goals; and (9) improving the flexibility of company network operations and maintenance ("O&M"), to permit the company to plan and operate a more complex network with direct utility management integrating DER facilities into the grid (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 70-74; ES-Policy/Solutions-1, at 44-45; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 66-68; NG-Policy/Solutions-1 (Corrected) at 44-46; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 47-48); UN-Policy/Solutions-1, at 36-39).

IV. FRAMEWORK FOR REVIEW

A. Introduction

In the Interlocutory Order on Scope at 14-16, 23, the Department explained that we would take a strategic plan approach and review the first ESMPs as long-term, strategic planning documents to determine whether and how each company's proposed planning solutions comport with the requirements established in Section 92B, support the Commonwealth's statewide GHG emissions limits and sublimits under G.L. c. 21N, and meet the requirements of G.L. c. 25, § 1A. The Department explained that we would establish the relevant standard of review to apply to the instant ESMPs and future ESMP filings, as well as investigate the forecast methods and net benefits proposals, the appropriate cost recovery framework for proposed ESMP investments, and, in the context of strategic plan documents only: (1) the costs and benefits of the Companies' proposed planning solutions; (2) investment proposals; (3) alternative approaches to financing, specifically, proposed and future capital investment projects ("CIPs"), including cost allocation arrangements and the potential benefits of those arrangements; and (4) rate design matters, including whether and how the Companies considered the potential changes in rate design in their ESMP forecasting and analyses, as well as whether and how such considerations on this issue should be addressed and/or incorporated into future ESMP filings. Interlocutory Order on Scope at 2, 15-16, 18, 19-20, 22, 23. The Department also explained that, as strategic plans, we would not otherwise adjudicate: (1) the Companies' budget pre-approval requests, including for newly proposed CIPs; (2) cost allocation proposals; or (3) rate design or rate redesign proposals. Interlocutory Order on Scope at 23.

Generally, the parties differ in their interpretation on the purpose of the plans in relation to electric distribution system planning. In this Section, the Department establishes the overarching framework for review of the ESMPs as strategic plans within the purview of Section 92B, An Act Driving Clean Energy and Offshore Wind, St. 2022, c. 179 ("2022

Clean Energy Act"), and other statutory provisions and addresses in further detail the strategic plan framework for this and future plan filings.[17]

B. Positions of the Parties

1. Attorney General

The Attorney General argues that the purpose of a strategic planning document is to establish an overarching direction for the development of the distribution grid (Attorney General Brief at 15, citing Exh. AG-BG-1, at 26). The Attorney General finds problematic the Companies' distinction between "core" and "incremental" ESMP investments and argues that the Companies exhibit inconsistent approaches in classifying those investments (Attorney General Brief at 42-44, 47, citing Exh. AG-BF-1, at 39-40; D.P.U. 24-10, Exhs. AG 2-5 & Att.; D.P.U. 24-11, Exh. NG-ESMP-1, at 373-374; Attorney General Reply Brief at 15 (citations omitted)). The Attorney General contends that the Companies have designated ESMP investments not based on fundamental differences in investment type but based on differences in how they propose to recover the costs associated with the investment (i.e., a rate case versus an ESMP proceeding) (Attorney General Brief at 44, citing Exh. AG-BF-1, at 40; Attorney General Reply Brief at 15, citing Tr. 4, at 501, 503-504). Additionally, the

[17] The Department addresses the Companies' forecasts in Section VI.C.; investment proposals in Section VII.C.4. and Section VII.F.4., respectively; net benefits (including analysis of the costs and benefits) in Section VII.I.4.; the cost recovery framework in Section VIII.D.; alternative to proposed investments in Section VII.D.4.; and alternative approaches to financing investments, including cost allocation arrangements and alternative funding sources in Section VII.F.4. and Section VII.G.3., respectively.

Attorney General disputes the Companies' omission of core investments from their net benefits analyses, contending that inclusion of such investments is required under Section 92B(b) (Attorney General Brief at 44, citing Exh. AG-BF-1, at 40).

The Attorney General contends that the ESMP statute requires the Companies to open their planning process to ongoing stakeholder collaboration designed to modernize distribution grid planning, grid operations, and market operations (Attorney General Brief at 9, 49). Specifically, the Attorney General asserts that the Companies should develop and file with the Department modernization roadmaps, including plans for modernizing grid planning, grid operations, and market operations (Attorney General Brief at 49, citing Exh. AG-NBC-1, at 10). The Attorney General maintains that development of such a publicly accessible roadmap will allow the Companies, GMAC, and other stakeholders to iterate on the roadmap over time and allow the Department to monitor each company's progress (Attorney General Brief at 49-50, citing Exh. AG-NBC-1, at 10). Further, the Attorney General states that the ESMP proceedings offer an opportunity for the Department to consolidate, streamline, and provide direction to the various stakeholder groups and processes related to grid modernization (Attorney General Brief at 50).

2. DOER

DOER shares the Attorney General's concerns regarding the misalignment of core and incremental ESMP investments and different investment categorizations and argues that the ESMPs should focus on all modernization efforts regardless of where costs are recovered (DOER Brief at 18, 39, citing Exh. AG-BF-1, at 48). According to DOER, the Companies' treatment of ESMP investments as separate and distinct from core investments is misaligned with the Department's strategic plan review of the ESMPs, because many of the proposed investments support and align with the Companies' core utility business functions and public service obligations of serving customers and ensuring safe and reliable service (DOER Brief at 58-59, citing Interlocutory Order on Scope at 14; DOER Reply Brief at 17). DOER maintains that, historically, when economic growth or new technologies led to periods of growing electric load, electric utilities were expected to invest in, and justify, new infrastructure necessary to support a reliable system as part of their core business (DOER Brief at 59). DOER states that this requirement remains true today, even if the load growth in the coming decades will be driven by policies to encourage electrification and DERs (DOER Brief at 59). DOER contends that the Companies' cost recovery mechanism proposals for ESMP investments cast doubt on their commitment to consider ESMP investments as an integral part of their ongoing, routine investment and operational plans (DOER Brief at 60).

DOER equates the strategic plan approach with the GMAC's recommendation to establish the ESMPs as the central distribution system planning document that describes and connects all filings in which the Companies have received or requested cost recovery (DOER Brief at 14, 15, 16, 18, citing GMAC Report at 13). DOER asserts that the ESMPs offer a novel opportunity to present "whole-of-business" planning to meet the Commonwealth's climate policy objectives and to move away from the silos under which electric grid planning has historically operated (DOER Brief at 16, citing GMAC Report at 6, 16). Like other stakeholders including GECA, DOER is concerned with the burden on stakeholders to follow and participate in the various grid modernization dockets "if important pieces are scattered about," a situation that, according to DOER, is at odds with the Department's efforts to expand outreach and participation (DOER Brief at 34-35, citing D.P.U. 24-10/D.P.U. 24-11, Exh. GECA-LC-1, at 8). DOER contends that the ESMPs can and should serve as a clear summary of ongoing processes, highlighting timelines for each and linking grid investments and grid modernization activities to clearly demonstrate how the Companies are planning for and progressing a grid that can support the Commonwealth's decarbonization goals (DOER Brief at 35).

DOER avers that requiring that the ESMPs be central distribution system planning documents is consistent with the intention of the 2022 Climate Law which created the GMAC and the ESMP requirements (DOER Brief at 17). DOER disagrees with the Companies' position that the ESMPs should stay focused on proposing new investments to meet the goals of the Climate Law, and argues that this approach conflicts with the 2022 Climate Law as well as the strategic plan approach (DOER Brief at 17, citing D.P.U. 24-10, Exh. ES-Policy/Solutions-2; D.P.U. 24-11, Exh. NG-Policy/Solutions-2; D.P.U. 24-12, Exh. UN-Policy/Solutions-2). Further, DOER contends that the ESMPs require not only specific investments to meet electrification needs, but also must include a number of alternatives as well as information about investments and alternatives that the Department has reviewed, approved or is considering, which is consistent with a strategic plan review (DOER Brief at 18, citing G.L. c. 164, § 92B(a) and (c)(ii)).

DOER recommends that the Department maintain the strategic plan approach for future ESMP cycles (DOER Brief at 12, 14, 15, citing Interlocutory Order on Scope at 13-14). According to DOER, retention of the strategic plan approach for future ESMPs would appropriately focus the emphasis on the goal of Section 92B(a), i.e., strategically updating the distribution system in a manner that allows the Commonwealth to realize its climate goals (DOER Brief at 18). DOER contends that such an approach is consistent with the Department's approach in the grid modernization proceedings where:

> the Companies' strategic plans were each company's roadmap outlining how the company intended to achieve the Department's grid modernization objectives, covering all grid modernization planning and investments, not only investments that were incremental or eligible for short-term targeted cost recovery through a reconciling mechanism.

(DOER Brief at 58, citing Interlocutory Order on Scope at 14-15).

3. Acadia Center, CLF, and GECA

Acadia Center, CLF, and GECA ("Joint Intervenors") urge the Department to take a holistic approach to the ESMP dockets by providing a comprehensive forum for strategic planning, integrated gas-electric planning, rate design, and ratepayer protection, with an eye toward the Commonwealth's climate goals (Joint Intervenor Reply Brief at 7). The Joint Intervenors object to the Companies' omission of non-ESMP investments from the bill impacts and net benefits analyses, as well as the Companies' bifurcation and inconsistent treatment of ESMP versus non-ESMP investments (Acadia Center Brief at 15-16, 26; GECA

Brief at 2, 7-8; Joint Intervenor Reply Brief at 2-3).[18] The Joint Intervenors also support the position that future ESMPs should be centralized, whole-of-business strategic planning documents, consistent with the GMAC recommendation noted by DOER (Acadia Center Brief at 17; CLC Brief at 20-22; CLC Reply Brief at 4-5; GECA Brief at 2, 12-13).

GECA also argues that the Companies' plans inappropriately focus on incremental ESMP investments rather than all planned, proposed, and related investments that leaves the Department, the GMAC, and stakeholders to deal with an assortment of investments in multiple dockets (GECA Brief at 1, 7-13, citing D.P.U. 24-10/D.P.U. 24-11, Exh. GECA-LC-1, at 8). GECA maintains that the inability to analyze non-ESMP with ESMP investments precludes the Companies from optimizing investments across ESMP and non-ESMP investments (GECA Brief at 13, citing GMAC Consultant Comments at 73). GECA maintains that the Companies' identification of projects as core or incremental investments is, in many cases, arbitrary (GECA Brief at 8, 14, citing Exh. AG-BF-1, at 8; GMAC Consultant Comments at 5-8).

Noting the GMAC consultant's observation that total increased costs and resulting burdens may make it more difficult to support the electrification necessary to meet Massachusetts's decarbonization goals, GECA states that, for this reason, the Companies must fully justify both the proposed ESMP and non-ESMP investments (GECA Brief at 12, 15, citing GMAC Consultant Comments at 85). GECA maintains that, under

[18] CLF did not address these arguments in its initial brief.

Section 92B(c)(ii), the rate impacts analysis of Section 92B(a) requires the Companies to "consider and include a summary of all proposed and related investments, alternatives to these investments and alternative approaches to financing these investments that have been reviewed, are under consideration or have been approved by the department previously" (GECA Brief at 7). Finally, GECA contends that depiction of only those investments defined as incremental also disrupts the essential purpose of the ESMP as an "integrated and comprehensive approach to distribution and transmission system planning" (GECA Brief at 12, citing Interlocutory Order on Scope at 12-13). According to GECA, the Companies' incremental approach: (1) does not present an integrated, comprehensive review of electric sector modernization planning and requires the Department, the GMAC, and stakeholders to identify an assortment of investments in multiple dockets, which is highly burdensome for stakeholders; and (2) precludes the Companies from optimizing their investments across ESMP and non-ESMP categories of investments (GECA Brief at 13, citing D.P.U. 24-10/D.P.U. 24-11, Exh. GECA-LC-1, at 8; GMAC Consultant Comments at 73).

4. Cape Light Compact

CLC maintains that the Companies' narrow interpretation of the scope for the ESMP ignores the plain language of the 2022 Climate Act, the Department's Interlocutory Order on Scope, and places the burden on stakeholders (CLC Reply Brief at 4-5, citing Companies' Joint Brief at 98-99; Interlocutory Order on Scope at 12-14). CLC agrees with the GMAC recommendation that the ESMP should be a centralized, whole-of-business strategic planning document that outlines the plan for meeting 2050 climate goals and, consistent with the

Attorney General and DOER, CLC argues that NSTAR Electric's ESMP does not accomplish that recommendation (CLC Brief at 20, citing Exhs. DOER-2, at 9; AG-BF-1, at 14-15). CLC argues, therefore, that the Department should direct NSTAR Electric to develop the next ESMP as a centralized, whole-of-business strategic planning document (CLC Brief at 21).

CLC also argues that the ESMPs should account for all the company's efforts to meet the 2050 climate goals, including those spread across various regulatory proceedings, so that the true cost of meeting the 2050 climate goals can be evaluated (CLC Brief at 26). CLC agrees that electric grid planning has historically operated in silos and expresses frustration with the need to monitor multiple Department proceedings and working groups (CLC Reply Brief at 4, citing DOER Brief at 16). As such, CLC recommends the silos and numerous connected issues, e.g., grid modernization, EE, performance-based ratemaking mechanisms, EVs, and advanced metering infrastructure ("AMI"), come together in the ESMPs for the purposes of meeting the 2050 climate goals (CLC Reply Brief at 4). CLC also urges that the ESMPs should serve as a hub for the various working groups when coordination on issues is necessary (CLC Reply Brief at 6, citing Attorney General Brief at 50).

5. Companies

The Companies argue that, under the plain language of Section 92B, the ESMPs are not plans to meet their core obligations but, rather, five-year plans to accelerate and proactively improve the distribution system to achieve specific objectives outlined in the statute, in particular, to meet projected 2050 demand and enable the Commonwealth to meet its 2050 climate targets without diminishing safety and reliability (Companies' Joint Reply Brief at 30, 65). The Companies each interpret the Section 92B(a) directive to "proactively upgrade the distribution [system]," coupled with the requirements in Section 92B(e), as requiring a plan that proposes discrete, incremental investments on an accelerated basis to achieve the Section 92B objectives, rather than closer in time to when the distribution investment is needed (Companies' Joint Brief at 42, citing D.P.U. 24-10, Exhs. ES-ESMP-1; ES-Policy/Solutions-1; D.P.U. 24-11, Exhs. NG-ESMP-1; NG-Policy/Solutions-1 (Corrected); D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected); UN-Policy/Solutions-1; Companies' Reply Brief at 10, 23, 30, 32, citing D.P.U. 24-10, Exh. DOER-Common 1-3; D.P.U. 24-11, Exh. DOER-Common 1-3; D.P.U. 24-12, Exh. DOER-Common 1-3 (additional citations omitted)). According to the Companies, a business-as-usual strategy would not achieve the same level of enablement on the timeline contemplated by Section 92B and would result in delayed customer adoption of clean energy technologies, e.g., installation of EV charging in certain regions (Companies' Joint Brief at 45, citing D.P.U. 24-10, Exh. DPU-Common 9-4; D.P.U. 24-11, Exh. DPU-Common 9-4; D.P.U. 24-12, Exh. DPU-Common 9-4).

The Companies state that, without the ESMPs, they would limit investments to those required to meet load growth driven by known customer needs for electricity in the near term as identified and incorporated into each company's normal planning processes which are based on observed data and shorter-term forecasts and not directly tied to the Commonwealth's vision of an electric power system capable of serving potential new load driven by long-term policy objectives (Companies' Joint Brief at 45, citing D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 146; D.P.U. 24-11, Exh. NG-Policy/Solutions-1 (Corrected) at 120; D.P.U. 24-12, Exh. UN-Policy/Solutions-1, at 93). In contrast, for proposed ESMP investments, the Companies state that they each assessed the capabilities of existing and planned infrastructure to identify the capacity potential of their respective systems, and, comparing that potential with forecast and demand assessments, identified the potential gaps between the planned capacity of the distribution system and the forecasted capacity for their systems if the Commonwealth meets its electrification and renewable energy generation goals by 2050 (Companies' Joint Brief at 44, citing D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 86-102; D.P.U. 24-11, Exh. NG-Policy/Solutions-1 (Corrected) at 58-68; D.P.U. 24-12, Exh. UN-Policy/Solutions-1, at 53-63).

The Companies contend that their proposed incremental investments are intended to supplement existing programs and core investments and are necessary to enable progress towards the Commonwealth's goals for electrification and DERs; they are not intended to meet a near term customer need or system safety and reliability need (Companies' Joint Brief at 43-45, citing D.P.U. 24-10, Exhs. ES-Policy/Solutions-1, at 131; DPU-Common 1-1; DPU-Common 1-2; DPU-Common 1-3; DPU-Common 9-1; DPU-Common 9-2; D.P.U. 24-11, Exhs. NG-Policy/Solutions-1 (Corrected) at 105; DPU-Common 1-1; DPU-Common 1-2; DPU-Common 1-3; DPU-Common 9-1; DPU-Common 9-2; D.P.U. 24-12, Exhs. UN-Policy/Solutions-1, at 81; DPU-Common 1-1; DPU-Common 1-2; DPU-Common 1-3; DPU-Common 9-1; DPU-Common 9-2). The Companies explain that the nature of core investments evolves based on a variety of customer and system needs and must remain responsive to emergent system performance and customer trends to a degree that is not consistent with the proactive nature of the proposed ESMP investments (Companies' Joint Brief at 45, 81). The Companies also explain that core investments: (1) are necessary to deliver on each company's public service obligations, which arise due to the company's franchise rights and include a duty to maintain safe and reliable service to all customers in its franchise area; (2) are not subject to review prior to deployment; and (3) should not be subject to a net benefit analysis, as it would be beyond the scope of Section 92B (Companies' Joint Brief at 43-44, 81, citing D.P.U. 24-10, Exhs. DPU-Common 1-2; DPU-Common 1-3; D.P.U. 24-11, Exhs. DPU-Common 1-2; DPU-Common 1-3; D.P.U. 24-12, Exhs. DPU-Common 1-2; DPU-Common 1-3).

The Companies argue that intervenors seek to inappropriately expand the scope of Section 92B by transforming a plan that proposes discrete investments into a comprehensive distribution company investment plan for all planned investments, including those previously approved by the Department (Companies' Joint Reply Brief at 6-7, 22, citing Attorney General Brief at 44; DOER Brief at 39; Acadia Center Brief at 26; GECA Brief at 3). The Companies assert that the intervenors conflate the requirements under Section 92B(b) with the elements in Section 92B(c) to be considered by the Companies when developing their plans (Companies' Joint Reply Brief at 6). For instance, according to the Companies, the intervenors assume that because Section 92B(c)(ii) requires the Companies to consider approved investments and investments under review in other proceedings in developing an

ESMP, the Department's review of the ESMP must also be a review of those investments (Companies' Joint Reply Brief at 6). The Companies state that the intent of the statute must be ascertained by reading it as a whole, and the intervenors' interpretation would result in an absurd reading of the statute and an attempt to shoehorn a stakeholder desire for a single review of all investments and impacts for their ease of review into a discrete proceeding under Section 92B (Companies' Joint Reply Brief at 6, citing State Tax Commission v. LaTouraine Coffee Company, 361 Mass. 773, 778 (1972); Hanlon v. Rollins, 286 Mass. 444, 447 (1934)).

Regarding intervenor arguments that the net benefits and bill impacts analyses should include estimates of non-ESMP investments, the Companies counter that the arguments are based on the false presumption that the ESMP is an overarching distribution planning document that encompasses all proposed investments and programs the Companies may implement over the next five years (Companies' Joint Reply Brief at 22-23, 33-34, citing Attorney General Brief at 44; DOER Brief at 39; Acadia Brief at 15-16, 26; CLC Brief at 24-27; CLF Brief at 16-17; GECA Brief at 7-11). For net benefits, the Companies maintain that the intervenors' interpretation of Section 92B would require the Department to ignore the plain language of Section 92B(a), (b), (c)(ii), and (d), and expand the scope of review to include non-statutory requirements (Companies' Joint Reply Brief at 24, citing Attorney General Brief at 44; DOER Brief at 12). Additionally, the Companies argue that the intervenors' proposed approach to net benefits would create significant regulatory uncertainty because: (1) if all planned distribution investments, including those previously approved by the Department, are included in an ESMP and subject to a net benefits analysis prior to implementation, then the Department's final Orders in many of proceedings, including grid modernization, AMI and EV programs, would effectively be rendered nonfinal; (2) the Companies would need to refrain from implementing previously approved programs and projects until approval of the ESMP; and (3) investments undertaken to fulfill the Companies' public service obligations would stall until they were approved as providing net benefits in an ESMP, jeopardizing the ability of the Companies to provide safe and reliable service to customers (Companies' Joint Reply Brief at 24-25). The Companies posit that nothing in Section 92B suggests that the Legislature intended to overturn existing approvals and fundamentally overturn the established regulatory framework for delivering safe and reliable service (Companies' Joint Reply Brief at 25).

The Companies maintain that each proposed ESMP exceeds core safety and reliability investment needs and includes a five-year strategic investment plan to proactively improve the electric distribution system for future electrification, renewable and DER integration, decarbonization-driven economic and environmental transitions, and customer empowerment, all at a pace faster than that of traditional system upgrades (Companies' Joint Brief at 1-2, 43, 45-46; Companies' Joint Reply Brief at 1). The Companies explain that while each ESMP sets forth specific proposed investment categories, anticipated budgets, and an explanation of the company's strategic approaches to implementing the plan, the specific investments are not finalized and the plan must be flexible to adapt to evolving circumstances and community input on final project designs (Companies' Joint Brief at 65). The

Companies state that once each ESMP is approved, they will begin developing projects for implementation, including siting of potential projects, at which time the likely benefits and burdens of the project can be assessed and addressed through engagement with the community hosting the project (Companies' Joint Brief at 65; Companies' Joint Reply Brief at 22, citing D.P.U. 24-10, Exh. DPU 4-2; D.P.U. 24-11, Exh. DPU 4-3; D.P.U. 24-12, Exh. DPU 3-4). The Companies do not anticipate a significant departure or overhaul in their overall ESMP and forecasts during the five-year term but may modify or reprioritize ESMP projects based on updated information, emerging needs, stakeholder input, as well as advances in technology and non-wire alternatives ("NWAs") (Companies' Joint Brief at 65, citing Tr. 6, at 857-859; D.P.U. 24-10, Exhs. DPU-Common 12-3; DPU-Common 12-4; D.P.U. 24-11, Exhs. DPU-Common 12-3; DPU-Common 12-4; D.P.U. 24-12, Exhs. DPU-Common 12-3; DPU-Common 12-4).

The Companies state that each ESMP includes comprehensive details on each company's "whole-of-business" strategic planning for context, but the statutory purpose of the ESMP is not to represent the entire distribution system planning scope (Companies' Joint Reply Brief at 5, citing D.P.U. 24-10, Exh. ES-Policy/Solutions-2, at 14; D.P.U. 24-11, Exh. NG-Policy/Solutions-2, at 14; D.P.U. 24-12, Exh. UN-Policy/Solutions-2, at 14). The Companies oppose intervenor requests to make the ESMP a "central planning document," countering that the intervenors advocate for an expansive and ultra vires ESMP scope, i.e., "a kitchen-sink proceeding to address every possible issue from a stakeholder" (Companies' Reply Brief at 56, 79). By way of example, the Companies point to intervenor arguments regarding integrated-energy planning deriving from Investigation into Role of Gas Local Distribution Companies as Commonwealth Achieves Target 2050 Climate Goals, D.P.U. 20-80-B (December 6, 2023), CLF's recommendations relating to new regulatory principles set forth in a separate petition for rulemaking filed by CLF, and CLC's requests for directives requiring NSTAR Electric to (1) work collaboratively with CLC on EE programs, (2) alter the operational parameters of existing company-owned ESS, and (3) report on double poles in the ESMP (Companies' Reply Brief at 79 (citations omitted)). The Companies insist it would be impossible for the Department to comprehensively investigate each and every capital investment, both core and proactive, necessary for the Companies to provide safe and reliable service and meet the Commonwealth's public policy goals in a single proceeding based on one, overall plan (Companies' Joint Reply Brief at 5).

The Companies also note that various Department filing requirements such as the annual reliability reports ("ARRs") require information about each company's broader distribution planning at timelines differing from the ESMPs (Companies' Joint Reply Brief at 5). The Companies maintain that the Department must rely on the Companies' reasonable business judgment with respect to the planning and design of the distribution system (Companies Joint Reply Brief at 5, citing Fitchburg Gas and Electric Light Company, 375 Mass. 571, at 584-585 (1978) ("Fitchburg"); New England Telephone & Telegraph Company v. Dep't of Public Utilities, 371 Mass. 67, 81-82 (1976); New England Telephone & Telegraph Company v. Dep't of Public Utilities, 327 Mass. 556, 560 (1951); Weld v. Gas and Electric Light Commissioners, 197 Mass. 556, 560 (1908); NSTAR Electric Company, D.P.U. 22-52 through D.P.U. 22-55, at 100 (June 4, 2024)).

C. Analysis and Findings

1. Overview

Although the parties generally agree that the Legislature intended for the ESMPs to serve a strategic planning function, they differ about the appropriate scope of the ESMPs, particularly whether they should encompass existing dockets and investment programs, and on how this strategic planning approach should be implemented. Several intervenors interpret Section 92B as requiring the ESMPs to serve as "central distribution system planning document[s]" that would consolidate existing system-planning and investment dockets and working groups into a single adjudicatory proceeding. Specifically, some intervenors argue that the ESMPs' net benefits and rate impacts analyses must include both non-ESMP investments (i.e., those proposed and pending review in other Department proceedings or otherwise already planned by the Companies) and incremental ESMP investments. The Companies counter that intervenors seek to inappropriately expand the scope of the role of ESMPs under Section 92B into a "kitchen sink proceeding." Further, the Companies argue that the ESMPs should serve as strategic investment plans that include flexible parameters to adapt to changing market and regulatory dynamics.

As cases of first impression, the Department must determine the Legislature's intent regarding the scope of investments to be presented in the ESMPs pursuant to Section 92B. In particular, the Department must resolve whether the scope of investments and Department review under Section 92B: (1) are limited to new, discrete investments proposed by the Companies, i.e., incremental or proposed ESMP investments; or (2) also includes "core" investments and investments previously approved by the Department. As discussed below, the Department finds that limiting its ESMP review to discrete investments proposed by the Companies pursuant to Section 92B(e) is most consistent with the Legislature's intent; however, proposed ESMP investments must be informed by the Companies' existing, planned and proposed investments.

2. Statutory Interpretation

a. Introduction

The purpose of the 2022 Clean Energy Act is to "authorize forthwith the advancement of offshore wind and clean energy in the [C]ommonwealth." This legislation is comprehensive, and comprehensive legislative enactments may leave gaps that require faithful interpretation by the agencies and courts charged with implementation. Memorial Drive Tenants Corp. v. Fire Chief of Cambridge, 424 Mass. 661, 663 (1997); Mailhor v. Travelers Ins. Co., 375 Mass. 342, 345 (1978); NSTAR Electric Company, D.P.U. 09-33, at 70-71 (2010) (citations omitted). In interpreting a statute, the Department first looks to the explicit language in the statute and must give effect to the statutory language "consistent with its plain meaning and in light of the aim of the Legislature unless to do so would achieve an illogical result." Interlocutory Order on Scope at 14, citing Olmstead v. Dep't of Telecommunications and Cable, 466 Mass. 582, 588 (2013) (additional citations omitted) ("Olmstead"); see also G.L. c. 4, § 6, cl. 3 (by statute, "[w]ords and phrases shall be construed according to the common and approved usage of the language" unless such words and phrases are technical in nature). The cannons of statutory construction provide that "[o]rdinarily, if the language of a statute is plain and unambiguous it is conclusive as to legislative intent." Sterilite Corp. v. Continental Casualty Co., 397 Mass. 837, 839 (1986). However, the intent of the Legislature in enacting a statutory provision must be ascertained not only by the ordinary and approved usage of the language, but also in connection with that statute's stated purpose and, if ambiguous, "from a view of the whole system of which it is but a part, and in the light of the common law and previous statutes." Sterilite Corp. v. Continental Casualty Co., 397 Mass. at 839; see also Alliance to Protect Nantucket Sound, Inc. v. Energy Facilities Siting Board, 457 Mass. 663, 673 (2010) ("We presume that the Legislature acts with full knowledge of existing law"); Commonwealth v. Welch, 444 Mass. 80, 85 (2005); Hanlon v. Rollins, 286 Mass. at 447; Bolter v. Comm'r of Corps. And Taxation, 319 Mass. 81, 84-85 (1946) (specifying that "[n]one of the words of a statute is to be regarded as superfluous" and each word "is to be given its ordinary meaning without overemphasizing its effect upon the other terms appearing in the statute, so that the enactment considered as a whole shall constitute a consistent and harmonious statutory provision capable of effectuating the presumed intention of the Legislature"); D.P.U. 09-33, at 70, citing Pereira v. New England LNG Company, 364 Mass. 109, at 115 (1973) (additional citations omitted).

b. G.L. c. 164, § 92B

We have carefully reviewed the operative statute, Section 92B, and we find clear legislative directives regarding the appropriate scope of the ESMPs. In subsections (a), (b), (c), and (e) of Section 92B, the Legislature outlined the requirements for draft ESMPs filed with the GMAC and to proposed ESMPs subsequently filed with the Department. While the Department must review the plans to ensure compliance with each subsection of Section 92B, it is Section 92B(d) that sets forth the parameters for Department approval, approval with modification, or rejection of an ESMP and that explicitly requires plans to provide net benefits to customers and to meet the criteria enumerated in Section 92B(a)(i) through (vi). Moreover, Section 92B(d) only requires a plan as a whole, rather than discrete investments, to meet each criterion enumerated in Section 92B(a)(i) through (vi).

Turning to the issue at hand, based on our review of Section 92B as a whole, the Department determines that subsection (c) of Section 92B is distinct from other subsections of Section 92B due to the Legislature's explicit language in this section. This distinction is germane to the determination of the scope of investments for the Department's Section 92B review. Specifically, in Section 92B(c), the Legislature utilized the language "[i]n developing a plan pursuant to [Section 92B(a)]" to direct each electric distribution company in Section 92B(c)(ii) "to consider and include a summary of all proposed and related investments, alternatives to these investments and alternative approaches to financing these investments that have been reviewed, are under consideration or have been approved by the [D]epartment previously . . . "

In contrast, the Legislature explicitly refers to an ESMP "developed pursuant to [Section 92B(a)]" in both Section 92(b) and Section 92(e). Section 92B(b) requires "[a]n [ESMP] developed pursuant to [Section 92B(a)]" to describe specific elements, including improvements to the electric distribution system to increase resiliency and reliability, the availability and suitability of new technologies, patterns and forecasts of DER adoption, opportunities to deploy energy storage technologies, and alternatives to proposed investments, among others. Similarly, Section 92B(e) requires that "[a]n [ESMP] developed by an electric [distribution] company pursuant to [Section 92B(a)] shall propose discrete, specific, enumerated investments to the distribution and, where applicable, transmission systems, alternatives to such investments and alternative approaches to financing such investments[.]" It is also the plan that has been *developed* pursuant to Section 92B(a) on which the GMAC must provide input and recommendations and to which the specific filing timelines apply. G.L. c. 164, §§ 92B(d), 92C(b). The Department finds that, in utilizing the language "[i]n developing a plan pursuant to [Section 92B(a)]" in subsection (c) rather than "in a plan developed pursuant to Section 92B(a)" in subsections (b) and (e), the Legislature identified a clear distinction between Section 92B(c) and the other ESMP-related statutory provisions. In other words, the items enumerated in Section 92B(c) identify the necessary considerations for plan development only.

Accordingly, based on the plain language in Sections 92B(c) and (e) (i.e., "[i]n developing a plan" versus "[a]n [ESMP] developed"), the Department interprets Section 92B(c) as the logical antecedent to other provisions within this statute. By its plain language, the Legislature outlines in Section 92B(c) the elements that must inform the development of the ESMP prior to submission of the finalized plan with the Department. As such, the Department declines to interpret the language in Section 92B(c) as expanding the scope of investments under review in these proceedings. The Department determines that pursuant to Section 92B(c), the electric distribution companies must consider their respective planned investments and those pending Department review in other proceedings in the development of new, discrete investment proposals to include in their ESMPs. Consistent with Section 92B(e), however, the Department's review and determination as to whether to approve or reject that plan is limited to the new, discrete, and incremental investments proposed in the ESMP, and which review will be informed by the company's planned non-ESMP investments.

Our determination that the scope of investment under review is limited to discrete investments proposals finds further support as follows. First, the express language of Sections 92B(a), (b), and (e) evince a clear Legislative intent for each company to submit a forward-looking plan that proposes "discrete, specific, enumerated investments" and "alternatives to such investments and alternative approaches to financing such investments" for implementation at an accelerated pace above and beyond the company's typical distribution system planning investments or those investments planned or proposed as a part of other existing mechanisms. These three subsections, repeatedly use terms, e.g., "improve/improvements" and "increase/increased", that indicate, in part, identification of specific investments to facilitate the clean energy transition over the long term and that are above and beyond other investments planned by the Companies to meet demand at a business-as-usual pace.

Second, the Department finds that the remaining language in Section 92B(c) also bolsters our determination of the scope of ESMP investments under review in these proceedings. For instance, pursuant to Sections 92B(c)(i) and (c)(iii), in developing its ESMP, an electric distribution company must: (1) prepare and use three planning horizons for electric demand, i.e., separate five- and ten-year forecasts and a demand assessment through 2050 to account for future trends; and (2) solicit input, such as planning scenarios and modeling, from the GMAC.[19] Preparation of the requisite forecasts and demand assessment, as well as input on planning scenarios and modeling, by necessity precede both a draft plan filed with the GMAC for input and a finalized plan submitted to the Department for review. As such, the entirety of Section 92B(c), including the requisite summary of investments in Section 92B(c)(ii), applies to the requisite considerations for developing the plan. We also note that this approach is consistent with the dynamic nature of typical distribution and transmission planning processes where the Companies rely, in part, on forecasts that are updated annually to plan and prioritize both near- and longer-term investments and to identify overall distribution system needs (Tr. 77-80, 85-87; Tr. 6, at 853-859; D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 76-78; DPU-Common 7-5(b);

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[19] Section 92B(c)(iii) also requires each company to respond to information and document requests from the GMAC, as well as conduct technical conferences and stakeholder meetings to inform the public and others. The Department addresses compliance with this provision in Section V.D. and Section VII.I.4.d., below.

D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 290-291, 416-417, DPU-Common 7-5(b); D.P.U. 24-10, Exhs. UN-ESMP-1 (Corrected) at 105-106, DPU-Common 7-5(b)).

Additionally, Section 92B(c)(ii) expressly limits the summary of investments to those "that have been reviewed, are under consideration or have been approved by the [D]epartment previously[.]" Thus, the Legislature unambiguously indicates that the summary of investments that must be considered and summarized as part of the development of an ESMP are investments proposed by the Companies outside the Section 92B framework. Such a summary prepared by each electric distribution company in developing an ESMP and provided to the GMAC and the Department, by logical extension, necessarily informs and provides context for the "discrete, specific, enumerated investments" that the company must propose with its ESMP pursuant to Section 92B(e). As such, it is clear that the Legislature intended the requirements of Section 92B(c) to inform the draft ESMPs filed with the GMAC and the ESMPs filed with the Department, the "proposed and related" investments to be included in the summary differ from the "discrete, specific, enumerated" ESMP investments proposed pursuant to Section 92B(e).

Further, on a separate but analogous reading of the statute, Section 92B(b) requires each ESMP to "describe in detail" multiple elements. Similar to the language in Section 92B(c)(ii) requiring a summary of non-ESMP investments considered to develop a plan (despite the fact that our review of the plan is limited to new, discrete investments), the descriptions required by Section 92B(b) may be broader than the proposed ESMP investments and may require, where appropriate, descriptions of not only how proposed ESMP investments meet particular elements, but also descriptions of whether and how the company incorporates these elements into its typical distribution system planning processes and practices. Similarly, like Section 92B(c) and the summary required therein, the statute does not refer to Section 92B(b) for Department approval of the plans. See G.L. c. 164, § 92B(d). Accordingly, like the summary required in Section 92B(c)(ii), the Department considers the descriptions provided in response to Section 92B(b)(i) through (ix) as informational only.

In contrast, the last sentence of Section 92B(b) provides that the electric distribution companies shall identify customer benefits for "all proposed investments and alternative approaches[.]" Thus, the logical interpretation of this sentence is that it only applies to any "discrete, specific, enumerated investments" proposed pursuant to Section 92B(e). As such, the net benefits requirement in Section 92B(d) only applies to the proposed ESMP investments.

Third, in addition to the explicit language of Section 92B, due process considerations and the requirements of the Massachusetts Administrative Procedure Act, Chapter 30A, as well as the safety, security, and reliability of the electric distribution system, require a narrow reading of Section 92B and the scope of investments for review as a strategic plan. There is also a need for finality in Department Orders to provide companies with certainty in the conduct of their business. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 21-60, at 8 (2021); Bay State Gas Company, D.P.U. 09-30, at 159 (2009); Fall River Gas Company, D.P.U. 89-199-A at 7 (1989); see also Boston

Consolidated Gas Company v. Dep't of Public Utilities, 321 Mass. 259, 265 (1947). If the Department were to include a company's full suite of planned and proposed investments during the ESMP term into our Section 92B analyses, in addition to discrete ESMP investments, then such a practice (1) would disrupt or undermine the adjudicatory process of matters pending or already decided by the Department in other proceedings relating to these investments, and (2) would negatively impact distribution system planning practices generally (see D.P.U. 24-10, Exh. DPU-Common 11-20; D.P.U. 24-11, Exh. DPU-Common 11-20; D.P.U. 24-12, Exh. DPU-Common 11-20). The Department finds both outcomes illogical. The Legislature expressed no intent to halt planned electric distribution company investments already reviewed or approved by the Department, or to override pending Department adjudications. Thus, as part of our review in determining whether to approve, approve with modification, or to reject an ESMP, the Department will not revisit a company's distribution system investments planned in response to final Department decisions, including but not limited to EV, AMI, solar, and second term grid modernization investments. The Department will also not require or incorporate into our Section 92B review for approval of any proposals pending in other proceedings, such as CIPs or utility-owned solar.[20]

Fourth, forecasting and distribution system planning as noted above are dynamic processes, and the Legislature in Section 92B(d) specifically limits the filing of ESMPs and any corresponding GMAC review, input, and recommendations to once every five years.

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20 To be clear, the Department intends to move forward in these and other proceedings, such as those that touch upon rate design, during the ESMP term.

Such a filing is effectively a snapshot in time of planned and proposed investments informed by then-existing forecasts to address more immediate system needs and the longer term GHG emission reduction objectives of Section 92B (Tr. 80, 85-86; Tr. 6, at 853-859). The Department finds nothing in Section 92B, Section 92C, or elsewhere in the 2022 Clean Energy Act that would override typical electric distribution system planning or the provisioning of safe and reliable electric service, nor limit such planning to a filing once every five years or for the Companies to await guidance from the GMAC. Accordingly, the Department finds that the Legislature did not intend to limit distribution system planning, generally, and the provision of safe, secure, and reliable electric service to a Section 92B review of investments once every five years by either the Department or the GMAC.

Several intervenors urge the Department to treat the ESMPs as central distribution system planning documents (DOER Brief at 16-18; Acadia Center Brief at 17; CLC Brief at 20-22; CLC Reply Brief at 4-5; GECA Brief at 2, 12-13). As discussed above, we find that requiring the Companies to implement this approach would add requirements that the 2022 Climate Law does not envision. As a result, the Department declines to broaden the scope of Section 92B as suggested.

Notwithstanding, the Department acknowledges intervenors' frustration regarding the need to monitor and attempt to influence multiple Department proceedings that touch upon distribution system planning (see DOER Brief at 34-35; CLC Brief at 20-22, 26; CLC Reply Brief at 4; GECA Brief at 12-13). Consolidating proceedings on distribution system planning and related matters would be less efficient than it appears and would impose substantial administrative burdens. For purposes of transparency and to facilitate greater understanding of distribution system planning, however, and to inform anticipated reporting on ESMP-specific investments, the Department sees value in the Companies reporting high-level, informational-only data in the ESMP reports relating to non-ESMP investments, including summary lists of, for example, relevant Department proceedings, docketed and non-docketed filings,[21] and related key metrics. The Department further explains this requirement in Section XI.D.3., below.

In sum, based on the above analysis, the Department determines that the express language of Section 92B evinces a clear Legislative intent for each company to submit a forward-looking plan that proposes "discrete, specific, enumerated investments" and "alternatives to such investments and alternative approaches to financing such investments" for implementation at an accelerated pace above and beyond the company's typical distribution system planning investments or those investments planned or already proposed as a part of existing mechanisms in other proceedings. Further, the Department concludes that this determination of the scope of investments for review is consistent with the purpose of the 2022 Clean Energy Act and other existing statutory and regulatory requirements. Finally, the

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[21] Not all Department proceedings and company filings involving distribution system planning and investments are adjudicated matters. Informational-only filings from the Companies include ARRs, grid modernization plan annual reports, and annual returns. For administrative purposes, the Department assigns docket numbers to the ARRs and grid modernization annual reports each year. The Department, however, does not docket annual return filings, although annual returns are accessible through our website.

Department declines to make the ESMPs each company's central distribution system planning document.

c. G.L. c. 25, § 1A

Notwithstanding the above, the Department finds it necessary to clarify requirements applicable to the Companies in the context of G.L. c. 25, § 1A. The statute requires the Department, with respect to itself and the entities it regulates, e.g., the Companies, to prioritize safety, security, reliability of service, affordability, equity, and reductions in GHG emissions to meet statewide GHG emission limits and sublimits established pursuant to G.L. c. 21N. G.L. c. 25, § 1A.[22] The Department addresses these priorities on a case-by-case basis as relevant to each proceeding. 2022-2024 Three-Year Energy Efficiency Plans, D.P.U. 21-120 through D.P.U. 21-129, at 13-14 (2022) ("2022-2024 Three-Year EE Plans"); Massachusetts Municipal Wholesale Electric Company, D.P.U. 21-29, at 31 n.15 (2021); Boston Gas Company, D.P.U. 21-GC-10, at 3-4 (2021). Four of the priorities listed, namely, safety, security, reliability of service, and affordability, represent the Companies' longstanding public service obligations and the central tenets for over a century by which the Department has overseen the utilities it regulates. Fitchburg Gas and Electric Light Company, D.P.U. 09-01-A at 6-8 & n.14 (2009) (citations omitted). Since the enactment of the Global Warming Solutions Act ("GWSA") in 2008, the Department has recognized GHG

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[22] The Companies incorporate equity and GHG emissions reductions considerations into their distribution system planning practices (D.P.U. 24-10, Exhs. DPU-Common 1-2; DPU-Common 1-3; D.P.U. 24-11, Exhs. DPU-Common 1-2; DPU-Common 1-3; D.P.U. 24-12, Exhs. DPU-Common 1-2; DPU-Common 1-3).

emissions reductions to be an important public policy goal of the Commonwealth. See, e.g., Fitchburg Gas and Electric Light Company, D.P.U. 23-80/D.P.U. 23-81, at 31-32 (June 28, 2024); Second Grid Modernization Plans, D.P.U. 21-80/D.P.U. 21-81/D.P.U. 21-82, at 192-193 (2022) ("Second Grid Modernization Plans (Track 2)"); NSTAR Electric Company, D.P.U. 22-22, at 48-49 (2022); D.P.U. 20-80-B at 4; Modernization of the Electric Grid, D.P.U. 12-76-B at 8-9 (2014); Electric Vehicles, D.P.U. 13-182, at 2-3 (2013); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 10-54, at 179-180 (2010).[23] The Commonwealth's public policy goals also include equity considerations, and the Department expects our understanding of how to advance equity as an objective in the oversight of regulated utilities to evolve over time. D.P.U. 22-22, at 124.[24]

Equity and GHG emissions reductions remain important public policy goals of the Commonwealth and with the enactment of G.L. c. 25, § 1A, are also part of the

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23 The GWSA, as amended by An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, St. 2021, c. 8 ("2021 Climate Act") and implemented by the Secretary of Executive Office of Environmental Affairs ("EEA"), requires the Commonwealth to reduce GHG emissions by certain levels by 2050. G.L. c. 21N § 4; EEA Determination of Statewide Emissions Limit for 2050 (April 22, 2020) (setting a legally binding statewide limit of net-zero GHG emissions by 2050, defined as 85 percent below 1990 levels).

24 The Department's consideration of equity in ratemaking precedes the 2021 Climate Act. See Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50, at 10-11 (2007).

Department's priorities.[25] However, just as the Department addresses these priorities on a case-by-case basis, the Department generally applies the same principles to each company. With regard to distribution system planning, where the priorities may not align, the goal is to find the appropriate balance.

In these proceedings, the Companies characterize base spending capital investment activities as core investments, i.e., planned investments funded through base distribution rates to maintain the safety and reliability of the electric distribution system in the normal course of business (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 8-9, 433; ES-Policy/Solutions-1, at 19, 137; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 21, 255; NG-Policy/Solutions-1 (Corrected) at 14-15, 56; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 160; UN-Policy/Solutions-1, at 10, 13, 50). In contrast, the Companies identify proposed ESMP investments as accelerated, incremental investments that supplement and go beyond existing programs and core investments, and which the Companies deem necessary over the next five years to enable progress towards the Commonwealth's clean energy and decarbonization goals through electrification and DERs (D.P.U. 24-10, Exhs. ES-Policy/Solutions-1, at 100, 131-132; DPU-Common 1-3; DPU-Common 9-1; DPU-Common 9-2; D.P.U. 24-11, Exhs. NG-Policy/Solutions-1 (Corrected) at 14-15, 105-106; DPU-Common 1-1; DPU-Common 1-2; DPU-Common 1-3; DPU-Common 9-1;

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25 The Department notes that these priorities and obligations are vested with the Department and the Companies, not the GMAC, which has an advisory role. See Section V.D., below.

DPU-Common 9-2; D.P.U. 24-12, Exhs. UN-Policy/Solutions-1, at 9-10, 81-82; DPU-Common 1-1; DPU-Common 1-2; DPU-Common 1-3; DPU-Common 9-1; DPU-Common 9-2). The Department finds this distinction to be reasonable and appropriate, since the provisioning of safe, secure, and reliable service remain core functions of the electric distribution system. See, e.g., An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protection Therein, St. 1997, c. 164, § 1(h) ("reliable electric service is of utmost importance to the safety, health, and wealth of the [C]ommonwealth's citizens and economy"); Boston Gas Company, D.P.U. 20-120, at 363 n.176 (2021) ("[a] utility company's obligation to fulfill safety requirements is absolute") (citations omitted). In this context, the requirements of G.L. c. 25, § 1A, represent baseline requirements within each company's distribution system planning and generally apply to the requirements identified in G.L. c. 164, inclusive of Section 92B.

In sum, the Department once again notes the fundamental evolution taking place in the way electricity is produced and consumed in Massachusetts. See, e.g., Second Grid Modernization Plans (Track 2) at 193; D.P.U. 20-120, at 66. This evolution involves a clean energy transition that has been driven, in large part, by a number of legislative and administrative policy initiatives designed to address climate change and foster a clean energy economy since the GWSA was first enacted. See, e.g., 2022 Clean Energy Act; An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, St. 2021, c. 8 ("2021 Climate Act"); An Act to Advance Clean Energy, St. 2018, c. 227; An Act to

Promote Energy Diversity, St. 2016, c. 188; An Act Relative to Competitively Priced Electricity in the Commonwealth, St. 2012, c. 209; An Act Relative To Green Communities, St. 2008, c. 169; Executive Office of Environmental Affairs ("EEA"), Clean Energy and Climate Plan for 2050 (December 2022) ("2050 CECP"); EEA, Energy Pathways to Deep Decarbonization: A Technical Report of the 2050 Decarbonization Roadmap Study (December 2020) ("2050 Decarbonization Roadmap"); EEA, Massachusetts Clean Energy and Climate Plan for 2025 and 2030 at xi (June 30, 2022) ("2025/2030 CECP").[26] To varying degrees, this evolution has been changing the operating environment for electric distribution companies in Massachusetts, and advances in technology are further driving fundamental changes in how power is generated, distributed, and consumed. Second Grid Modernization Plans (Track 2) at 193; D.P.U. 22-22, at 49. In the midst of this transition, as electrification efforts expand, ensuring affordability and equity, including the equitable distribution of the extensive benefits to be derived from a clean energy economy, is of particular importance to avoid overburdening customers financially, particularly those who already bear higher burdens in terms of not only costs but also other cumulative impacts. Energy Burden, D.P.U. 24-15, Vote and Order Opening Inquiry at 2 (January 4, 2024);

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26 EEA prepares a CECP every five years, beginning in 2010. The CECP sets forth a policy/roadmap for the Commonwealth to meet the GHG emissions limits by 2050. The Interim 2030 CECP developed by EEA was released in December 2020. The final CECP for 2025 and 2030 was released in June 2022 and can be found at https://www.mass.gov/doc/clean-energy-and-climate-plan-for-2025-and-2030/download (last visited August 29, 2024).

D.P.U. 20-80-B at 116; Cape Light Compact JPE, D.P.U. 22-137, at 43-44 (2023); 2022-2024 Three-Year EE Plans at 17; 2025/2030 CECP at 61.

d. Conclusion

Accordingly, it is within the above framework and context that the Department will review each company's ESMP filing and investments proposed therein to determine compliance with Section 92B and, ultimately, whether to approve, approve with modifications, or reject the plan. The Department finds appropriate and reasonable the exclusion of non-ESMP investments from our Section 92B and net benefits analyses. Other than the summary required pursuant to Section 92B(c)(ii), the Department will not otherwise evaluate or consider the Companies' planned distribution system investments or those investments proposed in other proceedings.

3. Strategic Plan Approach

In the Interlocutory Order on Scope at 14-16, the Department explained that we would review the first ESMPs as long-term strategic planning documents to determine whether and how each company's proposed planning solutions comport with the requirements outlined in Section 92B and G.L. c. 25, § 1A, and support the Commonwealth's statewide GHG emissions limits and sublimits under G.L. c. 21N. The strategic plan approach utilized in the current ESMP proceedings is guided by the approach utilized by the Department in the grid modernization proceedings. Interlocutory Order on Scope at 14-15. In those proceedings, the Companies' strategic plans were each company's roadmap outlining how the company intended to achieve the Department's grid modernization objectives, including the interconnection and integration of DERs,[27] for all grid modernization investments, not only investments that were incremental or eligible for short-term targeted cost recovery through a reconciling mechanism. Interlocutory Order on Scope at 15, citing Second Grid Modernization Plans (Track 2) at 136, 199; Grid Modernization – Phase II, D.P.U. 20-69-A at 28-29 (2021); First Grid Modernization Plans, D.P.U. 15-120/D.P.U. 15-121/ D.P.U. 15-122, at 99-107 (2018) ("Grid Modernization Order"); D.P.U. 12-76-B at 15; D.P.U. 12-76-A at 16 (2013).[28] The parties generally agree with a strategic plan approach, and the Companies urge that the ESMPs remain strategic investment plans with a measure of flexibility.

With the enactment of the 2022 Clean Energy Act, including Section 92B, the Department made clear that the legislation established a new regulatory construct for electric sector grid modernization and long-term electric system planning aimed, in part, at enabling DER development to increase timely adoption of renewable energy and DERs and that incorporated, among other things, considerations for transportation electrification.

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[27] Noting the increasing adoption of DERs at the time, and in support of the objective to interconnect and integrate DERs, the Department recognized that integrating DER into system planning and operations processes could enhance the reliability of electric service in the face of increasingly extreme weather but would require the electric distribution companies to adopt a system planning process that included input from third parties. Grid Modernization Order at 4, 103-104; D.P.U. 12-76-B at 7-8.

[28] The strategic plans in those proceedings were part of a broader regulatory construct first established by the Department in 2014, deriving from substantial stakeholder input and vision of a modern grid that included support for emerging technologies such as EVs, energy storage, and other innovations. D.P.U. 12-76-B at 28; D.P.U. 12-76, at 3-4 (2012); see also D.P.U. 13-182, at 1.

Interlocutory Order on Scope at 12-13; Electric Vehicles, D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, at 157, 201 (2022) ("Electric Vehicles 2022 Order"); Second Grid Modernization Order (Track 2) at 332; Distributed Energy Resource Planning and Cost Assignment, D.P.U. 20-75-C at 2-3 (2022). The Department determined that the new regulatory construct superseded the Department's grid modernization regulatory construct established in D.P.U. 12-76-B, as subsequently modified. Second Grid Modernization Plans (Track 2) at 332, 336. Accordingly, in consideration of the above, in establishing a strategic plan approach guided by the grid modernization proceedings, the Department expects the ESMPs to be each electric distribution company's roadmap outlining how the discrete investments proposed pursuant to Section 92B(e) will achieve the statutory objectives outlined in Section 92B(a).

Additionally, the Department has recognized that a comprehensive planning process that prioritizes distribution projects for construction may look forward five or more years, and that a measure of flexibility for both typical and grid modernization planning is necessary, especially for newer technologies and in response to evolving conditions. See, e.g., Grid Modernization Order at 107 ("it is important to provide the Companies with a certain level of flexibility to deviate from their projections to respond to changes that inevitably will take place over the term of the plan" and "[i]n the early stages of grid modernization, it is reasonable to expect that significant changes will take place associated with, among the things, the introduction of new technologies and the costs of new and existing technologies"); Notice of Inquiry and Rulemaking, D.T.E. 98-84, at 12 (2003) ("[t]he distribution planning process should be fluid enough so that individual distribution company analyses may be revised on an annual basis based on good engineering practices" and "a distribution planning process should identify the need for new resources or system reinforcements several years in advance to allow for the changes in conditions that may reveal different solutions"). The Companies identify a similar need for flexibility and the ability to reprioritize projects identified within their plans, as needed, to adapt to emerging and dynamic trends in policy, technology, and public movement towards the clean energy transition, system needs, adjustments arising from changes in annual forecasts, and public input on distribution infrastructure projects like substations (Tr. 6, at 853-859; D.P.U. 24-10, Exh. DPU-Common 12-3, at 2-3; D.P.U. 24-11, Exh. DPU-Common 12-3, at 2; D.P.U. 24-12, Exh. DPU-Common 12-3, at 2). The Department finds that flexibility in implementation of investments identified in a strategic ESMP plan is appropriate and necessary and best accounted for in the two reports to be submitted annually pursuant to Section 92B(e).[29]

This flexibility is distinct from the flexibility afforded by the Department to the Companies in grid modernization, however. In particular, the flexibility in those proceedings was tied more closely to the implementation of preauthorized investments identified in each company's short-term investment plan for purposes of cost recovery outside of base distribution rates, although, these short-term investment plans were generally the initial years

29 The Department addresses reporting requirements in Section XI.D.4.

of the longer-term strategic plans. Thus, the two plans (short-term and strategic) and the flexibility afforded were inextricably linked.

In contrast, in the current proceedings, as strategic plans, the Department is not pre-approving or preauthorizing any proposed ESMP investments or related costs identified by the Companies. See Interlocutory Order on Scope at 17-19, 23. Rather, Department approval of an ESMP is simply a finding that the plan has met the requirements of Section 92B, and approval with modification would involve, for instance, directing a company to revise its ESMP to ensure consistency with Section 92B.[30] The appropriateness of cost recovery outside of base distribution rates for particular investments identified in the ESMPs will be resolved in accordance with the guidance provided by the Department in Section VII.F.4. and Section VIII.D. Because the proposed ESMP investments derive from forecasts already more than a year and a half old as of the date of this Order and market conditions continue to evolve, the flexibility associated with the ESMPs as strategic plans during this term will involve, in part, the ability for the companies to refine, update, and/or reprioritize these investments for Department review for cost recovery and prudency at a later date, as appropriate. These changes shall be accounted for in the ESMP biannual reports.

30 For grid modernization, the Department similarly instructed that we would review each company's five-year strategic plan to ensure that it was consistent with the Department's grid modernization objectives and, if not, we would direct the company to revise its strategic plan accordingly. D.P.U. 20-69-A at 28-29; D.P.U. 12-76-A at 16.

As the Companies observe, however, there are distinct differences between the strategic plan approach in grid modernization and the approach to be taken for the ESMPs, primarily involving the inclusion of budgets, i.e., identification of estimated costs, and a net benefits analysis (Companies' Reply Brief at 22 n.14). In grid modernization, the estimated costs and net benefits analysis were provided with a company's shorter-term investment plan as a prerequisite to determine whether preauthorization for purposes of cost recovery was appropriate and to set a budget for cost recovery outside of base distribution rates. See, e.g., Second Grid Modernization Plans (Track 1) at 58-59 (2022); Grid Modernization Order at 106-110, 113-116, 137-138, 149-173, 205, 224-235.[31] For the ESMPs, a demonstration of net customer benefits, which by necessity includes incorporation of both estimated costs and benefits, is required for Department approval of a plan. Section 92B(d). In this Order, the Department reviews the associated costs, benefits, and investment proposals and, thus, the corresponding net benefits analysis, provided for each ESMP in the context of a strategic plan only and not for purposes of pre-approval or preauthorization relating to cost recovery. Interlocutory Order on Scope at 2, 18, 23.

Finally, the Department explained in the Interlocutory Order on Scope at 16, that we would determine whether a strategic plan approach is appropriate for future plan filings. After further consideration and consistent with the rationale above for the current ESMPs, the

[31] Costs incurred above the estimated budgets were otherwise eligible for recovery through base distribution rates, subject to a prudency review. See, e.g., Second Grid Modernization Plans (Track 2) at 161-162, 175-176, 190-191, 237, 257-258, 277.

Department finds that such an approach is appropriate for future ESMP filings. We note again that the Commonwealth is in the midst of a major transformation of the energy industry, both gas and electric, and the 2025 through 2030 term is a part of the initial stage of that transformation since enactment of the 2022 Clean Energy Act. Review of at least one more set of ESMP filings as strategic plans will provide the Department with the opportunity to collect annual data to inform those future filings as well as to resolve other proceedings and issues that impact distribution system planning. After the next ESMP filings, the Department may revisit this approach for those ESMP filings that follow.

V. GRID MODERNIZATION ADVISORY COUNCIL

A. Introduction

In developing their ESMPs, the Companies must solicit the GMAC's input, respond to the GMAC's information and document requests, conduct technical conferences, and hold at least two stakeholder meetings to inform the public, appropriate state and federal agencies, and companies that develop and install distributed generation, energy storage, vehicle electrification systems, and building electrification systems. G.L. c. 164, § 92B(c)(iii). Additionally, for these inaugural ESMPs, Section 92B(d) required the Companies to submit their draft ESMPs to the GMAC by September 1, 2023 and the GMAC to return those plans to the Companies with the GMAC's recommendations no later than 70 days before the Companies must file the ESMPs with the Department. In total, Section 92B(d) required the GMAC to complete its review and make recommendations on the plans within 80 days. In turn, the Companies must demonstrate in their plans submitted to the Department that they considered the GMAC's recommendations by including a list of each individual recommendation, the status of each recommendation, and an explanation of whether and why each recommendation was adopted, adopted as modified, or rejected, along with a statement of any unresolved issues. G.L. c. 164, § 92B(d).

In these proceedings, several intervenors recommend that the Department direct the Companies to incorporate the GMAC's recommendations more substantively. Intervenors also suggest specific responsibilities for the GMAC going forward. In this section, the Department first reviews the Companies' compliance with the GMAC-related requirements of Section 92B. The Department then addresses the GMAC's role over the course of the ESMP term.

B. Description of Company Filings

In their responses to the GMAC's recommendations submitted with their ESMP filings, the Companies indicated whether they adopted, adopted but modified, or rejected each recommendation and explained their reasoning for doing so (D.P.U. 24-10/ D.P.U. 24-11/D.P.U. 24-12, Exhs. ES-Bill Impacts-2/NG-Bill Impacts-2/UN-Bill Impacts-2; ES-Forecast-2/NG-Forecast-2/UN-Forecast-2; ES-Metrics-2/NG-Metrics-2/UN-Metrics-2; ES-Net Benefits-2/NG-Net Benefits-2/UN-Net Benefits-2; ES-Policy/Solutions-2/ NG-Policy/Solutions-2/UN-Policy/Solutions-2; ES-Stakeholder-2/NG-Stakeholder-2/ UN-Stakeholder-2). In total, the Companies adopted 14 of the GMAC's 88 recommendations, adopted with modification 63 recommendations, and rejected 11 of the GMAC's recommendations (D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, Exhs. ES-Bill Impacts-2/NG-Bill Impacts-2/UN-Bill Impacts-2; ES-Forecast-2/ NG-Forecast-2/UN-Forecast-2; ES-Metrics-2/NG-Metrics-2/UN-Metrics-2; ES-Net Benefits-2/NG-Net Benefits-2/UN-Net Benefits-2; ES-Policy/Solutions-2/ NG-Policy/Solutions-2/UN-Policy/Solutions-2; ES-Stakeholder-2/NG-Stakeholder-2/ UN-Stakeholder-2). Additionally, from the GMAC Equity Working Group, the Companies adopted one recommendation, adopted with modification nine recommendations, and rejected two recommendations (D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, Exhs. ES-Stakeholder-2/ NG-Stakeholder-2/UN-Stakeholder-2).

C. Positions of the Parties

1. Attorney General

The Attorney General recommends that the GMAC serve as the governing body under which all grid modernization-related stakeholder groups and processes operate, including the Community Engagement Stakeholder Advisory Group ("CESAG")[32] (Attorney General Brief at 50; Attorney General Reply Brief at 6). The Attorney General asserts that putting these stakeholder groups under the GMAC will streamline the various grid modernization-related stakeholder groups and processes (Attorney General Brief at 50).

2. DOER

DOER recommends that the Department require the Companies to substantively incorporate the GMAC's recommendations into their ESMPs (DOER Brief at 13).

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32 The CESAG is discussed in Section VII.H.

Additionally, DOER supports the Attorney General's recommendation that the GMAC oversee all grid modernization-related stakeholder groups, including the CESAG (DOER Reply at 3, 10). DOER contends that operation of the CESAG under the GMAC will provide accountability for the group's deliberation and outcomes as well as transparency in the selection of community-based organizations ("CBOs") serving on the CESAG (DOER Brief at 65-66).

DOER also recommends that the Department direct the Companies to collaborate with the GMAC to establish a GMAC forecasting working group to remedy deficiencies in the filed ESMP forecasts, including identifying areas for further alignment and standardization between the Companies and to develop a process and schedule for stakeholder input into the next ESMP forecasts prior to the submission of the draft ESMPs to the GMAC (DOER Brief at 27-28). The multi-year process recommended by DOER for the GMAC forecasting working group consists of the Companies: (1) sharing forecasts with the GMAC by September 1, 2026 or at least two years in advance of the deadline for submitting the next draft ESMPs to the GMAC; (2) presenting to the GMAC an overview of their forecasting methodologies; (3) forming subgroups of GMAC and non-GMAC members to develop recommendations on sector-specific forecasts; and (4) updating their forecasts to include GMAC recommendations before determining the scale or scope of investments in the forthcoming draft ESMPs (DOER Brief at 26-28, citing D.P.U. 24-10/D.P.U. 24-11/ D.P.U. 24-12, Exh. DOER-1, at 26-27).

3. Acadia Center, CLF, and GECA

Acadia Center, CLF, and GECA argue that any modification of aspects of the GMAC review process should not be at the expense of the full participation of voting members of the GMAC (Joint Intervenor Reply Brief at 7). They recommend certain guardrails on the Companies' participation, such as time restrictions, to ensure sufficient time for other GMAC members to speak (Joint Intervenor Reply Brief at 7, citing Companies' Joint Brief at 94-95). The Joint Intervenors support DOER's recommendation that the Department direct the Companies to work with the GMAC to establish a GMAC Forecast Working Group (Joint Intervenor Reply Brief at 6). Regarding the GMAC consultant, the Joint Intervenors assert that the consultant supplied important technical expertise to the GMAC in reviewing the draft ESMPs and will continue to play an essential role in future GMAC review processes (Joint Intervenor Reply Brief at 7, citing D.P.U. 24-10/D.P.U. 24-11, Exh. GECA-LC-4; GMAC Consultant Comments; Companies' Joint Brief at 91-92;).

Acadia Center asserts that the Companies accepted with modification 63 of the GMAC's 88 recommendations but did not adhere to the spirit and substance of many of those recommendations (Acadia Center Brief at 17). Acadia Center states that the GMAC's recommendations were not made lightly and urges the Department to require the Companies to better incorporate the GMAC's recommendations into both their current and future ESMPs (Acadia Center Brief at 17).

Additionally, both Acadia Center and CLF support DOER's recommendation for the CESAG to operate within the GMAC structure (Acadia Brief at 4, 27; CLF Brief at 14).

Acadia Center asserts that this would ensure that the CBOs have the full support of the GMAC and adequate technical assistance and compensation while CLF argues that integrating the CESAG into the GMAC would prevent duplication of efforts and ensure that CBOs have adequate technical assistance and compensation (Acadia Brief at 4, 27; CLF Brief at 14).

4. Cape Light Compact

CLC supports having NSTAR Electric participate in a GMAC-led stakeholder process to develop the next ESMPs prior to filing the draft plans with the GMAC (CLC Brief at 28; CLC Reply Brief at 13). CLC also supports having the CESAG operate within the existing GMAC structure (CLC Brief at 3, 16-17).

5. Companies

The Companies argue that the intervenors' recommendations would expand the role of the GMAC beyond its statutory authority (Companies' Joint Reply Brief at 9). The Companies contend that because the role of the GMAC is limited to providing recommendations on the ESMPs, not mandates, they are not required to implement the recommendations into their final plans (Companies' Joint Reply Brief at 9).

The Companies oppose the intervenors' recommendation that the CESAG operate within the existing GMAC structure, arguing that the GMAC and CESAG serve different purposes (Companies' Joint Reply Brief at 50-52). Specifically, the Companies contend that the CESAG is designed to be flexible and provide a forum for the Companies to partner directly with CBOs to develop strategies to meet community needs, whereas the GMAC structure is a formal government body subject to quorums and open meeting laws

(Companies' Joint Reply Brief at 51). The Companies argue that having the CESAG be part of the GMAC structure could inadvertently stifle the free exchange of ideas between stakeholders, limit the flexibility of the CESAG to achieve desired outcomes, and create an imbalance of power by giving the GMAC a central role in the CESAG process that would otherwise be filled by CBOs that operate in the Companies' service territories (Companies' Joint Reply Brief at 51-52). The Companies state that the CESAG is meant to enhance and formalize stakeholder engagement efforts that are already part of their business practices (Companies' Joint Reply Brief at 52).

The Companies state that they engage with multiple stakeholder groups in developing their forecasts as part of the ARR process and oppose creating another forecasting stakeholder process as DOER recommends (Companies' Joint Brief at 91-92). Further, the Companies argue that providing the GMAC with forecasts two years before filing the ESMPs with the Department, as recommended by DOER in its testimony, would result in ESMPs that contain out-of-date information (Companies' Joint Brief at 91-92). The Companies oppose requiring the integration of GMAC recommendations into their respective forecasts because not all recommendations may be suitable for each company and because they question the expertise of the GMAC's consultant to provide actionable forecasting feedback (Companies' Joint Brief at 92-93).

The Companies argue that the GMAC should adopt the Companies' proposed enhancements to the GMAC process, including allowing the Companies to directly present a summary of their ESMPs to the GMAC, holding technical sessions, and to allow the

Companies to engage in a dialog with the GMAC during GMAC meetings (Companies' Joint Brief at 94-95, citing D.P.U. 24-10, Exh. DPU-Common 7-7; D.P.U. 24-11, Exh. DPU-Common 7-7; D.P.U. 24-12, Exh. DPU-Common 7-7). The Companies contend that these enhancements would improve efficiency and feedback between all GMAC members by allowing the Companies to address the GMAC's concerns directly (Companies' Joint Brief at 95, citing Tr. 6, at 852; D.P.U. 24-10, Exh. DPU-Common 7-7; D.P.U. 24-11, Exh. DPU-Common 7-7; D.P.U. 24-12, Exh. DPU-Common 7-7). The Companies also contend that having technical sessions would facilitate a streamlined process and give the GMAC a deeper understanding of the draft ESMPs (Companies' Joint Brief at 96, citing Tr. 6, at 839). Further, the Companies state that they welcome feedback from the GMAC regarding the measurement and analysis of GHG emissions reduction benefits (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 668; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 481; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 294).

D. Analysis and Findings

In Section 92B, the Legislature assigned a monumental task to the newly formed GMAC. The GMAC was directed to review not one but three comprehensive, long-term distribution system planning proposals, including divergent investment proposals and approaches, based on three separate distribution systems with their own distinct characteristics. After assessing the extensive information provided in the draft plans, the GMAC was tasked with providing recommendations on each of those complex and technically-detailed plans within 80 days. The GMAC showed considerable care and attention in formulating its recommendations, and without question, the GMAC's extraordinary efforts helped to facilitate a more productive and efficient Department review. The Department and intervenors relied on the GMAC's recommendations extensively in drafting discovery on the ESMPs (See, e.g., D.P.U. 24-10, Exhs. DPU-Common 11-3; DPU-Common 11-4; DOER-Common 5-2; GECA 1-1; D.P.U. 24-11, Exhs. DPU-Common 11-3; DPU-Common 11-4; DOER-Common 5-2; GECA 1-1; D.P.U. 24-12, Exhs. DPU-Common 11-3; DPU-Common 11-4; DOER-Common 5-2).

Below, we provide a review of the GMAC's enabling statute, Section 92C, and the responsibilities delegated to the GMAC in Section 92B. We then address whether the Companies complied with the requirements in Section 92B pertaining to the GMAC prior to submission of their ESMPs to the Department. Finally, we address the GMAC's duties and responsibilities during the term of the ESMP and for subsequent ESMP review processes.

Section 92C established the GMAC to review and provide recommendations on the ESMPs prior to the Companies' filings with the Department. See also G.L. c. 164, § 92B(d). The GMAC is expressly charged with encouraging least-cost investments in the electric distribution systems, as well as alternatives to investments or financing of investments that will facilitate the achievement of the Commonwealth's GHG emissions limits and sublimits under Chapter 21N while increasing transparency and stakeholder engagement. G.L. c. 164, § 92C(b). Correspondingly, the electric distribution companies must: (1) solicit input from the GMAC; (2) respond to GMAC requests for information and documents; and (3) submit draft ESMP plans to the GMAC for review, input, and recommendations. G.L. c. 164, § 92B(c)(iii), (d).

Prior to submitting their current ESMPs to the Department, the Companies responded to GMAC requests and submitted their draft ESMPs to the GMAC for review and input on September 1, 2023, and the GMAC provided recommendations to the Companies on November 20, 2023 (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 31; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 33; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 30). No intervenor specifically disputed the Companies' compliance with these requirements as a practical matter. Some intervenors, however, questioned whether the Companies complied in spirit with the substance of the recommendations that were adopted with modifications. They argued that the Department should require the Companies to more fully incorporate the GMAC's recommendations into their ESMPs (DOER Brief at 13; Acadia Center Brief at 17). In response, the Companies maintain that they are not required to implement these recommendations into their final plans (Companies' Joint Reply Brief at 9). For the reasons discussed below, we conclude that nothing in Sections 92B and 92C mandates the Companies to incorporate the GMAC's recommendations into their ESMP proposals.

As noted, above, in Section 92C, the Legislature charged the GMAC with the responsibility of providing review, input, and recommendations on the Companies' draft ESMPs. Further, Section 92B(d) requires the Companies to show that they considered the GMAC's recommendations by including a list of these recommendations, the status of each recommendation, and an explanation of whether and why each recommendation was adopted,

adopted as modified, or rejected, along with a statement of any unresolved issues. Based on the express language of Sections 92B and 92C, the Department determines that the Legislature envisioned the GMAC as an advisory body that reviews the draft ESMPs and provides recommendations to the Companies that each company may adopt, adopt with modifications, or reject, at their discretion, provided that the Companies explain the basis for their treatment of each recommendation. G.L. c. 164, § 92B(d).

Prior to submitting their current ESMPs to the Department, the Companies responded to GMAC requests and submitted their draft ESMPs to the GMAC for review and input on September 1, 2023 (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 31; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 33; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 30). In their ESMP filings submitted to the Department, the Companies included a list of the GMAC's recommendations, indicated whether each recommendation was adopted, adopted as modified, or rejected, and provided an explanation for why the recommendation was adopted, adopted as modified, or rejected (D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, Exhs. ES-Bill Impacts-2/NG-Bill Impacts-2/UN-Bill Impacts-2; ES-Forecast-2/ NG-Forecast-2/UN-Forecast-2; ES-Metrics-2/NG-Metrics-2/UN-Metrics-2; ES-Net Benefits-2/NG-Net Benefits-2/UN-Net Benefits-2; ES-Policy/Solutions-2/ NG-Policy/Solutions-2/UN-Policy/Solutions-2; ES-Stakeholder-2/NG-Stakeholder-2/ UN-Stakeholder-2). In total, the Companies adopted 14 recommendations, adopted with modification 63 recommendations, and rejected eleven of the GMAC's recommendations (D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, Exhs. ES-Bill Impacts-2/NG-Bill

Impacts-2/UN-Bill Impacts-2; ES-Forecast-2/ NG-Forecast-2/UN-Forecast-2; ES-Metrics-2/NG-Metrics-2/UN-Metrics-2; ES-Net Benefits-2/NG-Net Benefits-2/UN-Net Benefits-2; ES-Policy/Solutions-2/NG-Policy/Solutions-2/UN-Policy/Solutions-2; ES-Stakeholder-2/NG-Stakeholder-2/UN-Stakeholder-2). Additionally, with respect to the recommendations from the GMAC Equity Working Group, the Companies adopted one recommendation, adopted with modification nine recommendations, and rejected two recommendations (D.P.U. 24-10/ D.P.U. 24-11/D.P.U. 24-12, Exh. ES-Stakeholder-2/ NG-Stakeholder-2/UN-Stakeholder-2). Based on our review of the record, the Department concludes that the Companies complied with the minimum requirements of Section 92B(c)(iii) and (d).

Notwithstanding this finding, the Department notes that several intervenors found the Companies' explanations confusing or incomplete (D.P.U. 24-10/D.P.U. 24-11/ D.P.U. 24-12, Exhs. DOER-1, at 38-48; AG-BF-1, at 10-11; GMAC Consultant Comments at 96). Indeed, over the course of these proceedings, both the Department and the Attorney General sought more detailed explanations as to the Companies' treatment of certain of the GMAC's recommendations (see, e.g., Tr. 7, at 1019-1026; D.P.U. 24-10/D.P.U. 24-11/ D.P.U. 24-12, Exh. DPU-Common 11-3). While the Department finds the Companies' decision and brief explanations for its actions on each recommendation to comply with the minimum requirements in Section 92B(d), the Department expects the Companies in the next ESMP review process to explain in more complete detail the basis of their decisions on each of the GMAC's recommendations. In particular, for any recommendations that the

Companies adopt with modifications, the Companies shall identify with specificity how the recommendation was adopted and the nature of the modification.

We now turn to the recommendations pertaining to the GMAC's role over the course of the EMSP term and for subsequent ESMP review processes. As discussed above, the GMAC is an advisory body created by the Legislature to review and provide recommendations on the Companies' draft ESMPs, and Section 92C does not contemplate a role for the GMAC to oversee stakeholder groups created by the Companies to facilitate the development of internal company policies and practices related to their ESMPs. The Department declines to expand the scope of the GMAC's authority beyond that explicitly contemplated by the Legislature. Specifically, the Department declines to require that the CESAG operate within the existing GMAC structure. The Companies propose as part of their equity framework to establish the CESAG as an independent stakeholder group comprising representatives from the Companies, CBOs, and an environmental or advocacy group (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 53; ES-Stakeholder-1, at 10; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 56; NG-Stakeholder-1, at 12; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 44; UN-Stakeholder-1 at 9). We agree with the Companies' argument that the GMAC and the CESAG serve different purposes and that requiring the CESAG to operate within the existing GMAC structure could frustrate the purpose of the CESAG.

Similarly, the Department declines to require the establishment of a joint forecasting working group as recommended by DOER. In Section IV.C., above, the Department concluded that nothing in Section 92B, Section 92C, or elsewhere in the 2022 Clean Energy Act overrides typical electric distribution system planning or the provisioning of safe and reliable electric service. The Department also noted in Section IV.C. that forecasting and distribution system planning are dynamic processes, and the Legislature in Section 92B(d) specifically directs that the filing of ESMPs and any corresponding GMAC review, input, and recommendations occur once every five years. Moreover, within a substantial range, utility business decisions are matters for company management to determine. Fitchburg, 375 Mass. at 578. Generally, notwithstanding our regulatory oversight responsibilities over the Companies, the Department may not interfere with reasonable company judgments made in good faith and within the limits of reasonable discretion. Fitchburg Gas and Electric Light Company, D.P.U. 09-09, at 38 (2009); Natural Gas Shortage, D.P.U. 555-C at 16 (1983). Further, it is inappropriate for the Department to substitute its own judgment for the judgment of the management of a utility. Attorney General v. Department of Public Utilities, 390 Mass. 208, 228 (1983). These limitations are even more applicable for the GMAC and other stakeholders who possess an advisory role on draft plans. Accordingly, the Department declines to require the Companies: (1) to share their forecasts with the GMAC two years in advance of the deadline for submitting the next draft ESMPs to the GMAC; (2) to form subgroups of GMAC and non-GMAC members to develop recommendations on sector-specific forecasts; and (3) to update their forecasts to include GMAC recommendations before determining the scale or scope of investments in subsequent draft ESMPs.

Although we decline to adopt recommendations that expand the GMAC's role beyond that identified in Sections 92B and 92C, the Department notes that in Section 92C the Legislature included the Companies as non-voting members of the GMAC, thereby creating an entity rooted in significant collaboration between GMAC voting members and the Companies. Further, the Department notes that in Section 92C(c), the Legislature explicitly permits the GMAC to submit annually a proposed budget for the retention of expert consultants and reasonable administrative costs. The Department therefore finds that the Legislature contemplated that the GMAC and the Companies would engage in ongoing collaboration during the period between draft ESMP filings.

Section 92C, however, does not explicitly identify specific activities for or expectations of the GMAC during the intervening time between draft plan filings. The Department encourages continued collaboration between the GMAC, any consultants that GMAC may retain, and the Companies during the intervening time. The Companies and the GMAC, in acknowledging the importance of collaboration to the ESMP process, make suggestions on how to facilitate a higher degree of cooperation for the next ESMP review process (D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, Tr. 6, at 833-834; Exhs. AG-NBC-1, at 98; DOER-1, at 26, 45-47; D.P.U. 24-10/D.P.U. 24-11, GECA-LC-1, at 13; D.P.U. 24-10, Exh. DPU-Common 7-5; D.P.U. 24-11, Exh. DPU-Common 7-5; D.P.U. 24-12, Exh. DPU-Common 7-5). Based on these suggestions, the Department encourages the Companies and the GMAC to engage in the following during the intervening time between draft plan filings: (1) company presentations on the Companies' forecasting methodologies (as suggested by DOER) to develop the GMAC's knowledge of each company's forecasting methodologies, including the differences in forecasting assumptions and methodologies; and (2) discussion of least cost investments in the electric distribution systems, as well as the process of identifying alternatives to investments or financing of investments so as to minimize or mitigate impacts on ratepayers. The above list is not exhaustive. The Department notes that such collaboration would ultimately expedite and improve the GMAC's review of subsequent draft plans and, in turn, result in recommendations based on a more granular understanding of the Companies' methodologies.

The Companies' second draft ESMPs must be submitted to the GMAC no later than February 12, 2029. See Section VII.A.4. Based on this filing deadline, these draft plans will be developed based on a prior year forecast which will then be updated shortly after filing of the draft plans with the GMAC. Further, our expectation is that the Companies will rely on the then-current forecasts to finalize their ESMP proposals to the Department. See Section VII.A.4. As such, a level of GMAC expertise on the Companies' forecasting methodologies gained over the intervening period between draft plan filings would be an asset in formulating actionable recommendations.

Finally, we note that Sections 92B and 92C do not address the precise method in which the GMAC must undertake its review of draft ESMPs. However, Section 92C does charge the GMAC with increasing transparency and stakeholder engagement in the grid planning process. A more efficient process within the confines of Sections 92B and 92C that takes advantage of the collaborative structure inherent in the GMAC will benefit not only the

GMAC and the Companies, but the Commonwealth as a whole. The Department concludes that company presentations to the GMAC of their subsequent draft ESMPs would be beneficial for stakeholders and therefore encourages the GMAC to consider the Companies' proposal to present summaries of their draft ESMPs to the GMAC and its consultant, as well as to conduct technical sessions for the GMAC, prior to filing of the draft ESMPs (D.P.U. 24-10, Exh. DPU-Common 7-7; D.P.U. 24-11, Exh. DPU-Common 7-7; D.P.U. 24-12, Exh. DPU-Common 7-7).

VI. FORECASTS AND DEMAND ASSESSMENTS

A. Methodologies and Results

1. Overview

The Companies create five- and ten-year demand forecasts annually and use these forecasts to develop their capital plans (D.P.U. 24-10, Exh. ES-Forecast-1, at 10; D.P.U. 24-11, Exh. NG-Forecast-1, at 5; D.P.U. 24-12, Exh. UN-Forecast-1, at 6-7). The methodologies each individual company employ are aligned for the baseload econometric forecast, design weather conditions, and whether DERs are load reducing or load growth resources (D.P.U. 24-10, Exh. ES-Forecast-1, at 15; D.P.U. 24-11, Exh. NG-Forecast-1, at 7; D.P.U. 24-12, Exh. UN-Forecast-1, at 8).[33] Each company started its demand forecast development with a weather normalized baseload forecast which is then adjusted for the

[33] Each company developed DER scenarios based on the decarbonization pathways outlined in the Clean Energy and Climate Plan 2050 (D.P.U. 24-10, Exh. ES-Forecast-1, at 43; D.P.U. 24-11, Exh. NG-Forecast-1, at 22; D.P.U. 24-12, Exh. UN-Forecast-1, at 20).

estimated impacts of DERs (e.g., EE, solar PV, ESS, EV, and electric heat pumps ("HP")) to reach the net demand forecast (D.P.U. 24-10, Exh. ES-Forecast-1, at 14; D.P.U. 24-11, Exh. NG-Forecast-1, at 6-7; D.P.U. 24-12, Exh. UN-Forecast-1, at 7). Each company independently forecasted DERs based on current market trends, policies, programs, and the Commonwealth's decarbonization pathways (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 242-255, 480; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 210, 393; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 78, 194-195).

The Companies update their forecasting methodologies continuously as technologies evolve or new factors are considered (D.P.U. 24-10, Exh. ES-Forecast-1, at 10; D.P.U. 24-11, Exh. NG-Forecast-1, at 5; D.P.U. 24-12, Exh. UN-Forecast-1, at 6-7). Further, each company conducted sensitivity analyses for demand assessments due to the increased uncertainty when forecasting loads to 2050 (Exhs. D.P.U. 24-10, Exh. ES-Forecast-1, at 41; D.P.U. 24-11, Exh. NG-Forecast-1, at 21; D.P.U. 24-12, Exh. UN-Forecast-1, at 19).

While both the five- and ten-year demand forecast and the demand assessment for 2035-2050 are based on the same data and use the same tools, the Companies use them for different purposes (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 473; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 390; D.P.U. 24-12, Exh. UN-Forecast-1, at 5-6, 17-18). More specifically, the five- and ten-year demand forecasts within the distribution planning horizon identify system constraints in the next ten years to ensure initiation of capital projects with sufficient lead time to address demand (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 473; D.P.U. 24-12, Exh. UN-Forecast-1, at 5-6). In contrast, the demand assessment provides policymakers and regulators a view into the future and to help develop new strategies which might help mitigate the overall capacity need laid out by the demand assessment (see D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 473; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 390). Furthermore, because the demand assessment provides visibility of longer-term needs, it allows the Companies to scale near-term investments with that visibility in mind (D.P.U. 24-10, Exh. ES-Forecast-1, at 38; D.P.U. 24-11, Exh. NG-Forecast-1, at 20; D.P.U. 24-12, Exh. UN-Forecast-1, at 18). Below, each company's demand forecast development process is described in further detail along with the results of these forecasts.

2. Demand Forecast Development

a. NSTAR Electric

To develop the demand forecast, NSTAR Electric began by recording the actual measured net station peak demand at each bulk substation (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 209). The company then adjusted each reported net station peak for local conditions such as load transfers at time of peak, back up generation that might have been running on the system, solar generation contribution, and the prevailing weather conditions at the time (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 209). The result of those adjustments yielded the reported, weather normalized, 90/10 gross station peak (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 209). The 90th percentile scenario means that with 90 percent certainty, all future loads that occur will not exceed the projected load (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 206-207).

The company then used the reported, weather normalized gross station peak and Moody's ten-year economic data to determine the historic trend in load growth relative to economic growth (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 176). Based on this historic trend, the company developed a trend demand forecast using future economic projections from Moody's (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 176). NSTAR Electric adjusted the trend demand forecast for EE, solar PV, EV, and step loads to derive the net forecast (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 209; ES-Forecast-1, at 11).

b. National Grid

To develop the peak demand forecast, National Grid first analyzed historical weather and then calibrated the peak demand forecast to correspond to peaks that occur under extreme conditions (i.e., the 90th percentile which corresponds to the hottest days in the summer and the coldest days in the winter or) (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 210). National Grid then disaggregated the historical demand data to separate out historical baseload demand and the historical impact of DERs, (e.g., EE, demand response, solar PV, ESS, EVs, and electric HPs) (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 210). The company used the disaggregated historical baseload demand and historical impacts of DERs to separately develop the baseload and DER forecasts (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 210; NG-ESMP-1 (Corrected) Appendix at Exhibit 7 (ELF Report-Peak) at 8; NG-Forecast-1, at 6). Finally, the company recombined the baseload and DER forecasts to get a net demand forecast calibrated against design weather conditions (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 210 & Appendix at Exhibit 7 (ELF Report-Peak) at 9; NG-Forecast-1, at 6).

c. Unitil

To develop the demand forecast, Unitil begins with the baseload forecast and then added or subtracted coincident peak demand loads for large loads, EE, solar PV, ESS, EV, electrification, and volt/VAR optimization ("VVO") (D.P.U. 24-12, Exh. UN-Forecast-1, at 7). The company then added the output deriving from historical system tie point power flows associated with significant DERs before calculating the demand forecasts (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 81). To develop the baseload peak forecast, the company used historical data to develop yearly regression models that correlate actual daily loads to a Weighted Temperature Humidity Index ("WTHI") (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 80). Finally, to establish baseload projections, the company ran a Monte Carlo simulation to produce random annual highest WTHI and random peak load estimates at those WTHI from each year's seasonal model that makes up the historical basis (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 81).

3. Five- and Ten-Year Forecast Results

a. NSTAR Electric

i. Overview

In NSTAR Electric's service territory, the net load is expected to grow from a 2023 baseline of 6,126 MVA to 7,369 MVA in 2033 (D.P.U. 24-10, Exh. ES-ESMP-1

(Corrected) at 243). Step loads of over 800 MW to fulfill direct customer requests is the key driver of the increased demand (D.P.U. 24-10, Exh. ES-Forecast-1, at 12). Step loads represent large (above 500 kW) new load additions from factors including new developments (residential and commercial/industrial), redevelopment of existing sites, confirmed EV fleet and depot charging loads, and large standalone storage systems (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 679; ES-Forecast-1, at 12). Further, load demand from underlying economic growth, which is concentrated in metropolitan areas, results in a compound annual growth rate ("CAGR") of the net forecast of 2.9 percent for eastern Massachusetts and 0.4 percent in western Massachusetts (D.P.U. 24-10, Exh. ES-Forecast-1, at 12).

ii. Demand Response

For the five- and ten-year forecasting windows, NSTAR Electric did not separately model and provide a demand response forecast (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 250). Instead, the company assumed existing demand response capacity is embedded in the baseload component of its forecast with no expected growth in demand response capacity (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 250).

NSTAR Electric plans to deploy VVO technology to actively manage voltage and reactive power to increase system efficiency and reduce demand, as a part of its 2022-2025 Grid Modernization Plan (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 327, 336). To date, the company has achieved a 1.8 percent reduction in demand on feeders with VVO deployed (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 327).

iii. Energy Efficiency

Under near-term forecasts, the results of NSTAR Electric's EE efforts were reflected in the demand forecast in two ways (D.P.U. 24-10, Exh. ES-Forecast-1, at 21). First, past efforts are implicitly reflected in the historic peak loads used for the trend forecast (D.P.U. 24-10, Exh. ES-Forecast-1, at 21). Second, the company includes future EE efforts as forecast adjustments consistent with the company's approved 2022 through 2024 Three-Year EE plan (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 244; ES-Forecast-1, at 21).

iv. Electric Vehicles

For the five- and ten-year forecasts, the company accounted for EV load growth, including light-, medium-, and heavy-duty vehicles (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 244; ES-Forecast-1, at 17). Light-duty vehicles are accounted for in the ten-year forecast using an adoption model in line with the state policy and mobility data, while medium- and heavy-duty vehicle charging, as well as charging stations for light-duty vehicles, are tracked and accounted for through the step load tracking process (D.P.U. 24-10, Exh. ES-Forecast-1, at 17).

v. Heat Pumps

While the company forecasts electric heating as part of the five- and ten- year forecasts, the forecasted electric heating load in the 10-year horizon is not sufficient to make the winter peak surpass the summer peak (D.P.U. 24-10, Exhs. ES-Forecast-1, at 19). As a result, all peak forecast values for the five- and ten-year forecast are for summer peak only, exclusive of an electric heating component (D.P.U. 24-10, Exhs. ES-Forecast-1, at 19; ES-ESMP-1 (Corrected) at 244).

vi. Energy Storage

The company accounted for behind-the-meter storage in its energy storage demand forecast through the econometric trend model (D.P.U. 24-10, Exh. ES-Forecast-1, at 28). By reducing individual customer peak demand during system peaks in a consistent manner over multiple years, the behind-the-meter storage applications reduce the forecasted gross trend load by lowering recorded peaks (D.P.U. 24-10, Exh. ES-Forecast-1, at 28). Large storage systems, specifically standalone and solar-plus-storage co-located applications, are not attributed with any load reduction for the five- and ten-year forecasts because the company does not have operational control over or visibility into these assets (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 244; ES-Forecast-1, at 28).

For front-of-the meter ESS that have reserved import capacity during peak load hours, the company included these in the forecast as a step load at the reserved import capacity level (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 244; ES-Forecast-1, at 29). An energy storage installation with no capacity reserved during peak hours in its schedule does not show up in the step loads (D.P.U. 24-10, Exh. ES-Forecast-1, at 29).

vii. Solar PV

The annual forecasted ground-mounted solar capacity followed the trajectory defined at the state level in the 2050 Decarbonization Roadmap (D.P.U. 24-10, Exh. ES-Forecast-1, at 23). First, the economics of developing ground-mounted solar for each technically available parcel was determined with consideration of all project costs, municipal restrictions, incentives, and revenue from power generation potential (D.P.U. 24-10, Exh. ES-Forecast-1, at 24). Second, the net present value and internal rate of return ("IRR") per project per parcel were calculated (D.P.U. 24-10, Exh. ES-Forecast-1, at 24). Third, projects were forecasted to develop in order of high to low IRR projects with the project and its required capacity assigned to the associated substation if capacity was available (D.P.U. 24-10, Exh. ES-Forecast-1, at 24). Fourth, if the existing substation hosting capacity is exceeded, projects could not be added to that station in the current year but could be enabled with a planned upgrade in a future year (D.P.U. 24-10, Exh. ES-Forecast-1, at 24). Once the allotted annual solar deployment was reached, the cycle started for the following year (D.P.U. 24-10, Exh. ES-Forecast-1, at 24). At the end of the forecast simulation, all the technically feasible projects in Massachusetts, their associated station, and their order of deployment were generated (D.P.U. 24-10, Exh. ES-Forecast-1, at 24).

Rooftop solar adoption was forecasted using annual solar deployment and spatial allocation (D.P.U. 24-10, Exh. ES-Forecast-1, at 25). Annual solar deployment was determined based on historical trends, the number of potential adopters, and top-down targets (D.P.U. 24-10, Exh. ES-Forecast-1, at 25). An econometric model was used to estimate the annual customer adoption rate of rooftop solar at a system level and considered multiple variables (D.P.U. 24-10, Exh. ES-Forecast-1, at 25). The model validated using historical data for the variables of interest (D.P.U. 24-10, Exh. ES-Forecast-1, at 25). The second part of the rooftop solar forecast involved allocating the adopters by distribution station

(D.P.U. 24-10, Exh. ES-Forecast-1, at 26). The allocation considered zip code-specific variables including land cover area, population density, proximity to other adopters and average age of homes (D.P.U. 24-10, Exh. ES-Forecast-1, at 26). Similarly, a regression model was employed to estimate adoption. Because models are heavily reliant on input variables, each input variable was monitored and updated based on its outlook (D.P.U. 24-10, Exh. ES-Forecast-1, at 26). Considerations for rooftop solar deployment included installation costs, incentives, and expected payback (D.P.U. 24-10, Exh. ES-Forecast-1, at 26).

viii. Sensitivity Analysis

NSTAR Electric did not perform a sensitivity analysis for the five- and ten-year electric demand forecasts because project timelines for bulk stations range from five to ten years (D.P.U. 24-10, Exh. ES-Forecast-1, at 14). Instead, NSTAR Electric selected a single demand scenario and considered only the 90/10 net station demand forecast adjusted for EVs, solar PV, EE, and step loads (D.P.U. 24-10, Exh. ES-Forecast-1, at 14, 15).

b. National Grid

i. Overview

In National Grid's service territory, the net system peak load is expected to grow from a 2023 baseline of 4,944 MW to 6,261 MW in 2034 (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 215). The aggregate demand is projected to increase at a CAGR of 1.1 percent through 2029, and 2.1 percent through 2034, due in large part to increasing vehicle electrification (D.P.U. 24-11, Exh. NG-Forecast-1, at 10).

ii. Demand Response

National Grid modeled and provided a separate demand response forecast for demand response resources enrolled in the retail program (i.e., not part of ISO New England ("ISO-NE") wholesale demand response) as load reduction in the demand forecast (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 215 & Appendix at Exhibit 7 (ELF Report-Peak) at 18). The company provided demand response capacity (in MW) projections for the near-term forecasting windows (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 215 & Appendix at Exhibit 7 (ELF Report-Peak) at 19).

Pursuant to its approved Grid Modernization Plan, the company will deploy VVO through 2025, and National Grid proposes to continue to deploy VVO as a part of proposed ESMP network investments (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 269). National Grid anticipates that the deployment of VVO could result in demand reduction in the net demand forecast (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 269).

iii. Energy Efficiency

In the short-term (i.e., through year 2024) forecast, EE targets are based on the company's approved 2022 through 2024 Three-Year EE plan (D.P.U. 24-11, Exhs. NG-Forecast-1, at 13; NG-ESMP-1 (Corrected) at 215). Beyond 2024, the cumulative value of persistent EE savings is expected to grow but at a slower annual rate that reflects market saturation and uncertainties in policies and funding (D.P.U. 24-11, Exhs. NG-Forecast-1, at 13; NG-ESMP-1 (Corrected) at 215).

iv. Electric Vehicles

For the five- and ten-year forecasts, the company included both plug-in hybrid EVs ("PHEVs") and battery-only EVs ("BEVs") since they both impact electric demand (D.P.U. 24-11, Exhs. NG-Forecast-1, at 11; NG-ESMP-1 (Corrected) at 215). Light-duty EV ("LDEV") adoption was modeled on the California's Advanced Clean Cars II Rule, which Massachusetts adopted and requires auto manufacturers to ensure that every new light-duty car sold in the state is a zero-emission vehicle by 2035 (D.P.U. 24-11, Exh. NG-Forecast-1, at 11). The company similarly modeled the adoption of medium-duty EV and heavy-duty EV and E-buses (both transit and school buses) based on the Commonwealth's adoption of California's Advanced Clean Trucks Regulation through 2035 (D.P.U. 24-11, Exh. NG-Forecast-1, at 11).

v. Heat Pumps

The company's approved 2022 through 2024 Three-Year EE Plan guides electric HP adoption projections through the year 2024 (D.P.U. 24-11, Exh. NG-Forecast-1, at 12). After 2024, the forecast follows a trajectory that meets the State's CECP "Phased" electrification scenario target by 2050, roughly aligning with interim state goals for 2030 and beyond (D.P.U. 24-11, Exhs. NG-Forecast-1, at 12; NG-ESMP-1 (Corrected) at 215). This "Phased" scenario allows for hybrid HP systems in the five- and ten-year and pivots to whole-home HPs in the long-term (D.P.U. 24-11, Exh. NG-Forecast-1, at 12).

vi. Energy Storage

National Grid's energy storage demand forecast assumes continuous growth in energy storage connection to meet the company's share of the statewide policy target of 1,000 MW by 2025 (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 215; NG-Forecast-1, at 13).

vii. Solar PV

From 2023 through 2027, based on solar PV project information from its interconnection queue and input from company subject matter experts, the company assumed it would meet its share of the Commonwealth's existing solar target of 3.2 GW by mid 2020s (D.P.U. 24-11, Exh. NG-Forecast-1, at 13).

viii. Sensitivity Analysis

For the near-term forecasts, the company used base, low, and high scenarios for each DER to generate a range of possible outcomes to address uncertainty in its forecasts (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) Appendix at Exhibit 7 (ELF Report-Peak) at 86-113). The company then combined all permutations of the sensitivities for the different DERs to create different demand scenarios, and an uncertainty range around the demand assessment (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) Appendix at Exhibit 7 (ELF Report-Peak) at 86-113).

c. Unitil

i. Overview

In Unitil's service territory the net system peak load is expected to grow from 104 MW in 2025 to 120 MW in 2034 (D.P.U. 24-12, Exh. UN-ESMP-1 at 101). During this period, the company's system will be summer peaking driven by step loads and growth in existing loads partially offset by DERs (D.P.U. 24-12, Exh. UN-Forecast-1 at 15).

ii. Demand Response

Unitil did not model and provide a separate demand response forecast for the five- and ten-year forecasting windows, but assumed existing demand response capacity was embedded in the baseload component of its demand forecast with demand response expected to increase at the historical baseload growth rate (Tr. at 47; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 101; AG 3-17). Unitil modeled and provided a separate VVO forecast for the five- and ten-year forecasting windows, and the company expects a demand reduction of 1.75 percent when VVO is fully deployed (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 98-101).

iii. Energy Efficiency

Past EE efforts and outcomes were embedded in the historical loading information Unitil used for the demand assessment forecast (D.P.U. 24-12, Exh. UN-Forecast-1, at 13). The company expects EE investments and savings to continue but does not identify them in the forecast due to the difficulty in disaggregating historical EE savings from the historical load data (D.P.U. 24-12, Exh. UN-Forecast-1, at 13). Based on the 2022 through 2024 Three-Year EE Plan, the expected energy savings is approximately 0.5 MW, and the company will adjust future annual demand forecasts as subsequent EE plans are developed (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 84).

iv. Electric Vehicles

For the five- and ten-year forecasts, the company included PHEVs and BEVs (D.P.U. 24-12, Exhs. UN-Forecast-1, at 10; UN-ESMP-1 (Corrected) at 101). The company used ISO-NE EV Adoption Forecasts by state as the basis for the company's EV load projections (D.P.U. 24-12, Exh. UN-Forecast-1, at 10). These ISO-NE forecasts along with ISO-NE state data on registered EV stock were used to project the number of EVs on the road and the number of EV chargers within Unitil's service territories (D.P.U. 24-12, Exh. UN-Forecast-1, at 10).

v. Heat Pumps

The company considered two types of residential electrification in its load projections, appliance load and heating/air conditioning load (D.P.U. 24-12, Exhs. UN-Forecast-1, at 11; UN-ESMP-1 (Corrected) at 101). The company used residential electrification assumptions to develop hourly residential electrification peak day forecasts (D.P.U. 24-12, Exh. UN-Forecast-1, at 11). Unitil added hourly residential electrification forecasts to the hourly base seasonal peak demand forecasts (D.P.U. 24-12, Exh. UN-Forecast-1, at 11). For commercial customers, the company used peak gas loads for all commercial/industrial gas customers as the basis for its commercial/industrial electrification demand forecasts along with typical hourly electric profiles for the same customer types to produce hourly commercial/industrial electrification demand forecasts (D.P.U. 24-12, Exh. UN-Forecast-1, at 11-12). These forecasts were then added to the hourly base seasonal peak demand forecasts (D.P.U. 24-12, Exh. UN-Forecast-1, at 12).

vi. Energy Storage

To develop the energy storage demand forecast, Unitil considered installed capacity, system configuration, and charging profile (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 85; UN-Forecast-1, at 8-9). The Company assumed sufficient "Bulk" ESS would be installed to level the load curve (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 101; UN-Forecast-1, at 14). Hourly system demand forecasts, including solar PV, EV, and electrification, were used for the five- and ten-year and demand assessment energy storage forecasts (D.P.U. 24-12, Exhs. UN-Forecast-1, at 8; UN-ESMP-1 (Corrected) at 85). The company used hourly load, above/below the peak day average hourly load, to determine the kW peak charge/discharge of energy storage needs (Tr. at 40; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 85). The company assumed that 25 percent of the forecasted energy storage would either be unavailable or doing the opposite of what was required at the time (i.e., charging when loads would dictate discharging and vice versa) (D.P.U. 24-12, Exh. DOER 4-2).

vii. Solar PV

Unitil's solar PV forecasts are based on the three- and five-year historical solar PV capacity growth rates and the number of solar PV facilities and customers served (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 84). The company incorporated these forecasts into the company's peak demand forecasts (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 84). To incorporate solar PV forecasts into the system demand forecasts, the company used the projected incremental solar PV (i.e., solar PV projection minus the in-service solar PV) to develop hourly solar PV projections (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 84). Unitil calculates the normalized hourly peak solar PV output using the average hourly solar PV output of large distributed generation ("DG") on the system for the three peak days of the previous three years for both the winter and summer seasons (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 84). The company then multiplied each hour of normalized average hourly peak solar PV output by the projected incremental solar PV (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 84). Unitil uses the calculated relationship factor between solar PVs with a nameplate capacity of less than 500 kW and solar PV with a nameplate capacity of 500 kW or more to calculate the expected peak output of the incremental forecasted solar PV for each hour (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 85).

viii. Sensitivity Analysis

Unitil conducted an informational-only sensitivity analysis for the five- and ten-year demand forecasts due to the short-term nature of the analysis and time necessary to develop major capital projects (D.P.U. 24-12, Exh. UN-Forecast-1, at 7). The company developed various ranges of adoption, both above and below the baseline forecast amount of each of the forecasts (baseload, solar PV, energy storage, HP, EV and VVO) (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 86). The company then incorporated these various ranges in the company's overall demand forecasting sensitivity analysis (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 86). DER adoption rates in these scenarios were as high as

15 percent to 25 percent above and ten percent to 15 percent below the baseline DER forecasts. (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 86).

4. Demand Assessments

a. NSTAR Electric

i. Overview

NSTAR Electric's 2035-2050 demand assessment indicates unprecedented growth in electric demand and solar generation in its territory (D.P.U. 24-10, Exh. ES-Forecast-1, at 63). The company expects an overall demand increase of 150 percent from today's peak load in its electric service territory to 15,348 MW by 2050 (D.P.U. 24-10, Exh. ES-Forecast-1, at 64).

ii. Demand Response

NSTAR Electric did not provide a separate demand response forecast for the demand assessment forecasting window (D.P.U. 24-10, Exh. AG 1-1, Att.).

iii. Rate Design

NSTAR Electric factored the impact of the existing time-varying rates ("TVRs") into its demand forecast (D.P.U. 24-10, Exh. AG-1-9). The company states that future TVRs are not captured in the forecast (D.P.U. 24-10, Exh. AG-1-9).

iv. Energy Efficiency

NSTAR Electric did not include a separate forecast of the EE component of the demand forecast for the demand assessment forecasting window (D.P.U. 24-10, Exh. AG-1-4).

v. Electric Vehicles

For the demand assessment forecasting window, the company considered the number and type of EVs, number of chargers, kW charger size, and the charging load profile to determine the EV charging demand forecast (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 509-516). NSTAR Electric developed the charging profile for light-, medium-, and heavy-duty vehicles using vehicle mobility data based on the assumption that vehicles charge upon trip termination with the charging duration based on the previous trip's length (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 515). NSTAR Electric also assumed medium- and heavy-duty vehicles charge overnight at their depots, or charge along the routes traveled for long distance trips (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 515-516).

vi. Heat Pumps

To develop the HP demand forecast, the company considered the number of HPs, the kW size of each HP, and load profile (D.P.U. 24-10, Exhs. ES-Forecast-1, at 16; ES-ESMP-1 (Corrected) at 487). For the demand assessment forecasting window, NSTAR Electric used the CECP "All Options" electrification scenario (D.P.U. 24-10, Exh. ES-Forecast-1, at 16). For the base case demand forecast, the company assumed air source HPs to be the core technology while considering other HP technologies as scenarios (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 487). The Company assumed a standard Massachusetts state level heating load profile (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 493).

vii. Energy Storage

For the demand assessment forecasting window, NSTAR Electric used the CECP "High Electrification" scenario to develop the energy storage demand forecast (D.P.U. 24-10, Exh. ES-Forecast-1, at 16). NSTAR Electric included behind-the-meter ESS installations as part of the demand response programs in the forecast (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 231). The company considered both standalone storage and storage co-located with solar PV to determine the energy storage forecast (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 231). The company considered the ESS interconnected to the system to be a load increase to the forecasted system peak unless the interconnection service agreement said otherwise (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 231; AG-1-7).

viii. Solar PV

The company forecasts the load reduction using the projected solar capacity and solar generation potential in its territory (D.P.U. 24-10, Exh. ES-Forecast-1, at 58). The solar capacity forecast incorporates existing and forecasted ground-mounted solar and rooftop solar projects (D.P.U. 24-10, Exh. ES-Forecast-1, at 58). The annual forecasted ground-mounted solar capacity followed the trajectory defined at the state level in the 2050 Decarbonization Roadmap, which projects ground-mounted solar to comprise 70 percent of installed solar capacity in Massachusetts by 2050 (D.P.U. 24-10, Exh. ES-Forecast-1, at 56).

ix. Sensitivity Analysis

For the demand assessment window, the company created its base case demand forecast for 2035-2050 using the Commonwealth's "All Options" pathways, with sensitivity analysis for additional heating pathways and varying levels of demand response and EV managed charging (D.P.U. 24-10, Exh. ES-Forecast-1, at 41). The company simulated HP electrification with the "Phased" scenario, "Full Electrification" scenario, "Hybrid" scenario and "High Electrification" scenario (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 481). The company simulated demand response scenarios with five percent demand response and no demand response (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 481). The company simulated EV electrification with scenarios for moderate, high, and ideal managed charging participation (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 481).

b. National Grid

i. Overview

National Grid's demand assessment is modeled to meet the Commonwealth's climate goals via the "All Options" and "Phased" Scenarios in the CECP and shows that electric demand will more than double by 2050 to 10,671 MW (D.P.U. 24-11, Exh. NG-Forecast-1, at 29). This increase in load is primarily driven by beneficial electrification in the transportation and heating sectors (D.P.U. 24-11, Exh. NG-Forecast-1, at 29).

ii. Demand Response

National Grid modeled and provided a separate demand response forecast for demand response resources enrolled in the retail program (i.e., not part of ISO-NE wholesale demand response) as load reduction in the demand assessment window (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) Appendix at Exhibit 7 (ELF Report-Peak) at 18). In 2022, the estimated impact on summer peak was 101 MW, in the retail program only, and is expected to grow to about 222 MW by the year 2050 (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) Appendix at Exhibit 7 (ELF Report-Peak) at 19).

iii. Rate Design

The impact of the existing TVRs for its G3 rate class was factored into National Grid's demand forecast with some modest customer growth in the G3 rate class based on the econometric forecast (D.P.U. 24-11, Exh. AG-1-7). However, the company made no assumptions beyond this forecast regarding rate design or TVRs (D.P.U. 24-11, Exh. AG-1-7).

iv. Energy Efficiency

National Grid assumed the cumulative amount of persistent EE savings will continue to increase but at a slower rate each year (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) Appendix at Exhibit 7 (ELF Report-Peak) at 13). For the entire service territory in 2022, the company's EE program reduced summer peak demand by 1,298 MW and by 2050, it is expected that this reduction in summer peak will increase to 1,641 MW (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) Appendix at Exhibit 7 (ELF Report-Peak) at 13-14).

v. Electric Vehicles

The company considered the number of EVs, number of chargers, kW charger size, and the charging load profile to determine the EV charging demand forecast (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 398 & Appendix at Exhibit 7 (ELF Report-Peak) at 16). The charging profile was based on the ISO-NE study (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 398; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) Appendix at Exhibit 7 (ELF Report-Peak) at 16).

vi. Heat Pumps

To develop the HP demand forecast, the company considered the number of HPs, the kW size of each HP, and the load profile (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 221, 227, 231-232, 391-400 & Appendix at Exhibit 7 (ELF Report-Peak) at 17-18, 110). The heating load profile showed a morning spike and a moderate evening increase (D.P.U. 24-11, Exh. NG-Forecast-1, at 23). For the demand assessment forecasting window, National Grid used the CECP "Phased" electrification scenario (D.P.U. 24-11, Exh. NG-Forecast-1, at 8, 12). This "Phased" scenario allowed for hybrid HP systems in the near term and pivoted to whole-home HPs in the long-term (D.P.U. 24-11, Exh. NG-Forecast-1, at 8, 12).

vii. Energy Storage

To develop the energy storage demand forecast, National Grid considered installed capacity, system configuration, and the charging profile (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) Appendix at Exhibit 7 (ELF Report-Peak) at 19, 113). For the demand assessment forecasting window, National Grid used the CECP "All Options" scenario to develop the energy storage demand forecast (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) Appendix at Exhibit 7 (ELF Report-Peak) at 19). The company assumed some customers may use their storage to serve their own needs and times (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) Appendix at Exhibit 7 (ELF Report-Peak) at 19). The company assumed that 85 percent of the installed energy storage amounts will impact the demand assessment peak load (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) Appendix at Exhibit 7 (ELF Report-Peak) at 113).

viii. Solar PV

The company's demand assessment included behind-the-meter rooftop and ground-mounted distributed solar PV as outlined in the "All-Options" scenario in the 2050 Roadmap (D.P.U. 24-11, Exh. NG-Forecast-1, at 28). For the Company's service territory, the base scenario models about 3.1 GW of behind-the-meter PV and 3.6 GW of ground-mounted solar PV (D.P.U. 24-11, Exh. NG-Forecast-1, at 28).

ix. Sensitivity Analysis

For the demand assessment windows, the company used base, low, and high scenarios for each DER to generate a range of possible outcomes to address uncertainty in its 2035 to 2050 forecasts (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) Appendix at Exhibit 7 (ELF Report-Peak) at 25-26; NG-Forecast-1, at 21;). The company then combined all permutations of the sensitivities for the different DERs to create different demand scenarios, and an uncertainty range around the demand assessment (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) Appendix at Exhibit 7 (ELF Report-Peak) at 25-26; NG-Forecast-1, at 21).

c. Unitil

i. Overview

Unitil's 2035-2050 demand assessment indicates that the company's system will be winter peaking driven by the electrification of heating loads, and that load is expected to increase approximately 2.5 times, after load reduction attributable to DERs, to 383 MW by 2050 (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 193; UN-Forecast-1, at 27).

ii. Demand Response

Unitil did not provide a separate demand response forecast for the demand assessment forecasting window, but rather it embedded existing demand response capacity in the baseload component of its demand forecast and expects demand response to increase at historical baseload growth rate (Tr. at 47; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 193; AG 3-17). Unitil modeled and provided a separate VVO forecast for the demand assessment forecasting window which shows an expected 5.7 MW reduction by 2050 (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 193).

iii. Rate Design

Unitil offers an EV TOU rate but did not indicate whether it considered the impact of this rate or other rate designs in its demand assessment (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 110).

iv. Energy Efficiency

Unitil did not include a separate forecast of the EE component of the demand forecast in its demand assessment (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 84). Based on the 2022 through 2024 Three-Year EE Plan, the expected energy savings is approximately

0.5 MW and the company will adjust future annual demand forecasts as subsequent EE plans are developed (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 84). For the demand assessment, the company assumed that past EE savings are embedded in the historical baseload and expects those savings to continue (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 84).

v. Electric Vehicles

Unitil considered the number of EVs, number of chargers, kW charger size, and the charging load profile to determine the EV charging demand forecast (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 202-205). The charging profile was based on ISO-NE and Edison Electric Institute data (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 202-205).

vi. Heat Pumps

To develop the HP demand forecast, the company considered the number of HPs, the kW size of each HP, and the load profile (D.P.U. 24-12, Exh. UN-Forecast-1, at 8, 21, 23). For the demand assessment forecasting window, Unitil used the CECP "All Options" electrification scenario (D.P.U. 24-12, Exh. UN-Forecast-1, at 8). For the demand forecast, the company assumed air source HPs to be the dominant technology with ground source HPs playing a minor role (D.P.U. 24-12, Exh. UN-Forecast-1, at 21). The heating load profile showed peaks are likely to occur in the morning hours (D.P.U. 24-12, Exh. UN-Forecast-1, at 23).

vii. Energy Storage

For the demand assessment forecasting window, Unitil used the CECP "All Options" scenario to develop the energy storage demand forecast (D.P.U. 24-12, Exh. UN-Forecast-1, at 8). Hourly system demand forecasts, including solar PV, EV, and electrification, were used as a basis for the energy storage forecasts (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 85; UN-Forecast-1, at 8). The company used hourly load, above or below the peak day average hourly load, to determine the kW peak charge/discharge of ES needs (Tr. at 40; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 85). The company assumed that 25 percent of the forecasted energy storage would either be unavailable or doing the opposite of what was required at the time (i.e., charging when loads would dictate discharging and vice versa) (D.P.U. 24-12, Exh. DOER 4-2).

viii. Solar PV

The company utilized the same forecasting methodology described under the five- and ten-year forecasts for the 2035-2050 electric demand assessment (D.P.U. 24-12, Exh. UN-Forecast-1, at 25). However, starting in 2035 the company assumed the addition of one additional "large" DER/PV facility per year through 2050 (D.P.U. 24-12, Exh. UN-Forecast-1, at 25). Unitil selected this adoption rate because it supports the recent adoption rates, while also meeting the demographics of the company's service territory and its scaled proportion of the Commonwealth's clean energy goals (D.P.U. 24-12, Exh. UN-Forecast-1, at 25).

ix. Sensitivity Analysis

For the demand assessment window, the company developed a sensitivity analysis for each of the forecasts (baseload, solar PV, ESS, HP, EV and VVO) that the company combined into the overall system peak forecasts (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 191). Based on current load growth and adoption and current equipment lead times, the company selected an overall forecast with a lower growth/adoption rate in the early years of the forecasts with a higher growth/adoption rate in the later years (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 191). In the event a more aggressive growth/adoption rate is realized, the required years for a project could move three to five years sooner than currently forecasted and the less aggressive forecasts could defer projects by one to two years (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 191).

5. Patterns and Forecasts of DER Adoption

a. Overview

The Companies maintain that they considered and incorporated DER adoption and electrification technology trends in their five- and ten-year demand forecasts and their demand assessments through 2050 and aligned their forecasts with the CECPs and 2050 Decarbonization Roadmap. The following tables provide the results of each company's forecast of DERs, including electrification technologies, and VVO. Tables 1 and 2 provide an overview of DER adoption through 2033 per sub-region of NSTAR Electric's service territory and through 2034 for National Grid's service territory, respectively (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 257, 266-267, 274, 282; D.P.U. 24-11, Exh. NG-ESMP-1

(Corrected) at 224, 228, 233, 241, 237, 245). Table 3 provides an overview of DER adoption through 2034 for the Unitil service territory (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 101).

Table 1:

	NSTAR Electric 10-Year DER Forecast (through 2033) MW					
	EV load	Heating	EE impact	Solar PV Impact	Step Load	Energy Storage
Metro Boston	129	0	-110	-3	605	0
Metro West	165	0	-89	-60	189	0
Southern	163	0	-43	-38	8	0
Western	144	0	-52	-74	31	0

Table 2:

	National Grid 10-Year DER Forecast (through 2034) MW			
	EV Load	Heating	EE Impact	Solar PV Impact
Central	150	13	-21	-20
Merrimack Valley	150	8	-12	-22
North Shore	116	9	-8	-11
South Shore	177	10	-17	-8
Southeast	157	12	-17	-19
Western	98	8	-8	-8

Table 3:

Unitil 10-Year DER Forecast (through 2034) MW				
EV Load	Heating	Solar PV Impact	Energy Storage	VVO
8.7	31.1	0	-3.4	-2.2

b. Demand Response

Each company considered the load-reducing impact of demand response programs to determine the net five- and ten-year forecasts consistent with the Commonwealth's CECP objective to prioritize greater deployment of load flexibility measures to minimize necessary distribution system expansion (Tr. at 46-47; D.P.U. 24-10, Exh. ES-Forecast-1, at 13-14; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 215 & Appendix at Exhibit 7 (ELF Report-Peak) at 18-19; D.P.U. 24-12, Exh. AG 3-17). See 2050 CECP at 75; 2050 Decarbonization Roadmap at 102. NSTAR Electric and Unitil did not provide separate demand response forecasts for any of the three forecasting windows. Rather, they both assumed existing demand response capacity is embedded in the baseload component of their forecast (Tr. at 47; D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 250; AG 1-1, Att.; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 101, 193; AG 3-17). NSTAR Electric assumed no expected growth, while Unitil assumed expected growth at the historical baseload rate (Tr. at 47; D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 250; AG 1-1, Att.; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 101, 193; AG 3-17). National Grid provided a separate demand response forecast for all three demand forecasting windows (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 215 & Appendix at Exhibit 7 (ELF Report-Peak) at 19). The estimated impact of demand response on the system peak is expected to grow to 84 MW by 2029 and 98 MW by 2034 and about 222 MW by year 2050 (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 215 & Appendix at Exhibit 7 (ELF Report-Peak) at 19).

c. Energy Efficiency

Each company considered the load-reducing impact of EE programs to determine the final net demand forecast consistent with the 2050 CECP State EE benchmarks for the buildings and industrial sectors (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 209, 482;

D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected at 393; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 190-191). See 2050 CECP at 23 and 25. NSTAR Electric and National Grid provided separate EE forecasts for the five- and ten-year forecasting windows, and National Grid did so for the demand assessment forecasting window as well (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 244; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 215 & Appendix at Exhibit 7 (ELF Report-Peak) at 13, 14). Unitil, for its part, expects EE investments and savings to continue, but did not provide separate forecasts (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 84, 101; UN-Forecast-1, at 13). For NSTAR Electric, the EE impact on the system peak is expected to increase to 182 MW by 2029 and 294 MW by 2033 (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 244). The EE impact on the system peak is expected to increase from 1,338 MW in 2023 to 1,547 MW and 1,641 MW in 2050 (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 215 & Appendix at Exhibit 7 (ELF Report-Peak) at 13, 14).

d. Electric Vehicles

To determine the EV demand forecasts, the Companies proportionally shared the Statewide Climate Benchmark data set out in the 2050 CECP (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 209, 482; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 393; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 78). See 2050 CECP at 22. The Companies then disaggregated the EV fleet into light-, medium-, and heavy-duty vehicles to develop model input assumptions for each vehicle type (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 511; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 397; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 191). The Companies each provided an EV forecast for all three forecasting windows. The EV charging impact on NSTAR Electric's system peak is expected to increase to 267 MW by 2029, 600 MW by 2033 and 4,186 MW in 2050 (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 244, 532). The EV charging impact on National Grid's system peak is expected to increase to 215 MW by 2029, 760 MW by 2034 and 3,110 MW in 2050 (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 215 & Appendix at Exhibit 7 (ELF Report-Peak) at 17). The EV charging impact on Unitil's system peak is expected to increase to 4.6 MW by 2029, 8.7 MW by 2034, and 98.5 MW in 2050 (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 101, 193).

e. Heat Pumps

To determine the electric HP demand forecast for each company, the Companies proportionally shared the statewide Climate Benchmark set out in the 2050 CECP (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 209, 482; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 393; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 78). See 2050 CECP at 23. National Grid and Unitil each provided separate electric HP forecasts for each forecasting window, while NSTAR did not because its system is expected to peak in summer through 2035. After 2035, NSTAR Electric's HP heating load on the system peak is expected to increase from 3,522 MW in 2035 to 7,517 MW in 2050 (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 252; AG 1-1, Att.). The HP load on National Grid's system peak is expected to increase to 28 MW by 2029, 74 MW by 2034 and 2,838 MW in 2050 (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 20, 215). The HP load on Unitil's system peak is expected to increase to 4 MW by 2029, 31 MW by 2034, and 208 MW by 2050. (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 101, 193).

f. Energy Storage

To determine the energy storage demand forecast for each company, the Companies proportionally shared the statewide Climate Benchmark set out in the 2050 CECP (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 482; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 393; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 78). See 2050 CECP at 24. Unlike NSTAR Electric, National Grid and Unitil provided separate energy storage forecasts for the three forecasting windows (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 244; AG 1-1, Att.; AG 1-7, at 2; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 20, 215; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 101, 193). For National Grid, the energy storage load-reducing impact on the system peak is expected to increase from 161 MW in 2023 to 297 MW in 2050 (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 20, 215). For Unitil, the energy storage load-reducing impact on the system peak is expected to increase from 0.5 MW in 2025 to 15 MW in 2050 (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 101, 193).

B. Positions of the Parties

1. Attorney General

The Attorney General contends that because the demand forecasts will guide the timing, location, and size of future investments, it is imperative that they be as accurate as possible, have reasonable inputs and assumptions, and are aligned across all three

Companies' ESMPs (Attorney General Brief at 11). The Attorney General further maintains that if the Companies' ESMPs are not aligned, progress towards the Commonwealth's climate goals could develop unevenly and unfairly (Attorney General Brief at 11, citing Exh. AG-BF-1, at 21).

The Attorney General notes that, despite the need for consistency, the ESMPs include significant differences regarding forecasting data inputs and methodologies (Attorney General Brief at 12). The Attorney General argues that the Companies must use consistent approaches to forecasting to allow meaningful comparison and evaluation of said forecasts, as well as alignment with the overall ESMP objectives (Attorney General Brief at 12, citing Exh. AG-BF-1, at 21-25).

The Attorney General noted that for the five- and ten-year forecasts, NSTAR Electric and Unitil did not model demand response and National Grid and NSTAR Electric did not model VVO (Attorney General Brief at 12, citing Exh. AG-BF-1, at 23-24). The Attorney General avers that demand response and VVO reduce demand on the distribution system and as separately modelled components would provide transparency around their contribution to load reduction as DERs (Attorney General Brief at 13, citing Exh. AG-BF-1, at 23-24). The Attorney General further contends that the Companies' forecasts did not comprehensively consider load management potential for energy storage, and electrified buildings and vehicles (Attorney General Brief at 17, citing Exh. AG-NBC-1, at 37-38). The Attorney General claims, therefore, that the Companies should evaluate all cost-effective load management programs (Attorney General Brief at 17, citing Exh. AG-NBC-1, at 37-38).

The Attorney General notes that none of the three company forecasts explicitly considered future building code changes and also that they assumed zero EE savings in their demand assessment forecasts (Attorney General Brief at 16, citing Exh. AG-NBC-1, at 36). The Attorney General asserts that the ESMPs fail to adequately analyze these potential load reduction factors and that the Companies are wrong to assume no impact to the forecasts outside of the historic baseload trend (Attorney General Brief at 16, citing Exh. AG-NBC-1, at 36). The Attorney General argues that this assumption ignores the potential for material changes to residential building codes, continuing investment in EE, and future technology development (Attorney General Brief at 16, citing Exh. AG-NBC-1, at 36-37).

The Attorney General notes that NSTAR Electric and Unitil's methodologies for EV forecasting were developed in-house and contends that they lack sufficient data to support the assumptions and calculations (Attorney General Brief at 16, citing D.P.U. 24-10, Exh. AG-1-6; D.P.U. 24-12, Exh. UN-ESMP-1, at 91). The AG argues that the tool National Grid used, the NREL EVI-Pro tool, uses more robust data, has been used across the country, and is a better option that the in-house methods NSTAR Electric and Unitil used (Attorney General Brief at 16-17, citing Exh. AG-NVC-1, at 36). Based on the above, the Attorney General contends that the Department should direct the Companies to develop a plan to present improved analysis of electrification loads in the next ESMP (Attorney General Brief at 17).

With respect to heating electrification, the Attorney General notes that the forecasts vary; NSTAR Electric and National Grid modeled HP adoptions through 2024 on their approved three-year EE plans, while Unitil did not (Attorney General Brief at 13). The Attorney General further notes that NSTAR Electric and National Grid used different CECP trajectories for HP modeling (Attorney General Brief at 13). The Attorney General argues these are apparently arbitrary choices (Attorney General Brief at 13).

The Attorney General argues that there is no uniformity in the CECP scenarios/trajectories the Companies used for their energy storage demand forecasts (Attorney General Brief at 12, citing Exhs. D.P.U. 24-10, Exh. ES-Forecast-1, at 16; D.P.U. 24-11, Exh. NG-Forecast-1, at 8-9; D.P.U. 24-12, Exh. UN-Forecast-1, at 8). Further, the Attorney General asserts that the need for a baseline consistency is not just necessary, but achievable (Attorney General Brief at 12, citing Exh. AG-BF-1, at 21-25).

The Attorney General notes that NSTAR Electric and National Grid did not provide forecast sensitivities in the five- and ten-year forecasts (Attorney General Brief at 14, citing Exh. AG-BF-1 at 25-27). The Attorney General asserts that regardless of the relatively shorter time range, the Department should require the Companies to run sensitivities for key assumptions in the five- and ten-year forecasts and that the sensitivities should be comparable across the Companies (Attorney General Brief at 15, citing Exh. AG-BG-1, at 14). The Attorney General also argues that the Companies should address demand forecast uncertainties as result of changing building codes, new technology, new equipment efficiencies, and changing customer adoption rates (Attorney General Brief at 15, citing Exh. AG-BG-1 at 26).

2. DOER

DOER argues that the ESMPs did not demonstrate that the Companies adequately considered load management measures to meaningfully reduce their peak load and meet the objectives for the ESMPs enumerated in the 2022 Climate Law (DOER Brief at 43). DOER contends that, to meet the Commonwealth's GHG emissions reduction mandates in a cost-efficient manner, the Companies' forecasts should reflect demand management and reduction technologies (DOER Brief at 43). DOER asserts that the Department should require the Companies to include robust load management and flexible DER programs as an element of the company forecasts for future ESMPs (DOER Brief at 45).

DOER argues that none of the Companies considered how rate design could impact their demand forecasts, thereby overlooking a critical forecast input (DOER Brief at 53, citing D.P.U. 24-10, Exh. AG-1-9; and D.P.U. 24-11, Exh. AG-1-7). DOER contends, therefore, that the ESMPs fail to adequately account for the critical role that rate design can play in load management, and the Companies fail to meet their statutory requirement to consider "alternatives to proposed investments, including changes in rate design" in their ESMPs (DOER Brief at 54, citing Section 92B(b)(viii)). DOER avers that this failure also undermines the Companies' forecasts' capacity to justify infrastructure investments (DOER Brief at 54). DOER recommends that the Department require that future ESMPs include a scenario analysis of rate design in the Companies' forecasts, and analysis and narrative discussion of the types of rate designs the Companies consider potentially able to support least-cost distribution system planning to meet clean energy goals (DOER Brief at 55).

DOER contends that each of the Companies' different approaches to energy storage underestimates the ability of ESS to lower peak demand, potentially resulting in lower investments on the Companies' systems (DOER Brief at 45). DOER noted that NSTAR Electric assumed zero MW impact of ESS in its ten-year demand forecast because the company does not forecast any peak demand reductions for ESS, except in limited circumstances (DOER Brief at 45-46, citing D.P.U. 24-10, Exh. ES-ESMP-1, at 231). DOER asserts that, by disregarding the role of energy storage in reducing peak demand, NSTAR Electric fails to meet the statutory requirement that its ESMP "promote energy storage and electrification technologies necessary to decarbonize the environment and economy," and "deploy energy storage technologies to improve renewable energy utilization" and "alternatives to proposed investments, including changes in load management" (DOER Brief at 46, citing Section 92B(a)(iii), (b)(vii)-viii)).

With respect to National Grid, DOER argues that the company's decision to keep the charge/discharge profiles of energy storage static through 2050 results in a counterintuitive and unlikely ESS forecast (DOER Brief at 47). DOER further maintains that National Grid's ESS assumptions are problematic, result in highly unlikely swings in peak impact year-over-year, and demonstrate significant underestimation of the impact of energy storage (DOER Brief at 47).

DOER notes that, like National Grid, Unitil assumed static charge/discharge profiles for energy storage throughout the forecast period, and further assumes 25 percent of the forecasted storage would be unavailable, or doing the opposite of what was required at the time (i.e., charging when loads would dictate discharging and vice versa) when needed (DOER Brief at 48, citing D.P.U. 24-12, Exh. DOER 4-2(a). DOER therefore asserts that due to these unsupported or erroneous assumptions, Unitil's forecasting approach is also flawed (DOER Brief at 49).

3. Acadia Center

Acadia Center avers that the Companies fail to supply sufficient explanation for why they make different forecasting assumptions, such as the fact that for DR, National Grid presumed existing company demand response programs would continue, NSTAR Electric simulated scenarios with five percent demand response or no demand response, and Unitil did not consider demand response (Acadia Center Brief at 28, citing D.P.U. 24-10, Exh. ES-ESMP-1, at 481). These variations in forecasting assumptions, Acadia Center contends, taken together with the Companies not including scenario analyses in their five- and ten-year forecasts, make it difficult to compare the reasonableness of the various company forecasts (Acadia Center Brief at 29, citing GMAC Consultant Comments 39). Acadia Center therefore argues that the Department should require the Companies to use consistent modeling assumptions and comprehensive explanations for why they made choices in future ESMP filings (Acadia Center Brief at 29).

4. Williams College

Williams College takes issue with National Grid's decision not to focus forecasting on customer-specific needs (Williams College Brief at 8-10). To achieve the Section 92B's requirement to accommodate increased building electrification and other potential future demands, Williams College contends, National Grid's ESMP must include either affirmative actions to engage with customers and meet their specific needs or concrete plans to implement such affirmative actions, and National Grid should not rely on generic system expansions based on forecasts that will "in all cases be too high or too low" (Williams College Brief at 10). Williams College avers that National Grid treats building electrification spot loads reactively, rather than proactively, and that the company's process places significant burdens on customers wishing to increase their loads, which is inconsistent with Section 92B's mandate for proactive plans to provide service for building electrification among other customer needs (Williams College Brief at 13-14).

5. Companies

The Companies argue that they complied with all statutory and Department-directed filing requirements (Companies' Joint Brief at 36). More specifically, the Companies contend that they provided reasonable, reviewable, and reliable forecasts and demand assessments based on accurate data and reasonable methods that provide a sound basis for the Companies' incremental ESMP investments (Companies' Joint Brief at 36-37).

The Companies aver that they worked together to align forecast assumptions and methodologies where possible (Companies' Joint Brief at 38, citing D.P.U. 24-10, Exh. DPU-Common 5-1; D.P.U. 24-11, Exh. DPU-Common 5-1; D.P.U. 24-12, Exh. DPU-Common 5-1). The Companies note that they all developed the baseload forecasts under the design weather criteria (the 90th percentile scenario), and all independently forecasted DERs based on current market trends, policies, programs, and the

Commonwealth's decarbonization pathways (Companies' Joint Brief at 38, citing D.P.U. 24-10, Exh. ES-ESMP-1, §§ 5.1, 8.1; D.P.U. 24-11, Exh. NG-ESMP-1, §§ 5.1, 8.1; D.P.U. 24-11, Exh. UN-ESMP-1, §§ 5.1, 8.1). Where the Companies used different forecast assumptions, they maintain, it was because doing so would produce more accurate forecasts for the particular company (Companies' Joint Brief at 39). The Companies argue that a "one-size-fits-all" forecast could limit the Companies' ability to facilitate meeting the Commonwealth's GHG emissions reduction targets, as standardization may come at the cost of nuance in factors present in each company's service territory (Companies' Joint Brief at 40, citing D.P.U. 24-10, Exh. DPU Common 7-5; D.P.U. 24-11, Exh. DPU Common 7-5; D.P.U. 24-12, Exh. DPU Common 7-5).

The Companies also assert that they used accurate, reliable data in the forecasts from internal sources to paid third-party subscriptions (Companies' Joint Brief at 41, citing D.P.U. 24-10, Exh. AG 4-5; D.P.U. 24-11, Exh. AG 3-5; D.P.U. 24-12, Exh. AG 3-5). The Companies aver that they have thoroughly explained their forecasting methodologies, including the rationale for methodologies and assumptions, as well as provided sources (Companies' Joint Brief at 41).

The Companies assert that Williams College's claims are baseless and without merit. The Companies argues, contrary to Williams College's assertion, that National Grid is not merely being reactive to spot loads (Companies' Joint Reply Brief at 47). The Companies assert that National Grid's ESMP five-year plan and proposed investments proactively build capacity in the system to avoid bottlenecks in meeting customer requests (Companies' Joint

Reply Brief at 47, citing Tr. 2, at 258). The Companies claim that National Grid uses local information, including land parcel characteristics, customer adoption records, customer heating fuel types, and demographic information, to analyze local load (Companies' Joint Reply Brief at 47-48). The Companies maintain that, even with proactive planning, a forecast cannot be a substitute for project- and site-specific consultation between customers and National Grid (Companies' Joint Reply Brief at 48). For this reason, the Companies aver, National Grid cannot rely on expectations or likely customer behavior when developing its forecasts (Companies' Joint Reply Brief at 48). Because forecasts are a critical component of capital planning and ensuring a safe and reliable power system, the Companies argue, National Grid must use only reliable and known data when forecasting (Companies' Joint Reply Brief at 49).

The Companies argue that they considered load management and demand response through the trend component of their forecasts to the extent these programs deliver quantifiable impacts (Companies' Joint Reply Brief at 44, citing Tr. at 135-137). The Companies contend that the Attorney General's recommendation to include the "technical potential" of future demand response would put the Companies in the untenable position of having to guess what future changes might occur on these important topics which may have meaningful impacts on the forecast results and planning the electric system for safe, reliable operation (Companies' Joint Reply Brief at 44-45). Accordingly, the Companies do not support the Attorney General's recommendation to include "technical potential" in the forecast (Companies' Joint Reply Brief at 45).

The Companies stated that they will collectively explore changes to rate design options, including TVRs, in a generic proceeding or other appropriate dockets, which may result in rate design changes to be implemented prior to the next ESMP or at the time of the next ESMP term (Companies' Joint Brief at 49).

The Companies claim that they captured the historical evolution of building codes to become more energy efficient in the underlying baseload forecast and all new step loads already adhere to the applicable building codes (Companies' Joint Reply Brief at 44, citing D.P.U. 24-10, Exh. ES-ESMP-1, at 504; D.P.U. 24-11, Exh. NG-ESMP-1, at 218; D.P.U. 24-12, Exh. UN-ESMP-1, at 22). According to the Companies, the Attorney General's recommendation to include the "technical potential" of future building code changes and energy efficiency would put the Companies in the untenable position of having to guess what future changes might occur on these important topics which may have meaningful impacts on the forecast results and planning the electric system for safe, reliable operation (Companies' Joint Reply Brief at 44). Accordingly, the Companies do not support the Attorney General's recommendation to include "technical potential" in the forecast (Companies' Joint Reply Brief at 44).

NSTAR Electric and Unitil strongly disagree with the Attorney General's conclusion that their EV forecasts are inaccurate because they were developed in-house, especially since NSTAR Electric and Unitil's models are directly matched to their territories, whereas the National Renewable Energy Laboratory ("NREL") models are national and intended to be universally applicable (Companies' Joint Reply Brief at 45). Contrary to the Attorney

General's assertion, the Companies contend that the fact that the NREL EVI-Pro tool is a nationwide tool does not necessitate each company's use of the tool (Companies' Joint Reply Brief at 46). The Companies argue that NSTAR Electric's EV modeling is very detailed and tailored to its service territory (Companies' Joint Reply Brief at 46).

The Companies argue that the different decarbonization pathways for heating electrification they used are substantially similar (Companies' Joint Brief at 39, citing Tr. at 153-154). The differences in these assumptions, the Companies contend, are superficial (Companies' Joint Brief at 39). More specifically, the Companies note that the "Full Electrification" scenario used by NSTAR Electric and National Grid is substantially similar to the "All Options" pathway used by Unitil (Companies' Joint Brief at 39, citing Tr. at 153-154). The Companies argue that even if they used different decarbonization pathways for energy storage, the "Full Electrification" scenario is substantially similar to the "All Options" pathway (Companies' Joint Brief at 39, citing Tr. at 153-154).

The Companies argued that they do not rely on sensitivities for the five-year and ten-year forecasts because the shorter-term forecast is used for capital projects needed in the near term (Companies' Joint Brief at 41, citing D.P.U. 24-10, Exh. ES-Forecast-1, at 14-15; D.P.U. 24-12, Exh. UN-Forecast-1, at 7). The Companies claim that the five- and ten-year forecasts are used to ensure each company maintains a reliable and safe electric system based on known and reliable data sources and, therefore, are not conducive to sensitivities based on stakeholder opinions of how load might develop over the next decade (Companies' Joint Brief at 41). The Companies assert that the introduction of sensitivities and external stakeholder opinion into the five- and ten-year forecasts, which drive capital plan decisions, would add significant and unacceptable risk to the ability of the Companies to provide safe and reliable service to their customers during these near-term periods (Companies' Joint Brief at 42). The Companies are willing to work with GMAC and other stakeholders on sensitivities to the long-term demand assessment (Companies' Joint Brief at 42).

C. Analysis and Findings

1. Introduction

Below, the Department first reviews each company's forecasts and demand assessments for compliance with the requirements of Section 92B(b)(iii) and (c)(i). Then we address the Companies' forecast methodology, including the appropriate standard for our review of the ESMP forecasts and demand assessment.

2. Compliance with Statute

Section 92B(b)(iii) directs that the ESMPs describe in detail the patterns and forecasts of DER adoption in the company's territory. Section 92B(c)(i) directs the Companies to prepare and use three planning horizons for electric demand, including a five-year forecast, a ten-year forecast, and a demand assessment through 2050 to account for future trends, including but not limited to, future trends in the adoption of renewable energy, DERs, energy storage, and electrification technologies necessary to achieve the statewide GHG emissions limits and sublimits under Chapter 21N. NSTAR Electric, National Grid, and Unitil each included in their respective ESMPs a description of DER adoption in its territory and forecasts of electric demand on its distribution system over the next five years, ten years, and through calendar year 2050 (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 245-254 & § 4.0; ES-Forecast-1, at 8; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected), §§ 4.0, 5.0; NG-Forecast-1, at 4; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 81-104 & § 4.0; UN-Forecast-1, at 5). Accordingly, the Department determines that each company's ESMP complies with the requirements of Section 92B(b)(iii) and (c)(i).

3. Forecasting Methodologies

Pursuant to G.L. c. 164, § 69*I*, gas distribution companies must submit for Department approval a long-range forecast and supply plan every two years. The Department's precedent for review of gas forecast and supply plans is well-established. The Department, in reviewing such plans, must determine whether the gas distribution company's long-range forecast and supply plan adequately projects and meets customer demand in its service area. See, e.g., Fitchburg Gas and Electric Light Company, D.P.U. 23-25, at 2 (December 22, 2023). The Department is authorized to approve a long-range gas forecast if the forecast projections are based on accurate information and reasonable methods and are consistent with the approved forecasts of other gas companies. D.P.U. 23-25, at 4.

Prior to the Restructuring Act, electric distribution companies submitted integrated resource plans ("IRP") for Department review and approval. These IRPs outlined the utility company's plans for meeting forecasted annual peak and energy demand over a specified period and were submitted pursuant to G.L. c. 164, § 69*I*, the same statute that continues to apply to gas forecast and supply plans today. As such, the Department finds that applying our long-standing precedent for review of gas forecast and supply plans to our review of the

ESMP forecasts and demand assessments is reasonable and appropriate. The Department will therefore assess the reasonableness of each company's forecast method based on whether the method is: (a) reviewable, that is, contains enough information to allow a full understanding of the forecast method; (b) appropriate, that is, technically suitable to the size and nature of the particular company; and (c) reliable, that is, provides a measure of confidence that the company's assumptions, judgments, and data will forecast what is most likely to occur. Bay State Gas Company, D.T.E. 02-75, at 2 (2004); The Berkshire Gas Company, D.T.E. 02-17, at 2 (2003). For the reasons discussed below, the Department determines that each company's forecast methods are reviewable, appropriate, and reliable.

The Companies have been developing demand forecasts to inform their capital investment plans and to fulfill their obligations to provide safe and reliable service long before passage of Section 92B that required the Companies to develop ESMPs (Tr. at 189; D.P.U. 24-10, Exhs. ES-Forecasting-1, at 10; DPU-Common 5-1; D.P.U. 24-11, Exh. DPU-Common 5-1; D.P.U. 24-12, Exh. DPU-Common 5-1). Each company's ESMP forecast methodology is consistent with the company's existing forecasting methodology for capital planning and based on known, factually-driven data (Tr. at 76-82; D.P.U. 24-10, Exh. ES-Forecasting-1, at 11; D.P.U. 24-11, Exh. NG-Forecast-1 at 5; D.P.U. 24-12, Exh. UN-Forecast-1, at 6-7). Indeed, the forecasts submitted with their ESMPs are no different than those that are included in each company's ARR (Tr. at 189, 214). Each year, after the June to August summer peak, the Companies each prepare five- and ten-year demand forecasts which are then completed in March of the following year and filed with the

Department in their ARRs due on March 31 of each year (Tr. at 189, 214; Tr. 6, at 847, 915-916; D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 209; D.P.U. 24-11, Exh. DPU-Common-7-5(b); D.P.U. 24-12, Exh. DPU-Common-7-5(b)). Further, the Companies improve upon their forecasting methodology each year (Tr. at 189; D.P.U. 24-10, Exh. ES-Forecasting-1, at 11; D.P.U. 24-12, Exh. NG-Forecast-1, at 5; D.P.U. 24-12, Exh. UN-Forecast-1, at 7, 15). The Companies update data, technology, and practices, including incorporating new empirical data, new programs, new loads, and new uses that were not previously available, doing so as the data and technologies evolve and their system and investment plans are reanalyzed and reprioritized (Tr. at 43, 56, 189-190; Tr. 2, at 254-255; D.P.U. 24-10, Exh. ES-Forecasting-1, at 11; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 293; D.P.U. 24-12, Exh. UN-Forecast-1, at 7).

In their respective ESMP filings, the Companies each detail the steps it took to develop the five- and ten-year forecasts and long-term demand assessment (Tr. at 202-205; D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected), § 5.0; ES-Forecast-1, at 12-16, 41-43; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected), § 5.0; NG-Forecast-1, at 6-10, 20-21; D.P.U. 24-12, Exh. UN-Forecast-1, at 7, 18-19). For example, NSTAR Electric began with actual measured net station peak demand at bulk substations, then adjusted each reported peak for local conditions which produced the weather normalized gross station peak (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 209). NSTAR Electric then used the weather normalized gross station peak plus third-party economic data to determine the historic trend in load growth relative to economic growth. That historic trend was then used to develop the trend demand forecast, which the company adjusted for EE, solar PV, EV, and step loads (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 176, 209; ES-Forecast-1, at 11).[34] Each company provided load projections for the five-year forecast, ten-year forecast, and demand assessment through 2050, and accounted for DERs and electrification technologies (e.g., HPs, EVs, EE, solar PV, and ESS) (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 243, 480; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 20, 215; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 101, 193). The data on which the Companies relied for their load projections is based on data from paid subscriptions and internal sources (D.P.U. 24-10, Exh. AG 4-5; D.P.U. 24-11, Exh. AG 3-4; D.P.U. 24-12, Exh. AG 3-5). This data includes reported substation peaks, years of historical peak-day weather data, territory-specific demographic data, the number of EVs, spot loads, solar PV and EV forecasts, and more (D.P.U. 24-10, Exh. AG 4-5; D.P.U. 24-11, Exh. AG 3-4; D.P.U. 24-12, Exh. AG 3-5). Notably, the Companies reviewed and compared assumptions for the five- and ten-year demand forecasts and each company's methodology is aligned for baseload econometric forecast, design weather conditions, and DERs (Tr. at 205-206; D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 207-208); D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 212, 393-393; D.P.U. 24-12, Exh. UN-ESMP-1, at 76).

Further, the Companies aligned their forecasting assumptions with the electrification scenarios and decarbonization pathways specified in the 2025/2030 CECP, 2050 CECP, and

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34 For further details of the Companies' forecasting methodologies, refer to Section VI.A.

the 2050 Decarbonization Roadmap, respectively (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 208; D.P.U. 24-11, Exh. NG-ESMP-1, at 209, 210; D.P.U. 24-12, Exhs. UN-ESMP-1, at 78, 190; UN-Forecast-1, at 20). The 2050 Decarbonization Roadmap identifies eight decarbonization pathways which support achievement of net zero GHG emissions in 2050 while the 2025/2030 CECP, and subsequently the 2050 CECP, updated modeling and GHG emissions accounting to establish sector-specific sublimits for 2025/2030 and 2050, respectively (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 208; ES-Forecast-1, at 39; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 209; NG-Forecast-1, at 22; D.P.U. 24-12, Exh. UN-Forecast-1, at 18). NSTAR Electric applied the "All Options"[35] pathway from the 2050 Decarbonization Roadmap as the basis for components of its five- and ten-year forecasts, while National Grid and Unitil applied both the "All Options" pathway as well the "Phased" scenario[36] from the 2025/2030 CECP (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 208; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 209; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 77, 195).

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35 The "All Options" pathway is the "benchmark compliant" decarbonization pathway that achieves deep decarbonization and uses midpoint assumptions across most technical parameters. 2050 Decarbonization Roadmap at 15.

36 The "Phased" scenario is described as representing both long-term and near-term benefits over other building decarbonization approaches, involving a rapid adoption of both partial- and whole-home HP systems but allowing for hybrid fossil fuel and electric HP systems in the 2020s and then whole home retrofits thereafter, and leveraging as many intervention points as possible to maximize cost-effective electrification of stock. 2025/2030 CECP at 25-26.

Intervenors identify several areas of concern with the Companies' forecast inputs and methods. Several intervenors raised concerns with the lack of uniformity in the Companies' forecasting methodologies and assumptions, including use of different decarbonization pathways or electrification scenarios for their HP and energy storage forecasts or different forecasting methods for EVs, or the lack of separate forecasts of various inputs such as demand response and VVO (Attorney General Brief at 13, 16-17, citing D.P.U. 24-10, Exh. AG-1-6; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 91). Some intervenors contend that the Companies failed to fully support their assumptions or that they failed to fully consider customer-specific step loads, or load reducers such as rate design, load management, energy storage or future building codes (Attorney General Brief at 16, 17, citing Exh. AG-NBC-1, at 36, 37-38; DOER Brief at 43; Williams College Brief at 8-10). Last, the Attorney General recommended that the Companies address demand uncertainties for key assumptions by providing sensitivity analyses in all three forecasting windows (Attorney General Brief at 15, citing Exh. AG-BF-1, at 14).

In response, the Companies counter that they worked closely to align forecast assumptions and methodologies where possible (Companies' Joint Brief at 38, citing D.P.U. 24-10, Exh. DPU-Common 5-1; D.P.U. 24-11, Exh. DPU-Common 5-1; D.P.U. 24-12, Exh. DPU-Common 5-1). Where they used different forecast assumptions, the Companies maintain it was because doing so would produce more accurate forecasts for the particular company (Companies' Joint Brief at 39). The Companies further contend that they have thoroughly explained their forecasting methodologies, including the rationale for their methodologies and assumptions, as well as provided sources (Companies' Joint Brief at 41).

To begin, the Department determines that notwithstanding differences in certain assumptions, each company's underlying forecasting methods are consistent (Tr. at 191-205, 206-207, 252). In particular, each company plans to use similar design criteria, including recorded system peak and weather normalization to a 90/10 event, as well as to use economic trend analysis to forecast the underlying trend load forward (Tr. at 206-207; D.P.U. 24-10, Exh. ES-Forecast-1, at 12; D.P.U. 24-11, Exh. NG-Forecast-1, at 6; D.P.U. 24-12, Exh. UN-Forecast-1, at 8). Regarding forecasting inputs, the Companies all also used their approved 2022 through 2024 Three-Year EE Plans for EE forecasts and solar forecasting assumptions, each treats spot loads in the same way, and each uses their respective interconnection queues for the five- and ten-year forecasts (Tr. 2, at 252; D.P.U. 24-10, Exh. ES-Forecast-1, at 16, 44; D.P.U. 24-11, Exh. NG-Forecast-1, at 10, 13, 22; D.P.U. 24-12, Exh. UN-Forecast-1, at 9, 13, 21). Further, while one company may separately model an input, that same input may be embedded in another input for another company, or each company may consider data at a different stage (e.g., during planning rather than forecasting) (Tr. at 191-205; Tr. 2, at 252).[37] The ultimate goal of each pathway and scenario is achievement of GHG emissions reduction limits and sublimits and, thus, the

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[37] See, e.g., Section VI.A.5. The tables therein reflect some of the Companies' different approaches to input modeling.

forecasts and demand assessments reasonably and appropriately account for DER adoption and electrification technology trends.

Similarly, the Department disagrees with the Attorney General's claim that NSTAR Electric's and Unitil's methods, each developed internally, for forecasting EV are lacking. Unitil used ISO-NE 2022 transportation electrification forecasts, including EV data specific to Massachusetts, in combination with third-party reports from established research entities including Edison Electric Institute and company expertise to forecast the number of chargers and EV charging profiles (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 77, 89-91; UN-Forecast-1, at 10-11; AG 3-5). NSTAR Electric used two different company-specific methods to model the EV charging load profiles at the zip code and bulk substation level (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 515-516; ES-Forecast-1, at 51-55). The first method used third-party vehicle mobility data and the second one used on-board telematics data (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 515; ES-Forecast-1, at 54). NSTAR Electric also developed an adopting propensity model for allocation to specific regions that relied on customer factors such as income, dwelling type, "green" behavior, density, and family demographics (D.P.U. 24-10, Exh. ES-Forecast-1, at 51). Based on the above, the Department determines that NSTAR Electric's and Unitil's methods to forecast EVs are each reviewable, appropriate, and reliable. Accordingly, the Department rejects the Attorney General's recommendation to require NSTAR Electric and Unitil to use the NREL EVI-Pro tool for forecasting EV load.

The Department acknowledges that there is variation between the Companies' forecasting inputs and assumptions; however, we find none of the differences identified by intervenors in the forecasting inputs or methods of the Companies prevented review of each company's five- and ten-year forecast methods or input or, more importantly, reduced the reliability of the forecasts. To the contrary, we are persuaded that some variation is not only allowable but necessary and likely increases the reliability of the forecasts. In certain instances, it would be inappropriate for the Companies to align their forecasts and assumptions due to the varying characteristics of each company's service territory (Tr. at 206; D.P.U. 24-10, Exhs. DPU-Common 5-1; DPU-Common 7-5; D.P.U. 24-11, Exhs. DPU-Common 5-1; DPU-Common 7-5; D.P.U. 24-12, Exhs. DPU-Common 5-1; DPU-Common 7-5). These varying characteristics can impact the Companies' demand forecasts and demand assessments (D.P.U. 24-10, Exhs. DPU-Common 5-1; DPU-Common 7-5; D.P.U. 24-11, Exhs. DPU-Common 5-1; DPU-Common 7-5; D.P.U. 24-12, Exhs. DPU-Common 5-1; DPU-Common 7-5). For example, the differences between rural communities and urban centers, residential or commercial areas, as well as customer demographics, building stock, available open space, and load growth and technology adoption, all vary significantly across the Companies' territories and, as a result, the assumptions associated with the specific characteristics of one company's service territory may not be applicable to another company's service territory (D.P.U. 24-10, Exh. DPU-Common 5-1; D.P.U. 24-11, Exh. DPU-Common 5-1; D.P.U. 24-12, Exh. DPU-Common 5-1). In fact, forecasts of different subregions or circuits within a single company's service territory may not be comparable due to regional differences or variations in customer base, load, growth drivers, and system characteristics (Tr. at 207-212). As such, we are convinced that attempts to establish a forecasting method with uniform assumptions and inputs would not recognize the diversity across the state and could reduce the reliability of the forecasts.

A forecast should provide a sound basis for a company's resource planning decisions. D.T.E. 02-75, at 2; D.T.E. 02-17, at 2. The ability of the Companies to provide a safe and reliable system depends on a company accurately forecasting demand (Tr. at 81). The Department determines that the uncertainty of future assumptions and the potential impact on loads associated with rate design, DR, HP, EE, EV, storage, solar PV, and building efficiency codes, particularly when they may rely on actions of third parties outside the Companies' control or on hypothetical data, would render the Companies five- and ten-year forecasts less reliable for capital planning purposes (Tr. at 81; Tr. 2, at 244-246, 272-273). Similarly, incorporating potential or undefined customer-specific spot loads, even if known,[38]

[38] We note that NSTAR Electric, National Grid, and Unitil provide service to approximately 1.4 million, 1.3 million, and 30,500 customer accounts, respectively (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 64, 91; ES-Policy/Solutions-1, at 14, 39; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 15, 48, 62; NG-Policy/Solutions-1 (Corrected) at 31; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 5; UN-Policy/Solutions-1, at 5). Of these customer totals, NSTAR serves approximately 200,000 C&I customers, National Grid serves approximately 126,250 C&I customers, and Unitil serves approximately 4,000 C&I customers (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 64, 91; ES-Policy/Solutions-1, at 14, 39; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 15, 48, 62; NG-Policy/Solutions-1 (Corrected) at 31; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 5; UN-Policy/Solutions-1, at 5).

absent a formal customer load request[39] could also reduce the reliability of a company's five- and ten-year forecasts in that it could result in a company planning capital investments based on forecasted load that may or may not ultimately occur (Tr. at 81, 86). The Companies must use reliable and firm data to develop its demand forecast for capital planning purposes.

Moreover, based on each system's characteristics and needs, each company's forecasting methods are a matter for utility management's judgment and, within a substantial range, utility business decisions are matters for company management to determine. Fitchburg, 375 Mass. at 578. Generally, notwithstanding our regulatory oversight responsibilities over the Companies, the Department may not interfere with reasonable company judgments made in good faith and within the limits of reasonable discretion. D.P.U. 09-09, at 38; D.P.U. 555-C at 16. Further, it is inappropriate for the Department to substitute its own judgment for the judgment of the management of a utility. Attorney General v. Dep't of Public Utilities, 390 Mass. at 228. Accordingly, the Department declines to require the Companies to include uniform assumptions in their five- and ten-year forecasts for DR, HP, EE and building efficiency codes, EV, energy storage, and solar PV. Even though we decline to adopt the intervenors' recommendations due to the speculative nature of the data, the Department expects that as confidence in data develops, the

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39 In 2018 to 2023, National Grid received over 1,600 load requests, primarily from commercial customers, and as new load requests are received, the company reevaluates and reprioritizes the scope and timing of proposed investments (D.P.U. 24-11, Exhs. DPU 11-43, Att. 1; WC 1-4; WC 1-7).

Companies will incorporate the new data during subsequent annual forecasting cycles. As discussed in Section VII.D.4., we find that DOER's requests for consideration of a scenario analysis of rate design in the Companies' forecasts, as well as an analysis to support least-cost distribution system planning to meet clean energy goals, are consistent with our decision to review the ESMPs as strategic plans, and direct the Companies to include such information in their next ESMPs.

Finally, the Companies use the base forecast, i.e., the most probable forecast, to develop near-term investments and solutions, and not the range of forecasts considered as part of any sensitivity analyses (Tr. at 116, 120, 125). While the Department acknowledges there is uncertainty over adoption rates of DERs, including EVs, the Department questions the value of sensitivity analyses in the five- and ten-year forecasts, considering that the companies prioritize their investments solely on their base-case scenario, and the forecasts are updated annually (Tr. at 117-132). The Department therefore declines at this time to require each company to perform sensitivity analyses in its near-term forecasts. The Department may require inclusion of sensitivity analyses for informational purposes in the future, depending on the extent of variations between forecasted and actual demand described in the biannual reports, as discussed below. The Department requires the Companies to collaborate with the GMAC and other interested stakeholders on potential sensitivity analyses for the 2050 long-term demand assessment to be submitted with the Companies' next ESMP filing (Tr. at 133-134; D.P.U. 24-10, Exh. DPU-Common 7-6; D.P.U. 24-11, Exh. DPU-Common 7-6; D.P.U. 24-12, Exh. DPU-Common 7-6).

In sum, based on our review of the record, the Department finds that each company's forecasting method and assumptions are reasonable, appropriate, and reliable. Notwithstanding this finding, the Department directs the Companies to comply with the following reporting requirements for the present ESMP term and filing requirements for subsequent ESMP filings.

In their biannual reports, the Department requires the Companies to provide a comparison of the forecasted demand (according to the most recently updated ARR) and actual demand, separated by component (baseload and DERs) for each completed year in the ESMP term. Furthermore, each company should include variances between five- and ten-year demand forecast components in the approved ESMP and the updated ARR ten-year demand forecast components. This will allow the Department and stakeholders to assess the reliability of each company's forecast. The Department will further develop this biannual filing requirement as part of a subsequent phase of these proceedings.

Additionally, based on the deployment timelines included in each company's approved grid modernization plan, each company has begun deploying AMI meters with full deployment of AMI expected in Unitil's service territory in 2025, in NSTAR Electric's service territory in 2028, and in National Grid's service territory in 2027. Second Grid Modernization Plans (Track 2) at 238, 258, 277, 290. We expect that AMI will expand the opportunities and programs available to customers through rate design and TVR to reduce demand, as well as provide the Companies with additional fact-driven data on DERs, including HPs, solar PV, energy storage, EVs, EE, and more. Further, even prior to full deployment, the Companies will gain access to data from AMI meters in those locations where they have been deployed. As such, rate design and DERs will play a larger role in demand forecasts in the next ESMP term. Likewise, building electrification load is anticipated to be significant in the future (D.P.U. 24-10, Exh. ES-ESMP-1, at 484; D.P.U. 24-11, Exh. NG-ESMP-1, at 394; D.P.U. 24-12, Exh. UN-ESMP-1, at 195). 2050 CECP at 7 and 25. Accordingly, in future ESMP filings, in addition to performing sensitivity analyses for their 2050 demand assessment, the Department directs each company to separately model for all three demand forecasting windows: (1) demand response and other demand management programs not managed under the ISO-NE wholesale markets; and (2) the impact of EE, including implementation of building efficiency codes. The Companies shall also demonstrate how they considered and accounted for TVRs in their near- and long-term forecasts and for the impact of building weatherization on the HP demand forecast.

VII. ELECTRIC SECTOR MODERNIZATION PLANS

A. ESMP Term and Next ESMP Term

1. Introduction

For these first ESMPs, the timeline pursuant to Section 92B(d) consisted of: (1) the Companies filing their draft plans with the GMAC on September 1, 2023; (2) the GMAC providing its recommendations on the draft plans within 70 days, which the GMAC accomplished on November 20, 2023; (3) the Companies filing their proposed ESMPs with the Department on January 29, 2024, or 80 days after receiving the GMAC's recommendations; and (4) the Department issuing a final Order within seven months, or by

August 29, 2024. For subsequent ESMP reviews, Section 92B affords the Department the discretion to establish the schedule, provided certain parameters are met. Several intervenors support a schedule that affords the GMAC additional time beyond that provided for these first ESMP filings. The Companies oppose the timeframe sought by these intervenors.

2. Description of Company Proposals

As part of these first ESMPs, the Companies proposed a five-year ESMP term of January 1, 2025 through December 31, 2029 (D.P.U. 24-10, Petition at 1, 15; D.P.U. 24-11, Petition at 1, 15; D.P.U. 24-12, Petition at 1, 15). No intervenor addressed the proposed term for the present ESMPs. Additionally, the Companies anticipate that the next five-year ESMP term will be for the period January 1, 2030, through December 31, 2034 (D.P.U. 24-10, Exh. DPU-Common 7-4(b); D.P.U. 24-11, Exh. DPU-Common 7-4(b); D.P.U. 24-12, Exh. DPU-Common 7-4(b)). The Companies recognize this timeline is contingent on the initial plan approval and effective timeframes and any further direction provided by the Department (D.P.U. 24-10, Exh. DPU-Common 7-4(b); D.P.U. 24-11, Exh. DPU-Common 7-4(b); D.P.U. 24-12, Exh. DPU-Common 7-4(b)).

3. Positions of the Parties

a. DOER

DOER argues that the GMAC was unable to fully engage with many components of the draft plans due to the tight timeline and therefore urges the Department to establish a schedule that allows the GMAC to fully assist with the development of the ESMPs (DOER Brief at 19; DOER Reply Brief at 4-5). Additionally, DOER observes that the time constraints prevented the Companies from including their net benefits analyses in the draft plans and, in turn, the GMAC was unable to review these analyses (DOER Brief at 19). To provide additional time for collaboration between the GMAC and the Companies on the next ESMPs, DOER recommends that the Department allow at least 140 days for GMAC review of the draft ESMPs and 100 days for the Companies to respond to the GMAC recommendations and revise their plans, for a total of 240 days from the filing of the draft ESMP with the GMAC to the filing with the Department (DOER Brief at 21; DOER Reply Brief at 4-5). Based on this proposed timeline, assuming the Companies are required to file their ESMPs with the Department on January 29, 2029, the Companies would then submit their next ESMP drafts to the GMAC by May 29, 2028, and the GMAC would submit its recommendations to the Companies by October 23, 2028 (DOER Brief at 22). Finally, DOER disputes the Companies' assertion that extending the GMAC review would result in out-of-date information in the final ESMPs because the ESMPs are strategic plans (DOER Brief at 22).

b. Acadia Center, CLF, and GECA

Acadia Center, CLF, and GECA recommend that for future ESMPs, the Department should direct the Companies to follow a multi-year schedule that allows full participation and review by the GMAC (Joint Intervenor Reply Brief at 4). These intervenors support DOER's recommendation that the Department should direct the Companies to submit draft ESMPs to the GMAC 240 days before filing the plans with the Department, noting that the

GMAC lacked sufficient time to fully engage with components of the draft ESMPs (Joint Intervenor Reply Brief at 4).

c. Cape Light Compact

CLC also supports DOER's recommendation to provide the GMAC 140 days to review the draft plans and the Companies 100 days to respond to the GMAC's recommendations before filing the plans with the Department (CLC Reply Brief at 12-13).

d. Companies

The Companies oppose DOER's recommendation, arguing that the 240-day review period would alter the statutory timelines and the role of the GMAC (Companies' Joint Reply Brief at 60). The Companies argue that giving more time for GMAC review reduces the amount of time the Companies have to review their respective forecasts and develop the ESMPs, which may force the Companies to use older forecasts (Companies' Joint Brief at 90; Companies' Joint Reply Brief at 61). The Companies contend that having to use older forecasts may necessitate making significant changes to the ESMPs between the draft plan provided to the GMAC and the final plan submitted to the Department (Companies' Joint Brief at 91; Companies' Joint Reply Brief at 61-62).

4. Analysis and Findings

The Department first addresses the term for these first ESMPs. The Companies propose January 1, 2025 as the start date for the first five-year ESMP term. Section 92B is silent as to a particular five-year period for these first ESMPs, and we find nothing would prevent us from establishing a term that differs from the Companies' proposal. Accordingly, for the following reasons, the Department establishes the first five-year ESMP term to begin on July 1, 2025 and to end on June 30, 2030.

The Department determines that beginning the first ESMP term on July 1, 2025, will not unduly delay the Companies' deployment of ESMP investments. In Section VIII.D., below, the Department determined that accelerated cost recovery of ESMP investments through an annual reconciling factor is appropriate for certain incremental ESMP investments, with a separate process for the proposed CIPs and EV program extension, for example, but stated that we would establish the precise parameters for cost recovery in a subsequent phase of these proceedings. The Department questions the likelihood of the Companies proceeding with deployment of proposed ESMP investments without a cost recovery mechanism in place (D.P.U. 24-10, Exhs. DPU-Common 9-4; DPU-Common 9-6; DOER-Common 1-3; D.P.U. 24-11, Exhs. DPU-Common 9-4; DPU-Common 9-6; DOER-Common 1-3; D.P.U. 24-12, Exhs. DPU-Common 9-4; DPU-Common 9-6; DOER-Common 1-3). The record also shows that the cost estimates provided in the ESMPs are only preliminary or conceptual and must be refined based on final scope, engineering, design, and vendor quotes prior to seeking approval through the Companies' internal project authorization processes (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 83; DPU 1-1; AG 4-20, Att.; D.P.U. 24-11, Exhs. DPU 1-1; AG 1-10, Att.; D.P.U. 24-12, Exh. DPU 1-1). While the Department intends to proceed with all deliberate speed to establish the cost recovery parameters for ESMP investments, it is unlikely that we will complete this subsequent phase, along with review and final approval of the associated cost recovery tariffs, with sufficient lead time for the Companies to complete the necessary engineering and design analyses, procurement processes, and internal approvals to begin deployment of any ESMP investments as of January 1, 2025.

On the other hand, the Department finds it more likely that a July 1, 2025, start date for the first ESMP term will provide the Department sufficient time to investigate and establish the cost recovery mechanism, review the associated tariffs, and also provide the needed lead time for the Companies to begin deployments on or about July 1, 2025. As such, the Department establishes the first ESMP term for the period July 1, 2025 through June 30, 2030, and the second ESMP term for the period July 1, 2030 through June 30, 2035.

Next, the Department addresses the schedule for the second ESMP review process. The Department agrees with observations that complying with the abbreviated schedule afforded by Section 92B for these first ESMP filings was challenging, not only because this review process was the first of its kind but also because of the scope and complexity of the draft plans. The Department notes that the GMAC and the Companies, as well as the Department, have complied with the abbreviated timeframes for review of these first ESMP filings. This was no small task, and we commend the diligence and commitment of all involved. The Department now has the opportunity to consider what adjustments to the schedule may be appropriate for the next ESMP review process.

Section 92B(d) provides the Department with the discretion to establish the schedule for the next ESMP filings provided four parameters are met. First, the Companies must submit a plan to the Department once every five years. Second, the Companies must submit the draft plan to the GMAC no later than 150 days before the Companies file the plan with the Department. Third, the GMAC must return the plan to the Companies with recommendations no later than 70 days before the company files the plan with the Department. Finally, regardless of the schedule we establish for the various filing deadlines for the subsequent ESMP term, Section 92B(d) requires the Department to render a decision on the proposed ESMP within seven months of its filing with the Department. The schedule we establish below fully complies with these parameters.

DOER requests that the Department establish a schedule that affords the GMAC a total of 140 days to review and provide recommendations on the Companies' draft ESMPs and a total of 100 days for the Companies to respond to the GMAC recommendations and revise their plans (DOER Brief at 21; DOER Reply Brief at 4-5). DOER's recommendation provides the GMAC with an additional 60 days to submit recommendations beyond the minimum 80 days afforded under the statute for these first ESMP plans and also provides the Companies an additional 30 days beyond the minimum time established by the statute for submission of the plans to the Department. Given the breadth and complexity of these plans, the Department agrees with DOER and other intervenors that additional time for both the GMAC and the Companies is warranted. Additional time for the GMAC will allow the GMAC to more thoroughly develop and refine its recommendations. Further, affording the Companies additional time to consider the GMAC's recommendations, to modify their plans, where appropriate, and to include in their ESMP filings detailed explanations of the basis for accepting in whole, in part, or rejecting a GMAC recommendation, may help to resolve concerns, issues, and differences regarding the plans and enable a more efficient Department review of the proposed plans. Therefore, the Department determines that for the next ESMP term that begins on July 1, 2030: (1) the Companies must submit their draft plans to the GMAC by February 12, 2029, approximately 210 days before the Companies file their proposed ESMPs with the Department; (2) the GMAC must issue its recommendations on the draft ESMPs to the Companies by June 18, 2029, approximately 85 days prior to submission of the proposed ESMPs with the Department;[40] (3) the Companies must submit their proposed ESMPs for the period July 1, 2030 to June 30, 2035 to the Department on or before September 11, 2029; and (4) the Department shall issue a final Order by April 11, 2030, seven months after the submission of the proposed ESMPs. Pursuant to this schedule, the GMAC is afforded approximately 125 days to submit final recommendations to the Companies, and the Companies are afforded approximately 85 days to consider the GMAC's recommendations before submission to the Department.

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40 The Department notes that prior to submitting their November 20, 2023 recommendations on the draft ESMPs to the Companies, the GMAC maintained a list of aggregated draft recommendations and feedback that was accessible by the Companies and members of the public and posted with the GMAC meeting materials, available at https://www.mass.gov/info-details/gmac-meeting-schedules (last visited August 29, 2024). The Department encourages the GMAC to continue that approach and further encourages the Companies to engage with the GMAC on the issues and concerns raised in the draft recommendations. The Department anticipates that this dialogue could help the formulation of the final GMAC recommendations as well as allow the Companies to consider modifications to their plans even before the GMAC finalizes its recommendations.

The Department finds that the above schedule balances the GMAC's need for additional time to review the draft plans and the Companies' need to update their plans. The Department recognizes that, under this schedule, the draft plan filed with the GMAC in February 2029 will be based on each company's prior-year forecast, which will be described in the ARRs to be filed on March 31, 2028. As DOER noted, the next ESMP will also be a strategic plan that each company will need to update before proceeding with deployment, provided the Department approves the plan. As the Companies have made clear, the assumptions underlying their forecasts are valid only at a precise point in time and, thus, they must reevaluate their investment portfolio based on forecasts that are constantly updated (Tr. 6, at 853-860; D.P.U. 24-10, Exhs. DPU-Common 7-5(b); DPU-Common 7-6; D.P.U. 24-11, Exhs. DPU-Common 7-5(b); DPU-Common 7-6; D.P.U. 24-12, Exhs. DPU-Common 7-5(b); DPU-Common 7-6). Thus, the fact that the draft 2030-2035 ESMP will be developed based on a prior year forecast is of limited significance. The Department notes that the Companies will complete updated forecasts prior to submission of their ARRs on March 31, 2029. We fully acknowledge that these updated forecasts may require the Companies to revisit and reprioritize investments in their draft 2030-2035 ESMP filed with the GMAC which, in turn, could result in changes to the investment portfolio that is ultimately included in the proposed ESMP submitted to the Department. To be clear, we expect the Companies to utilize and account for their most current forecasts in proposing investments in their next ESMP filing with the Department, and to fully account for changes in investment priorities between the draft ESMP and the ESMP filed with the Department.

We encourage the GMAC to fully explore each company's reprioritization process and the resulting modifications to the investment portfolio from the updated forecast. The Department expects that the schedule we adopt here for the next ESMP review process will allow the Department to gain a more granular understanding of each company's five-year distribution system planning processes and allow us to gain greater insight into the Companies' decision-making in light of data that is continually changing. In sum, the Department concludes that the schedule we establish for the next ESMP term filings comports with the parameters in Section 92B(d).

B. Integrated Energy Planning

1. Introduction

The Companies' ESMPs each include a chapter devoted to integrated energy planning ("IEP"),[41] which they describe as a process to optimize gas, electric, and decarbonization investments that achieve the Commonwealth's clean energy goals (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 641-699; ES-Policy/Solutions-1, at 123-131; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 456-464; NG-Policy/Solutions-1 (Corrected) at 99-105; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 263-271; UN-Policy/Solutions-1, at 75-81). The Companies state that IEP is a "tactical toolkit" to evaluate and shape where, why, how much, and by when to make critical investments in gas and electric networks so that gas and

41 National Grid and Unitil also refer to IEP as "integrated gas-electric planning" (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 456-464; NG-Policy/Solutions-1 (Corrected) at 99-105; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 263-271; UN-Policy/Solutions-1, at 75-81).

electric utilities have a shared plan for how to meet the energy needs of customers while reducing GHG emissions (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 642; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 458; NG-Policy/Solutions-1 (Corrected) at 100; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 263; UN-Policy/Solutions-1, at 76). During the ESMP term, the Companies propose to: (1) convene a joint utility planning working group ("Joint Working Group"); (2) develop a comprehensive data exchange; and (3) conduct electrification feasibility assessments (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 643-644; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 459-460; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 264-265). The Companies maintain that their respective proposals for IEP advance the Department's guidance in D.P.U. 20-80-B (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 641, ES-Policy/Solutions-1, at 128-129; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 456; NG-Policy/Solutions-1 (Corrected) at 101; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 263).

The goal of the Joint Working Group, which will include the Companies, Massachusetts gas local distribution companies ("LDCs"), DOER, Attorney General, and other stakeholders (e.g., environmental groups and consumers) is to develop a coordinated capital plan (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 649-650; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 462-463; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 267-469).[42] The Companies suggest that the Joint Working Group meet every two months with broad stakeholder participation (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 649; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 462; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 267-268).

The Companies state that coordinated utility planning is critical to the success of IEP, and the limited overlap of the Companies' electric service territories and their affiliated LDCs' service territories necessitates the development of a comprehensive data exchange between the Companies and the LDCs (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 643; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 458-459; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 264). The Companies indicate that the data exchange will include information on: (1) building stock and electrification suitability; (2) residential and commercial hourly heating usage; (3) gas and electric capital upgrade plans; and (4) other information identified by the Joint Working Group (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 648-649; AG 3-2; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 462; AG 2-2; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 267-268; AG 2-2).

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[42] As proposed, the Joint Working Group's objectives may include: (1) developing a shared understanding of the utilities' networks and network planning processes; (2) leveraging IEP best practices; (3) conducting joint gas-electric planning studies; (4) creating a roadmap to strengthen IEP capabilities; (5) establishing a framework for assessing the benefits of IEP; (6) providing recommendations for how the EE program process should align with IEP; (7) keeping apprised of regulatory developments as well as identifying policies to enable IEP, and (8) exploring opportunities for input from stakeholders (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 650; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 463-464; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 270).

Each of the Companies also describes initiatives to assess electrification feasibility on its electric system. NSTAR Electric and Unitil each propose to assess the feasibility and implementation timing of upgrading electric infrastructure coupled with the timing of targeted customer electrification (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 646-648; ES-Policy/Solutions-1, at 129; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 264-265). NSTAR Electric underscores that it has conducted electric system planning analysis in a pilot area and developed a preliminary plan to transition customers in the pilot area from natural gas to electric heating, and Unitil explains that it will develop its proposed targeted electrification pilot in 2025 (D.P.U. 24-10, Exh. AG 3-2, at 1; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 270-271).

National Grid states that it has completed a desktop study in collaboration with its LDC affiliate on the impacts of electrifying residential gas heating in two cities within its service territory (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 458; DPU-Common 4-2). As a next step, National Grid proposes to develop electrification pilots in those two cities that will target gas customers supportive of electrification and served by leak-prone pipe segments (D.P.U. 24-11, Exh. DPU-Common 4-1, at 2-3).

2. Positions of the Parties

a. Attorney General

The Attorney General states that the Companies' proposals represent a good first step toward comprehensive IEP (Attorney General Brief at 39). The Attorney General maintains that the Companies should evaluate all LDC capital investments for targeted electrification

(Attorney General Brief at 39, citing Exh. AG-NBC-1, at 53-56). In addition, she contends that the Companies should develop screening criteria with the LDCs to quickly filter projects that do not qualify for targeted electrification or non-pipeline alternatives due to safety concerns or limited timelines (Attorney General Brief at 39, citing Exh. AG-NBC-1, at 53-56). The Attorney General also recommends that the LDCs provide location-based capital forecasts and maps of planned projects as part of the data exchange to make feasibility assessments more efficient (Attorney General Brief at 39, citing Exh. AG-NBC-1, at 53-56).

b. DOER

DOER endorses the need for the IEP process outlined in the Companies' ESMPs and recommends that the Department establish a timeline for the Joint Working Group's creation, development of goals and deliverables, and alignment of deliverables with the Department's directives in D.P.U. 20-80-B (DOER Brief at 75). DOER contends that the Joint Working Group should include the LDCs, DOER, the Attorney General, the Massachusetts Office of Energy Transformation, and any of the intervenors in the ESMP and D.P.U. 20-80 proceedings that wish to participate (DOER Brief at 75). DOER also asserts that the Joint Working Group should meet monthly starting no later than 60 days after this Order is issued, hold public meetings and listening sessions, and maintain a website for posting materials related to its activities (DOER Brief at 75). Further, DOER urges the Department to direct the Companies to produce a Joint Working Group report by April 1, 2025 for inclusion in the LDCs' Climate Compliance Plans (DOER Brief at 75, citing D.P.U. 20-80-B at 143). DOER recommends that the report describe: (1) IEP objectives that support the

Commonwealth's clean energy targets; (2) data and technical analysis required to advance IEP; (3) pilot programs currently underway or planned; and (4) estimated costs of IEP and how these costs relate to existing operating costs for the Companies and LDCs (DOER Brief at 75). Lastly, DOER recommends that the Companies' biannual reports and stakeholder engagement include updates on the progress of IEP and transitioning customers from natural gas to electric service, including updates on any planned pilot programs for strategic electrification (DOER Brief at 70).

c. Acadia Center

Acadia Center contends that the Companies should revise their ESMPs to ensure consistency with the Department's directives in D.P.U. 20-80-B (Acadia Center Brief at 19). Specifically, the Acadia Center asserts that the Department should require the Companies to fully implement the GMAC's IEP recommendations and direct the Companies to remove projects associated with hybrid heating, renewable natural gas, and hydrogen from their ESMPs (Acadia Brief at 19-21).

d. Cape Light Compact

CLC asserts that the Department should approve NSTAR Electric's IEP proposal subject to several requirements (CLC Reply Brief at 15). CLC argues that the Department should maintain supervision over the Joint Working Group, which should include broad stakeholder representation (CLC Brief at 10-11; CLC Reply Brief at 15). CLC contends that NSTAR Electric should submit an annual report starting in 2025 on the Joint Working Group's progress and IEP electrification efforts, with a complete report included in its next

ESMP (CLC Brief at 11-12; CLC Reply Brief at 15). CLC also urges the Department to ensure a fair and equitable cost recovery process for IEP with cost allocation between gas and electric customers (CLC Brief at 12; CLC Reply Brief at 15)

e. Companies

The Companies contend that they summarized preliminary approaches to IEP in the ESMPs for transparency and context and clarify that they are not seeking Department approval for IEP processes or methods as part of the ESMPs (Companies' Joint Reply Brief at 7-8, citing D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 451; DPU 1-1; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 253). The Companies explain that they have not proposed specific IEP investments in their ESMPs for the Department's approval; however, the Companies claim to have proposed ESMP investments that further the objectives of Section 92B and facilitate the Companies' IEP efforts, such as software products included in the network and customer investments categories that support asset planning, management and work execution (Companies' Joint Reply Brief at 13-14, citing D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 451; DPU 1-1; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 253, 261).

The Companies maintain that IEP will involve complicated internal planning processes between multiple private and municipally controlled entities and that they intend to work together with the LDCs and stakeholders to develop and refine an IEP process (Companies' Joint Reply Brief at 8, citing D.P.U. 24-10, Exhs. DPU-Common 4-5; DPU-Common 6-5; D.P.U. 24-11, Exhs. DPU-Common 4-5; DPU-Common 6-5; D.P.U. 24-12, Exhs. DPU-Common 4-5; DPU-Common 6-5). The Companies assert that they must now work with these entities to develop an IEP process that aligns with the Department's directives in D.P.U. 20-80-B and, therefore, the Department should not adopt the intervenors' recommendation to define the scope and timelines of the Joint Working Group before the collaboration with those entities can occur (Companies' Joint Reply Brief at 7-8). Further, the Companies argue that Acadia Center's arguments relating to hybrid heating and the Attorney General's proposed directives to the LDCs are beyond the scope of these proceedings (Companies' Joint Reply Brief at 7 & n.6).

3. Analysis and Findings

In December 2023, just prior to the Companies filing their ESMPs, the Department announced a regulatory framework in D.P.U. 20-80-B intended to set forth its role and that of the LDCs in helping the Commonwealth achieve its target of net-zero GHG emissions by 2050. The Department acknowledged that "the transition of the natural gas industry in Massachusetts is an exceedingly complex undertaking" that "can be addressed effectively only with broad participation of all the constituencies affected by the transition." D.P.U. 20-80-B at 17, 18. To that end, the Department determined that "coordinated and comprehensive planning between electric and gas utilities is needed to facilitate the energy transition" and directed the LDCs and the Companies to consult with stakeholders regarding such a joint planning process that, while not Department led, may lead to proposals for Department review. D.P.U. 20-80-B at 131-132.

After review, we find that the Companies' IEP proposals are a necessary first step in the development of an IEP process that will enable customers to transition from natural gas heating to electric heating, leading to the achievement of statewide GHG limits (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 641-699; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 456-464; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 263-271). G.L. c. 164, § 92B(b)(iv)-(vi). Further, we find that the Companies' proposed approach to collaborate with the LDCs and stakeholders to define the scope and timelines of the Joint Working Group is reasonable and consistent with the Department's recent directives for the LDCs and Companies to develop IEP processes with broad stakeholder participation. D.P.U. 20-80-B at 131-132. Accordingly, we decline to adopt the intervenors' recommendations to define the timelines or work product of the Joint Working Group in this Order.

Acadia Center also asserts that the Department should require the Companies to remove planning solutions associated with hybrid heating, renewable natural gas, and hydrogen from their ESMPs (Acadia Brief at 19-21). We disagree. As discussed in D.P.U. 20-80-B, Section 77 of the 2022 Clean Energy Act explicitly prohibited the Department from approving the LDCs' specific decarbonization pathways prior to conducting an adjudicatory proceeding. D.P.U. 20-80-B at 20, 80 n.57, 133, citing St. 2022, c. 179, § 77. To facilitate that review, the Department directed the LDCs to file Climate Compliance Plans every five years, with the first plans due on or before April 1, 2025. D.P.U. 20-80-B at 144. Since the Department has not made a final decision as to the propriety of these decarbonization strategies, we cannot find that Companies erred by including them among their many other planning solutions. At the same time, the Department expects the Companies' proposed course of action in their ESMPs to be consistent with the preliminary determinations reached by the Department on these respective issues in D.P.U. 20-80-B at 55-56, 68-70, 79-84. The Department directs the Companies to account for any future Department decisions on the propriety of these technologies in their future ESMPs.

For the reasons discussed above, the Department finds that the Companies' IEP proposals are reasonable and consistent with the objectives of the ESMPs and the Department's directives in D.P.U. 20-80-B. G.L. c. 164, § 92B(a); D.P.U. 20-80-B at 17, 18, 131-132. Given the importance of the IEP process to the clean energy transition, the Department directs each company to include status reports on the progress on the IEP processes in its biannual ESMP reports, including, but not limited to, updates on the Joint Working Group, data exchange, feasibility assessments, and targeted electrification projects.

C. Planned and Proposed Investments

1. Introduction

Section 92B includes multiple requirements for investments to be identified in NSTAR Electric's, National Grid's, and Unitil's respective ESMPs. In the Interlocutory Order on Scope at 2, 23-24, the Department explained that we would assess whether the plans comply with statutory requirements and would review investment proposals in the context of strategic planning documents. In this Section, the Department addresses the Companies' planned and proposed investments within the statutory framework outlined in Section 92B and the parameters discussed in Section IV.C.

2. Description of Company Investments

a. Overview

In their filings, the Companies describe three types of capital investments and O&M spending within their distribution systems over the 2025 through 2029 period: (1) planned "base" or "core" investments and spending, estimated at $14.42 billion,[43] which are part of the Companies' typical distribution system planning to support load growth and provide safe and reliable service, and the costs of which are generally recovered through base distribution rates; (2) planned investments and spending that have been pre-approved or preauthorized by the Department or are pending Department review in separate proceedings – specifically, CIPs, AMI, company-owned solar facilities and related energy storage infrastructure, grid modernization investments, EV program expenses, and EE electrification, and demand response program expenses – estimated at $7.21 billion; and (3) proposed ESMP investments and spending, estimated at $3.40 billion, which the Companies identify as incremental to the other investments described in their plans (D.P.U. 24-10, Petition at 7; Exhs. ES-ESMP-1 (Corrected) at 8, 432-438; ES-Net Benefits-1, at 14-15; ES-Net Benefits-3 (Corrected) at 32; DOER-Common 1-1, Att.; D.P.U. 24-11, Petition at 7; Exhs. NG-ESMP-1 (Corrected) at 356-362; NG-Net Benefits-1 (Corrected) at 14-15; NG-Net Benefits-3 (Corrected) at 32;

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43 All figures in this Order are rounded.

DOER-Common 1-1, Att.; D.P.U. 24-12, Petition at 7; Exhs. UN-ESMP-1 (Corrected) at 152-166; UN-Net Benefits-1 (Corrected) at 10; UN-Net Benefits-3 (Corrected) at 31; DOER-Common 1-1, Att.).[44]

For proposed ESMP investments, the Companies coordinated on identifying investment categories although noted that each company did not propose investments in each category (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 435, 438; ES-Policy/Solutions-1, at 134-137; ES-Net Benefits-1, at 14-15; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 358-362; NG-Policy/Solutions-1 (Corrected) at 108-109; NG-Net Benefits-1 (Corrected) at 14; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 152-166; UN-Policy/Solutions-1, at 83-85; UN-Net Benefits-1 (Corrected) at 11). Each company explained that, while its EE and active demand reduction programs would continue to play key roles in GHG reductions, the proposed ESMP investments would proactively enable the Commonwealth's electrification and DER goals by building network capacity and reliability to support these goals (D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 131-132; D.P.U. 24-11, Exh. NG-Policy/Solutions-1 (Corrected) at 105-106; D.P.U. 24-12, Exh. UN-Policy/Solutions-1, at 81-82). Each company also explained that, without the ESMPs, the company and its network would still aid in supporting the Commonwealth's policy objectives, but the pace of enablement would be driven by normal distribution system

44 Department staff compiled these totals based on the data in each company's exhibits. For Unitil, the Department relied on D.P.U. 24-12, Exhibits UN-ESMP-1 (Corrected) at 160, 166, and DOER-Common 1-1, Attachment. Differences due to rounding and different presentation of costs in exhibits may be reflected.

planning processes using nearer-term considerations (D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 132; D.P.U. 24-11, Exh. NG-Policy/Solutions-1 (Corrected) at 106; D.P.U. 24-12, Exh. UN-Policy/Solutions-1, at 82).

The Companies developed substantially similar definitions for proposed ESMP investment categories, which are described in the below table:

ESMP Investment Category Descriptions

Type	**Investment Category**	**Description**
Proposed ESMP Investments	Customer Investments	New programs and demonstrations to advance Virtual Power Plants ("VPPs") and use of DER for grid services, and investments in new clean energy customer portals & enabling technologies
	Platform Investments	Investments identified to leverage data, digitalization, and other platforms to optimize infrastructure and meet evolving customer needs
	Network Investments	New substation and distribution line upgrades to support electrification load growth and DER interconnections, as well as investments to install and manage additional technology hardware to improve network operations and management

Type	Investment Category	Description
	Resiliency	Undergrounding, reconductoring and other storm hardening infrastructure upgrades
	CIP	Substation and line upgrades to enable DER interconnections with cost allocation
	EV Programs	Continuation of existing EV make ready and charging infrastructure enablement programs
	Solar	Programs to support adoption of solar and storage technologies in EJ populations
	Program Administration	Program administration of incremental ESMP projects

(D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 24, 435, 438; ES-Net Benefits-1, at 14; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 253-254, 362, 373-374; NG-Net Benefits-1 (Corrected) at 13-14; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 160, 176; UN-Net Benefits-1 (Corrected) at 11).

The below table summarizes each company's estimated spend for the period 2025 through 2029:

Summary of Estimated Spending ($ Nominal) 2025-2029[45]

Type	Investment Category	NSTAR Electric ($ Million)	National Grid ($ Million)	Unitil ($ Million)
Planned Base or Core Spending	Core Capital	$4,482.1	$4,248.0	$79.3
	Core Operating	$2,479.5	$3,063.6	$65.9
Planned Spending Through Reconciling Mechanisms	CIP[46]	$340.4	$234.0	N/A
	AMI	$538.9	$412.0	$0.4
	Solar	$112.0	N/A	N/A
	Grid Mod	$47.0	$86.6	$5.0
	EV Programs	$113.4	$126.0	$0.6[47]
	EE, Electrification, and Demand Response	$2,625.0	$2,529.0	$40.0
Proposed ESMP Investments	Customer Investments	$58.5	$99.7	$1.0
	Platform Investments	$55.5	$400.1	$0.7[48]
	Network Investments	N/A	$1,634.0	$42.6

45 There may be slight variations in numbers due to rounding and different presentations in exhibits. These numbers are estimates subject to revision.

46 Planned spending for CIP investments includes projects pending before the Department for approval in separate proceedings. Costs presented here are based on exhibits filed in D.P.U. 24-10, D.P.U. 24-11, and D.P.U. 24-12, and in some cases vary from costs in previously filed CIP dockets.

47 For Unitil, this figure relies on the values in Exhibit UN-ESMP-1 (Corrected) at 111.

48 For Unitil, this figure relies on the values in Exhibits UN-ESMP-1 (Corrected) at 160, 166, and DOER-Common 1-1, Attachment.

Type	Investment Category	NSTAR Electric ($ Million)	National Grid ($ Million)	Unitil ($ Million)
	Resiliency	$225.0	N/A	$5.0
	CIP	$261.8	$71.8	N/A
	EV Programs	$168.9	$299.2	$1.2
	Solar	$50.0	N/A	N/A
	Program Administration	N/A	$20.1	$0.4
Totals		**$11,558.0**	**$13,224.1**	**$242.3**

(D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 435, 438; ES-Net Benefits-3 (Corrected) at 32; DOER-Common 1-1, Att.; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 358, 362, NG-Net Benefits-3 (Corrected) at 32; DOER-Common 1-1, Att.; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 111, 160, 166; DOER-Common 1-1, Att.).

b. NSTAR Electric

i. Planned Core Spending

NSTAR Electric's planned core spending for the period 2025 through 2029 totals $6.96 billion[49] (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 8, 298, 433-438; ES-Net Benefits-3 (Corrected) at 32; DOER-Common 1-1, Att.). The associated budget is for capital and O&M expenditures that are planned for equipment repair, new customer connections, peak load growth, and maintaining reliability, as well as expenditures to support

49 All values in this Order are rounded.

business operations, customer support, estimated major storm response, employee benefits, and other corporate costs, among others (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 435-436, 438).

The company's estimated core capital investments for 2025 through 2029 total $4.48 billion, separated into four categories: (1) peak load and capacity ($1.33 billion) for upgrades and new build of substations and distribution lines to accommodate load growth over the ten-year planning horizon; (2) basic business ($1.09 billion), including equipment repairs, fleet vehicles, workforce tools, telecommunications, and IT; (3) reliability ($1.63 billion), for upgrades to overhead and underground infrastructure, including hardening, conversions, aging infrastructure replacements, and automation; and (4) new customer ($424.9 million), to provide infrastructure for new customer loads (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 433; DOER-Common 1-1, Att.). The company's O&M expenditures total $2.48 billion, separated into four categories: (1) electric operations ($814.0 million), for equipment maintenance and repair, new customer connections, peak load growth, and maintaining reliability; (2) storm ($114.0 million), for major storm response; (3) business support ($1.25 billion), including human resources, accounting, legal, communications, IT, and employee benefits and other corporate costs; and (4) customer support ($298.0 million), including call center, communications, and billing (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 435; DOER-Common 1-1, Att.).

The company's planned activities include investigating smart inverter controls in the DER interconnection process, which was successfully demonstrated on its ESS-based microgrid in Provincetown (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 104-105). The company stated that the future rollout of smart inverter controls would be dependent upon the proposed "use cases" for DER operation and control, and specific ESS deployments (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 105).

ii. Pre-Approved or Preauthorized Spending

(A) Introduction

NSTAR Electric's planned investments through 2029 that have been pre-approved or preauthorized by the Department or are pending Department review in separate proceedings are estimated at \$3.78 billion, including capital investments and O&M expenditures, fall into six categories: (1) CIPs (\$340.4 million); (2) AMI (\$538.9 million); (3) company-owned solar facilities and related energy storage infrastructure (\$112.0 million); (4) grid modernization investments (\$47.0 million); (5) EV program expenses (\$113.4 million); and (6) EE, electrification, and demand response program expenses (\$2.63 billion) (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 435, 438; ES-Policy/Solutions-1, at 84-85; DOER-Common 1-1, Att.).

(B) Capital Investment Projects

The planned CIPs involve Provisional Program[50] projects from six group studies conducted at saturated substations and submitted for approval in D.P.U. 22-47 (Marion-Fairhaven), D.P.U. 22-51 (Freetown), D.P.U. 22-52 (Plainfield-Blandford), D.P.U. 22-53 (Dartmouth-Westport), D.P.U. 22-54 (Plymouth), and D.P.U. 22-55 (Cape Cod) (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 104, 133, 153, 180; DOER-Common 1-1, Att.).[51] The company explained that these CIPs include substation and line upgrades that would facilitate interconnection of additional DG and hosting capacity (D.P.U. 24-10, Exh. ES-Bill Impacts-1, at 12-13). NSTAR Electric's planned and pending CIPs are summarized below.

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50 In D.P.U. 20-75-B, the Department established the Provisional Program and cost allocation requirements for planning and funding upgrades to the EPS to foster timely and cost-effective development and interconnection of DG until a long-term system planning program was established. D.P.U. 20-75-B at 2, 41.

51 On December 30, 2022, the Department approved the company's Marion-Fairhaven CIP proposal. NSTAR Electric Company, D.P.U. 22-47 (2022). On June 4, 2024, the Department approved four additional CIPs for NSTAR Electric. D.P.U. 22-52 through D.P.U. 22-55, at 12, 105. The company's request in D.P.U. 22-51 remains pending.

NSTAR Electric – Provisional Program CIPs				
Group Study Docket	Number of Substations	Existing DG (MW)	Provisional Program DG (MW)	Enabled Large DG (MW)
D.P.U. 22-47 (Marion-Fairhaven)*	4	69	49	140
D.P.U. 22-51 (Freetown)	1	13	22	52
D.P.U. 22-52 (Plainfield-Blandford)*	1	38	13	40
D.P.U. 22-53 (Dartmouth-Westport)*	2	72	16	60
D.P.U. 22-54 (Plymouth)*	7	237	123	380
D.P.U. 22-55 (Cape Cod)*	8	149	71	296
Total	**23**	**578**	**294**	**968**

* Department-approved CIP proposals are identified with an asterisk.
(D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 302).

(C) Advanced Metering Infrastructure

NSTAR Electric's planned AMI investments were pre-approved through 2028 in D.P.U. 21-80, and include meters, communications infrastructure, a head-end system, a meter data management system ("MDMS"), a customer information system, analytics capabilities, a customer portal and data sharing abilities, and integration with other key systems on its network (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 329-330;

ES-Policy/Solutions-1 at 86; DOER-Common 1-1, Att.).[52] Between 2025 and 2028, the company estimates $448.4 million in capital expenses and $90.5 million in O&M for this program, resulting in the deployment of approximately 1.5 million advanced meters to customers supported by back-office systems (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 324, 435, 438; ES-Policy/Solutions-1 at 84-85). Meter deployment will begin in 2025 in the company's western Massachusetts territory with full deployment across the company's service territory by year-end 2027 (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 330). The company anticipates full AMI implementation will: (1) enable increased customer access to more granular usage information and, thus, facilitate energy savings opportunities through EE, clean energy, and demand response programs; (2) support TVR; (3) inform analytics to improve grid planning and operations; (4) enable behind-the-meter DERs through a DER management system ("DERMS"); and (5) improve outage communications in storm events (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 19, 21, 324, 330-332, 443, 448, 557; ES-Policy/Solutions-1, at 115). The company also identified the AMI working group jointly convened by the Companies to discuss data sharing and customer opportunities afforded by AMI (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 331).

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52 The Department preauthorized a combined seven-year budget cap of $534.8 million for core AMI investments and provided preliminary approval of up to $133.1 million for supporting AMI investments. Second Grid Modernization Plans (Track 2) at 238.

(D) Solar

During the 2025 through 2029 period, NSTAR Electric estimates $112.0 million in capital investments related to utility-owned solar and solar storage projects, including a pending 2.1 MW solar project with ESS in D.P.U. 22-64 and its proposed Eversource Community Solar Access Program ("ECSAP")[53] submitted in docket NSTAR Electric Company, D.P.U. 20-145 (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 319-320, 435; ES-Policy/Solutions-1, at 86; ES-Bill Impacts-1, at 8, 13).

(E) Grid Modernization

NSTAR Electric estimated $47.0 million in planned capital investment in 2025 for grid modernization investments preauthorized in D.P.U. 21-80, and which includes seven investment categories: (1) advanced distribution management system ("ADMS"); (2) communications; (3) monitoring and control; (4) VVO; (5) advanced load flow; (6) DERMS; and (7) measurement, verification, and support (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 299, 435; ES-Policy/Solutions-1, at 86; DOER-Common 1-1, Att.).

The company stated that ADMS provides an as-operated real-time power flow model of the distribution system that incorporates telemetry and control capabilities from all substations and field devices and will be used to monitor and optimize grid conditions,

53 The ECSAP aims to encourage low-income household participation in community shared solar projects and more development of SMART community Solar Tariff Generation Units (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 319).

including real time needs that can be solved with DERs (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 324). The company indicated that the communications investments will improve data transmission and control signals between field devices and system operators, a necessity for the ADMS (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 324). Additional categories of pre-approved grid modernization investments planned by the company through 2025 also include: (1) substation automation (i.e., upgrades to substation feeder relays to enhance data capture functionality); (2) VVO deployment; (3) advanced load flow system planning tools; and (4) DERMS Phase I in western Massachusetts (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 324, 326). The company maintains that the combined grid modernization plan investments will enable the company to use DERs to provide grid services while lowering costs and improving reliability (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 323-324). The company explained that these and its AMI program investments will serve as critical foundations to its proposed ESMP investments (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 323-324).

(F) Electric Vehicle Program

NSTAR Electric's Phase II EV program was pre-approved through 2026 in D.P.U. 21-90, with program costs totaling an estimated $113.4 million during 2025 through 2026, of which $35.4 million is attributed to capital expenses and $78.0 million to O&M expenses (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 314; ES-Policy/Solutions-1, at 86; DOER-Common 1-1, Att.). The Phase II EV program includes make-ready and EV service equipment ("EVSE") rebates for the public and workplace, residential, and light-duty fleet sectors as well as fleet assessment services, a medium and heavy-duty fleet pilot for EJ populations, and a direct current fast charger ("DCFC") hub pilot for EJ populations (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 314-317; ES-Policy/Solutions-1 at 77-79).

(G) Energy Efficiency

NSTAR Electric estimates $2.63 billion in operating costs in 2025 through 2029 to administer Mass Save incentive programs for EE, demand response, and electric heat pumps (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 438; ES-Policy/Solutions-1, at 74; DOER-Common 1-1, Att.). For this program, the company assumes that its most recent three-year EE plan for 2022 through 2024 will be continued (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 438; DOER-Common 1-1, Att.). The company explained that, under Mass Save, customer rebates for the installation of heat pumps have increased significantly over the past five years (D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 79-80).

iii. Proposed ESMP Investments

(A) Introduction

NSTAR Electric's proposed ESMP investments for 2025 through 2029 fall into six categories: (1) customer investments ($58.5 million); (2) platform investments ($55.5 million); (3) resilience ($225.0 million); (4) CIPs ($261.8 million); (5) EV program ($168.9 million); and (6) solar ($50.0 million) (D.P.U. 24-10, Exhs. ES-Net Benefits-3 (Corrected); DOER-Common 1-1, Att.).

(B) Customer Investments

NSTAR Electric's customer investments category includes new programs and demonstrations to advance VPPs, the use of DERs for grid services, and investments in new clean energy customer portals and enabling technologies, and consists of five sub-categories totaling $58.5 million for 2025 through 2029: (1) Federal Energy Regulatory Commission ("FERC") Order 2222; (2) integrated energy planning; (3) Southampton ESS; (4) grid services;[54] and (5) Grid Services Compensation Fund (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 24, 429, 435, 438, 451; ES-Net Benefits-1, at 14; ES-Net Benefits-3 (Corrected) at 32, 35; DPU-1-1 & Atts. (a)-(d)).

To address operational needs in response to FERC Order 2222,[55] the company proposes investments to collect information on dispatch schedules, system constraints, planned outages, and other events, to communicate with ISO-NE regarding dispatch limitations, and to monitor ISO-NE dispatch in real time (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 340; DPU 1-1, at 2).

The company's proposed integrated energy planning investment includes software to translate location-specific gas demand into electric system loadings and distribution planning models (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 649; DPU 1-1, at 1;

[54] The company did not attribute a direct cost to this category (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 336; Net-Benefits-3 (Corrected) at 35; DPU 1-1).

[55] FERC Order 2222 aims to facilitate DER dispatch to support wholesale market needs (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 339-340).

DPU-Common 10-2). Cost estimates for this project would be developed during a pilot being conducted with National Grid and Unitil, with final costs known by fourth quarter 2025 (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 649; DPU-Common 10-2).

The company's Southampton ESS project involves the installation of a two MW energy storage system at an existing company-owned PV site in Southampton, Massachusetts and installation of a three MVA inverter to provide reactive support (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 340-341). The proposed ESS would provide voltage/reactive power support for a circuit out of the company's Gunn substation and levelized PV output (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 340-341). The company explained that co-locating the ESS with DERs will: (1) coordinate charging/discharging at the point of interconnection; (2) integrate the DERs into the VVO and DERMs platforms; (3) establish communication between the PV and ESS for data sharing; and (4) provide the company with a better understanding of such co-located installations (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 341).

The company's investments in enabling DER to provide grid services aim to deploy infrastructure to address load growth, enable decarbonization, and support customer reliability and grid flexibility (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 332). These investments include leveraging NWAs, including DERs (e.g., microgrids or batteries) and programs focused on load management, demand response, or EE (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 332, 451). The company did not attribute a direct cost to this category but explained that enabling DER as a grid service will require platform investments in the company's communication, control, dispatch, and optimization capabilities, and customer grid services program demonstrations, to support large scale NWA program implementation (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 336; Net-Benefits-3 (Corrected) at 35; DPU 1-1).

NSTAR Electric, in coordination with National Grid and Unitil, proposed establishing a Grid Services Compensation Fund to compensate dispatchable DER and flexible loads to allow utility dispatch and provide grid services (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 429; ES-Policy/Solutions-1, at 88). The company explained that recommendations from the Grid Services Study,[56] jointly being pursued by the Companies and the Massachusetts Clean Energy Center ("MassCEC"), will inform the eligibility requirements for compensation to dispatchable DER and flexible load with capacity to provide grid services (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 429). The company explained that the Grid Services Compensation Fund will target bridge-to-wires and grid services solutions, both of which would be dispatched through DERMS (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 334, 580 & n.180). Lessons learned from implementing the Grid Services Compensation Fund will inform a Transactional Energy Study to be conducted later in the term to assist in the development of proposals in the company's next ESMP (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 334 n.180, 430, 580).[57] The company

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[56] The Department discusses the Grid Services Study in Section VII.C.2.e.

[57] The Department discusses the company's NWA solutions in further detail in Section VII.D.2.a. and the Transactional Study in VII.C.2.e.

estimates $25.0 million in incentive payments during the ESMP term based on an assessment of the level of participation at an estimated $/MW annual incentive level, although annual costs may vary based on the results of the Grid Services Study (D.P.U. 24-10, DPU 1-1 & Att. (d)).

(C) Platform Investments

For its platform investments category, NSTAR Electric identified a DERMS Phase II investment totaling estimated at $55.5 million during the 2025 through 2029 period (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 435, 438; ES-Net Benefits-3 (Corrected) at 32). NSTAR Electric explained that DERMS Phase II will: (1) expand on DERMS investments included in the company's 2022 through 2025 grid modernization plan; (2) add new functionalities, including multi-variable dispatch optimization and improved dispatch logic to be able to support more market-based dispatch as envisioned by the Grid Services Compensation Fund; (3) improve the control room DER dispatch process; and (4) upgrade the supervisory control and data acquisition ("SCADA") energy control system to align its eastern service territory SCADA with the newer SCADA software in the western portion (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 337-338, 451).

(D) Network Investments

NSTAR Electric did not propose ESMP network investments since related investments are included in its core capital expenditures (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 451).

(E) Resilience

NSTAR Electric proposed incremental resiliency investments as a part of a ten-year $450.0 million plan, with a five-year $225.0 million program for the first ESMP term (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 625-626; ES-Policy/Solutions-1, at 67; DPU 6-12). The proposed ESMP-specific targeted resiliency investments involve undergrounding, reconductoring, and storm hardening infrastructure upgrades, as well as resiliency tree work,[58] to address the impacts of climate change as identified by its analysis of recent outage data from major storm events (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 434, 440, 451, 622-623; ES-Policy/Solutions-1, at 60-61, 66-67). The company explained that it considers undergrounding, aerial cable, reconductoring, and resilience tree work to be a part of its proposed distribution resiliency hardening program, with resilience tree work as the only resilience solution that aims to mitigate the cause rather than adapting and hedging against it (D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 64, 66-67).

To develop its proposed resiliency investment plan, however, the company first utilized historical outage data[59] to scan its distribution system for locations which have experienced high criticality outages (i.e., outages impacting many customers), long duration

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58 The company currently recovers costs associated with a resiliency tree work program through a reconciling mechanism for that work. This was not included in the investment summary, above.

59 The dataset consists of major storm event outage data over four recent years, 2019 through 2022 (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 620; ES-Policy/Solutions-1, at 60).

outages, and multiple outages in the same system zone[60] (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 619-620; ES-Policy/Solutions-1, at 49). To be eligible for consideration in the resilience plan, a zone must have experienced multiple events or more than 1,000,000 customer minutes of interruption ("CMI") per event (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 621; DPU 6-9). Next, the company would identify the eligible zones with the highest criticality and pair this subset of eligible zones with the highest impact solutions based on the estimated all-in system average interruption duration index ("SAIDI") improvement (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 622-623; ES-Policy/Solutions1, at 49). Once all high criticality eligible zones are paired with a corresponding solution, the company would determine the estimated change in SAIDI[61] provided by the potential resiliency investments (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 625; ES-Policy/Solutions-1, at 49). Then, NSTAR Electric would determine the optimal level of resiliency investment considering the diminishing returns of the potential projects' cost-efficiency, i.e., the change in SAIDI per dollar spent on each project, by identifying the investment point at which total cost-efficiency would resemble the levels from

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60 In its proposed resiliency plan, NSTAR Electric refers to the part of a circuit that is between two isolation/protection devices as a zone (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 619).

61 Delta SAIDI refers to the difference of the historical pre-hardening SAIDI and the projected post-hardening all-in SAIDI of each zone that was paired with an investment solution (D.P.U. 24-10, Exh. DPU 6-12). NSTAR Electric calculated the projected post-resiliency investment all-in SAIDI by multiplying the pre-hardening all-in SAIDI of each zone with the estimated percentage improvements of each resiliency investment project type (D.P.U. 24-10, Exh. DPU 6-12).

the company's established reliability programs and at which the cost-efficiency curve appears saturated (Tr. 5, at 641-645; D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 625-626; ES-Policy/Solutions-1, at 49; DPU 11-11). Further, to prioritize resilience projects serving or impacting customers in EJ populations, the company would consider one additional criterion for eligibility, namely, zones in circuits serving 85 percent or more EJ customers (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 626; ES-Policy/Solutions-1, at 49-50).

Based on this planning process, the company estimated all-in SAIDI reductions of 10.1 percent and 13.3 percent, respectively, for its proposed resiliency program (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 626; ES-Policy/Solutions-1, at 49). The Company provided that 35.6 percent of total customers impacted by the proposed resilience program investment projects would be customers in EJ populations (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 626). The table below summarizes the resulting resiliency investment portfolio from NSTAR Electric's proposed resiliency investment planning process.

NSTAR Electric Proposed Resiliency Investment Portfolio

Eligible Zone CMI per event	Resiliency investment	Cost ($M/mile)	Estimated All-in SAIDI Improvement	Resulting portfolio makeup
>300,000	Undergrounding	4.0	98%	50%
150,000-300,000	Aerial Cable	2.2	82%	16%
<150,000	If bare wire, reconductoring to tree wire. If insulated wire, resiliency tree work.	1.1 0.1	50% 35%	22% 12%

(D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 622-623; ES-Policy/Solutions-1, at 66-67).

As noted above, NSTAR Electric commissioned a climate change vulnerability assessment ("CVA") study to assess the impacts of climate change on resilience across its service territory (D.P.U. 24-10, Exhs. ES-ESMP-1, at 628 (Corrected); ES-Policy/Solutions-1, at 68). The CVA projected six climate hazards out to 2080 across multiple climate change scenarios (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 628-630; ES-Policy/Solutions-1, at 68-69). Specifically, the CVA modeled multiple climate hazards, namely, extreme temperature, energy demand, heavy precipitation, drought, sea level rise, and storm surge under "middle-of-the-way" and "worst-case" scenarios[62] (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 629-630, 638; ES-Policy/Solutions-1, at 68-69; DPU 11-13). In addition, because the climate models do not forecast specific events, the company formulated two plausible extreme future scenarios to determine the potential impact of climate change-driven storms on electric assets (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 635; ES-Policy/Solutions-1).[63]

NSTAR Electric plans to use the results of the CVA to expand its target set of grid vulnerabilities to inform its resiliency program investments (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 636; ES-Policy/Solutions-1, at 67-68). The company anticipates its CVA-informed resiliency planning process will pair grid vulnerabilities with the optimal resilience project based on the type of climate hazard that the company expects will most impact the asset (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 637-638; ES-Policy/Solutions-1, at 67-68). NSTAR Electric states that it plans to weigh the probability of climate change scenarios, costs of mitigations, and estimated performance

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62 The company used the Shared Socioeconomic Pathways ("SSP") 2-4.5 and SSP 5-8.5 models (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 609, 630-639; ES-Policy/Solutions-1, at 68-69). Storm surge under a middle-of-the-way scenario is based on the SSP 2-4.5 model that assumes GHG emissions start decreasing mid-century while storm surge under a worst-case scenario is based on the SSP 5-8.5 model that assumes GHG emissions continue to increase (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 609, 630-631; ES-Policy/Solutions-1, at 68-69).

63 Based on historical events and climate change projections, the Company modeled two high-impact low probability events: a major ice storm followed by a cold snap and a prolonged drought followed by a tropical storm (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 635).

improvement when determining how to invest to protect against climate vulnerability (D.P.U. 24-10, Exh. DPU 11-13).

(F) Capital Investment Projects

NSTAR Electric proposed an extension of the cost allocation methodology proposed in D.P.U. 20-75-B (2021) to the seven additional CIPs utilized in D.P.U. 22-47 for the 2025 through 2029 term (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 9, 104, 133, 153, 180, 434-435; ES-Policy/Solutions-1 at 135, 144). The company explained that this methodology would avoid some disadvantages of the cost causation principle, including queue stagnation and free rider issues until an alternative method is developed (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 104). In addition to interconnecting the Group Study projects, NSTAR Electric expects the upgrades will enable future DER interconnections and help address potential electrification and load growth needs in the identified areas (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 374, 415, 417, 419, 422-423). The company also identified several new projects within the ten-year planning horizon expected to be in service between 2030 and 2034 (D.P.U. ES-ESMP-1 (Corrected) at 378). NSTAR Electric's proposed CIPs for the current ESMP term are summarized in the table below:

NSTAR Electric – Proposed ESMP Capital Investment Projects

Group Study Area	Number of Substations	Group Study (MW)[64]	Enabled Large DG (MW)	Enabled Small DG (MW)	Estimated CIP Fee ($/kW)	Estimated Total Cost ($ Million)[65]
East Freetown	2	45	119	10	476	112
Maynard-Acton	1	7	53	10	657	50
Walpole-Sharon	1	9	83	15	204	35
Whately-Deerfield	6	96	189	31	513	200
Southwick-Granville	1	24	88	3	488	82
Agawam-Feeding Hills	1	9	54	5	162	17
Dalton-Hinsdale	1	21	99	4	432	91
Total	**13**	**211**	**685**	**78**	**N/A**	**587**

(D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 374-377, 400-401, 415-424; DPU 8-1).

64 In response to information request DPU 8-1, NSTAR Electric provided revised numbers for the total MW of Group Study projects. The revised total is 211 MW of Group Study projects, reflecting an increase of 12 MW from the initial 199 MW (D.P.U. 24-10, Exh. DPU 8-1).

(G) Electric Vehicles

NSTAR Electric proposed to extend its existing Phase II EV make-ready and charging infrastructure program through 2029, which would otherwise end in 2026 (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 434; ES-Policy/Solutions-1 at 135, 137, 139; NG-Net Benefits-3 (Corrected) at 44). The company explained that its program invests in EV and fleet charging infrastructure, fleet telematics, and garage equipment to support EVs, and that such investments encourage and promote EV adoption in all customer class segments and, as a result, results in reduced GHG emissions and air pollutants (D.P.U. 24-10, Exh. NG-Net Benefits-3 (Corrected) at 44). The company's existing Phase II program includes make-ready and EVSE rebates for the public and workplace, residential, and light-duty fleet sectors (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 314-315, 427-428; ES-Policy/Solutions-1 at 77-78). NSTAR Electric assumes these same categories of spending in its proposed extension of its EV program, along with a similar breakdown of capital and O&M costs (D.P.U. 24-10, Exh. DOER-Common 5-6).

(H) Solar

NSTAR Electric proposed an Affordable Solar Access Plan ("ASAP") to operate in concert with the Commonwealth's existing solar incentive programs (D.P.U. 24-10,

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65 The estimated total costs provided for each Group Study Area reflect the company's preliminary analysis (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 374-377, 400-401, 415-424). The company provided bar charts without identifying a numerical estimate for each area; therefore, the Department evaluated the charts to provide the representative costs in this column. Total costs include projects that are expected to go into service in the next ESMP term, 2030 through 2034.

Exh. ES-ESMP-1 (Corrected) at 320). This program would apply to low-income and multi-family affordable housing property owners and other qualified participants in EJ populations (D.P.U. 24-10, Exhs ES-ESMP-1 (Corrected) at 320-321; ES-Policy/Solutions-1, at 111; ES-Bill Impacts-1, at 21; ES-Net Benefits-3 (Revised) at 46). Under the ASAP, NSTAR Electric would pay the solar project costs, with participating customers repaying the initial investments via monthly on-bill charges (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 321; ES-Policy/Solutions-1, at 111). NSTAR Electric would monetize all applicable incentives for participating customers and pass the incentives along through reduced monthly solar payments (D.P.U. 24-10, Exhs ES-ESMP-1 (Corrected) at 320-321; ES-Policy/Solutions-1, at 111; ES-Bill Impacts-1, at 21). To the extent customers discontinue making monthly solar payments, NSTAR Electric would seek cost recovery from all ratepayers (D.P.U. 24-10, Exhs ES-ESMP-1 (Corrected) at 319-321; ES-Bill Impacts-1, at 21). The company explained that, if directed to do so in D.P.U. 24-10, it would file a comprehensive program proposal and associated tariff seeking approval of the program (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 321).

(I) ESMP Program Administration

NSTAR Electric does not include any program administration costs as part of its ESMP proposed investments (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 450-451, ES-Net Benefits-1, at 14).

c. National Grid

i. Planned Core Spending

National Grid's planned core spending for the period 2025 through 2029 totals $7.31 billion (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 255, 358, 362; NG-Policy/Solutions-1 (Corrected) at 55-58; DOER-Common 1-1, Att.). The associated budget is for capital and O&M expenditures for equipment replacement and repair, system capacity and performance, and new customer connections and customer requests, as well as expenditures to support business operations, customer support, and estimated major storm response, among others (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 255, 358, 362; NG-Policy/Solutions-1 (Corrected) at 55-57; DOER-Common 1-1, Att.).

The company's estimated core capital investments for 2025 through 2029 total $4.25 billion, broken down into six categories: (1) system capacity and performance ($992.0 million) projects such as large substation expansions, new capacitor banks, reconfigurations of feeders and feeder ties, and resiliency measures such as infrastructure hardening; (2) asset condition ($789.0 million) projects to replace, repair, or upgrade poor performing assets including substation replacements and retirements, and replacement of direct-buried underground cables; (3) damage and failure ($498.0 million) projects to replace failed or damaged equipment and to restore the system to its original configuration and capability; (4) customer requests and public requirements ($1.70 billion) projects for new residential and business connections, third party attachments, land rights, and public requirements for municipal and customer interconnections; and (5) non-infrastructure

($270.0 million) projects for capital investments that do not fit into the prior categories, such as IT, fleet, tools, field and test equipment, and property investments in the company's facilities (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 255, 358-359; NG-Policy/Solutions-1 (Corrected) at 14, 34; DOER-Common 1-1, Att.).

The company's base O&M expenditures total $3.06 billion for the period 2025 through 2029 to support electric operations, storm response, business support/IT, and customer programs (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 362; NG-Policy/Solutions-1 (Corrected) at 14, 34, 57; DOER-Common 1-1, Att.).

The company's planned activities include membership on the Massachusetts Technical Standards Review Group, which includes a sub-group exploring smart inverter functionality (D.P.U. 24-11, Exh. AG 1-10). The company explained that smart inverter specifications have already been incorporated into the company's requirements for interconnections, and that all DERs in the company's power flow model and proposed interconnection applications are modeled according to these requirements (D.P.U. 24-11, Exh. AG 1-10).

ii. Pre-Approved or Preauthorized Spending

(A) Introduction

National Grid identified five categories of planned investments through 2029 that have been pre-approved or preauthorized by the Department or are pending Department review, with estimated spending of $3.39 billion: (1) CIPs ($234.0 million); (2) AMI ($412.0 million); (3) grid modernization investments ($86.6 million); (5) EV program expenses ($126.0 million); and (6) EE, electrification, and demand response program expenses ($2.53 billion) (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 359, 362; DOER-Common 1-1, Att.).

(B) Capital Investment Projects

The company's planned CIPs involve Provisional Program projects from multiple group studies submitted to the Department in D.P.U. 22-61 (Shutesbury), D.P.U. 22-170 (Monson-Palmer-Longmeadow East), D.P.U. 23-06 (Gardner-Winchendon), D.P.U. 23-09 (Barre-Athol), and D.P.U. 23-12 (Spencer-Rutland) (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 257; NG-Policy/Solutions-1 (Corrected) at 21-22, 58; DOER-Common 1-1, Att.). The proposed upgrades in these matters involve eight distribution substations, retirement of one existing substation, and the construction of one new substation (D.P.U. 24-11, Exh. NG-Policy/Solutions-1 (Corrected) at 21). The company explained that these CIPs, if approved, would allow interconnection of solar PV and ESS projects in specific areas (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 257). National Grid's pending CIPs are summarized below:

National Grid – Provisional Program CIPs				
Docket	**Group Study**	**Number of Applicants**	**MW of PV in Group Study**	**MW of ESS in Group Study**
D.P.U. 22-61	Shutesbury 001	5	20	14
D.P.U. 22-170	Monson-Palmer-Longmeadow (East) 001	7	18	1
D.P.U. 23-06	Gardner-Winchendon 001	8	7	42
D.P.U. 23-09	Barre-Athol 001	10	20	39
D.P.U. 23-12	Spencer-Rutland 001	16	36	76

(D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 87, 192, 257; NG-Policy/Solutions-1 (Corrected) at 21 n.1; DPU 9-1).

(C) Advanced Metering Infrastructure

National Grid's planned AMI investments were pre-approved through 2027 in D.P.U. 21-81, and include meters, communications infrastructure, a head-end system, an MDMS, and customer information system, analytical tools and system integrations, customer engagement and education, and customer enablement products and services (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 359; NG-Policy/Solutions-1 (Corrected) at 41). See Second Grid Modernization Plans (Track 2) at 258. Between 2025 through 2027, the company estimates $295.0 million in capital expenses and $117.0 million O&M for this program (D.P.U. 24-11, Exh. DOER-Common 1-1). Meter deployment will begin in 2024, with full deployment expected by 2027 (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 27, 256). The company anticipates that AMI implementation will: (1) enable customers to actively participate in energy programs and manage their energy usage and costs, including through TVR; (2) provide the company with automatic outage information; (3) enable remote service connection and disconnection and day-of service restoration; (4) in conjunction with DERMS, enable use of behind-the-meter DERs to manage demand; and (5) enable power quality and NWA performance monitoring (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 27, 65, 277-278, 299, 416, 428; NG--Policy/Solutions-1 (Corrected) at 74, 96). The company also identified the AMI working group jointly convened by the Companies to discuss data sharing and AMI-enabled opportunities for customers (D.P.U. 24-11, Exh. ES-ESMP-1 (Corrected) at 276, 426).

(D) Solar

National Grid does not identify any planned solar investments or associated spending in its ESMP filing (D.P.U. 24-11, Exhs. NG-Policy/Solutions-1 (Corrected) at 110; DOER-Common 1-1, Att.).

(E) Grid Modernization

The company estimated $86.6 million in planned spending in 2025 related to its grid modernization investments preauthorized in D.P.U. 21-81 (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 255, 359; DOER-Common 1-1, Att.). The company's planned grid modernization investments include seven categories of investments: (1) ADMS; (2) monitoring and control, including feeder monitors; (3) conservation volt reduction

("CVR")/VVO; (4) advanced distribution automation; (5) communications; (6) IT and operational technology, including data management, integration, and security; and (7) DERMS, including demonstration projects for active resources integration and local export power control (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 255-256, 269). The company indicates that these investments, along with its AMI program investments, will serve as critical foundational and supporting investments to its proposed ESMP investments (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 255, 260-261, 264, 278, 282).

National Grid described ADMS as enabling real-time management and control of its distribution network, including control of DERs (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 255, 264). The company explained that the feeder monitors enable real-time visibility into its network (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 255, 271-272). The company indicated that CVR and VVO would optimize voltage profiles (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 269). The company explained that DERMS track, manage, and operate DERs, whereas the local export power control demonstration projects will reduce interconnection costs and time for customers adding load and generation on the system simultaneously and will permit local management of customer assets (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 256, 264-265). Finally, the company described its IT and data investments as improvements to its technology foundation to deliver "any data, any service, any time" via data management and analytics, integration services, and cybersecurity (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 256).

(F) Electric Vehicle Program

National Grid's Phase III EV program was pre-approved through 2026 in D.P.U. 21-91, with program costs totaling $126.0 million during 2025 through 2026, of which $17.0 million is attributed to capital expenses and $109.0 million to O&M expenses (D.P.U. 24-11, Exh. DOER-Common-1, Att.). (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 257; NG-Policy/Solutions-1 (Corrected) at 58). The Phase III EV program includes make-ready and EVSE rebates for the public and workplace, residential, and fleet sectors (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 257; NG-Policy/Solutions-1 (Corrected) at 36-37). In addition, the program includes fleet assessment services and an off-peak charging rebate program (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 257; NG-Policy/Solutions-1 (Corrected) at 36-37).

(G) Energy Efficiency

The company plans to spend an estimated $2.53 billion in operating costs in 2025 through 2029 to administer Mass Save incentive programs for EE, demand response, and electric heat pumps (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 256; DOER-Common 1-1, Att.). For this program, the company assumes that its current three-year EE plan for 2022 through 2024 will be continued (D.P.U. 24-11, Exhs. NG-Policy/Solutions-1 (Corrected) at 57; DOER-Common 1-1, Att.). National Grid's planned programs through Mass Save include: (1) incentives to install EE measures in homes and businesses; (2) incentives for electric heat pumps; and (3) incentives for custom C&I projects (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 256, 344-345). The company indicated that it also runs several actively controlled DER measures in collaboration with other EE program administrators through its ConnectedSolutions program, also approved through its three-year plan (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 256, 344-345).

iii. Proposed ESMP Investments

(A) Introduction

National Grid proposed ESMP investments for 2025 through 2029 grouped within the six categories: (1) customer investments ($99.7 million); (2) platform investments ($400.1 million); (3) network investments ($1.63 billion); (4) CIPs ($71.8 million); (5) EV program ($299.2 million); and (6) ESMP program administration ($20.1 million) (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 358, 362; NG-Net Benefits-3 (Corrected) at 32; DOER-Common 1-1, Att.). National Grid explained that the proposed investments are proactive investment plans without which the company and its network would still aid in supporting the Commonwealth's policy objectives for electrification and DERs but at a pace driven by normal distribution system planning process using nearer-term considerations (D.P.U. 24-11, Exh. NG-Policy/Solutions-1 (Corrected) at 106, 120).

(B) Customer Investments

For its customer investments, National Grid identified six investment sub-categories totaling an estimated $99.7 million for the period 2025 through 2029: (1) customer portals for clean energy programs; (2) metering and billing systems; (3) a Grid Services Compensation Fund; (4) flexible connections for EVs; (4) and (5) VPP programs and demonstrations, including building-to-grid VPP and VPPs in EJ populations (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 253-254, 347-352, 358, 374, 362; NG-Net Benefits-3 (Corrected) at 32; DPU 1-1, Att. (13)). The company also described a Resilient Neighborhoods program as a customer investment, which it plans to propose and fund outside of the ESMP (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 254).[66] The company explained that customer investments involve new programs and demonstrations to VPPs, the use of DERs for grid services, and investments in new clean energy customer portals and enabling technologies (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 254, 374).

Regarding customer portals for clean energy programs, the company proposed two sets of investments: (1) a Clean Energy Platform 2.0; and (2) DER customer experience enhancements for its ConnectNow: End-to-End Load Connection Management Portal ("ConnectNow"), among other platforms (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 279-281; NG-Policy/Solutions-1 (Corrected) at 83, 86-87; DPU 1-1, Att. (13)). The company explained that these investments include customer-facing and internal systems to support clean energy programs such as EE, EV, and new customer interconnections (D.P.U. 24-11, Exh. NG-Policy/Solutions-1 (Corrected) at 86). The proposed Clean Energy 2.0 platform would be a new technology software-as-a-service platform to replace its existing

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66 The company described two additional customer investments in its ESMP that it plans to propose and fund outside of the ESMP: (1) incentives for EE, demand response, and electric heat pumps; and (2) TVR (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 254). The incentives for EE, demand response, and electric heat pumps involve the Mass Save program, which the Department discusses above. As noted in Section VII.D.4., TVR and rate design considerations will be addressed by the Department at a later date.

demand-side management system, InDemand (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 281-282). The company intends the Clean Energy 2.0 platform investment to be a unified customer portal for customers and vendors to facilitate future participation in customer rebates and incentive programs for EV, electric heat pumps, EE, and demand response programs (D.P.U. 24-11, Exh. NG-Policy/Solutions-1 (Corrected) at 87).

The company explained that its proposed DER customer experience enhancements for ConnectNow would improve the DER interconnection and electric connection processes, with a focus on same-day approvals for residential customer interconnection applications (D.P.U. 24-11, Exh. NG-Policy/Solutions-1 (Corrected) at 86-87). The proposed investments include merging the company's two existing DER interconnection portals into a new ConnectNow platform for trade partners (e.g., electricians and installers) to submit and manage connection requests (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 279). The company would also upgrade the current version of its Electric Connections portal to expedite load connection requests (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 280).

The company also proposed a pre-application customer interface to enhance the DER interconnection process that includes a guided questionnaire tool to assist customers and their contractors in designing an optimal technology solution using real-time location-specific information (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 280). The interface would display a detailed construction schedule and would also improve the company's public System Data Portal ("SDP"), which displays hosting capacity maps, heat maps, and distribution data

(D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 281; NG-Policy/Solutions-1 (Corrected) at 87).

For the metering and billing systems, the company proposed two investments: (1) a TVR billing system; and (2) a markets settlement engine (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 260, 275-279).[67] The company stated its current billing system does not have the functionality to support TVR other than for large C&I customers (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 66, 278; NG-Policy/Solutions-1 (Corrected) at 40). The company identified a need for a TVR billing engine to support accurate billing and settlement for customers who will be participating in future TVR and pricing structures that build on AMI capabilities (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 66, 278; NG-Policy/Solutions-1 (Corrected) at 86). The company expects TVR to be a critical component for managing load on the network and a critical prong in its strategy to better integrate flexible demand to reduce system peak (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 278).

The company's proposed markets settlement engine would allow National Grid to implement new incentive programs to activate and compensate individual customers and third-party aggregators for using flexible DERs for grid services (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 279; NG-Policy/Solutions-1 (Corrected) at 86). The

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67 National Grid stated that it received pre-approval for full deployment of AMI and does not propose additional AMI investments in its ESMP (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 276).

company explained that it will need new capabilities to accurately track and measure the performance of these flexibility service providers and issue timely and accurate settlements based on that performance (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 279; NG-Policy/Solutions-1 (Corrected) at 86).

National Grid, in coordination with NSTAR Electric and Unitil, proposed the establishment of a Grid Services Compensation Fund to support delivery of NWA projects over the five-year term (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 296-297, 374). The fund would recover costs associated with its proposed VPP ESMP programs and target bridge-to-wire and asset deferral[68] NWA projects (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 296, 348-351). The company explained that recommendations from the Grid Services Study,[69] jointly being pursued by the Companies and the MassCEC, will inform the company's locational grid service offerings as soon as 2025 and will help to develop a statewide DER compensation framework (D.P.U. 24-12, Exh. NG-ESMP-1 (Corrected) at 296, 351). The company set a $50.0 million cap on the proposed Grid Services Compensation Fund based on a preliminary assessment of the expected capacity needed, customer incentive level required to attain sufficient participation, and the potential deferral value of the two feeder expansion projects for which the company plans on pursuing asset deferral NWAs (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 296).

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68 These types of NWAs are discussed in further detail in Section VII.D.2.b., below.

69 The Department discusses the Grid Services Study in Section VI.C.2.e, below.

The proposed flexible connections for EV investment would accelerate EV fleet adoption by enabling a flexible connections option (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 347). The company explained that the significant lead time of two to five years or more to build infrastructure for large EV charging projects presents challenges for fleet operators seeking to meet zero-emission vehicle goals (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 347). The proposed program would allow EV charging sites, under certain conditions, to charge vehicles prior to the completion of system upgrades by allowing the company to actively manage the facility (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 347). The company proposes to build, test, and pilot the technology with EV charging customers in select locations during the ESMP term (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 347). In the next ESMP, National Grid plans to expand the program (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 347).

In addition to the flexible connection program for EV fleets, the company proposed additional customer incentive programs to compensate customers and third parties for providing local grid services as NWA solutions, including local EE/DR/EV managed charging incentives as VPPs, local flexibility market VPPs, an all-electric new construction demonstration project, and an income-eligible battery offering (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 254, 348-351l NG-Policy/Solutions-1 (Corrected) at 75-77). The local EE/DR/EV managed charging incentives as a VPP program would offer new incentives to customers to reduce peak load, either via reducing onsite load or increasing generation, to alleviate capacity constraints during local feeder- or substation-level peaks

(D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 348-349; NG-Policy/Solutions-1 (Corrected) at 75). The company explained that it plans to propose and fund this project outside of the ESMP (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 254, 348).

The company states that its local flexibility market VPPs proposal would supplement the local EE/DR/EV managed charging incentives proposal by procuring additional load flexibility though local, technology-agnostic, flexibility market auctions DER (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 349; NG-Policy/Solutions-1 (Corrected) at 75-76). To successfully deliver this platform, the company indicated the need for its corresponding DERMS Phase II and metering and billing system investment proposals (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 349; NG-Policy/Solutions-1 (Corrected) at 76).

The all-electric new construction demonstration project would involve partnering with an all-electric multifamily or large C&I new construction project (with solar, ESS, EV charging, heat pumps, other DER and/or smart devices controlled by building management) in a constrained bride-to-wires location to utilize DERMS technology solutions for greater company control of customer load and generation (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 349; NG-Policy/Solutions-1 (Corrected) at 76). The company would provide the customer financial incentives in exchange for operating the customer's integrated load and generation assets in ways that address both locational hosting capacity and peak loading constraints (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 349; NG-Policy/Solutions-1 (Corrected) at 76).

The income-eligible VPP offering would provide an ESS at no upfront cost to income-eligible customers in a bridge-to-wires NWA location (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 350-351; NG-Policy/Solutions-1 (Corrected) at 76-77). In exchange, the company would retain control of the ESS for use as an NWA to address locational peak load constraint (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 350-351; NG-Policy/Solutions-1 (Corrected) at 76-77).

Finally, the company identified a Resilient Neighborhoods program proposal involving company-owned solar and ESS projects to provide resiliency and climate adaptation benefits to EJ populations as a result of the passage of Section 77 of the 2021 Climate Act (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 351-352; NG-Policy/Solutions-1 (Corrected) at 81). The company indicated that it has been working to identify the best opportunities to site such solar and storage projects (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 351-352; NG-Policy/Solutions-1 (Corrected) at 81). The company will propose and fund this project outside of the ESMP at a later date (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 254, 351).

(C) Platform Investments

As part of its platform investment category, National Grid proposed investments in: (1) network management technologies (including DERMS); (2) communications; (3) data management; (4) digital products for asset planning, management, and operations; and (5) cybersecurity (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 23, 254, 260, 374; NG-Policy/Solutions-1 (Corrected) at 108). The company observed that several of these investments are an extension of the grid modernization plan and that federal funding from the U.S. Department of Energy ("DOE") under the Infrastructure Investment and Jobs Act ("IIJA") will offset a portion of its anticipated platform investment costs (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 23, 260-261, 264-265, 371, 374; NG-Policy/Solutions-1 (Corrected) at 69).

For its proposed investment in network management technologies, National Grid identified DERMS Phase II, active power restoration services ("APRS"), and future of network demonstration projects (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 265). Under DERMS Phase II, the company plans to expand the DERMS Phase I investments pre-approved as part of the company's 2022 through 2025 grid modernization plan to accelerate interconnection of DERs (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 265). The company indicated that it would use the DERMS Phase II investments to scale and expand capabilities for flexible interconnections, enhance hosting capacity, and leverage DERs for grid services (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 265-266). National Grid plans to leverage DERs for grid services in the following three ways: (1) accelerate pathways to procure and manage DERs flexibly to provide grid services that address distribution system constraints, provide reliability, and defer and/or avoid network investments; (2) enable customer DERs to participate in the ISO-NE wholesale markets; and (3) enhance customer experience and accelerate DER adoption (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 266).

The company explained that the APRS project would support the deployment of new features in its ADMS and DERMS to better integrate DERs on the network as part of its outage restoration strategy (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 267-268). This project would enhance its current fault location, isolation, and service restoration ("FLISR") control scheme capabilities to include situational awareness of customer connections by enhancing or adding integration with ADMS, DERMS, and AMI (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 268).

The future of network demonstration projects would test the ability of substation-edge computing to facilitate more autonomous data-driven management of the network (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 268). This project focuses on two components: (1) exploring autonomous management of digitized assets for different use cases; and (2) pushing data computation and infrastructure to the grid edge (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 268). For its planned investment in communications, National Grid proposes to expand its private-fiber network, leveraging on-going efforts where possible, and to scale up its field area network ("FAN") (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 272). To further build out its communications infrastructure, the company proposes additional investments in: operational telecommunications security; operational telecommunications data centers; connectivity for operational telecommunications administration; enterprise network edge protection; software-defined wide-area networking; corporate data networks; dedicated voice networks; configuration and change management; asset management; automation and orchestration; physical security and cameras; and an

IT/OT lab (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 273-276). The company explained that it currently utilizes a combination of private telecom networks and leased wired and wireless circuits and services to meet its communications needs but that its network must be upgraded and expanded to support future grid modernization efforts (D.P.U. 24-11, Exh. NG-Policy/Solutions-1 (Corrected) at 39-40).

In contrast, the FAN would provide near ubiquitous coverage throughout the company's Massachusetts service territory and continue to support the company's plans to integrate remote sensors, advanced capacitor controls, line voltage regulators, reclosers and circuit-breakers, and connected DER devices with the distribution control center ADMS (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 272). The company plans to leverage fiber deployment for back-hauling FAN communications (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 272).

For its planned investment in data management, National Grid proposed investments in intelligent data capture, grid asset data enhancements, and a transactional digital twin (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 283-285). The company anticipates that the proposed investment would provide more granular data to its ADMS and other tools to better understand, maintain, and operate the company's network; the grid asset data enhancements proposal would enable National Grid to fully digitize data processes, leverage AMI data in company planning processes, support DER digital product investments, and enable wider use of data-driven decision making; and the company's transactional digital twin would provide real-time visibility into the performance and condition of the electric network by combining a visual representation of physical assets on the electric network with real-time data (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 283-285).

For its planned investment in digital products for asset planning, management, and operations, National Grid proposed to deploy new technology to increase the efficiency and effectiveness in how the company plans, designs, builds, and operates the electric network (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 285). The company has preliminarily identified several applications where digital solutions may provide benefits, including more robust network infrastructure decision making processes, customer bill savings, reduced customer outages with faster restoration times, improved storm response preparation, and a reduced likelihood of equipment overloading as the company builds out network infrastructure (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 285-287).

Finally, National Grid identified cybersecurity investments to support its proposed technology investments (e.g., VVO, ADMS, DERMS) (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 288). To facilitate the integration of new technology and manage potential cybersecurity risks, the company would invest in device management, including network authentication; network convergence, including security and communication protocols to integrate information and operational technology; penetration testing, including threat detection models and security testing; and security orchestration automation and response to detect, mitigate and respond to security events (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 287-288).

(D) Network Investments

For its network investments, National Grid identified four sub-categories totaling an estimated $1.63 billion for the period 2025 through 2029: (1) substation and distribution line upgrades; (2) expanded CVR/VVO and early fault detection; (3) integrated energy planning; and (4) warehouse expansion to support incremental workplan and company EV fleet infrastructure and acceleration; (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 253; NG-Net Benefits-3 (Corrected) at 35). The company explained that the primary focus of the network investments is to enable capacity to meet the electrification forecast by enabling both load-serving and DER hosting capacity but, where appropriate, scoping considerations were made to address known reliability or resiliency concerns (D.P.U. 24-11, Exh. NG-Policy/Solutions-1 (Corrected) at 60, 114). These investments also include continuation of certain grid modernization plan investments such as CVR and VVO (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 269-270).

The company's proposed substation and distribution feeder projects for its five-year outlook include 13 substation upgrades or rebuilds and 14 new feeders to address capacity deficiencies and to support electrification and DER interconnections of new solar and ESS in line with the Commonwealth's interim 2030 adoption targets (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 21, 251, 291-292, 301-302, 313, 318, 324, 330, 336; NG-Policy/Solutions-1 (Corrected) at 21-22, 70). The company stated that these proactive upgrades are driven primarily by adoption of electric transportation and building heating (D.P.U. 24-11, NG-ESMP-1 (Corrected) at 364-365). The company expects the five-year outlook to enable over 800 MW of new capacity by 2029 to support the adoption of EVs and heating (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 251; NG-Policy/Solutions-1 (Corrected) at 70). The company distinguishes these projects from the CIP substation projects they propose under the D.P.U. 20-75-B cost allocation methodology (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 253). The company explained that its existing infrastructure is at capacity in many areas and has been designed to maintain safety and reliability under relatively stable loads levels over the past decade and, thus, cannot in such areas accommodate a new fleet electrification request at the pace of the Commonwealth's clean energy goals and forecasted need without substantial infrastructure investment (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 69-70, 291-292, 368-369; NG-Policy/Solutions-1 (Corrected) at 19).[70]

As noted above, the company's proposed CVR/VVO investments continue grid modernization plan investments (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 269-270). The company anticipates its CVR/VVO to: (1) achieve energy conservation; (2) provide support for renewable energy by ensuring steady voltage levels; (3) ensure equipment can operate at optimal levels providing enhanced equipment longevity; (4) provide superior reactive power control to ensure power is received within the desired range; (5) improve grid

70 The company noted that it has proposed a cost recovery mechanism in its pending base distribution rate proceeding to enable it to make the level of core and incremental investments identified for the first five years of its ESMP to achieve the Commonwealth's net zero goals (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 300).

visibility by incorporating VVO/CVR into the ADMS; and (6) improve the company's ability to optimize and control load flow (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 269-270).

The company proposed early fault detection technology investments to detect and locate defects in electrical infrastructure (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 270). National Grid proposes to extend deployment of the technology onto a mix of higher-risk circuits as well as circuits that service identified EJ populations within the company's service area (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 270-271).

Additionally, the company proposed integrated gas-electric planning investments to enable coordination and information sharing with other utilities and to permit the company to provide information on where there will be sufficient electricity network hosting capacity in the future to enable targeted electrification of gas network segments (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 253, 373; NG-Policy/Solutions-1 (Corrected) at 100).[71]

The company also proposed accelerating EV fleet adoption by testing and enabling a flexible connection option as an interim solution for EV fleets awaiting distribution upgrades (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 347). The proposed program would allow EV charging sites, under specific conditions, to charge vehicles before the completion of construction of system upgrades (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 347).

Regarding its proposed warehouse expansion, the company explained that its investments between now and 2050 require twice the current capacity space to manage

[71] The Department addresses the company proposed IEP framework in Section VII.B.

inventory levels (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 353). The warehouse plan also includes proposed: (1) lease costs associated with the company's fleet transition to EV; (2) costs for garage maintenance staff; and (3) costs to support a fleet telematics system (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 352-353).

(E) Resilience

National Grid did not propose specific resiliency investments incremental to its core investments in its ESMP (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 432; NG-Policy/Solutions-1 (Corrected) at 51-52). National Grid included in its ESMP its own CVA for developing adaptation plans to address climate change-driven risks to its assets (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 444; NG-Policy/Solutions-1 (Corrected) at 51).

(F) Capital Investment Projects

National Grid proposed to extend the cost allocation methodology and process proposed in D.P.U. 20-75-B, and identified three additional CIPs involving four substation upgrades in its ESMP with more to follow (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 251, 371; NG-Policy/Solutions-1 (Corrected) at 21, 108, 118-119). Following completion of the ongoing Group Studies, National Grid plans to submit the new CIP proposals to the Department as individual filings similar to the previously docketed CIPs (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 371; DOER 1-2). The three CIPs identified in the ESMP are summarized below:

National Grid – Proposed ESMP Capital Investment Projects					
Group Study Area	**Number of Applicants**	**MW of PV in Group Study**	**MW of ESS in Group Study**	**Total Enabled MW**	**Estimated CIP Fee ($/kW)**
Bridgewater 001	2	0	10	45	192
Cape Ann 001	3	0	15	87	277
Monson-Palmer-Longmeadow (NW) 002	5	9	37	112	525
Total	**10**	**9**	**62**	**244**	**N/A**

(D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 320-321, 332-333, 339-340; DPU 9-1).

(G) Electric Vehicles

National Grid proposed to extend its existing Phase III EV make-ready and charging infrastructure program through 2029, which would otherwise end in 2026 (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 346; NG-Policy/Solutions-1 (Corrected) at 79). The company's existing Phase III program includes make-ready and EVSE rebates for the public and workplace, residential, and fleet sectors (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 257; NG-Policy/Solutions-1 (Corrected) at 36). National Grid assumes these same categories of spending in its proposed extension of its EV program (D.P.U. 24-11, Exh. DOER-Common-5-6).

(H) Solar

National Grid did not propose ESMP solar investments (D.P.U. 24-11, Exhs. NG-Net Benefits-3 (Corrected) at 32; DOER-Common-1, Att.). However, the company identified an anticipated Resilient Neighborhoods Program proposal, which the company grouped with its proposed customer investments and the Department addressed in Section VII.C.2.c.iii.(B)., above.

(I) ESMP Program Administration

National Grid proposed $89.0 million in ESMP program administration costs, of which $20 million is for the 2025-2029 term O&M costs (D.P.U. 24-11, Exh. NG-Net Benefits-3 (Corrected) at 12, 32). This category of spending includes ESMP portfolio management and stakeholder engagement (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 362).

d. Unitil

i. Planned Core Spending

Unitil's planned core spending for the period 2025 through 2029 totals an estimated $145.2 million (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 13-19, 152-166; UN-Policy/Solutions-1, at 49-53; DOER-Common 1-1, Att.). The associated budget is for capital and O&M expenditures planned for equipment repair, new customer connections, peak load growth, and maintaining reliability, as well as expenditures to support business operations, customer support, estimated major storm response, and vegetation management, among others (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 14-16, 155-160, 163-164; UN-Policy/Solutions-1, at 50-51; DOER-Common 1-1, Att.). The company's estimated core capital investments for 2025 through 2029 total an estimated $79.3 million, separated into six categories: (1) annual "blankets" ($32.14 million) for blanket authorizations for categories of projects where each individual project cost is below $30,000 and typically includes items such as distribution improvements, new customer additions, outdoor lighting, emergency and storm restoration, billable work, and transformer and meter purchases; (2) distribution ($22.40 million), which involves individually authorized distribution projects for capacity improvements or equipment replacement; (3) substation ($9.42 million), which involves individually authorized substation projects for capacity improvements or equipment replacement; (4) reliability/resiliency ($5.40 million) projects developed as part of its annual reliability planning process; and (5) other ($9.98 million) for small categories of projects such as software/IT, communications, tools, laboratory, office furniture and equipment, and building improvements (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 14-15, 153-156; DOER-Common 1-1, Att.).

The company's base O&M expenditures total $65.9 million for the period 2025 through 2029, separated into four categories: (1) electric operations ($21.5 million), for distribution and substation maintenance, street light maintenance, underground maintenance, metering, field services, as well as the field and local supervisory labor associated with these activities; (2) business support and professional services ($22.5 million), for support of operations including finance, human resources, legal, and communications, including outside professional resources; (3) storm and vegetation management ($13.4 million), which involves estimates for its storm resiliency program maintenance activities and routine vegetation management (cycle pruning and hazard tree removal); (4) customer ($8.5 million), which involves costs to support customer experience including communications, billing, and other programs (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 16, 161, 163-164; DOER-Common 1-1, Att.).

ii. Pre-approved or Preauthorized Spending

(A) Introduction

Unitil identified four categories of planned investments through 2029 that have already been pre-approved or preauthorized by the Department or are pending Department review in separate Department proceedings, with estimated spending of an estimated $46.3 million: (1) AMI ($0.4 million); (2) grid modernization investments ($5.0 million); (3) EV program expenses ($0.6 million); and (4) EE, electrification, and demand response program expenses ($40.0 million) (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 160-161; UN-Policy/Solutions-1, at 50-52; DOER-Common 1-1, Att.).[72]

(B) Advanced Metering Infrastructure

The company's planned AMI investments were pre-approved through 2025 in D.P.U. 21-82, and include meters, costs attributed to customer engagement, and a data sharing platform (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 119-124;

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72 In its filing, Unitil explained that it did not have existing or planned CIPs (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 27). The company stated that, although it has experienced a high level of penetration with respect to DERs (specifically rooftop solar) interconnections, the quantity and size of the DER interconnections have not driven the need for group studies or the implementation of CIP project funding in its territory (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 168, 231). Additionally, Unitil indicated that it previously installed utility-owned solar on its system and is not planning or proposing any solar investments in its ESMP (D.P.U. 24-12, Exhs UN-ESMP-1 (Corrected) at 160, 166; DOER-Common-1, Att.).

UN-Policy/Solutions-1, at 50). The company's planned AMI capital expenses for 2025 total $0.4 million (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 107, 160; UN-Policy/Solutions-1, at 50). The company identified the AMI working group jointly convened by the Companies to discuss data sharing and opportunities that AMI will offer for customers (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 123-124).

(C) Grid Modernization

The company estimated $4.0 million[73] in planned capital and O&M in 2025 related to its preauthorized grid modernization investments (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 160, 166; DOER-Common 1-1, Att.). The company's planned grid modernization investments include: (1) SCADA; (2) AMI/OMS integration; (3) VVO; (4) FAN; (5) ADMS/DERMS; (6) mobile damage assessment platform; and (7) DER mitigations (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 107). The company indicated that the SCADA project is an enabling technology for other projects, including VVO and ADMS, which collectively help to optimize demand and reduce the effects of outages (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 114). The company described AMI/OMS integration as a software project to improve the ability of AMI meters to communicate with the OMS and assist outage predictions and response (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 115).

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73 The company also lists an additional $1.0 million in grid mod expenses for 2026 – 2029 (D.P.U. 24-12, Exh. DOER-Common 1-1, Att.).

The company's VVO project optimizes voltage and includes installation of: (1) automated controls on all voltage and reactive power equipment; and (2) voltage and energy monitors at strategic locations on the circuits (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 115-116). The FAN provides the communications backbone for the VVO, ADMS, DERMS, and SCADA systems (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 116). The ADMS provides self-healing automation, DER control, additional SCADA functions, real-time load flow and circuit analysis, demand response, outage restoration, direct load control, and network configuration, and the ADMS project includes the implementation of a DERMS as an add-on (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 117-118). DERMS will provide the company with the ability to manage the impact of multiple DER facilities and other infrastructure (e.g., EV charging stations, demand response) (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 118). The company described the mobile damage assessment platform as enabling greater operational efficiency and reducing the time to relay field information, resulting in greater situational awareness during large-scale weather events (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 118). The company explained that, as the proliferation of DERs on electric distribution systems increases, the challenges caused by reverse power flow and sustained energization increase (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 118-119). The company states the DER mitigation project involves overvoltage protection improvements on the 69 kV side of several distribution substations (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 118).

(D) Electric Vehicle Program

Unitil's Phase I EV program was pre-approved through 2027 in D.P.U. 21-92, with program costs totaling an estimated $0.6 million from 2025 through 2027 (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 111). The Phase I program includes make-ready rebates for the public and residential sector and EVSE rebates for low-income- residential customers (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 110-111).

(E) Energy Efficiency

Finally, the company plans to spend an estimated $40.0 million in operating costs in 2025 through 2029 to administer Mass Save incentive programs for EE, demand response, and electric heat pumps (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 16, 109-110; DOER-Common 1-1, Att.). For this program, the company assumes that its current three-year EE plan for 2022 through 2024 will be continued at the same funding level during the ESMP term (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 16, 18, 166).

iii. Proposed ESMP Investments

(A) Introduction

Unitil proposed ESMP investments for 2025 through 2029 grouped in six categories: (1) customer investments ($1.0 million); (2) platform investments ($0.7 million); (3) network investments ($42.6 million); (4) resilience ($5.0 million); (5) EV program ($1.2 million); and (6) ESMP program administration ($0.4 million) (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 160, 166; DOER-Common 1-1, Att.). Unitil explained that the proposed investments are proactive investment plans without which the company and its network would still aid in supporting the Commonwealth's policy objectives for electrification and DERs but at a pace driven by normal distribution system planning process using nearer-term considerations (D.P.U. 24-12, Exh. UN-Policy/Solutions-1, at 82, 93).

(B) Customer Investments

Unitil proposed two company-specific customer investments totaling an estimated $1.0 million for the period 2025 through 2029: (1) FERC Order 2222 enablement; and (2) DER/NWA enablement, including the Grid Services Compensation Fund (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 124-128, 132-133, 154, 157-158, 160, 162, 166, 176; UN-Net Benefits-3 (Corrected) at 40). The company explained that the FERC Order 2222 enablement program would involve modifications to company software, control systems, and other system upgrades to help incentivize customers to adopt DERs (D.P.U. 24-12, Exhs. UN-Policy/Solutions-1, at 69, 133; UN-Net Benefits-3 (Corrected) at 40; DPU 1-1, at 4-5). The company identified several benefits for this program, including integrating DERs, supporting state energy policies, avoiding renewable energy curtailment, reducing capacity constraints, increasing renewal energy resource integration, deferring distribution investments, and enabling customers in EJ populations and non-EJ populations to take control of their energy futures (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 173).

The DERs/NWAs grid services investments are intended to develop a framework to compensate DERs for providing locational grid services solutions, including mechanisms to increase the value of DERs deployed in EJ populations (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 124; UN-Net Benefits-3 (Corrected) at 40). Unitil's proposed investments include establishment of the Grid Services Compensation Fund, in coordination with NSTAR Electric and National Grid, to compensate dispatchable DERs and flexible loads participating in a program to allow utility dispatch and provide grid services (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 125; UN-Policy/Solutions-1, at 65, 89). The recommendations from the jointly proposed Grid Services Study will inform the creation of the Grid Services Compensation Fund and the eligibility requirements (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 125).

(C) Platform Investments

For its platform investment category, Unitil proposed ADMS/DERMS, telecommunications, and cybersecurity investments (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 18, 116, 128-132, 176; UN-Net Benefits-3 (Corrected) at 31). The proposed ADMS/DERMS investment would be a continuation of the company's current grid modernization program investments pre-approved in D.P.U. 21-82 (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 15, 107, 128-132). Unitil plans to incorporate the DERMS model into its ADMS platform and transition from its existing "model-based" VVO to a "meter-based" VVO system (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 128). In addition, Unitil plans to complete implementation of the unbalanced load flow and short circuit modules within ADMS to enable the ADMS platform to perform all FLISR, VVO, and other required load flow functions (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 128). The proposed cybersecurity investments include enhancements to the company's operations technology and IT to identify and mitigate risks (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 133).

(D) Network Investments

For its network investments, Unitil identified three investment sub-categories in capital spending: (1) Lunenberg substation; (2) South Lunenberg substation; and (3) VVO and early fault detection/automation (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 14, 129-132, 157-158, 160, 176; UN-Net Benefits-3 (Corrected) at 12). The company explained that these investments are intended to proactively meet electrification load growth and DER interconnections (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 157-158; UN-Policy/Solutions-1 (Corrected) at 83-84).

The company proposed the Lunenberg and South Lunenberg substation projects to increase the reliability and hosting capacity of the system, and to alleviate loading constraints (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 167, 174-175). The Lunenberg substation and the new South Lunenburg substations will enable more than 15 MW and 30 MW, respectively, and the capacity additions for these projects were informed by the company's demand assessment (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected), at 158, 173-174).

The proposed VVO and automation investments involve continued installation of automated communications and controls on all voltage regulators, capacitor banks, energy measurement devices, and substation load tap changers, implementation of automation functionality at the company's remaining substations, and extension of SCADA monitoring and control out on the distribution system (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 128-132). The company explained that this investment is foundational to reducing outage response and restoration times through improved outage awareness and FLISR capabilities (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 132).

(E) Resilience

Unitil proposed ESMP-specific targeted resiliency investments involving targeted installation of spacer cable, undergrounding projects, and developing or automating circuit ties where they do not exist over the first five-year ESMP term (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 159, 256; UN-Policy/Solutions-1, at 48-49). The company proposals involve a spending increase from its current targeted resiliency investments to support approximately two additional miles of spacer cable or 700 to 1,800 feet of undergrounding (Tr. 5, at 648-649; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 159, 256; UN-Policy/Solutions-1, at 48-49; DPU 6-9; DPU 10-14). Unitil proposed to deploy its incremental resiliency investments in poor performing parts of the company's distribution system, identified using historical outage data (D.P.U. 24-12, Exhs. DPU 6-9; DPU 10-13; DPU 10-14). Under the proposed investment plan, the company would estimate customer outage minutes and customer interruptions saved by the resiliency investments and determine the cost effectiveness of each project based on modeling that relies on historical outage history by circuit and outage type to determine CMI savings for each project (Tr. 5, at 649-650; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 255; DPU 6-6; DPU 10-12). Unitil then plans to prioritize resiliency investments based on cost per saved customer minute and cost per saved customer interruption (Tr. 5, at 649-650;

D.P.U. 24-12, Exh. DPU 6-9). Unitil explained that it is in the early stages of designing and implementing an iterative CVA framework to assess the risks associated with climate change and implement mitigation measures to improve system resilience (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 257, 260-262; UN-Policy/Solutions-1, at 47). The CVA framework involves five high-level steps: (1) conduct a CVA to analyze climate impacts to the region and the company's assets; (2) evaluate and prioritize risk utilizing multiple climate change models;[74] (3) develop and evaluate mitigation options for the identified risks, including determining the impact to EJ populations and low- to moderate-income customers; (4) prioritize implementation of mitigation options; (5) evaluate success; and (6) repeat full CVA within three years (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 261; UN-Policy/Solutions-1, at 47; DPU 10-15).

(F) Capital Investment Projects

As noted above, Unitil has not identified the need for any CIPs and did not propose any CIPs as part of its ESMP (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 27). The company stated, however, that if it identifies a need to conduct a group study that results in significant capital investment, it proposes to apply the CIP methodology established by the Department in D.P.U. 20-75-B (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 168).

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74 Unitil considered a range of climate change scenarios, from Representative Common Pathway (RCP) 2.6, which models a low warming scenario, to RCP 8.5 which is considered a worst possible outcome (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 257; DPU 6-1).

(G) Electric Vehicles

Unitil proposed to extend its existing Phase I EV make-ready and charging infrastructure program through 2029, which would otherwise end in 2027 (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 15, 112; UN-Policy/Solutions-1 at 53, 87). The company's existing Phase I program includes make-ready rebates for the public and residential sector and EVSE rebates for low-income residential customers (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 110). Unitil assumed these same categories of spending in its proposed extension of its EV program but doubles the proposed budgets for each spending category to accelerate the enablement of clean energy goals (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 111-112; UN-Policy/Solutions-1, at 84; DOER-Common 5-6).

(H) Solar

Unitil did not propose any solar investments in its ESMP (D.P.U. 24-12, Exh. DOER-Common-1, Att.).

(I) ESMP Program Administration

Unitil proposed $0.4 million in ESMP program administration costs for 2025-2029 O&M costs (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 135; UN-Net Benefits-3 (Corrected) at 12, 31; DOER-Common-1, Att.). This category of spending includes stakeholder outreach, including CESAG compensation, and any measurement and verification efforts (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 17, 135).

e. <u>Grid Services Study and Transactional Energy Study</u>

The Companies jointly identified two studies to inform compensation for locational grid services and their proposed Grid Services Compensation Fund: (1) a Grid Services Study and (2) a Transactional Energy Study. For the Grid Services Study, the Companies plan to coordinate with the MassCEC and engage a third-party consultant to study the value of DERs and load flexibility as a locational grid service (D.P.U. 24-10, Exh ES-ESMP-1 (Corrected) at 429; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 351; D.P.U 24-12, Exh. UN-ESMP-1 (Corrected) at 125). The Companies expect to complete the study in 2024, and therefore the budget is not included in the 2025-2029 ESMP budget (<u>see</u> D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 429). The study would help the Companies establish specific levels of compensation for locational grid services (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 429; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 351; D.P.U 24-12, Exh. UN-ESMP-1 (Corrected) at 125).

In addition, the Companies intend the study to assess how underserved EJ populations can obtain added value from dispatchable DERs (D.P.U. 24-10 Exh. ES-ESMP-1 (Corrected) at 429; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 351). The Companies propose to conduct the study collaboratively through stakeholder engagement, including DER developers (D.P.U. 24-10, Exh ES-ESMP-1 (Corrected) at 429; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 351; D.P.U 24-12, Exh. UN-ESMP-1 (Corrected) at 125). The Companies expect the results from the study to inform the proposed Grid Services Compensation Funds

(D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 429; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 351; D.P.U 24-12, Exh. UN-ESMP-1 (Corrected) at 125).

The proposed Transactional Energy Study would build on the findings from the Grid Services Study to develop recommendations for a more dynamic locational value compensation framework (D.P.U. 24-10, Exh ES-ESMP-1 (Corrected) at 430; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 351; D.P.U 24-12, Exh. UN-ESMP-1 (Corrected) at 125). The Companies plan to conduct the Transactional Energy Study during the second half of the ESMP term to inform proposals in the Companies' next ESMPs (D.P.U. 24-10, Exh ES-ESMP-1 (Corrected) at 429; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 351; D.P.U 24-12, Exh. UN-ESMP-1 (Corrected) at 125).

3. Positions of the Parties

a. Attorney General

The Attorney General maintains that the Companies' division among core, planned, and ESMP investments is problematic (Attorney General Brief at 44, 47, citing Exh. AG-BF-1, at 40). The Attorney General points to the Companies' inconsistent approaches in classifying investments as either core or ESMP, noting the differing treatment by NSTAR Electric and National Grid of resiliency investments and, as a result, the differences resulting in the Companies' net benefits analyses (Attorney General Brief at 42-43, citing Exh. AG-BF-1, at 39-40; D.P.U. 24-10, Exhs. AG 2-5 & Att.; D.P.U. 24-11, Exh. NG-ESMP-1, at 373-374; Attorney General Reply Brief at 15 (citations omitted)). According to the Attorney General, the Companies have designated ESMP investments not based on fundamental differences in investment type but based on the docket for which they seek recovery for the investments (i.e., a rate case versus an ESMP proceeding) (Attorney General Brief at 44, citing Exh. AG-BF-1, at 40; Attorney General Reply Brief at 15, citing Tr. 4, at 501, 503-504).

The Attorney General generally supports the Companies' development of a grid services program framework, including the Grid Services Compensation Fund, Grid Services Study, and Transactional Study, and National Grid's proposed VPP demonstration projects, as a means to cost-efficiently improve system reliability and efficiency, but provides the following recommendations: (1) the Companies should solicit comments from stakeholders regarding the Grid Services Study and document consensus and non-consensus recommendations; (2) the Department should order the Companies to file the results of the Grid Services Study, any associated DER compensation framework, and consensus and non-consensus recommendations from stakeholders for Department approval; and (3) the Department should order the Companies to collaborate with stakeholders to develop a uniform, statewide market design framework and set of programs (Attorney General Brief at 27-29). The Attorney General also suggests that the Department consider National Grid's proposed ESMP offerings as a model for the market design framework, given the company's experience in market development in other jurisdictions (Attorney General Brief at 29, citing Exh. AG-NBC-1, at 90-95; D.P.U. 24-11, Exh. NG-ESMP-1, at 349).

The Attorney General observes that since EV load will drive load growth and system upgrades through 2035, interconnecting EV load to the distribution system as efficiently and cost-effectively as possible while offering EV-specific flexible interconnection options may reduce the need for future investments at ratepayer expense (Attorney General Brief at 20-21). The Attorney General points to National Grid's flexible interconnection pilot proposal enabling active EV charging management as a positive example which should be pursued collaboratively by NSTAR Electric and Unitil (Attorney General Brief at 21, citing D.P.U. 24-11, Exh. NG-ESMP-1, at 347).

b. DOER

DOER requests that the Department require the Companies to provide an updated and more standardized investment table that meets the requirements set forth in the 2022 Clean Energy Act (DOER Brief at 37). According to DOER, the ESMPs lack clarity regarding proposed and approved investments and cost recovery mechanisms (DOER Brief at 38). DOER also suggests that the different investment amounts and categories complicated the GMAC review process and hindered intervenors' review of the ESMPs (DOER Brief at 38, citing GMAC Consultant Comments at 3, 5-6; Exh. DOER-1, at 18, 40-42). As an example, DOER notes National Grid's inclusion of IEP in its network investments category while NSTAR Electric included IEP investments in its customer investment category (DOER Brief at 38, citing D.P.U. 24-10, Exh. ES-Net Benefits-1, at 14; D.P.U. 24-11, Exh. NG-Net Benefits-1, at 13). In addition, DOER points out that NSTAR Electric and Unitil proposed incremental ESMP resiliency investments while National Grid did not (DOER Brief at 38, citing D.P.U. 24-10, Exh. ES-ESMP-1, at 435; D.P.U. 24-11, Exhs. NG-ESMP-1, at 431; DPU 6-6; D.P.U. 24-12, Exh. UN-ESMP-1, at 159). Lastly, DOER observes that NSTAR Electric did not include any network investments as part of its ESMP for review and approval, whereas both National Grid and Unitil did and this category comprises the largest portion of their proposed investments (DOER Brief at 38, citing D.P.U. 24-10, Exh. ES-ESMP-1, at 435; D.P.U. 24-11, Exh. NG-ESMP-1, at 358; D.P.U. 24-12, Exh. UN-ESMP-1, at 160).

DOER states that the different categorization of investments poses challenges to evaluating the ESMP across Companies and makes it difficult to determine which type of investment should be analyzed in which Department docket (DOER Brief at 39). Further, DOER shares the Attorney General's concerns about discrepancies between core and incremental investments (DOER Brief at 39, citing Exh. AG-BF-1, at 48). Pointing to Section 92B(c)(ii), DOER recommends that the Department require the Companies to provide a standardized, summary investment Excel table in a compliance filing that identifies all proposed and related investments, alternatives to these investments, and alternative approaches to financing these investments, including all pending Department-approved capital and O&M expenses and the newly proposed ESMP investments with the following information: (1) the investment category, (2) an investment summary and description, (3) the ongoing or expected cost recovery mechanism, (4) the expenditure for each year throughout the 2025-2029 ESMP term, and (5) the total expenditure for the ESMP period (DOER Brief at 37-38, 40-41). For approved capital and operational investments, DOER states that the table should also include: (1) details on the docket/Order where they were approved, (2) the approved investments; and (3) incurred investments, or investments that the company expects to incur for the three years prior to filing the ESMP (DOER Brief at 41). For capital and operational investments expected to be requested during the ESMP term, DOER maintains that the Department should require the Companies to provide in the table: (1) an expected approximation of investments for the ESMP term; (2) the process by which the company expects the investment will be approved; and (3) the proposed cost recovery mechanism and period for recovery (DOER Brief at 41). Within the table, DOER requests that the Companies standardize the categories of investments or provide explanations of any differences in categorization (DOER Brief at 41). DOER also requests for this table to be submitted as part of future ESMP filings (DOER Brief at 41).

DOER also recommends that the Department require the Companies to use a standardized tool, as well as standardized forecasting windows and parameters, for their CVAs (DOER Brief at 56-57). Additionally, DOER maintains that the varied application of ESMP versus non-ESMP categorization of resiliency investments poses challenges for evaluating and comparing the ESMPs across Companies (DOER Brief at 38-39).

DOER supports the Attorney General's recommendation that the Department require NSTAR Electric and Unitil to collaborate with National Grid to develop the flexible connections for the EV program to incentivize fleet electrification despite long wait times for distribution infrastructure upgrades (DOER Reply Brief at 13, citing Attorney General Brief at 19, 50; D.P.U. 24-11, Exh. NG-ESMP-1, at 347). Additionally, DOER argues that load management of EV charging is critical to a modern and resilient grid, and collaboration among the three Companies allows for standardization of EV load management offerings

(DOER Reply Brief at 14, citing D.P.U. 24-10, Exh. ES-ESMP-1, at 253; D.P.U. 24-11, Exh. NG-ESMP-1, at 69).

DOER generally supports the intent of NSTAR Electric's proposed ASAP but does not find the ESMP an appropriate channel for preauthorizing the program since the ESMP focuses on grid planning (DOER Brief at 62). DOER agrees with the GECA that the Department should not consider the costs, benefits, and investment proposals related to ASAP in this ESMP (DOER Brief at 62, citing D.P.U. 24-10/D.P.U. 24-11, Exh. GECA-LC-1, at 11). In addition, DOER encourages the Department and NSTAR Electric to consider direct, on-bill financing of solar for income-eligible tenants in another venue (DOER Brief at 62-63).

a. Acadia Center, CLF, and GECA

Acadia Center, CLF, and GECA recommend that the Department direct the Companies to submit a more standardized ESMP with common glossary of investments and clear timelines of ongoing and future activities related to grid planning and investments for the next plan term to allow for more efficient stakeholder engagement (Joint Intervenor Reply Brief at 4, 6-7; GECA Brief at 20-21). The Joint Intervenors also urge a similar requirement in a compliance filing for the current proceedings (Joint Intervenor Reply Brief at 7, citing DOER Brief at 32-41; CLC Brief at 27; GECA Brief at 20-21). Further, the Joint Intervenors maintain that bifurcation and inconsistent treatment of ESMP versus non-ESMP investments are particularly problematic with regard to resiliency investments (Joint Intervenor Reply Brief at 2-3).

CLF recommends Department approval of the ESMPs with the requirement that the Companies design and construct resilient electric grid infrastructure prepared to withstand climate change impacts required by Section 92B(a)(i) and (iv) (CLF Brief at 18). CLF contends that consistency among the Companies' hazard mitigation and adaptation planning is vital to ensure a resilient grid (CLF Brief at 18). CLF points to its petition to the Department for the development of Hazard Mitigation and Climate Adaptation Plans ("HMCAPs") and recommends that the Companies incorporate the principles of the HMCAPs into their resilience planning pending the Department's response to CLF's petition (CLF Brief at 19-20, citing CLF Petition for MA DPU Rulemaking (dated May 3, 2023) ("CLF Petition")). The proposed HMCAP requirements include: (1) an evaluation of climate-related risks; (2) an assessment of impacts of climate change on existing operations, planning, and assets; (3) identification and prioritization of climate adaptation strategies; (4) an evaluation of costs and benefits of possible future scenarios and climate adaptation strategies; and (5) an implementation timeline (CLF Brief at 19, citing CLF Petition at 47-48). Further, CLF asserts that the Companies should employ consistent standards that will enable adherence to best practices (CLF Brief at 20).

GECA argues that the ESMPs should include strategies to facilitate EV adoption (GECA Brief at 17). GECA contends that descriptions of future EV charging and buildout in the Companies' ESMPs do not provide the detail reasonably expected in a comprehensive strategy to meet the Commonwealth's climate goals (GECA Brief at 19). Further, GECA argues that the Companies offer little information about how the ESMPs will promote EV charging infrastructure beyond the assertion that they will extend existing programs (GECA Brief at 19).

GECA maintains that NSTAR Electric's proposed ASAP program exemplifies the potential for duplicative or poorly conceived ESMP expenditures (GECA Brief at 15, citing D.P.U. 24-10/D.P.U. 24-11, Exh. GECA-LC-1, at 9, 11-14). GECA asserts that the company does not explain how the ECSAP and Community Solar Resilience Program or other federal, state, or local governments would work together without duplication or customer confusion about overlapping programs (GECA Brief at 15, citing D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 319). According to GECA, NSTAR Electric cannot adequately explain why the company should assume functions of pre-qualifying solar installers, administering a community request for proposals ("RFP') process for installation, and taking on the role of assuring consumer protection standards and associated production guarantees (GECA Brief at 15, citing Exh. GECA-LS-1, at 13). GECA contends that any solar-for-all-type programs should build off a consensus approach involving on-bill financing and to ensure as much consistency as possible (GECA Brief at 16-17, citing Exh. GECA-LS-1, at 12).

Further, GECA argues that the ESMPs do not meet Section 92B's requirement to "minimize or mitigate impacts on the ratepayers of the Commonwealth" (GECA Brief at 13). Specifically, GECA claims that the Companies consider every expenditure as qualitatively minimizing or mitigating impacts on ratepayers, without quantifying ratepayer savings (GECA Brief at 13, citing D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 443-449;

D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 317-320). GECA challenges the Companies' assertion that the Companies' planning alone will minimize costs and reduce the need for infrastructure upgrades (GECA Brief at 13-14, citing D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 6, 18, 447, 459; ES-Net Benefits-1, at 29-30; D.P.U. 24-11, Exh. NG-Net Benefits-1 (Corrected) at 42).

b. Cape Light Compact

CLC supports standardizing the ESMPs across Companies (CLC Brief at 27-28, citing Exh. DOER-1, at 41-42; GMAC Report at 30). Pointing to DOER's statements, CLC reiterates three main inconsistencies: (1) NSTAR Electric proposes resiliency investments as part of its incremental investments while National Grid does not propose any resiliency investments, (2) NSTAR Electric includes integrated energy planning investments as a part of its customer investments while National Grid proposes integrated energy planning investments as part of its network investments, and (3) NSTAR Electric does not include any network investments, while network investments comprise the largest portion of National Grid and Unitil proposed investments (CLC Brief at 27-28, citing DOER-1, at 18, 41-42; GMAC Report at 28). CLC asserts that the lack of uniformity in the ESMPs emphasizes the need for them to have standardized figures and tables for all investments (CLC Brief at 27-28).

Regarding NSTAR Electric's proposed solar program, CLC argues that low-and moderate-income programs should be discussed in the ESMPs since they are consistent with the Commonwealth's 2050 climate goals set under the 2022 Clean Energy Act (CLC Brief at 2, 19 & n.15). The Compact supports NSTAR Electric's ASAP and recommends that the

Department direct NSTAR Electric to file the program in a separate Department proceeding and to (1) coordinate the program with the DOER and Mass Housing and (2) not allow customers to qualify for ASAP and the MassCEC's Solar for All program or the Energy Saver Home Loan programs (CLC Brief at 2, 19, citing D.P.U. 24-10, Exh. CLC-ES 3-1). As such, CLC requests that the program include a limitation that customers may qualify for only one low- and moderate-income solar program (CLC Brief at 19-20, citing D.P.U. 24-10, Exh. CLC-ES 3-1).

c. Clean Energy Coalition

The Coalition recounts that National Grid's representatives testified that network upgrades would provide sufficient solar capacity but did not provide details of this increased capacity (CEC Brief at 13, citing Tr. 6, at 908-910). Thus, the Coalition requests that the Department direct the Companies to file for Department review and approval, within 18 months of the ESMP Order, proposals for capital investments necessary to enable DG hosting capacity to meet the Commonwealth's CECP mandate in accordance with any long-term system planning process ("LTSPP") to be developed (CEC Brief at 15).

d. EVgo

EVgo supports the Companies' proposed extensions of their EV programs, stating that the programs will be necessary to create a robust charging network and achieve the Commonwealth's climate and electrification goals (EVgo Brief at 4). EVgo also argues that the Department should exclude public DCFC in managed charging programs, due to inelastic demand from EV drivers looking to charge their vehicles quickly (EVgo Brief at 4-6).

Additionally, EVgo argues that the Department should avoid requiring on-site batteries and other DERs in EV incentive programs, as there are many economic and practical constraints to installing on-site energy storage co-located with DCFC stations (EVgo Brief at 6-7).

e. Companies

The Companies argue that, generally, no intervenor opposed the Companies' proposed incremental ESMP investments, with the exception of NSTAR Electric's proposed ASAP program (Companies' Joint Reply Brief at 10). The Companies contend they have proposed discrete investments to proactively upgrade the distribution system and, collectively, achieve the specific objectives set forth in Section 92B(a) and (e) (Companies' Joint Brief at 42 (citations omitted)). The Companies recognize that they play a vital role in developing an electric distribution system that will enable customers to reduce GHG emissions through electrification of heating and transportation, and adoption of renewable energy generation (Companies' Joint Brief, citing D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 131; D.P.U. 24-11, Exh. NG-Policy/Solutions-1, at 105-106; D.P.U. 24-12, Exh. UN-Policy/Solutions-1, at 81). The Companies maintain that the ESMP investments for these initial five-year strategic plans will help facilitate the achievement of the Commonwealth's climate goals by enabling significant levels of EV and heat pump adoption, timely integration of DERs and modernizing the distribution system and encouraging customers to shift energy consumption to avoid renewable energy curtailment, while maintaining safe and reliable service (Companies' Joint Brief at 43). The Companies contend that their proposed investments are designed to build on each company's unique system while ensuring safe and reliable service through its core investments (Companies' Joint Brief at 43, citing D.P.U. 24-10, Exhs. ES-Policy/Solutions-1, at 131; DPU-Common 1-1; DPU-Common 1-2; DPU-Common 1-3; D.P.U. 24-11, Exhs. NG-Policy/Solutions-1, at 105; DPU-Common 1-1; DPU-Common 1-2; DPU-Common 1-3; D.P.U. 24-12, Exhs. UN-Policy/Solutions-1, at 81; DPU-Common 1-1; DPU-Common 1-2; DPU-Common 1-3).

The Companies explained that, during the development of the ESMP, they each assessed the capabilities of existing and planned infrastructure to identify the capacity potential of their respective systems and, comparing that potential with forecast and demand assessments, identified the potential gaps between the planned capacity of the distribution system and the likely required capacity for their systems if the Commonwealth meets its electrification and renewable energy generation goals by 2050 (Companies' Joint Brief at 44, citing D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 86-102; D.P.U. 24-11, Exh. NG-Policy/Solutions-1, at 58-68; D.P.U. 24-12, Exh. UN-Policy/Solutions-1, at 53-63). Further, each company's proposals assume the continuation or extension of existing programs, including EE programs, the progression of pending CIPs, and delivery of authorized investments for AMI, EV programs, and grid modernization (Companies' Joint Brief at 44, citing D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 132-133; D.P.U. 24-11, Exh. NG-Policy/Solutions-1, at 106; D.P.U. 24-12, Exh. UN-Policy/Solutions-1, at 82). The Companies maintain that they then assessed potential incremental investments, as well as alternatives, to close the gap but that, unlike core investments, the proposed incremental

ESMP investments are not intended to meet a near term customer need or system safety and reliability need; rather each incremental ESMP investment or program is intended to build on existing or planned distribution infrastructure to address one or more of the statutory, long-term objectives (Companies' Joint Brief at 44, citing D.P.U. 24-10, Exhs. ES-Policy/Solutions-1, at 131; DPU-Common 1-1; D.P.U. 24-11, Exhs. NG-Policy/Solutions-1, at 105; DPU-Common 1-1; D.P.U. 24-12, Exhs. UN-Policy/Solutions-1, at 81; DPU-Common 1-1). According to the Companies, a business-as-usual strategy would not achieve the same level of enablement on the proactive timeline contemplated by Section 92B and would result in delayed customer adoption of clean energy technologies (Companies' Joint Brief at 45, citing D.P.U. 24-10, Exh. DPU-Common 9-4; D.P.U. 24-11, DPU-Common 9-4; D.P.U. 24-12, Exh. DPU-Common 9-4).

The Companies assert that they are aligned on the definitions for their categories of ESMP incremental investments but maintain that each company has unique system characteristics and different capabilities (Companies' Joint Brief at 45, citing Tr. 5, at 590-592). The Companies state that they developed consistent investment categories, but the individual proposed projects differ because of the Companies' different starting points and specific system characteristics (Companies' Joint Brief at 46, citing Tr. 5, at 590-592; D.P.U. 24-10, Exh. ES-ESMP-1, § 7.0; D.P.U. 24-11, Exh. NG-ESMP-1, § 7.0; D.P.U. 24-12, Exh. UN-ESMP-1, § 7.0). Regarding the classification of investments, the Companies contend that differences are not due to a lack of standardization of investment categories but rather differences in identified system needs (Companies' Joint Reply Brief at 12). The Companies maintain that variations in proposed investments should be expected because each service territory and distribution system is different and, as such, each company's portfolio of investments will vary (Companies' Joint Reply Brief at 12-13, citing DOER Brief at 38; CLC Brief at 38; D.P.U. 24-10, Exh. ES-ESMP-1, § 7.0; D.P.U. 24-11, Exh. NG-ESMP-1, § 7.0: D.P.U. 24-12, Exh. UN-ESMP-1, § 7.0). The Companies suggest that DOER and CLC are concerned that the Companies are not offering the same investments, such as plans for network investments, but plans vary because the Companies' service territories and distribution systems are different (Companies' Joint Reply Brief at 12-13, citing Tr. 5, at 590-592; D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 146; D.P.U. 24-11, Exh. NG-Policy/Solutions-1 (Corrected) at 120; D.P.U. 24-12, Exh. UN-Policy/Solutions-1, at 93).

The Companies assert that their proposed platform and customer investments will enhance interconnections and provide customers with new renewable energy opportunities or, in National Grid's case, to accelerate and support the transition to a DER-heavy distribution system (Companies' Joint Brief at 48, 52, 59, citing D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 138; D.P.U. 24-11, Exh. NG-EMSP-1, at 360; D.P.U. 24-12, Exh. UN-Policy/Solutions-1, at 86).

The Companies assert that all their customer investments will enhance interconnections, give customers new opportunities to access renewable energy, and facilitate the electrification of transportation and buildings (Companies' Joint Brief at 48, 54, 59, citing D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 138-139; D.P.U. 24-11, Exh. NG-ESMP-1, at 112; D.P.U. 24-12, Exh. UN-Policy/Solutions-1, at 87, 89). National Grid also states that its customer investments will encourage the development of energy storage through VPPs and NWAs (Companies' Joint Brief at 54, citing D.P.U. 24-11, Exh. NG-ESMP-1, at 114).

The Companies note that the Attorney General supports their respective grid services offerings but proposes certain modification related to stakeholder input and standardization, which they oppose (Companies' Joint Reply Brief at 11). The Companies assert that the Attorney General's proposals would interfere with the study led by MassCEC (Companies' Joint Reply Brief at 11, citing Attorney General Brief at 29; D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 103-140; D.P.U. 24-11, Exh. NG-Policy/Solutions-1, at 77; D.P.U. 24-12, Exh. UN-Policy/Solutions-1, at 89). In addition, the Companies request flexibility to implement grid services offerings as described in their ESMPs to support NWAs and demonstrate how location-specific solutions can benefit customers and the system (Companies' Joint Reply Brief at 12). The Companies state that standardizing the Grid Services Compensation funds can defeat the purpose of the grid services offerings and requests the Department to not require standardization at this time (Companies' Joint Reply Brief at 12). The Companies argue that the recommendations made by the Attorney General and DOER related to flexible interconnection would be better suited to the interconnection working groups the Department has established (Companies' Joint Reply Brief at 70).

Regarding managed charging programs, the Companies state that NSTAR Electric is working on a managed charging proposal for submission in 2024 and Unitil plans to work with the Department and stakeholders in the future (Companies' Joint Reply Brief at 72, citing D.P.U. 24-10, Exhs. AG 5-20; DOER 1-3; D.P.U. 24-12, Exh. UN-Forecast-1, at 24-25). Additionally, NSTAR Electric and National Grid already offer incentives for vehicle-to-grid demand reductions through the ConnectedSolutions program, allowing customers to use their bidirectional vehicles and charging infrastructure as a battery in the program (Companies' Joint Reply Brief at 72, citing D.P.U. 24-10, Exh. DPU-Common-11-14; D.P.U. 24-11, Exh. DPU-Common-11-14). The Companies argues that issues regarding development and implementation of managed charging should be addressed in other proceedings (Companies' Joint Reply Brief at 72). Finally, the Companies note that the intervenors conflate the development of managed charging and load management programs with forecasting, arguing that while managed charging and load management programs will impact energy forecasts, the design and implementation of the programs are distinct from their projected impact once implemented (Companies' Joint Reply Brief at 72, citing Tr. at 137-138).

In response to DOER and CLC's comments on IEP investments, NSTAR Electric and National Grid maintain that there is not a specific set of proposed IEP investments and assert that IEP is a joint gas-electric coordination and planning process (Companies' Joint Reply Brief at 13, citing D.P.U. 24-10, Exh. ES-ESMP-1, at § 11.0; D.P.U. 24-11, Exh. NG-ESMP-1, § 11.0). The Companies acknowledge, however, that NSTAR Electric included certain IEP-related software deployment projects in its customer investments category, while National Grid proposed several digital products under its network investments category (Companies' Joint Reply Brief at 13, citing D.P.U. 24-10, Exhs. ES-ESMP-1, at 451; DPU 1-1; D.P.U. 24-11, Exh. NG-ESMP-1, at 253, 261). The Companies contend that, although these investments will help support IEP processes, these investments are distinct, provide different functions, are appropriately categorized and, if included under different investment categories, there is no meaningful impact in the review and approval of the proposed investments (Companies' Joint Reply Brief at 13).

Regarding resiliency investments, the Companies state that each company seeks to improve reliability and resiliency as a core business function (Companies' Joint Reply Brief at 13, citing D.P.U. 24-10, Exhs. DPU-Common 9-1; DPU-Common 9-2; D.P.U. 24-11, Exhs. DPU-Common 9-1; DPU-Common 9-2; D.P.U. 24-12, Exh. DPU-Common 9-1). Therefore, the Companies state that while NSTAR Electric and Unitil propose targeted resiliency programs that are incremental to their current efforts and are designed to balance proactive hardening and costs, National Grid includes resiliency in its pending base distribution rate case (Companies' Joint Reply Brief at 13, citing Tr. 5, at 609-652; D.P.U. 23-150; D.P.U. 24-10, Exh. DPU-Common 9-2; D.P.U. 24-12, Exh. DPU-Common 9-2). In addition, National Grid states that it may propose incremental resiliency investments in future ESMP filings (Companies' Joint Reply Brief at 13, citing Tr. 5, at 653-654; D.P.U. 24-12, Exhs. DPU-Common 9-1; DPU-Common 9-2).

The Companies argue that CLF's request to introduce its regulatory principles and standards from its separate petition for rulemaking incorrectly expands the scope of this proceeding (Companies Joint Reply Brief at 8, citing CLF Brief at 20). The Companies allege that there is no record or process to support such directives and that CLF's recommendation asks the Department to forego the requirements of the Administrative Procedure Act (Companies Joint Reply Brief at 8).

NSTAR Electric maintains that its proposed ASAP is an alternative method to allow historically underserved customers to finance solar with NSTAR Electric covering the upfront payment of solar project costs for customers who will repay the initial investment via monthly on-bill charges (Companies' Joint Reply Brief at 68-69, citing D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 111). The company states it is aware of the Solar for All program and other new Department-approved low-income solar programs but claims ASAP is a distinct alternative financing program that can work with other federal grant programs (Companies' Joint Reply Brief at 69, citing D.P.U. 24-10, Exh. CLC-ES 3-1). The company argues that it proposed the ASAP in response to the failure of state solar programs to equitably serve customers, and that the program will provide direct solar benefits to affordable housing and low-income customers, unlike its recently approved ECSAP that increases access to shared solar facilities (Companies' Joint Reply Brief at 69). NSTAR Electric affirms that DOER, GECA, and CLC generally support the concept of expanding access to solar for low-income customers but do not support approval of the ASAP as filed (Companies' Joint Reply Brief at 69 (citations omitted)).

NSTAR Electric states that it has not asked the Department to approve the ASAP for immediate implementation but seeks Department direction as to whether the company should pursue the program (Companies' Joint Reply Brief at 70). The company states that, if the Department approves the ASAP as part of the ESMP, it will file a detailed proposal in a separate proceeding for Department review and approval to implement the ASAP (Companies' Joint Reply Brief at 68, citing D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 111). NSTAR Electric maintains that it will develop the filing though stakeholder collaboration, including with DOER, Mass Housing, and MassCEC (Companies' Joint Reply Brief at 70). However, NSTAR Electric requests that the Department not preemptively prohibit the company from leveraging federal grant programs to offset the costs of ASAP since the proposed tariffed on-bill financing method has the potential to complement federal funding and reduce barriers to low-income solar adoption (Companies' Joint Reply Brief at 70).

4. Analysis and Findings

a. Introduction

The Department has determined it will review the ESMPs as strategic plans, including whether each plan complies with the requirements of Section 92B. Interlocutory Order on Scope at 2, 13-16, 23-24. In this Section, the Department addresses the Companies' planned and proposed investments for their compliance with Section 92B and the framework established in Section IV.C. Additionally, the Department addresses intervenor arguments relating to the Companies' investments. With the exception of NSTAR Electric's proposed ASAP program, however, no intervenor explicitly opposed the Companies' proposed investments.

b. Contested Issues

i. Investment Classification

Multiple intervenors raised concerns with the Companies' differing classifications for investments, specifically each company's: (1) bifurcation of core and ESMP investments; (2) differing treatment of certain investment types as core or ESMP; and (3) differing ESMP categorization of substantially similar proposed investments. The Department addresses the Companies' bifurcation of core and ESMP investments in Section IV.C.2.c. and need not revisit that discussion here, other than to note that we find such bifurcation reasonable and appropriate for the reasons discussed therein.

Regarding the differing treatment of certain investment types as being core or ESMP, this primarily involves resiliency and network investments identified in the Companies' filings. In particular, NSTAR Electric and Unitil both include targeted resiliency investments with their proposed ESMP investments, whereas National Grid includes resiliency as part of its planned core spending, i.e., the company does not include targeted resiliency investments as part of its proposed ESMP investments (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 625-626; ES-Policy/Solutions-1, at 67; DPU 6-12; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 432; NG-Policy/Solutions-1 (Corrected) at 51-52; NG-Net Benefits-1 (Corrected) at 14; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 159, 256; UN-Policy/Solutions-1, at 48-49). Additionally, National Grid and Unitil both include network investments as part of their proposed ESMP investments, whereas NSTAR Electric includes these investments as part of its planned core spending (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 451; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 253, 359; NG-Net Benefits-3 (Corrected) at 35; D.P.U. 24-12, D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 14, 129-132, 157-158, 160, 176; UN-Policy/Solutions-1 at 84; UN-Net Benefits-3 (Corrected) at 12). In addition, there are differences in how the Companies group certain investments across ESMP investment categories. For example, NSTAR Electric includes integrated energy planning investments as a part of its customer investments, whereas National Grid proposes integrated energy planning investments as part of its network investments (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 451; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 253).

Intervenors raise concerns about these differences, arguing that these inconsistencies make it more challenging to review the ESMPs, confuse interpretation of the net benefits analysis, and prevent stakeholders and policymakers from clearly identifying the burdens that ratepayers will be asked to bear in support of decarbonization (Attorney General Brief at 42-47; Attorney General Reply Brief at 15-16; DOER Brief at 38-39; CLC Brief at 27-28; Joint Intervenor Reply Brief at 23). The Companies acknowledge that they did not standardize the ESMP investments within categories (e.g., resiliency and IEP investments) but contend that these reflect differences in the investment needs of the Companies (Companies' Joint Reply Brief at 12 (citations omitted)).

The Department declines to require the Companies to uniformly treat certain investment types as either core or ESMP; rather, we find that a measure of flexibility in ESMP investment planning is appropriate and warranted, consistent with typical distribution system planning practices. In other words, the Companies do not need to each propose ESMP investments for every investment category identified as part of the net benefits analysis and within the ESMPs. As the Companies note, each distribution system has unique characteristics and system needs, and their proposals are tailored to the present state of each system (see generally D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected), §§ 6.0, 7.0; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected), §§ 6.0, 7.0; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected), §§ 6.0, 7.0. See Section III. Based on each system's characteristics and needs, whether particular investments should be included in the ESMPs is a matter for utility management's judgment and, within a substantial range, utility business decisions are matters for company management to determine. Fitchburg, 375 Mass. at 578. Generally, notwithstanding our regulatory oversight responsibilities over the Companies, the Department may not interfere with reasonable company judgments made in good faith and within the limits of reasonable discretion. D.P.U. 09-09, at 38; D.P.U. 555-C at 16. Further, it is inappropriate for the Department to substitute its own judgment for the judgment of the management of a utility. Attorney General v. Dep't of Public Utilities, 390 Mass. at 228.[75]

In contrast, the Department agrees that substantially similar investments between Companies should be grouped within the same investment categories rather than different

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75 While we decline, for the reasons discussed, to require a consistent treatment of investment categories, the Department observes that the different classifications presented challenges in our, and intervenors', review of the plans, and thus, we recognize the value of a more consistent treatment. The record, however, includes enough information to allow a full understanding of the strategic planning processes and methodologies included in the ESMPs.

investment categories or, otherwise, the investments should be more clearly delineated as to the differences, if applicable. Just as consistent terminology for similar investments and categories of investments helps to streamline review, so too does consistent grouping of substantially similar investments (compare D.P.U. 24-10, Exh. DPU 1-1, at 1, & Att. (a); with D.P.U. 24-11, Exh. DPU 1-1, at 2, & Att. (10)). See Grid Modernization Order at 140 n.73. Accordingly, we direct the Companies to better coordinate[76] to ensure consistent groupings of substantially similar investments in future ESMP filings.

ii. Minimization or Mitigation of Ratepayer Impacts

Section 92B(a)(vi) requires each company to develop an ESMP to proactively upgrade the distribution system to minimize or mitigate impacts on ratepayers. Similarly, Section 92B(b) requires each company to identify customer benefits, including the minimization or mitigation of impacts on ratepayers, associated with the proposed investments. GECA argues that the ESMPs do not meet Section 92B's requirement to "minimize or mitigate impacts on the ratepayers of the Commonwealth[,]" arguing that the Companies do not quantify or explain how proposed spending would generate savings for ratepayers (GECA Brief at 13). GECA challenges the Companies' assertion that their planning alone will minimize costs and reduce the need for infrastructure upgrades (GECA Brief at 13-14). The Companies do not respond to this argument.

76 The Department acknowledges the limited time afforded by the Legislature to the Companies to coordinate on comprehensive ESMPs and anticipates that consistent categorization of proposed ESMP investments will be easily resolved ahead of the next term filings.

As discussed in Section VII.I.2. and Section VII.I.4., the Companies relied on the customer benefits identified in Section 92(b) to inform the net benefit analysis required under Section 92B(d), and we found the Companies' net benefits analysis methods to be reasonable and appropriate. In their analyses, the Companies classify reduced future utility costs as benefits derived from the minimization or mitigation of impacts on the ratepayers of the Commonwealth (D.P.U. 24-10, Exh. ES-Net Benefits-3 (Corrected) at 13; D.P.U. 24-11, Exh. NG-Net Benefits-3 (Corrected) at 13; D.P.U. 24-12, Exh. UN-Net Benefits-3 (Corrected) at 13). The Companies each calculated a quantified benefit for minimization and mitigation of ratepayer impacts for specific categories of proposed investments; in addition, they described qualitative benefits (D.P.U. 24-10, Exh. ES-Net Benefits-3 (Corrected) at 15-17, 21; D.P.U. 24-11, Exh. NG-Net Benefits-3 (Corrected) at 15-17, 21; D.P.U. 24-12, Exh. UN-Net Benefits-3 (Corrected) at 15-17, 21).

Additionally, as discussed in Section VII.G.3., the Companies will and are required to identify opportunities to mitigate the cost increases borne by ratepayers by applying for federal and state grants, low interest loans, and tax incentives (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 441-442; ES-Policy/Solutions-1, at 143; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 370; NG-Policy/Solutions-1 (Corrected) at 117; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 168; UN-Policy/Solutions-1, at 91). The record reflects and this Order also directs that the Companies incorporate considerations in their typical planning processes that can help to mitigate or delay the need for investments and, thus, costs to ratepayers, including: (1) continuous review of forecasts and reprioritization of investments based on customer adoption rates and system needs (see, e.g., Tr. 6, at 864-866); and (2) as discussed in Section VII.D., consideration of NWAs, including ESS, for higher-cost projects (Tr. at 5, at 590-592, 594, 607, 705-708; D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 438-439, 584; ES-Policy/Solutions-1, at 104-105, 115; AG 4-24; AG 5-2(d); DOER 1-11; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 70, 256, 259, 264, 295; NG-Policy/Solutions-1 (Corrected) at 65; DPU-Common 8-8; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 216, 228-229; UN-Policy/Solutions-1, at 57; DPU 8-2, Att.). Further, in Section IX.D., the Department finds that the estimated bill impacts resulting from the proposed ESMP costs are within the range of reasonableness in light of the anticipated benefits that the investments may provide. Accordingly, the Department finds that the Companies have each satisfied the requirements of Section 92B(a)(iv) and Section 92B(b).

iii. Grid Services Study

As noted above, the Companies jointly identified two studies to inform compensation for locational grid services and their proposed Grid Services Compensation Fund: (1) a Grid Services Study, and (2) a Transactional Energy Study. For the Grid Services Study, the Companies are developing an RFP in coordination with MassCEC to engage a third-party consultant to conduct a study on the value of DERs and load flexibility as locational grid services (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 429; AG 5-23; CLC-ES 1-17; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 351; AG 3-32; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 125). The study is intended to help the Companies establish specific levels of compensation for locational grid services while taking into consideration the value created in either capacity or voltage use cases (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 429; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 351; D.P.U 24-12, Exh. UN-ESMP-1 (Corrected) at 125). The Companies expect the results from the study to inform the proposed Grid Services Compensation Funds (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 429; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 351; D.P.U 24-12, Exh. UN-ESMP-1 (Corrected) at 125).

The Attorney General supports the general framework of a Grid Services Study as a means to cost-efficiently improve system reliability and efficiency but recommends that (1) the Companies solicit comments from stakeholders regarding the study and document consensus and non-consensus recommendations, (2) the Department order the Companies to file the results of the study, any associated DER compensation framework, and consensus and non-consensus recommendations from stakeholders for Department approval, and (3) the Department order the Companies to collaborate with stakeholders to develop a uniform, statewide market design framework and set of programs (Attorney General Brief at 28-29). The Companies state that standardizing the Grid Services Compensation could defeat the purpose of the grid services offerings (Companies' Joint Reply Brief at 12). As such, the Companies request that the Department not require standardization at this time (Companies' Joint Reply Brief at 12).

The Department understands the Companies are working with MassCEC to develop the Grid Services Study and plan to develop Grid Services Compensation Funds based on the study's results, which the Department finds appropriate and reasonable. Therefore, the Department declines the Attorney General's request. The Department encourages the Companies to collaborate with stakeholders, however, to develop a framework that is as consistent as possible across Companies and, because this will inform proposed ESMP investments, i.e., the Grid Services Compensation Funds, the Department directs the Companies to file related updates in their biannual reports, with reporting details to be established in a subsequent phase of these proceedings.

iv. NSTAR Electric ASAP

NSTAR Electric proposes an Affordable Solar Access Program to provide on-bill[77] financing for solar project installations on affordable housing and low-income customer properties in EJ populations (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 320-321; ES-Policy/Solutions-1 at 111; ES-Bill Impacts-1, at 21; ES-Net Benefits-3 (Corrected) at 46). The company does not seek Department approval of the ASAP for immediate implementation; rather, NSTAR Electric seeks Department direction as to whether to file a comprehensive proposal and associated tariff seeking approval (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 321; DPU 10-5; DPU 10-7).

DOER, CLC, and GECA generally support the idea of expanding low-income customer access to solar but do not support approval of the ASAP as filed and question

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77 Under the ASAP, NSTAR Electric would pay for the solar project costs, with participating customers repaying the initial investments via monthly on-bill charges (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 321; ES-Policy/Solutions-1, at 111).

whether the ASAP program would be duplicative of other incentive programs, namely the Solar for All initiative (DOER Brief at 62-63; GECA Brief at 15-16; CLC Brief at 19-20). DOER also argues that the ESMPs are not the appropriate venue for the proposed program (DOER Brief at 62). The company states that the Solar for All program would not sufficiently fund the ASAP and that the existing program has failed to spur meaningful participation (D.P.U. 24-10, Exh. DPU 10-5). NSTAR Electric also states that it plans to further develop the ASAP process through stakeholder collaboration, including with DOER, Mass Housing, and MassCEC and, subsequently, to seek approval from the Department in a separate, fully adjudicated docket (Companies' Joint Reply Brief at 70).

The Department acknowledges DOER's and GECA's concern that the ESMP is not the proper channel for pre-approving the ASAP; however, the Department finds it appropriate for the company to submit preliminary information in its ESMP on a program it is exploring. Such an action is consistent with the spirit and intent of Section 92B. See G.L. c. 164, § 92B(a)(ii). The Department concurs that a stakeholder process to develop ASAP would be beneficial for the company to determine whether to pursue such a program. As noted previously, as part of our strategic plan review, we are not pre-approving any proposed ESMP investments or costs in this Order. To the extent that NSTAR Electric submits a formal ASAP proposal in a separate proceeding, the Department would review the filing consistent with our normal practice.[78]

[78] The Department notes relevant intervening developments since the company filed its ESMP. Specifically, the U.S. Environmental Protection Agency formally selected the

c. Compliance with Section 92B

i. Reliability, Resiliency, and Climate-Driven Impacts

Section 92B(a)(i) and (iv) requires each company to develop an ESMP to proactively upgrade the distribution system to improve grid reliability and resiliency[79] and to prepare for future climate-driven impacts. G.L. c. 164, § 92B(a)(i), (iv). Each ESMP must also describe in detail improvements to the electric distribution system to improve reliability and strengthen system resiliency to address potential weather- and disaster-related risks. G.L. c. 164, § 92B(b)(i). As discussed in Section IV.C.2.b., Section 92B(a) applies to proposed ESMP investments, whereas the descriptions required pursuant to Section 92B(b) are not limited to ESMP investments and may include descriptions of how the company

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Commonwealth's Solar for All proposal on April 22, 2024, with total funding in the amount of $156 million. See Healey-Driscoll Administration Celebrates Winning $156 Million in EPA's Solar for All Competition | Mass.gov (last visited August 29, 2024). Further, the Department has taken steps to improve low-income residents' access to solar energy. See, e.g., Fitchburg Gas and Electric Light Company, D.P.U. 20-145-D at 23-67 (June 4, 2024); Guidelines for Municipal Aggregation Proceedings, D.P.U. 23-67-B at 2-6 (July 24, 2024).

[79] Traditionally, reliability has focused on day-to-day or "blue-sky" performance that excludes low-probability and major events from consideration in measuring normal system performance based on regulatory criteria and accepted industry metrics and standards (D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 61; D.P.U. 24-11, Exh. NG-Policy/Solutions-1 (Corrected) at 47; D.P.U. 24-12, Exh. UN-Policy/Solutions-1, at 39). Resiliency, on the other hand, is focused on the unlikely events and involves the ability of the distribution system to withstand and recover from disturbances and adverse events, including major storm events (D.P.U. 24-10, Exhs. ES-Policy/Solutions-1, at 61-62; DPU-Common 9-1; D.P.U. 24-11, Exhs. NG-Policy/Solutions-1 (Corrected) at 47; DPU-Common 9-1; D.P.U. 24-12, Exhs. UN-Policy/Solutions-1, at 39; DPU-Common 9-1).

accounts for the elements identified in Section 92B(b) in its typical distribution system processes and practices. As such, the Department determines that the descriptions required by Section 92B(b)(i) must include discussion of the company's existing measures, reporting, and activities to monitor and improve reliability and resiliency, which each company has provided, and includes such activities as vegetation management and tree work, emergency response plans, asset management and pole replacements, targeted hardening of infrastructure, and undergrounding distribution cables, among others (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected), §§ 4.1.9, 10.0; ES-Policy/Solutions-1, at 64-67; DPU-Common 9-1; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected), §§ 4.3.9, 10.0; NG-Policy/Solutions-1 (Corrected) at 48-51; D.P.U. 24-12, Exhs.UN-ESMP-1 (Corrected), §§ 4.1.9, 10.0; UN-Policy/Solutions-1, at 40-44). Each company also describes the development of a CVA for its distribution system, which will be used to target resiliency investments, and the steps utilized in its CVA analysis (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 628-638; ES-Policy/Solutions-1, at 67-69; CLC-ES 4-1; DPU 11-3; DPU 11-13; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 444, 455; NG-Policy/Solutions-1 (Corrected) at 51; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 257-262; UN-Policy/Solutions-1, at 47; DPU 10-15). Accordingly, the Department finds that the Companies have each complied with Section 92B(b)(i).

The Department also finds that each company has complied with the requirements in Section 92B(a)(i) and (iv) to develop a plan to proactively upgrade the distribution system to improve grid reliability and resiliency and to prepare for future climate-driven impacts, based on its proposed ESMP investments. For NSTAR Electric and Unitil, this includes their proposed resiliency investments, which are specifically geared towards meeting these statutory requirements, as well as their proposed substation investments (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 457, 625-626; ES-Policy/Solutions-1, at 67; DPU 6-12; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 159, 183, 256; UN-Policy/Solutions-1, at 48-49). NSTAR Electric proposes resiliency ESMP investments based on a new approach to its resiliency planning. First, the company proposes to use historical outage information that now includes four years of major storm event data to identify areas of its distribution system for proactive hardening to deploy cost-optimal and highly-targeted projects (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 440-441, 618-619). The company's five-year investment portfolio consists of undergrounding, aerial cable, tree wire conversion, and resilience tree work (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 622-626). Second, NSTAR Electric plans to incorporate its CVA framework to select investments that target grid vulnerabilities based on climate change projections for various climate hazards (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 637-638; CLC-ES-4-1; DPU 11-3).

Unitil proposes a new approach to resiliency planning beyond its current practices that would result in a one million dollar increase in annual spending to deploy targeted resiliency investments in the form of spacer cable and undergrounding (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 256). The Company proposes to use historical outage data to identify locations for its investments and anticipates relying on its in-development CVA framework to identify future resiliency investments (D.P.U. 24-12, Exhs. DPU 6-8; DPU 10-13).

National Grid did not propose any resiliency investments in its ESMP; however, like NSTAR Electric and Unitil, the company identifies its proposed substation and feeder expansion projects within its network investments category, as well as its proposed CIPs, among other proposed investments, as providing a secondary benefit of improved reliability and resiliency (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 27, 271, 380; DPU-Common 9-1). The company explained that it has proposed such investment in its pending base rate case, D.P.U. 23-150 (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 432; NG-Policy/Solutions-1 (Corrected) at 52; DPU-Common 9-2). National Grid has developed a targeted hardening strategy to implement mitigations in areas of its distribution system that have experienced historical resiliency challenges (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 432; NG-Policy/Solutions-1 (Corrected) at 50). The company also stated that it may propose specific resiliency investments in future ESMPs (D.P.U. 24-11, Exh. DPU-Common 9-1).

As the intensity and frequency of weather-related events due to climate change increase, the Department determines that reliance on system performance beyond those occurring under "blue sky" operating conditions as well as each company's incorporation of a CVA framework are imperative to accurately assess the resiliency of the system and those locations in need of hardening. An accurate assessment of the resilience of the system, including identification of weak points on that system, is critical to forward-looking distribution system planning that will help the Commonwealth to move closer to realizing its GHG emissions reduction goals. Climate change vulnerability and hazard analyses will provide crucial information for utility resilience planning not only at the strategic plan level but also at the more granular investment planning level. Several intervenors noted the importance of consistency among the Companies in the resiliency planning processes (see CLF Brief at 18-20; DOER Brief at 57), although no intervenor opposed the Companies' planning processes for targeted resiliency investments.[80] The Department agrees that some consistency and certain modifications to the Companies' proposed targeted resiliency investment planning process are necessary, as follows.

First, the Department requires each company to use historical performance information that includes major event data, such as all-in CMI and/or all-in SAIDI data, to identify and prioritize locations to deploy targeted resiliency investments. While all three Companies proposed using historical outage data in its targeted resiliency investment planning, each company's respective method to identify suitable locations for specific targeted resiliency investments varies (Tr. 5, at 653-654; D.P.U. 24-10, Exhs. ES-ESMP-1

[80] The Department recognizes that certain investments, such as reliability investments and updates to distribution and construction standards, may improve system resilience (see D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 432-443, 454). The Department also acknowledges that reliability is a subset of resiliency and, thus, our reference to "targeted" resiliency investments is intended to refer to: (1) targeted historical data-driven grid hardening investments intended to go above and beyond the Companies' core obligation to provide reliable service, as defined by the reliability metrics in the Service Quality Guidelines, D.P.U. 12-120-D, Att. A at 2, 6 (2015) ("SQ Guidelines"); and (2) targeted adaptation investments resulting from CVAs.

(Corrected) at 618-620; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 443; D.P.U. 24-12, Exhs. DPU 6-8; DPU 10-13). For instance, NSTAR Electric uses all-in CMI, whereas Unitil reviews worst-performing circuits' outage history and National Grid reviews all-in data to identify feeders with one outage event per-year (Tr. 5, at 653-654; D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 620-621; D.P.U. 24-12, DPU 10-13). The Department determines that identifying suitable locations for targeted resiliency investments based on major event-inclusive performance data (e.g., all-in CMI or all-in SAIDI) is not only consistent with the definition of targeted resiliency investments, as indicated in footnote 80, above, but will assist the Companies to more accurately identify and prioritize those locations with the greatest need for targeted resiliency improvements.

Second, to improve system resilience without overburdening ratepayers, the Department determines that the Companies must all assess the cost effectiveness of targeted resiliency investments as part of their resiliency investment planning process. The record shows that the Companies differ on how the cost of targeted resiliency investments is considered when identifying and prioritizing projects. Specifically, NSTAR Electric and Unitil assess project cost-efficiency, such as the dollars per CMI saved by the mitigation, to determine whether to proceed with construction of a project or the order in which to deploy them (Tr. 5, at 649-650; D.P.U. 24-12, Exh. DPU 6-6;). National Grid, however, does not consider relative cost when determining which projects will move forward (Tr. 5, at 653-654).

The impact of each additional dollar spent on targeted resiliency projects is expected to have declining benefits for system resilience (Tr. 5, at 642-645; D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 625-626). Further, while NSTAR Electric performed analyses to contemplate reductions in storm restoration costs and the avoided cost of outages, it did not use these analyses to inform the size for, or appropriate locations of, resiliency investments, but instead assesses impacts after the fact (Tr. 5, at 614, 645-646). The Department finds that analyzing cost-effectiveness as part of targeted resiliency planning will assist each company in identifying optimal investments and prioritizing least-cost investment solutions and, in turn, help to minimize bill impacts on ratepayers. Further, the Department expects the Companies to coordinate on developing and evaluating novel ways to assess and measure the cost-effectiveness of targeted resiliency investments to assist in identifying and prioritizing suitable locations and solutions for resiliency investments.

Third, the Department notes that the Companies are required to maintain lists of critical facilities, including area hospital and other state and municipal Level 1 critical care facilities, and to prioritize restoration to customers on their critical facilities lists in the respective emergency response plans (Tr. 5, at 626-628, 650-652; D.P.U. 24-10, Exh. DPU 11-7; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 250-251). Emergency Response Plan Guidelines, D.P.U. 14-72-A, App. at 8, 13 (2015). While using historical outage data is an appropriate way to identify suitable locations for targeted resiliency investments, the Department is concerned that neither NSTAR Electric nor Unitil is considering the needs of critical facilities in developing its targeted resiliency investment plans (Tr. 5, at 650-652; D.P.U. 24-10, Exh. DPU 11-7). The Department therefore determines that the Companies must cross-reference the results from their respective outage analyses with the locations and requirements of critical facilities in their respective services territories to evaluate whether specific community resiliency concerns associated with these critical facilities exist and should be addressed through these targeted resiliency investment plans. Specifically, the Companies shall consider whether their targeted resiliency planning process, in conjunction with other company planning efforts, sufficiently addresses the resiliency needs of critical facilities and to also consider municipal input in assessing the resiliency requirements of critical facilities (e.g., whether the facilities have self-generation, have been adequately served by storm response prioritization, or have benefited from other company reliability/resiliency improvements such as vegetation management programs).

Fourth, the Companies' targeted resiliency planning process using historical data does not currently incorporate the results of work completed to date as part of their CVAs (D.P.U. 24-10, Exhs. DPU 6-14; DPU 11-3; D.P.U. 24-12, Exh. DPU 10-13). As such, the Department directs the Companies to verify that assets identified as requiring targeted resiliency improvements in fact face a heightened outage risk going forward by using the results of their CVAs. The CVAs are new, forward-looking assessments which are wholly consistent with Section 92B. The additional verification using the initial CVA output will identify those locations in need of targeted resiliency investments based not only on historical data indicating poor performance but also that face a heightened risk due to climate change.

Regarding the Companies' CVA frameworks, the Department finds these frameworks, including the analysis of the potential impacts of climate change across various scenarios, to be integral to forward-looking distribution system planning and successful pursuit of the objectives identified in Section 92B(a)(i), (iv), and Section 92B(b)(i). However, we find the need for greater consistency between the Companies' CVAs and direct NSTAR Electric, National Grid, and Unitil to resolve or justify certain discrepancies in their respective frameworks and/or to make modifications to the CVA frameworks. For instance, NSTAR Electric utilized climate change projections extending to 2080, while National Grid and Unitil employ scenario forecasts extending to 2100 (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 630; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 444; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 257 n.54). The record is unclear as to the whether climate change projections should use a common forecasting window and, unless the Companies can justify the need for differing forecasting windows, the Department directs the Companies to use a common forecasting window. Further, while the Companies largely rely on similar climate hazard pathways and climate change scenarios, where differences between the Companies' inclusion and definition of these parameters and related data inputs exist, we direct the Companies to use a standardized set of climate hazards and climate change scenarios parameters moving forward unless the Companies can demonstrate a basis for the inconsistencies.

Next, the ESMPs lack detail on how the Companies will prioritize and implement mitigations identified through the CVAs, particularly regarding how the Companies plan on balancing increased resilience levels with the associated increase in costs for their customers[81] (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 637-640; DPU 11-3; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 455; DPU 6-4; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 261; DPU 6-11). The Department expects the Companies to coordinate on the development of processes and practices to prioritize and deploy targeted resiliency investments in a cost-effective manner. This prioritization should use and build upon the Companies' initial CVA framework proposals and, at a minimum, address the following: (1) an assessment of the risk level associated with the hazard's probability of occurrence under the climate change scenario studied; (2) the cost of the targeted resiliency investment; (3) potential resilience benefits, which could include improved electric grid performance, avoided restoration costs, avoided outage costs, and community benefits; (4) impacts to critical facilities and EJ populations; and (5) a prioritization process to implement resiliency investments based on the assessment. The Companies shall provide updates on their progress towards finalizing their frameworks for climate vulnerability risk assessments in line with the above directives in their biannual ESMP filings. Last, we decline to require at this time the Companies to incorporate CLF's requested CVA standards into their CVA frameworks (see

[81] For example, NSTAR Electric generally states it will consider scenario probability, cost and simulated performance improvement when weighing implementation strategies (D.P.U. 24-10, Exh. DPU 11-3). Unitil states it will prioritize mitigation options according to several principles, such as likelihood of occurrence, cost to implement, and impact on environmental justice populations (D.P.U. 24-12, Exh. DPU 6-11). National Grid has not yet identified criteria regarding the hazard risk levels that may trigger an investment or a method to ensure such investments are cost-effective (D.P.U. 24-11, Exh. DPU 6-4).

CLF Brief at 20) because there is an insufficient evidentiary record in these proceedings to support doing so.

The Department concludes that establishing more consistency in targeted resiliency investment planning, including the Companies' CVA frameworks, will enable the development of shared best practices that will help to identify and prioritize suitable locations and solutions for targeted resiliency investments and, in turn, increase the effectiveness of targeted resiliency planning decisions and outcomes over the long run. We reiterate that the strategic planning processes included in these first ESMPs are only the initial step in the long-term planning to proactively upgrade the distribution system to achieve the goals of Section 92B. The Department expects the Companies' targeted resiliency investment planning processes, including their CVA frameworks, to evolve over the course of this first and subsequent ESMP terms to incorporate lessons learned.

In sum, the Department directs the Companies to modify their respective targeted resiliency planning processes, including their CVA frameworks, as indicated above. In their biannual ESMP reports, the Companies shall provide updates on their progress towards finalizing their frameworks for climate vulnerability risk assessments as well as on their targeted resiliency investment identification and prioritization method. Additionally, each company shall describe and explain any adjustments to the proposed portfolio of targeted resiliency investments included in its ESMP in these proceedings and explain the basis for those adjustments. Going forward, the Department expects greater coordination among the Companies on common parameters for targeted resiliency investment planning as well as the development of shared best practices to further enhance efforts towards achieving the goals of Section 92B.

Finally, for future ESMP filings and biannual reporting, the Department determines that the descriptions required by Section 92B(b)(i) include identification of targeted resiliency investments aimed at strengthening system resiliency and addressing potential weather-related and disaster-related risks regardless of whether such investments are classified as core or proposed ESMP investments.[82] Targeted resiliency investments are intended to improve grid performance during major weather events,[83] which are expected to increase in frequency due to the impacts of climate change. Accordingly, only targeted resiliency investments as clarified above must be described as part of the ESMPs. For National Grid, the identification and description of targeted resiliency investments must also include flood mitigation investments identified by the company's CVA as well as any hardening investments that the company identified based on all-in historical data (Tr. 5, at 653-654; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 443).

The Department determines that including in the ESMPs a description of a company's targeted resiliency investments along with the associated costs, regardless of core or ESMP classification, will allow the Department to comprehensively evaluate the targeted resiliency

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82 To clarify, we do not interpret Section 92B(b)(i) as requiring a description in the ESMPs of all resiliency investments.

83 Including Excludable Major Events as currently defined in SQ Guidelines, Att. A at 4.

planning process for strategic planning purposes as well as for more granular investment deployment decision-making reasons. Further, it will also allow the Department, stakeholders, and importantly, each company, to compare and assess their respective suites of targeted resiliency investments and, in turn, enable the development of best practices through lessons learned during this and subsequent ESMP terms that will result in more cost-effective resiliency investment planning over the long-term. In its first biannual ESMP report, each company shall provide a description of its planned targeted resiliency investments, as defined above.

ii. Electric Vehicle Investments

Pursuant to Section 92B(a)(ii) and (v), the Companies must file ESMPs to proactively upgrade the distribution system to, in part, enable increased, timely adoption of renewable energy and accommodate increased electrification. The Companies each request an extension of its current EV program (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 434; ES-Policy/Solutions-1 at 135, 137, 139; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 346, 358, 362; NG-Policy/Solutions-1 (Corrected) at 79; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 15, 112; UN-Policy/Solutions-1 at 53, 87). EVgo supports approval of the proposed EV program extension (EVgo Brief at 4). No party opposed this proposed investment. The Department finds that the proposed EV program extensions will enable the electrification of transportation across the residential, public, workplace, and fleet EV charging sectors, leading to reduced GHG, NO_x, and $PM_{2.5}$ emissions (D.P.U. 24-10, Exh. ES-Net Benefits-3 (Corrected) at 44; D.P.U. 24-11, Exh. NG-Net Benefits-3 (Corrected) at 44-45; D.P.U. 24-12, Exh. UN-Net Benefits-3 (Corrected) at 41-42).[84]

Additionally, National Grid proposes to implement an EV flexible connection offering as part of its flexible interconnection plans (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 347). The Attorney General considers National Grid's proposal a good first step towards reducing the need for ratepayer funded investment in EV infrastructure and recommends that the Department order NSTAR Electric and Unitil to collaborate with National Grid to implement EV flexible connection as part of their flexible interconnection plans (Attorney General Brief at 20-21). DOER supports these recommendations (DOER Reply Brief at 13-14). The Companies argue that the recommendations made by the Attorney General and DOER related to flexible interconnection would be better suited to the interconnection working groups the Department has established (Companies' Joint Reply Brief at 70). The Department recognizes the potential benefits to ratepayers of a flexible interconnection program that includes EV infrastructure, particularly if such an offering reduces the need for ratepayer investment in EV make-ready infrastructure. Accordingly, the Department finds that such a proposal, if implemented, could serve to accommodate increased transportation electrification, consistent with the requirement outlined in Section 92B(a)(v). As such, the Department determines that NSTAR Electric and Unitil must develop and include an EV flexible interconnection offering in their next ESMP filings. Additionally, we encourage

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84 In Section VIII.D., the Department provides instruction to the Companies on the next steps to take if they would like to extend their current EV programs.

NSTAR Electric and Unitil to collaborate with National Grid to build on lessons learned from National Grid's flexible connections for EVs offering to develop similar programs.[85]

GECA argues that the Companies' ESMPs lack sufficient analysis of the benefits of EV managed charging and that the ESMPs should include EV managed charging program proposals (GECA Brief at 18). EVgo requests the Department to ensure that public DCFCs are not required to participate in any future EV managed charging program proposed by the Companies and that DCFC site hosts are not required to co-locate DCFCs with energy storage as a prerequisite to participation in any such program (EVgo Brief at 2). The Companies argue that the design and implementation of EV managed charging programs is more appropriately addressed outside of the ESMP process because they involve a diverse group of stakeholders (Companies' Joint Reply Brief at 72).

Neither Section 92B nor Section 92C requires or restricts the Companies from including EV managed charging program proposals in their ESMPs. In the instant proceedings, each of the Companies' ESMPs included a summary of its EV managed charging program plans. NSTAR Electric indicated that it plans to submit an EV managed charging program proposal with the Department later this year (D.P.U. 24-10, Exhs. AG 5-10; DOER 1-3). Unitil stated that it plans to work with the Department and stakeholders to develop an EV managed charging program (D.P.U. 24-12, Exh. UN-Forecast-1, at 24-25). National Grid stated that it currently has a residential and

85 To be clear, NSTAR Electric and Unitil need not await their next ESMP filings to move ahead with such a program.

fleet managed charging program offering, and it does not propose any changes to the program at this time (D.P.U. 24-11, Exhs. GECA-Common 2-1; GECA-Common 2-2). For purposes of the Department's strategic plan review of the ESMPs, the Department determines that the Companies' description of their EV managed charging program plans is sufficient. Additionally, the Department encourages NSTAR Electric and Unitil to submit EV managed charging program proposals for the Department's review in the near term. The Department will address any concerns or recommendations regarding the Companies' EV managed charging program proposals in those proceedings.

Regarding GECA's remaining arguments on brief involving the downward pressure on rates associated with EV adoption and whether the Companies adequately explained how they will promote EV charging infrastructure buildout (GECA Brief at 17, 19), the Department is satisfied that the Companies and their plans have met the requirements of Section 92B. Additionally, the issues of the impact of EV adoption on rates we well as rate design are beyond the scope of the current proceedings, premature, and better addressed through comprehensive proceedings where all factors affecting rate structure can be examined. See Interlocutory Order on Scope at 20-21. Regarding information on company promotion of EV charging infrastructure buildout, that is an issue that may be explored in the biannual reporting process to follow this Order.

iii. Substation and CIP Investments

Pursuant to Section 92B(a)(ii) and (v), the Companies must file ESMPs to proactively upgrade the distribution system to enable increased, timely adoption of renewable energy and

DERs, and must also accommodate increased transportation and building electrification and other potential future demand on their distribution systems. Further, Section 92B(b)(iv) requires a detailed description of improvements to the distribution system that will enable customers to express preferences for access to renewable energy resources, and Section 92B(b)(v) requires a detailed description of improvements to the distribution system that will facilitate transportation or building electrification, and Section 92B(b)(vi) requires a detailed description of improvements to the transmission or distribution system to facilitate achievement of the statewide GHG emissions limits under Chapter 21N. The Companies each describe a number of substation projects in furtherance of these directives, including projects classified as CIP projects and network investments.

NSTAR Electric and National Grid each identify additional CIP proposals to be submitted as part of the extended Provisional Program, applying the CIP allocation methodology proposed in D.P.U. 20-75-B (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 9, 104, 133, 153, 180, 434-435; ES-Policy/Solutions-1 at 135, 144; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 257; NG-Policy/Solutions-1 (Corrected) at 21-22, 58). The Department addresses these proposals in Section VII.F.4.

Additionally, National Grid and Unitil each propose substation projects, categorized as network investments, outside the cost allocation framework (see D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 253; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 14, 27, 158, 176). Specifically, National Grid proposes substation and distribution feeder projects for its five-year outlook, including 13 substation upgrades or rebuilds and 14 new feeders, with more to follow in subsequent years (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 21, 251, 291-292, 301-302, 313, 318, 324, 330, 336; NG-Policy/Solutions-1 (Corrected) at 21-22, 70). Some of the costs identified by the company for the 2025 through 2029 term include costs for substations that would go into service after 2030 (D.P.U. 24-11, Exh. NG-Net Benefits-3 (Corrected) at 35). Similarly, Unitil proposes two substation projects, one a new substation and one an expansion of an existing substation (D.P.U. UN-ESMP-1 (Corrected) at 158, 176).

National Grid states that its proposals aim to address capacity deficiencies and to support electrification and DER interconnections of new solar and ESS in line with the Commonwealth's interim 2030 adoption targets (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 21, 251, 291-292, 301-302, 313, 318, 324, 330, 336; NG-Policy/Solutions-1 (Corrected) at 21-22, 70). Unitil states that the amount of capacity addition was informed by its longer-term demand assessment in preparation of the ESMP, and that both projects will provide the capacity needed to support load growth from the electrification of the transportation and building sectors as well as to increase the hosting capacity for the integration of new DERs, such as PV, ESS, and wind resources (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 158, 160, 176). Accordingly, we find that the projects as described comply with the requirements outlined in Section 92B(a)(ii) and (v) and Section 92B(iv) through (vi).

Notwithstanding our finding, however, the Department observes that the costs and scale of these projects are far larger than the other investments identified in each company's portfolio (see D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 22-23, 358-359, 362; NG-Net Benefits-3 (Corrected) at 32, 35; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 160, 166; UN-Net Benefits-3 (Corrected) at 31, 34). The Department reiterates our obligation to ratepayers to preserve affordability through rigorous oversight of utility expenditures to ensure that costs are minimized and that the Companies are giving due consideration to alternative, lower cost solutions. See Section VIII.D. Further, the Department anticipates projects such as these will be accounted for in the LTSPP to be established. See Section VII.F.4.

iv. Remaining Investments

For all remaining investments, if not otherwise addressed herein and based on our review of the comprehensive records in each proceeding, the Department finds that NSTAR Electric, National Grid, and Unitil have each submitted an ESMP, identified planning processes, and identified and described in detail planned and proposed investments consistent with the requirements of Section 92B(a) and (b), and have proposed investments in accordance with Section 92B(e). Specifically, each of the Companies established that it has developed an ESMP and proposed investments and related improvements that will, among other things: (1) enhance interconnections and facilitate the interconnection of DERs; (2) provide customers new opportunities to access renewable energy; (3) facilitate the electrification of transportation and buildings and support other future demands on its systems; (4) enhance safety and reliability; (5) enable and support integration of VPPs, DER as grid assets, and NWAs; and (6) provide greater customer reliability and flexibility for grid planning. Regarding arguments addressing flexible interconnection, the Department directs consideration of the role of flexible interconnection in deferring or negating the need for certain system upgrades as a topic to be explored in the LTSSP stakeholder process. See Section VII.F.4. In addition, the Department notes that flexible interconnection can contribute to NWA solutions, and as such should be considered as an alternative to proposed investments. See Section VII.D.

v. Summary of Investments

Section 92B(c)(ii) requires each electric distribution company, in developing an ESMP, to consider and include a summary of all proposed and related investments, alternatives to these investments and alternative approaches to financing these investments that have been reviewed, are under consideration or have been approved by the Department previously. DOER requests that the Companies provide a more standardized investment table in Excel format in a compliance filing (DOER Brief at 37-41). The Companies did not directly address this request.

Each company provided summary investment tables of planned and proposed investments in its ESMP (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 435, 438; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 356-362; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 160, 166). In Section IV.C.2., we found that Section 92B(c)(ii) applies only to non-ESMP investments. The Department finds, however, that summaries of all investments, ESMP and non-ESMP, for the ESMP term as provided by the Companies facilitate review and understanding of the filings and proposed ESMP investments.

Accordingly, the Department finds that the Companies have complied with the requirements of Section 92B(c)(ii).

In terms of the standardization of filings, we observe that NSTAR Electric and Unitil each provided an investment summary in tabular form for both its ESMP and non-ESMP investments, whereas National Grid did not provide a table in tabular form or a clear delineation in summarizing ESMP and non-ESMP investments (compare D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 435, 438; DD.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 160, 166; with D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 356-362). To further facilitate review of future ESMP filings, the Department directs all three Companies to include tables of planned and proposed investments in tabular form in the ESMP, consistent with what NSTAR Electric and Unitil have done in this iteration.

Regarding DOER's request for each company to submit a standardized Excel document of planned and proposed investments as a compliance filing, we find that such a summary is better addressed in the Companies' biannual reports. Similarly, the Joint Intervenors' request for clear timelines of ongoing and future activities related to grid planning and investments for the next ESMP term is better addressed through the biannual reporting (Joint Intervenor Reply Brief at 4, 6-7; GECA Brief at 20-21). As discussed elsewhere in this Order, the Department plans to explore the form and content of the Companies' biannual reporting requirements in a subsequent phase of these proceedings. See Section XI.D. Regarding the common glossary of investments also requested by the Joint Intervenors, the Department notes that each ESMP includes a common glossary of terms and acronyms, and we direct the Companies to continue to provide common glossaries of terms in future ESMP filings (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 675-686; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected), Appendix, Exhibit 1; D.P.U. 24-12, UN-ESMP-1 (Corrected) at ix-xvii).

D. Alternatives to Proposed Investments

1. Introduction

Pursuant to Section 92B, the Companies must address alternatives to non-ESMP investments and to proposed ESMP investments. For non-ESMP investments, Section 92B(c)(ii) requires each company to consider and include a summary of all proposed and related investments, as well as alternatives to these investments, in developing their plans. For proposed ESMP investments, Section 92B(e) requires the Companies to each propose alternatives to those investments. Additionally, Section 92B(b)(viii) requires that each ESMP describe in detail "alternatives to proposed investments, including changes in rate design, load management and other methods for reducing demand, enabling flexible demand and supporting dispatchable demand response," and Section 92B(b)(ix) requires that for proposed ESMP investments, each ESMP identify customer benefits associated with those alternatives. NWAs for major investments may include considerations of ESS, and Section 92B(b)(ii) and (vii) direct that the plans describe in detail "the availability and suitability of new technologies" including, but not limited to, energy storage technology for meeting forecasted reliability and resiliency needs, as applicable; and "opportunities to deploy energy storage technologies to improve renewable energy utilization and avoid curtailment."

Each company addressed alternatives to investments in their initial filings and provided additional information on the issue during the course of the proceedings. Additionally, the Companies requested that the Department defer review of opportunities to dispatch energy storage technologies to the currently open dockets addressing new storage tariffs, pointing to dockets D.P.U. 23-115, D.P.U. 23-117, and D.P.U. 23-126, and to defer consideration of alternative rate designs to either a new proceeding or ongoing proceedings (D.P.U. 24-10, Petition at 14-15 & n.1; Exhs. ES-ESMP-1 (Corrected) at 35; ES-Policy/Solutions-1, at 141; D.P.U. 24-11, Petition at 14-15 & n.1; NG-ESMP-1 (Corrected) at 37; NG-Policy/Solutions-1 (Corrected) at 141; D.P.U. 24-12, Petition at 14-15 & n.1; UN-ESMP-1 (Corrected) at 34; UN-Policy/Solutions-1, at 89). The Companies reasoned that, given the ESMPs' broad scope of issues and limited statutory review period, deferral would allow for more reasoned analysis and consideration of potential rate redesign options, which could be implemented at or prior to the next ESMP term (D.P.U. 24-10, Petition at 15 & n.1; D.P.U. 24-11, Petition at 15 & n.1; D.P.U. 24-12, Petition at 15 & n.1; Exhs. ES-ESMP-1 (Corrected) at 35; ES-Policy/Solutions-1, at 141; NG-ESMP-1 (Corrected) at 37; NG-Policy/Solutions-1 (Corrected) at 141; UN-ESMP-1 (Corrected) at 34; UN-Policy/Solutions-1, at 89).

We address these matters below.

2. Description of Company Alternatives

a. NSTAR Electric

NSTAR Electric explained that it evaluates alternatives to investments in its internal processes for normal distribution system planning and capital project authorizations (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 82-84, 438-439; ES-Policy/Solutions-1, at 45-46; AG 1-11; DOER 3-3; Tr. at 113). The company's normal planning processes and planned investments informed the development of its ESMP and the proposed ESMP investments, including the corresponding alternatives considered or that would be considered by the company (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 438-439; ES-Policy/Solutions-1, at 86-88; AG 4-21; AG 5-2(d); DOER 1-11; DOER 2-3(b)). For both non-ESMP and ESMP investments, the company considers both traditional and non-traditional alternatives, such as NWAs[86] for larger projects, to maximize cost-effectiveness, seeking to ensure that the selected solution provides the highest value at

[86] NSTAR Electric defines NWAs as "technologies or operating practices intended to reduce grid congestion and manage peak demand to offset a utility's need to make additional investments in conventional assets like wires, poles, and substations" and "[t]he technologies can include [DERs], such as microgrids or batteries, and practices and programs focused on load management, demand response or [EE]" (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 332). The company explained that, at a high level, an NWA modifies the load to match available system capacity, as opposed to expanding system capacity to match the load, as a traditional upgrade would (D.P.U. 24-10, Exh. DOER 3-3). The company includes the construction and application of NWA solutions as one of its five more common design concepts to address increased capacity demands, along with system reconfiguration, existing equipment upgrades, addition of new equipment, and, when other options are exhausted, construction of a new substation. (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 82).

the lowest cost (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 74-76, 439; ES-Policy/Solutions-1, at 52, 100, 141). Alternatives to proposed investments also include delay or deferral of investments or, based on updated forecasts or community input, reprioritization of or revisions to projects (D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 98, 101-102, 141).

To determine the suitability of an NWA in lieu of a traditional project, the company has developed three initial screening criteria. Specifically, the traditional project: (1) must have an estimated value of $3 million or more; (2) must not have an immediate need, in that the need date must be at least 24 months to ideally more than 36 months into the future; and (3) need cannot be related to asset age, asset condition, or safety issues (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 438-439, 581; ES-Policy/Solutions-1, at 104-105; AG 4-24; AG 5-2(d)). For projects which meet these criteria, the company then refers to its NWA framework for a more detailed engineering screening and cost comparison to alternative solutions that may meet the need, e.g., targeted EE, demand response, charge management, storage, local generation, and VVO (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 75; ES-Policy/Solutions-1, at 52, 104-105; AG 4-24; CLC-ES 1-5). The company explained that the initial screening process is designed to prevent the unnecessary pursuit of detailed design activity by filtering out low-value projects (less than $3 million) that are unlikely to succeed or result in ratepayer benefits, while the more detailed engineering and cost analysis determines which NWA solution or combination of solutions is most appropriate and would have a lower revenue requirement impact than the traditional solution (D.P.U. 24-10, Exhs. DOER 3-3, CLC-ES 1-5). The company also explained that it has limited experience deploying NWAs (D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 102).

NSTAR Electric specified that all DERs that make up a VPP are considered in its NWA analysis (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 680; DPU-Common 11-23). In its ESMP, the company defined a VPP as an aggregation of DERs to utilize for grid purposes (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 680; DPU-Common 11-24; DOER 1-11). NSTAR Electric clarified that VPPs require active monitoring and control and are capable of responding to coordinated remote dispatch to provide grid benefits (D.P.U. 24-10, Exhs. DOER 1-11; DPU-Common 11-24). Moreover, the company stated that it regards VPPs as potentially comprising both behind-the-meter DERs co-located with customer load and front-of-the-meter, stand-alone DERs interconnected to the distribution system and controlled by the company[87] (D.P.U. 24-10, Exhs. DPU-Common 11-23, DPU-Common 11-24).

NSTAR Electric identified three factors necessary for effective VPPs: (1) the VPP resource must be electrically connected to the grid in a location capable of providing the required grid service (e.g., interconnected to reduce load or add generation on that specific feeder in the as-operated grid configuration); (2) the dependability of the VPP resources will dictate the degree to which the grid operator will rely on the VPP to provide grid services,

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87 Controlled by the company directly or through compensation mechanisms of the proposed Grid Services Compensation Fund discussed in further detail in Section VII.C.2.b.iii.

namely, the company views VPP resources that it does not dispatch directly and/or that the customer can override as relatively less valuable from a grid asset perspective;[88] and (3) VPPs requiring advance notification requirements provide less flexibility as a resource for real-time dispatch based on the as-operated grid configuration (D.P.U. 24-10, Exh. DOER 1-11, at 1).

The company identified five categories of NWA resources utilized or potentially utilized in its distribution system planning processes. The company characterizes the categories as follows: (1) independent resource additions, such as EE programs, DG, and EV/battery discharge schedules independent of specific grid need, all of which the company considers in its forecasts and serve to subtract from the forecasted system peak load; (2) bridge-to-wires services, which involve DERs owned and operated by third parties contracted to provide certain grid services at specific times; (3) Non-Traditional Approach services, which involve DERs owned and operated by the company based on criteria utilized in NSTAR Electric's NWA framework; (4) Grid Services Solutions, which also involve third-party DERs but that can be deployed to provide real-time relief during periods of system constraint; and (5) flexible interconnections, such as co-located storage at solar farms, that allow for more cost-effective interconnection by avoiding some costly system upgrades (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 333-334, 578-580). No matter the solution,

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88 The company explained that the degree to which customers can override behind-the-meter DERs control and dispatch settings will limit the ability of the company to count on these resources for grid services (D.P.U. 24-10, Exh. AG 5-18(b)).

the company conveyed that direct utility control will be essential in solidifying the usefulness of DERs in providing grid services to maintain safe and reliable service in accordance with established standards (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 231, 584; AG 5-18; DOER 1-11). The company observed that if electric distribution companies retain ownership of an NWA, then the performance or failure of that asset remains within the jurisdictional control of the Department, which has no jurisdiction over third parties that may wish to install an NWA on the distribution system (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 584).

Regarding independent resource additions, NSTAR Electric identified EE and DG (e.g., solar PV) as the two key NWAs used in reducing peak demand and deferring system capacity needs and considers both in its five- and ten-year forecasts to inform planned and proposed investments (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 249-250, 333-334). The company explained that, over the past decade, EE has proven to be an exceptionally impactful method for reducing peak system load, but that future EE impacts are expected to be lower as some critical savings opportunities, such as lighting, have been addressed (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 249, 311-312). The company assumed that its EE programs would continue to have an impact on the overall peak load, at approximately 294 MVA or the equivalent of two bulk substations over the next decade, if EE funding is maintained at current levels (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 249-250).

The company stated that DG represented the second largest NWA deferral of capacity needs in its ten-year forecast (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 250). The company also stated that, while it expects DER growth to continue impacting the overall peak of the system, high adoption rates will reduce the benefits of peak deferral as more solar generation goes online and the net system peak will shift to later in the day, thus decreasing the incremental impact of the next MW of installed solar on the actual system peak (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 250). Further, the company considered ESS, noting that with more storage systems being proposed for co-located installations, the evening reach of solar installations is extended (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 250-252). The company explained that, utilizing the Pathways Model, actual projected solar installations are expected to reach 2.5 GW by 2033 (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 250-251). As a result of these DG activities, the company projected that the overall deferral of infrastructure needs would reach 176 MVAs, or about one bulk substation (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 251).

NSTAR Electric identified third-party operated bridge-to-wires NWAs as an additional solution to delay or defer the company's need to deploy infrastructure (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 333-334, 578). NSTAR Electric stated that this solution provides operational flexibility in areas of growing demand and stays in place until the company has developed a traditional or non-traditional solution but that, ultimately, the underlying traditional asset would need to be replaced (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 333, 578, 675). The company identified the proposed Grid Services Solution, involving the dispatch of customer-owned aggregated behind-the-meter and third-party front-of-the-meter DERs to manage system constraints or better optimize voltage levels, as an option that could be utilized during operation of a future system with a high degree of resource flexibility and significant stochastic behavior, such as in support of microgrids (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 334, 578). Both the bridge-to-wires and Grid Services Solution NWA categories would be dispatched through DERMS, which the company proposed as an incremental ESMP investment for the first term, e.g., 2025 through 2029, and would be funded through the Grid Services Compensation Fund (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 14, 336-338, 580, 676; DOER 1-11).[89]

NSTAR Electric stated that flexible interconnections can be deployed outside its capacity planning efforts using operating constraints agreed upon with the developer (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 578-579, 677). The company explained that these NWAs depend on the developer's business case analysis and do not generate direct value for ratepayers (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 579). As a result, the company does not attribute a value stream to these solutions other than potentially avoiding certain system upgrades that would otherwise be needed (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 579). The company, however, identified lower interconnection costs and increased hosting capacity as grid-related benefits (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 334). The company has not implemented any flexible interconnections to date,

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89 In Section VII.C.2., the Department discusses in further detail each company's proposals relating to DERMS and the Grid Services Compensation Fund.

because it is dependent on the company's implementation of DERMS (D.P.U. 24-10, Exh. AG 5-19).[90]

NSTAR Electric identified several challenges with implementing NWAs (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 584). Specifically, the company noted that since an NWA project will serve only to defer the need to invest in the traditional project, the benefits associated with an NWA are calculated based on the length of time the NWA project can delay the necessary traditional project (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 584; ES-Policy/Solutions-1, at 116-117). As such, the company explained that rapid increases in electric demand will shorten the potential deferral timelines, thereby reducing the cost effectiveness of NWAs (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 584). Second, for an NWA project to be considered a reliable solution, the company explained that the project must exhibit availability and performance standards comparable to that of traditional assets (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 584). The company noted that distribution constraints are typically very localized, thus creating a challenge to ensuring reliability (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 584). The company suggested that third-party ownership may present risks to the viability of an NWA due to potential bankruptcy of the owner, unregulated battery discharge, and operation beyond Department jurisdiction (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 584). The company also explained that continued investment in traditional utility projects, specifically existing

[90] In Section VII.C.2., the Department discusses in further detail each company's flexible interconnection proposals.

grid modernization technologies, will support the company's capacity to provide DER as a grid service and to include a broader swath of alternative solutions in the next ESMP term (D.P.U. 24-10, Exh. ES-Policy/Solutions-1 (Corrected) at 141-143).

During the course of the proceedings, the company summarized instances when it explored the use of NWA solutions. Specifically, during the period 2019 through 2023, the company performed detailed engineering analyses on the following two substations and one submarine distribution cable system for potential NWA application upon meeting its three suitability criteria; however, the company ultimately did not pursue these solutions: (1) the New Cambridge #8025 Substation; (2) the New East Eagle Substation #131; and (3) ESS as an alternative to additional submarine distribution cables to Martha's Vineyard (D.P.U. 24-10, Exh. DPU-Common 8-8). The company rejected these NWA solutions due to concerns regarding reliability, project costs, increased load forecasts, and construction timeframe and, instead, pursued more traditional investment options to mitigate identified capacity and/or reliability deficiencies (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 157, 351-354, 392-393; DPU-Common 8-8). The company would have owned all three rejected NWA solutions (D.P.U. 24-10, Exh. DPU-Common 8-8). Conversely, during this period, the company placed in service its Provincetown ESS microgrid, which utilizes grid-forming inverter technology to improve the reliability and resiliency of NSTAR Electric's distribution system in the Lower Cape Cod area (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 104-105, 402; DPU-Common 8-5, Att.; DPU-Common 12-5).[91]

For the 2025 through 2029 period involving its planned, non-ESMP investments, the company identified two company-owned NWA ESS solutions currently in development – one in Hyde Park and one in New Bedford (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 289, 355-356, 362, 402; DPU-Common 8-5, Att.). As of the company's initial filing, both ESS projects had met the three suitability criteria and entered the detailed engineering and cost-analysis phase through its capital project approval processes (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 289, 355-356, 362, 402; DPU-Common 8-5, Att.; CLC-ES 1-5). While the two projects are considered NWAs, the primary use cases of the projects involve improvements in distribution reliability and resiliency and, if approved through its capital project approval processes, will be utilized: (1) as an interim operational measure until a new substation is built and for potential future testing for new applications/usages of the ESS (Hyde Park); and (2) to resolve long-standing power quality issues affecting industrial customers within the New Bedford Business Park (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 355-356, 402; CLC-ES 1-5; CLC-ES 1-16).

In its proposed ESMP investments, discussed above, NSTAR Electric proposed to install a two MW/three MWh ESS in Southampton, although the primary use case of the project would be to provide smoothing of PV output, rather than to defer any traditional

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91 This project was approved by the Department in 2017. See NSTAR Electric Company, D.P.U. 23-49, at 3 & n.3 (2023); D.P.U. 17-05, at 464-465, 470.

wires investment as an NWA project (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 340-341). However, to support the use of customer-owned DER as a grid asset, the company proposed ESMP investments during the term, including via the Grid Service Compensation Fund jointly proposed with the other electric distribution companies and a proposed VPP demonstration program commencing in 2025, to enable the use of VPP technology to procure services from DERs after the current ESMP term (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 291, 339, 451; ES-Policy/Solutions-1, at 110; DOER 1-11, at 2-3).[92] The company stated that this VPP enablement would be distinct from the form of VPP that it currently uses to provide system-level peak load reduction as part of its demand response ConnectedSolutions program (D.P.U. 24-10, Exh. DOER 1-11, at 1-2).

Finally, NSTAR Electric requested that the Department defer review of opportunities to dispatch energy storage technologies to improve renewable energy utilization and avoid curtailment to the currently open dockets addressing new storage tariffs, pointing to dockets D.P.U. 23-115, D.P.U. 23-117, and D.P.U. 23-126 (D.P.U. 24-10, Petition at 14-15).

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92 Based on lessons learned during the proposed VPP demonstration, the company stated that it expects VPP implementation at scale to be feasible starting in 2030 (D.P.U. 24-10, Exh. DOER 1-11, at 3). The company stated that such implementation at scale, however, requires completion of all ESMP technology and process upgrades proposed for the 2025 through 2029 term and a long-term compensation mechanism reflecting experience implementing the proposed Grid Services Compensation Fund (D.P.U. 24-10, Exh. DOER 1-11, at 3).

b. National Grid

National Grid explained and provided documentation on how it evaluates alternatives to investments in its internal processes for normal distribution system planning and capital project authorizations (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 60, 66; NG-Policy/Solutions-1 (Corrected) at 64-65; AG 3-23; AG 4-2, Att. at 7-9, 11; Tr. at 116-117). The company's normal planning processes and planned investments informed the development of its ESMP and the proposed ESMP investments, including the corresponding alternatives considered or that would be considered by the company (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 289-291, 295; NG-Policy/Solutions-1 (Corrected) at 65, 115). For both non-ESMP and ESMP investments, the company actively pursues NWA[93] solutions during the system planning assessment process, with a goal of developing a combination of wires solutions and NWAs that solve capacity deficiencies in a cost-effective manner, factoring in the potential benefits and risks (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 23, 295; NG-Policy/Solutions-1 (Corrected) at 115).

93 National Grid defines NWAs as "the use of a non-traditional solution to a specific electric network constraint that defers or removes the need to construct or upgrade specific components, or reduces the operational risk related to a specific network constraint, on the distribution and/or transmission system" (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 294-295; NG-Policy/Solutions-1 (Corrected) at 64-65). The company explained that its approach to NWAs is both ownership- and technology-agnostic, with resources such as energy storage, localized demand response, solar PV, EV managed charging, localized EE measures, flexible interconnection technologies, or a combination of technologies aggregated as a VPP all considered as potential solutions (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 295-296; NG-Policy/Solutions-1 (Corrected) at 65).

Alternatives to proposed investments also include delay or deferral of investments or, based on updated forecasts, reprioritization of projects (D.P.U. 24-11, Exh. NG-Policy/Solutions-1 (Corrected) at 67, 116).

To determine the suitability of an NWA in lieu of a traditional project, the company's NWA guidelines have three initial screening criteria. Specifically, the traditional wires project: (1) must be related to load relief or reliability; (2) must start construction at least 18 months in the future; and (3) must cost at least $500,000 (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 70, 295; NG-Policy/Solutions-1 (Corrected) at 65; DPU-Common 8-8). The company stated that most customer-driven projects, whether load or DER, do not meet these criteria (D.P.U. 24-11, Exh. DPU-Common 8-4). The company explained that it screens and develops alternative infrastructure and NWA plans during its Area Planning Study phase of distribution system planning after it conducts a detailed systems assessment and engineering analysis of a traditional wires solution, and the costs and benefits of alternative plans are subsequently compared to those of the traditional solution (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 290-291).

The company emphasized the significant potential of VPPs in balancing electrical supply and demand, providing services similar to a traditional power plant (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 298). The company specified that VPPs can be used as NWAs if they can be managed reliably to provide grid services based on a local grid constraint, but that this would require new capabilities and processes beyond those required to administer system peak VPPs, such as DERMS technology (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 298). Additionally, the company noted that it is relatively early on in its journey with NWAs and that the successful deployment of NWA options at scale depends on the implementation of various investments described in its ESMP, e.g., AMI and DERMS, among others, and reliance on lessons learned from initial utility-scale NWA projects (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 23-24, 296; NG-Policy/Solutions-1 (Corrected) at 73-74).

National Grid incorporated into its demand forecasts the use of NWA resource inputs, namely EE, demand response, solar PV, energy storage, EVs, and electrification of heat, which the company relies on to help inform its planned and proposed investments (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 12, 207-208, 211, 295; NG-Policy/Solutions-1 (Corrected) at 34-36, 75). The company stated that, over the past decade, EE and demand response programs through Mass Save have resulted in a peak demand reduction of 30 percent or 1.3 GW, keeping load growth flat and allowing the company to avoid or defer some investments in distribution system expansions and upgrades (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 63-64). The company assumed that its EE programs would continue to have an impact on the overall peak load over the next decade, albeit at a slower rate each year due to the saturation of claimable savings as well as policy and funding uncertainties, resulting in a peak load savings of 1,547 MW over the next decade (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 64, 211, 215, 217-219). National Grid estimated that peak load savings attributable to demand response and energy storage would be more modest over the next decade, reaching approximately 98 MW and ten MW, respectively, while solar PV adoption was not estimated to provide any peak load savings due to the peak hours shifting to later in the day when PV has less impact on peak demand (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 64, 211, 215, 217-220). National Grid also identified the ongoing benefits of its ConnectedSolutions program, a demand response VPP program designed to shave system peaks by dispatching residential and commercial demand response technologies, and specified that its EV managed charging program also functions as a VPP by aggregating and shifting EV load away from system peak (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 298).[94]

National Grid distinguished between two categories of NWAs utilized or potentially utilized in its distribution system planning processes: (1) asset deferral; and (2) bridge-to-wires (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 23, 295; NG-Policy/Solutions-1 (Corrected) at 65-66, 72). The company categorized asset deferral NWAs as those that defer the date by which the company would have pursued a wires solution, but specified that these NWAs are usually appropriate in situations with a high traditional solution cost and slow growth in expected demand (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 295; NG-Policy/Solutions-1 (Corrected) at 65-66). The company categorized bridge-to-wires NWAs as those that provide quick peak demand reductions or peak supply increases to maintain reliable service during times when a capital

94 Similar to NSTAR Electric, National Grid defines VPP as an aggregation of DERs to provide utility scale and utility-grade services (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 680; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 23, 298 & Glossary at 7).

project is needed but cannot be installed within time to address the need (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 295; NG-Policy/Solutions-1 (Corrected) at 66). In both instances, the NWA defers the underlying wires solution for a period of time (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 23, 295; NG-Policy/Solutions-1 (Corrected) at 65-66, 72).

The company identified instances in which it explored NWA solutions. Specifically, during the period 2019 through 2023, the company identified six projects that met its three NWA screening criteria but were ultimately not pursued due to a lack of technical feasibility (D.P.U. 24-11, Exh. DPU-Common 8-8). Reasons for not pursuing an NWA solution at the six project sites included insufficient NWA load reduction capabilities, reliability issues not fully addressed by the NWA, and effects of the COVID-19 pandemic on resourcing and materials (D.P.U. 24-11, Exh. DPU-Common 8-8). National Grid explained, however, that NWA projects in affiliated service territories provide invaluable lessons learned, identifying a 48 MWh ESS facility at the Bunker Road Substation installed by New England Power Company in 2019[95] and two projects and an EE bonus incentive project by Niagara Mohawk Power Corporation (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 295 n.9; DPU-Common 8-5; DPU-Common 8-6; DPU-Common 8-7).

In this ESMP, to support potential NWA projects over the term, National Grid jointly proposed with the other electric distribution companies a Grid Service Compensation Fund to recover costs for customer and third-party incentives for providing locational flexibility, as

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95 The battery is owned by New England Power Company and operated by the company (D.P.U. 24-11, Exh. DPU-Common 8-5).

well as increased support for administrative costs associated with identifying potential asset deferral and bridge-to-wire NWA projects (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 296-297; NG-Policy/Solutions-1 (Corrected) at 77-78). Additionally, National Grid proposed two asset deferral NWA projects to test deferral of three feeder expansions and support load growth, two at the Litchfield Street substation in Leominster and one at the Millbury substation in Millbury (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 9, 24, 254, 305-306, 308-309). The company also identified seventeen preliminary candidate locations for bridge-to-wires NWA projects across the company's sub-regions: seven in the Central sub-region, two in the Merrimack sub-region, two in the North Shore sub-region, three in the Southeast sub-region, two in the South Shore sub-region, and one in the Western sub-region (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 310, 316, 321, 327, 333, 340). The company stated that its proposed ESMP NWA solutions should be viewed as a first step in a multi-year process to advance NWA capabilities (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 23). While the exact makeup of the NWA solution across the 19 total asset deferral and bridge-to-wires NWA sites has not been determined, the company explained that the projects could incorporate a variety of DER types, including customer-sited EE and flexible demand via managed EV charging and Wi-Fi enabled thermostats, PV solar systems, and/or ESS facilities (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 348; NG-Policy/Solutions-1 (Corrected) at 75).

Additionally, the company seeks to expand its VPP offerings to provide NWA use cases in addition to peak shaving capabilities by growing its existing ConnectedSolutions and

EV off-peak managed charging programs, pursuing necessary enabling technologies, and exploring novel customer and third-party incentive mechanisms (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 298-299; NG-Policy/Solutions-1 (Corrected) at 75-77). For instance, the company proposed in the current ESMP flexible connection offerings for commercial and fleet EV charging customers in select locations (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 347; NG-Policy/Solutions-1 (Corrected) at 79-80). The company also proposed several customer incentive programs to compensate customers and third parties for providing local grid services as NWA solutions, local EE/DR/EV managed charging incentives as VPPs, and local flexibility market VPPs (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 348-349; NG-Policy/Solutions-1 (Corrected) at 75-76).

The company stated that it anticipates further development of NWA capabilities as technologies progress, DER deployment increases, and a variety of NWA methods are implemented (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 309, 311). Looking forward, National Grid expects that with new regulatory frameworks and policy support, customer offerings can evolve to include expanded managed charging opportunities and utility or third-party management of heat pumps and behind-the-meter storage (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 300). The company also explained that continued investment in traditional utility projects, specifically existing grid modernization technologies, will support the company's capacity to provide DER as a grid service and to include a broader swatch of alternative solutions in the next ESMP term (D.P.U. 24-11, Exh. NG-Policy/Solutions-1 (Corrected) at 115-116).

Finally, National Grid requested that the Department defer review of opportunities to dispatch energy storage technologies to improve renewable energy utilization and avoid curtailment to the currently open dockets addressing new storage tariffs, pointing to dockets D.P.U. 23-115, D.P.U. 23-117, and D.P.U. 23-126 (D.P.U. 24-11, Petition at 14-15).

c. Unitil

Unitil evaluates alternatives to investments in its internal processes for normal distribution system planning and capital project authorizations (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 105; UN-Policy/Solutions-1, at 30-31, 56-57). The company's normal planning processes and planned investments informed the development of its ESMP and the proposed ESMP investments, including the consideration of alternatives (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 167; UN-Policy/Solutions-1, at 56-57). For both non-ESMP and ESMP investments, Unitil considered NWAs[96] alongside traditional utility investments using a standardized approach outlined in its Project Evaluation Procedure, to maximize reliability and cost-effectiveness while minimizing environmental impacts (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 149; UN-Policy/Solutions-1, at 56-57; DPU 8-2). Alternatives to proposed investments also include delaying or deferring

96 Unitil defines NWAs as "technologies or operating practices intended to reduce grid congestion and manage peak demand to offset a utility's need to make additional investments in conventional assets like wires, poles, and substations" and the technologies "can include [DER], such as microgrids or batteries, and practices and programs focused on load management, demand response or [EE]" (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at XV).

investments or, based on updated forecasts, reprioritizing projects (D.P.U. 24-12, Exh. UN-Policy/Solutions-1 (Corrected) at 61-62, 67, 90).

To determine the suitability of an NWA in lieu of a traditional project, the company has developed two primary screening criteria. Specifically, the traditional project must have: (1) an estimated value of at least $500,000; and (2) a required construction start date within three to five years (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 228-229; UN-Policy/Solutions-1, at 57; DPU 8-2, Att.). If these criteria are met, the company then requires a more detailed cost-benefit analysis for the project and may proceed with an RFP for potential NWAs (D.P.U. 24-12, Exhs. UN-Policy/Solutions-1, at 57; DPU 8-2, Att.). The company does not consider NWA solutions for projects being justified based solely on condition replacement or reliability benefits, or for customer-requested projects regarding DG interconnection, line relocations, or new development installations (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 229; UN-Policy/Solutions-1, at 57; DPU 8-2, Att.). During discovery, however, Unitil indicated that it may consider NWA solutions which do not meet the cost and timeline thresholds if: (1) the required load reduction is small and the distribution system master plan does not anticipate a possible future need for a traditional option; and (2) a traditional solution could be quickly implemented to defer the required need long enough to provide sufficient opportunity for the evaluation of NWA solutions (D.P.U. 24-12, Exh. DPU 8-1). The company also explained that it has limited experience deploying NWAs (D.P.U. 24-12, Exh. UN-Policy/Solutions-1, at 62).

Unitil defined VPPs as an aggregation of DERs to utilize for grid purposes (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at xvii; DPU-Common 11-24). Unitil considers a VPP as an NWA to traditional infrastructure improvements to address loading and voltage concerns so long as the VPP is evaluated on a similar capacity, availability, and reliability basis as a traditional investment (D.P.U. 24-12, Exh. DPU-Common 11-23). Unitil explained that any VPP proposed as an NWA would be evaluated through the RFP process against other NWAs and traditional alternatives for an identified constraint (D.P.U. 24-12, Exh. DPU-Common 11-23). The company noted that it does not have experience with VPPs and still must determine how the VPPs will be aggregated, controlled, and dispatched through its typical DER interconnection process (D.P.U. 24-12, Exh. DPU-Common 11-24).

Unitil classified into one of five categories NWA resources in its distribution system planning processes: (1) load reducers, such as solar PV and EE resources that lower forecasts and delay the timing of system constraints; (2) Non-Traditional Investments, which involve individual investments like energy storage or other highly reliable and available technologies typically owned and operated by the company that can alleviate system constraints; (3) DER as a Grid Service, which involves groupings of customer-owned DER that can provide load reduction services typically based on monitoring, control, and operating agreements with the company; (4) bridge-to-wires, which involves quickly dispatchable, typically third-party owned resources like demand response and ESS that can address locational constraints in the near term when traditional solutions cannot be constructed in time for the projected need; and (5) flexible interconnections, or customer owned DER that can occasionally cause system constraints but can be strategically disconnected by the company when the DER cannot be supported by the system (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 227-228). Unitil noted that it does not currently offer a flexible interconnection process to customers but will evaluate implementing one (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 228). For any project to be considered an NWA, particularly for energy storage systems, Unitil requires monitoring and control of the asset by the company to ensure the resource can reliably contribute to the distribution system when needed (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 216).

Unitil considered EE and DER (e.g., solar PV, ESS, grid services) in its load forecasts as load reducers when those resources are in place and able to provide a load reduction when the system needs it (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 76, 83-89, 99, 227; UN-Policy/Solutions-1, at 17-18). While Unitil expects EE savings to continue in the future, the company did not present forecasted load impacts of EE programs due to the difficulty in separating historical EE savings from historical load data (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 84). Regarding DER, Unitil developed five- and ten-year forecasts on an annual basis using the five-year and three-year historical slope of DER capacity growth, overall number of DER facilities, and the number of customers served (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 84). The company stated that for DERs to be considered alternatives to traditional investments, they must exhibit the same level of reliability, redundancy, and availability as traditional investments

(D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 88). Over the next decade, Unitil projected that ESS and solar PV resources could reduce peak load by up to 3.4 MW and 2.6 MW, respectively (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 85-87).

The company explained that it currently has a single NWA in operation in its territory, which it stated is an example of a "Non-Traditional Investment" designed to defer the need to expand substation transformer capacity by reducing expected peak load during key hours of the day (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 150, 228; DPU-Common 8-5). Specifically, the company installed a two MW/four MWh utility-scale ESS at its Townsend substation with the ability to serve over 1,300 homes for over two hours and to provide voltage and frequency regulation to the market (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 150). The facility was placed in service in 2021 (D.P.U. 24-12, Exh. DPU-Common 8-5). For the period 2019 through 2023, Unitil did not identify any additional NWA candidates that were ultimately not pursued (D.P.U. 24-12, Exh. DPU-Common 8-8).

In this ESMP, the company does not propose any ESS-specific NWA projects, citing the need to ensure appropriate company control of DER resources, advance current systems and technologies, and establish an efficient compensation mechanism to incentivize customer-owned DER to participate in real time load management programs (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 167; UN-Policy/Solutions-1, at 58-59).[97] The company

[97] The company stated that its two proposed capacity-related projects, the Lunenburg Substation Capacity Addition and the new South Lunenburg Substation, have required

explained, however, that its proposed DERMS platform investments, among others, will enable it to implement future NWAs and potentially procure load flexibility in the future (D.P.U. 24-12, Exh. UN-Policy/Solutions-1, at 65, 89-90). Additionally, to support the use of customer-owned DERs as a grid asset in the future, the company proposed the Grid Services Study, Grid Service Compensation Fund, and Transactional Energy Study jointly with the other electric distribution companies (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 125, 150, 167-168; UN-Policy/Solutions-1, at 65, 89).

Finally, Unitil requested that the Department defer review of opportunities to dispatch energy storage technologies to improve renewable energy utilization and avoid curtailment to the currently open dockets addressing new storage tariffs, pointing to dockets D.P.U. 23-115, D.P.U. 23-117, and D.P.U. 23-126 (D.P.U. 24-12, Petition at 14-15).

3. Positions of the Parties

a. DOER

DOER argues that the Companies should consider customer-sited solutions, such as DER and NWAs, including resources and alternatives administered and/or owned by third parties, expressing concern with the Companies' emphasis on constructing additional distribution infrastructure (DOER Brief at 68). DOER points to National Grid's four proposed VPP programs as well as NSTAR Electric's proposed 2025 VPP

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project start dates within three years and, thus, do not meet the preliminary screening criteria for NWAs (D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 138-139; UN-Policy/Solutions-1, at 57). The Department discusses these proposed investments in further detail in Section VII.C.2.d.iii.

demonstration project and 2030 VPP implementation goal as important first steps towards evaluating alternatives to traditional distribution system investments (DOER Brief at 43-44, citing D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 336; DOER 1-11; D.P.U. 24-11, Exh. NG-ESMP-1, at 348-350). However, DOER contends that considerable effort will be needed to ensure that alternative investments like VPPs can compete with traditional resources in the next ESMP planning cycle (DOER Brief at 44).

DOER contends that the Companies downplay energy storage systems as a means of reducing peak demand, noting the specific emphasis that the 2022 Climate Law placed on energy storage (DOER Brief at 45, citing G.L. c. 164, § 92B(a)(iii), (b)(ii)&(vii), (c)(i)). DOER also contends that the Companies did not adequately consider potential peak demand reduction benefits from managed EV charging programs and the enablement of bidirectional charging (DOER Brief at 49). Further, DOER highlights the exclusion of vehicle-to-everything ("V2X") capabilities from the Companies' system planning, even if V2X is a nascent technology (DOER Brief at 51, citing D.P.U. 24-10, Exh. ES-ESMP-1, at 227; D.P.U. 24-11, Exh. NG-ESMP-1, at 220; D.P.U. 24-12, Exh. UN-ESMP-1, at 110).

Regarding rate design, DOER asserts that the ESMPs should include considerations of how alternative rate structures will affect load forecasts because rate design is a critical load management instrument that can align customer behavior, the Commonwealth's policy priorities, and the Companies' business practices while minimizing the cost of distribution system upgrades (DOER Brief at 54). DOER maintains that before the next ESMP term, AMI-driven MDMS and customer information system rollout will have begun and TVR should be available (DOER Brief at 54). DOER argues that the Department should direct the Companies to include the following information in future ESMPs: (1) scenario analysis of rate design in the Companies' forecasts; and (2) analysis and discussion of the types of rate designs each company sees as strategically promising to support least-cost distribution system planning to meet clean energy goals (DOER Brief at 55).

Further, DOER contends that the Department should align ESMP requirements with the directives that result from the Department's forthcoming review of the AMI Stakeholder Working Group's final report (DOER Brief at 76). DOER asserts that future ESMPs should include information about: (1) statewide data access plans with descriptions of functional and enabled data access; (2) clear implementation plans and timelines for ongoing data access developments; (3) the deployment status of AMI meters; and (4) how customers and third parties can understand, access, and utilize the data from AMI meters (DOER Brief at 76).

b. Acadia Center, CLF, and GECA

Acadia Center, CLF, and GECA contend that the Companies' ESMPs fail to comply with Section 92B's requirements to account for or meaningfully consider alternative investments or NWAs and their benefits on ratepayer impacts or the net benefits analysis (Acadia Center Brief at 14-15, citing Exh. DOER-1, at 12; CLF Brief at 11-12, citing GMAC Consultant Comments at 69-73; GECA Brief at 13, 15, 18-19; Joint Intervenor Reply Brief at 3). Specifically, the intervenors assert that the ESMPs fail to sufficiently consider NWAs, VPPs, incremental EE, incremental distributed solar, incremental storage, or EV adoption strategies, which can help defer or avoid the need for ESMP investments (Joint Intervenor Reply Brief at 3, citing GMAC Consultant Comments at 69-70; Acadia Center Brief at 15; GECA Brief at 13-14, 17-18; DOER Brief at 44, 68). GECA also asserts that the Companies, specifically NSTAR Electric and National Grid, should consider managed charging programs more comprehensively in their ESMP filings and include more robust managed charging offerings in their proposed EV programs (GECA Brief at 18-19).[98] GECA further argues that the Companies' analyses fail to account for the downward pressure on rates that has been seen in other jurisdictions with higher rates of EV adoption (GECA Brief at 17).

Regarding potential alternative rate designs, GECA contends that TVR is more understandable and actionable for a consumer than residential demand charges (GECA Brief at 20, citing Exh. GECA-AV-1, at 14). GECA also asserts that demand charges are especially problematic for EV drivers because the price signal of a demand charge is not actionable (GECA Brief at 20, citing Exh. GECA-AV-1, at 14).

c. Cape Light Compact

CLC argues that NSTAR Electric should maximize the value of ESS by further exploring alternative uses like peak shaving (CLC Brief at 14). CLC notes that both the Provincetown ESS and the proposed New Bedford ESS have peak shaving mode functionality and that NSTAR Electric has expressed a willingness to develop greater peak shaving uses

98 The Department addresses alternatives arguments related to forecasting in Section VI.C. and arguments relating to net benefits in Section VII.I.4.

for ESS in the next ESMP (CLC Brief at 14-15). CLC calls for the Department to direct NSTAR Electric to test secondary use parameters of its ESS within reliability constraints and to include progress reports on secondary use parameter development in ESMP annual reports and the next ESMP (CLC Brief at 15). CLC also urges the Department to address how and when AMI and data access issues will be resolved as well as the timing of TVR adoption (CLC Brief at 32-34).

d. Clean Energy Coalition

The Coalition notes that while NWAs will play a critical role in the Commonwealth meeting its clean energy mandates, substantial distribution capacity still needs to be added to address future DG hosting needs (CEC Brief at 13 n.49). Additionally, the Coalition observes that NWAs and flexible interconnection should help maximize the use of existing and future infrastructure upgrades (CEC Brief at 13 n.49).

e. NRG Retail Companies

Like CLC, NRG contends that the Department should address how and when AMI and data access issues will be resolved as well as when TVR should be instituted (NRG Brief at 6). More specifically, NRG maintains that the Department's order should: (1) indicate how and when the Department will consider any contested AMI-related issues following completion of the AMI Stakeholder Working Group's final report; and (2) identify a process and timetable for review of TVR rates (NRG Brief at 7-8).

f. Companies

The Companies each maintain that it identified alternatives to its proposed investments, and that it considers alternatives to traditional capital investments as part of its planning processes (Companies' Joint Brief at 27, 31, 34, 49, 54-55, 59-60 (citations omitted)). Each acknowledges that stakeholders desire more alternatives to be incorporated into ESMPs and anticipates improvements in its ability to propose alternative offerings in the next ESMP filing (Companies' Joint Brief at 49, 55, 60). However, the Companies contend that, for the current ESMP term, critical foundational investments must be made to support the long-term energy transition and to allow the Companies to gain experience and expertise in its evolving role of managing and influencing load patterns (Companies' Joint Brief at 50, 55, 60). The Companies each note that the Grid Service Compensation Fund and future exploration of rate design options in a separate proceeding will provide greater opportunity for alternative investment considerations in future ESMPs (Companies' Joint Brief at 49, 59-60; Companies' Joint Reply Brief at 11 & n.11). National Grid also noted that its ESMP proposals included two priority asset deferral NWAs and several other bridge-to-wires NWA projects, with a focus on customer and third-party solutions (Companies' Joint Brief at 54-55). Regarding CLC's request for the Department to direct NSTAR Electric to test secondary use parameters of its existing ESS, the Companies counter that this request is outside the scope of the proceeding (Companies' Joint Reply Brief at 9).

Regarding rate design, the Companies maintain that rate design issues should not be proposed and reviewed in future ESMP filings and restate their request to explore changes to rate design in generic proceedings or other appropriate dockets (Companies' Joint Brief at 48, 55, 59, citing D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 41, 89, 115). The Companies further state that they expect to introduce TVR and load management programs soon, which will help inform any rate designs considered in subsequent proceedings (Companies' Joint Brief at 86).

4. Analysis and Findings

Pursuant to Section 92B, the Companies must address alternatives to non-ESMP investments and to proposed ESMP investments. For non-ESMP investments, Section 92B(c)(ii) requires each company to consider and include a summary of all proposed and related investments, as well as alternatives to investments, in developing their plans. Section 92B(e) requires the Companies to each propose alternatives to those investments. Additionally, Section 92B(b)(viii) requires that each ESMP describe in detail "alternatives to proposed investments, including changes in rate design, load management and other methods for reducing demand, enabling flexible demand and supporting dispatchable demand response" and, for proposed ESMP investments, to identify customer benefits associated with those alternatives.

Multiple intervenors generally contend that the Companies did not adequately consider alternative investments, including those involving NWAs, managed charging, ESS, or more nascent technologies, in their ESMPs. Some intervenors requested the Department's guidance on when and how various contested rate design issues would be resolved and the Department's direction on what rate design information should be provided in the Companies' next ESMPs. The Companies maintain that they both identified alternatives to their proposed investments and generally consider alternatives to traditional capital investments as part of their typical planning processes but contend that the current ESMP term requires focus on foundational investments to inform and facilitate future alternative approaches. For the reasons discussed below, the Department finds that the Companies have complied with the statutory requirements applicable to alternatives to investments. Further, we address intervenor comments on rate design issues.

As a preliminary matter, the Department observes that alternatives to investments under the various provisions of Section 92B may involve an array of programs and considerations that vary based on context. Alternatives may include changes in rate design, load management, and other methods for reducing demand, enabling flexible demand, and supporting dispatchable demand response, as outlined in Section 92B(b)(viii). All the foregoing alternatives rely on customer-side, behind-the-meter decisions (e.g., managed charging) and can help to offset system load and to delay or, in some instances, eliminate the need for traditional infrastructure investments. For utility infrastructure investments and typical distribution system planning, and for larger projects in particular, alternatives may include non-traditional investments such as ESS and VPPs or revisions to project scope and/or locations based on, for instance, community input, the results of detailed engineering analyses, or evolving system needs. The statute does not expressly define or restrict Department consideration of alternatives to those categories outlined in Section 92B(b)(viii) and, like the parties, we see no reason to limit analyses or arguments to customer-side alternatives. Such an approach is also necessary in consideration of the broad array and scale of investments planned and proposed by the Companies over the next five years, since an alternatives analysis that may be utilized for one set of investments (e.g., proposed EV program extension) may not be appropriate for or align with an alternatives analysis that may be utilized for a different set of investments developed to address, for instance, a system need (e.g., a new substation).

For purposes of the alternatives requirements of Section 92B(b)(viii), (c)(ii), and (e), however, given the broad range of possible proposals and investment options and the Department's strategic plan review of ESMP investment proposals, the Department concludes that it is reasonable and appropriate for summaries and discussions of alternative investments in the ESMPs: (1) for both ESMP and non-ESMP investments, to address a company's distribution system planning framework process and policies (e.g., distribution system planning, capital authorization, and NWA policies), including discussions of how alternatives are considered in that framework and, if applicable, how and why the process(es) for developing proposed ESMP investments differ for non-ESMP investments; and (2) for proposed ESMP investments only, to describe ESMP proposals for non-traditional utility investments or foundational investments to enable non-traditional investments (e.g., VPP, ESS, etc.), as well as any specific alternatives, if applicable, that the company considered in its development of its ESMP investment proposals. It would simply not be feasible for the Companies to address in their plans the entire array of alternatives, either customer-facing or distribution infrastructure alternatives, and corresponding scenarios that could apply to each proposed set of ESMP investments.

Additionally, as part of typical distribution system planning practices, the Companies do not conduct more detailed alternatives analyses until a project need has been identified or, in the case of policy directives, the Department has preapproved or preauthorized particular investments for cost recovery outside of base distribution rates (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 75, 439, 581-583; ES-Policy/Solutions-1, at 104-105; AG 4-24; CLC-ES 1-5; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 66, 289-291, 295; NG-Policy/Solutions-1 (Corrected) at 64-65; AG 3-23; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 105; UN-Policy/Solutions-1, at 30-31, 56-57). In the instant proceedings, the proposed ESMP investments are not attributed to the Companies' system needs in the provisioning of their core public service obligations to provide safe and reliable electric service; rather, the proposed investments are geared towards enabling the Commonwealth to achieve its clean energy goals as a result of a statutory directive. As strategic plans, the Department is not preapproving or preauthorizing the proposed investments identified therein but is, instead, reviewing the plans for compliance with Section 92B. See Interlocutory Order on Scope at 23-24. Thus, there is very limited value for, and it would not be feasible to require, more comprehensive alternatives proposals or analyses at the ESMP strategic planning stage. Instead, more comprehensive alternatives analyses for ESMP investments are better addressed: (1) for major infrastructure projects (e.g., CIPs and new substations) in Department preapproval proceedings, such as the Provisional Program extension or the forthcoming LTSPP,[99] similar to the requirements already applied to projects submitted to the Energy Facilities Siting Board ("EFSB") for review; and (2) if appropriate, when ESMP investments are submitted to the Department for review for purposes of prudence and cost recovery. See G.L. c. 164, § 64, § 69J; NSTAR Electric Company, EFSB 22-03/D.P.U. 22-21, at 30 (June 28, 2024); D.P.U. 20-80-B at 98.

Based on these considerations and in the context of strategic plans, and contrary to intervenor arguments, the Department finds that NSTAR Electric, National Grid, and Unitil have each sufficiently complied with the statutory requirements relating to alternatives to investments. Specifically, the records reflect that: (1) the Companies consider alternatives to investments as part of their typical distribution system planning processes, both in forecasting, as it relates to adjustments for programs like DERs, EVs, and EE, and in their consideration of capital and other investments; and (2) each company's normal planning processes and planned investments informed the development of its ESMP and the proposed ESMP investments, including the corresponding alternatives considered or that would be considered by the company (Tr. at 110-118; Tr. 5, at 578-579, 635-636, 667-669; Tr. 6, at 913; D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 74-76, 82-84, 249-250, 333-334, 438-439; ES-Policy/Solutions-1, at 44-46, 52, 86-88, 100, 141; DPU-Common 8-8; AG 1-11; AG 4-21; AG 5-2(d); DOER 1-11; DOER 2-3(b); DOER 3-3; CLC-ES 1-5; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 12, 23, 66, 207-208, 211, 289-291, 295;

[99] The Department addresses the Provisional Program extension and the next stages for the establishment of a LTSPP in Section VII.F.4.

NG-Policy/Solutions-1 (Corrected) at 34-36, 58-65, 75, 115; DPU-Common 8-8; AG 4-2, Att. at 7-9, 11; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 76, 83-89, 99, 149, 167, 227; UN-Policy-/Solutions1, at- 17-18, 53-57; DPU 8-2; DPU-Common 8-5). For instance, in their forecasts, the Companies each incorporate inputs from their existing customer-facing programs, including EE, which helps to lower system demands and forecasted peak loads, thus helping to offset the need for additional infrastructure investment and associated costs (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 249-250, 333-334; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 63-64; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 76, 83-89, 99, 227; UN-Policy/Solutions-1, at 17-18).[100] Additionally, the Companies each described activities and savings achieved (in MW) and expected from their active demand response programs, including the Mass Save and ConnectedSolutions programs, with plans to continue and/or propose expansion of those programs during the ESMP term, which may help to mitigate or minimize ratepayer impacts by delaying the need for new investments (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 18, 101, 104, 106, 129, 133-134, 149, 154, 176, 181, 249-250, 312-313, 321-322, 427, 436, 448; AG 5-11; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 17, 63, 88, 113, 133, 153, 172, 193, 220, 256; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 83-84, 112-113, 166).[101]

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100 The Department addresses arguments relating to inputs relied on by the Companies in their forecasts in further detail in Section VI.C., above.

101 While such savings may help to minimize or mitigate impacts to ratepayers by delaying a company's need to invest in new infrastructure, the Department observes

Regarding planned and proposed investments, the records also reflect that the Companies generally consider NWAs, including ESS, for higher-cost projects, and each considers company ownership and/or direct control over a DER to be a critical component in maintaining necessary safety and reliability standards for its systems (Tr. at 5, at 590-592, 594, 607, 705-708; D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 438-439, 584; ES-Policy/Solutions-1, at 104-105, 115; AG 4-24; AG 5-2(d); DOER 1-11; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 70, 256, 259, 264, 295; NG-Policy/Solutions-1 (Corrected) at 65; DPU-Common 8-8; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 216, 228-229; UN-Policy/Solutions-1, at 57; DPU 8-2, Att.). As discussed in further detail in Section VII.C.e., the Companies' planned, non-ESMP alternatives investments include a Grid Services Study and a Transactional Energy Study based on collaborations with the MassCEC (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 429-430; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 351; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 124-126). Additionally, for the first term of the ESMP, the Companies each proposed multiple incremental ESMP investments to support or facilitate DER integration, VPPs, and the use of DERs for grid services onto its system, including: (1) DERMS Phase II, which the Companies identify as a foundational platform capability intended to increase the efficiency and effectiveness of DER integration and to enable the use of DERs as grid assets; and (2) establishment of a Grid Service Compensation Fund to compensate dispatchable DER

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that each company's EE programs are also funded by ratepayers (see, e.g., D.P.U. 24-11, Exh. AG 1-2(a)). 2022-2024 Three-Year EE Plans at 215-227.

and flexible loads participating in a program to allow utility dispatch to provide grid services (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 336-337, 429-430; ES-Net Benefits-3 (Corrected) at 12; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 265-266, 351; NG-Net Benefits-3 (Corrected) at 12; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at xii, 60, 118, 128-129, 172-173; UN-Net Benefits-3 (Corrected) at 12).[102] Further, because proposed ESMP investments reflect accelerated investments proposals geared towards facilitating the Commonwealth's clean energy transition rather than planning for each company's core public service obligations of providing safe and reliable service to customers, a possible alternative to the proposed investments would be for the Companies to not pursue or delay those investments until needed to address system needs as core investments (Tr. 3, at 314-333; 373-381; D.P.U. 24-10, Exhs. ES-Policy/Solutions-1, at 19, 142; DPU-Common 9-4; D.P.U. 24-11, Exhs. NG-Policy/Solutions-1 (Corrected) at 14-15, 116; DPU-Common 9-4; D.P.U. 24-12, Exhs. UN-Policy/Solutions-1, at 10, 60-61; DPU-Common 9-4).

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102 Regarding DOER's contention that integrating customer- or third party-owned resources in lieu of additional distribution infrastructure will prove necessary in mitigating future capacity constraints and improving community resiliency (DOER Brief at 68), the Companies plan to explore these issues through their planned Grid Services and Transactional Energy Studies, and through other planned and proposed investments. This will inform the Companies' next ESMP filings (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 429-431; ES-Policy/Solutions-1, at 88, 103-105, 110, 141; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 296-297, 349; NG-Policy/Solutions-1 (Corrected) at 73-77; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 125, 150; UN-Policy/Solutions-1, at 65, 89).

Additionally, regarding the Companies' request to defer review of opportunities to dispatch energy storage technologies on their systems, the Department finds that the Companies have sufficiently complied with the Section 92B(b)(ii) and (vii) requirements addressing energy storage technology considerations for purposes of the first ESMPs and a deferral is not necessary. Specifically, the Companies each discuss how ESS as NWAs are utilized on its system, considered as part of its distribution system planning processes, and require direct utility control to ensure a safe and reliable provisioning of service (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 231, 584; ES-Policy/Solutions-1, at 115, 139-140; DOER 1-11; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 295; NG-Policy/Solutions-1 (Corrected) at 65; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 59, 216, 227-229; UN-Policy/Solutions-1, at 56-59). Additionally, the Companies each identify and discuss customer trends involving behind-the-meter ESS and PV solar, among other technologies (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 249-252; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 207-208, 211, 215, 295; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 76, 83-88).

Notwithstanding this finding, the Department observes that Section 72 of the 2022 Clean Energy Act also required each electric distribution company to file with the Department for approval, a tariff addressing the operational parameters to apply to energy storage systems interconnected to its respective distribution networks. The Companies submitted their proposed tariffs on October 31, 2023, which the Department docketed as D.P.U. 23-115 (National Grid), D.P.U. 23-117 (Unitil), and D.P.U. 23-136 (NSTAR

Electric), respectively. Those matters remain pending at this time. As a result, in their next ESMPs, the Department expects the Companies to summarize and address the status of energy storage systems interconnected to their networks under any Department-approved tariffs on the matter. Regarding CLC's request for the Department to direct NSTAR Electric to test secondary use parameters within reliability constraints on its company-owned ESS (CLC Brief at 15), the Department determines that such a finding would not be appropriate in the context of a strategic plan review. However, for purposes of biannual reporting, the Companies shall report on whether they have conducted such testing on company-owned ESS and any corresponding results, in addition to other requirements to be established by the Department. See Section XI.D.

Finally, regarding the parties' comments on rate design issues, the Department determined in Section IV.C.3. that we would use a strategic plan approach to review the Companies' next ESMPs. That review shall include whether the Companies' ESMPs include potential changes to rate designs to reduce demand as alternatives to the investments proposed to achieve the Commonwealth's GHG emissions reductions limits. G.L. c. 164, § 92B(b)(viii). Similarly, the Department finds it unnecessary to address GECA's concerns related to the potential for NSTAR Electric and National Grid to impose residential demand charges on their EV customers at this time. NSTAR Electric and National Grid do not propose residential demand charges for the Department's review in these proceedings. If NSTAR Electric and National Grid propose to implement residential demand charges in a future proceeding, the Department will consider any concerns or recommendations specific to those proposals at that time.

Turning to DOER's specific recommendations, which the Companies do not explicitly endorse or oppose, we find that DOER's requests for (1) consideration of scenario analysis of rate design in the Companies' forecasts and analysis, and (2) discussion of the types of rate designs each company sees as strategically promising to support least-cost distribution system planning to meet clean energy goals, are consistent with our decision to review the ESMPs as strategic plans and direct the Companies to include such information in their next ESMPs.

The Legislature's decision to include changes in rate design, load management, and other methods of reducing demand as alternatives to the investments proposed in the ESMPs is a clear acknowledgement of the potential for AMI-enabled rate designs as a tool to achieve the Commonwealth's policy goals. G.L. c. 164, § 92B(b)(viii). The Legislature's inclusion of changes in rate design in Section 92B is also a clear endorsement of the Department's recent decisions to require the full deployment of advanced metering functionality, to approve the Companies' AMI deployment timelines, and to establish the AMI Stakeholder Working Group. Second Grid Modernization Plans (Track 2) at 200-206, 325-329; D.P.U. 20-69-A at 38-39. We share the intervenors' eagerness to resolve the many complex issues surrounding the deployment of AMI as well as the design and implementation of AMI-enabled rate designs, such as TVR. The Department is currently reviewing the AMI Stakeholder Working Group's final report, which was received earlier this month, and intends to review the Interagency Rates Working Group's final report recommendations as soon as they are available. See Interlocutory Order on Scope at 20-22. We intend to resolve the AMI-related issues that remain in contention and to investigate changes to rate design enabled by the full deployment of AMI as soon as practicable. As part of those processes, the Department may consider how the data generated by AMI deployment should be incorporated into future ESMPs.[103]

E. Transmission

1. Introduction

Section 92B requires the Companies' ESMPs to proactively upgrade not just the distribution system, but the intrastate transmission system as well. Below, the Department addresses the ESMPs' proposed transmission system upgrades.

2. Company Proposals

The Companies' ESMPs focus on upgrades to the distribution system, but they also identify transmission-related projects related to proposed ESMP investments (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 291; AG 7-4; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 299-339; AG 8-2; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 140-143). The Companies note the significant lead time to deploy transmission assets and coordinate distribution and transmission system planning (D.P.U. 24-10, Exhs. ES-Policy/Solutions-1,

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103 In response to GECA's comments, the Department notes that we approved demand charge alternative rates, and for Unitil to implement its EV time-of-use ("TOU") rate, in Electric Vehicles 2022 Order at 265-266, 270. In separate proceedings, the Department is investigating EV TOU rate proposals for NSTAR Electric and National Grid. NSTAR Electric Company, D.P.U. 23-84; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 23-85.

at 51-52; DPU-Common 11-9; DPU-Common 11-10; DPU-Common 11-11; DPU-Common 11-12; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 299; DPU-Common 11-9; DPU-Common 11-10; DPU-Common 11-11; DPU-Common 11-12; D.P.U. 24-12, Exhs. DPU-Common 11-9; DPU-Common 11-10; DPU-Common 11-11; DPU-Common 11-12). Further, each company will continue to use its existing processes to identify needed upgrades to the transmission system (D.P.U. 24-10, Exh. DPU-Common 11-11; D.P.U. 24-11, Exh. DPU-Common 11-11; D.P.U. 24-12, Exh. DPU-Common 11-11).

3. Positions of the Parties

CLC maintains that Section 92B requires the ESMPs to describe improvements to the transmission system to facilitate achievement of the statewide GHG emission limits. CLC argues that the ESMPs lack detail on transmission investments despite recognizing that distribution upgrades require new transmission assets and that transmission planning is necessary to meet the 2050 climate goals (CLC Brief at 22-23, citing Tr. 5, at 585; D.P.U. 24-10, Exhs. ES-ESMP-1, at 291-292; AG 7-4). CLC therefore urges the Department to require NSTAR Electric to include transmission planning to the greatest extent possible in its next ESMP (CLC Brief at 22-24; CLC Reply Brief at 16)). NSTAR Electric did not respond to this argument on brief.

4. Analysis and Findings

As more distribution capacity is added, thermal or voltage limitations may be triggered that may require substantial transmission investments (Tr. 5, at 585; D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 291-292; DPU-Common 11-11; D.P.U. 24-11, Exh. DPU-Common 11-11; D.P.U. 24-12, Exh. DPU-Common 11-11). Given the necessary lead time to deploy transmission assets, which can take more than ten years, the Companies take a coordinated planning approach for distribution and transmission system investments (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 77, 82, 88, 205; ES-Policy/Solutions-1, at 51-52; DPU-Common 11-9; DPU-Common 11-10; DPU-Common 11-11; DPU-Common 11-12; D.P.U. 24-11, Exhs. DPU-Common 11-9; DPU-Common 11-10; DPU-Common 11-11; DPU-Common 11-12; D.P.U. 24-12, Exhs. DPU-Common 11-9; DPU-Common 11-10; DPU-Common 11-11; DPU-Common 11-12). NSTAR Electric integrates its transmission planning, distribution planning, DER planning, reliability and resiliency planning, and advanced forecasting and modeling in a single planning unit (D.P.U. 24-10, Exhs. ES-Policy/Solutions-1, at 51-52; DPU-Common 11-11). When an identified investment requires the addition or upgrade of a substation transformer, National Grid works with its transmission affiliate and operator, New England Power Company, to develop a solution and identify transmission investments to support distribution needs (D.P.U. 24-11, Exhs. NG-Policy/Solutions-1 (Corrected) at 22; DPU-Common 11-9: DPU-Common 11-11). Unitil takes transmission service from National Grid's transmission system, and when the need for transmission upgrades arises, Unitil works with the transmission owner to design the solution (D.P.U. 24-12, Exhs. DPU-Common 11-9: DPU-Common 11-12). Further, in New England, studies to identify transmission upgrades are performed in coordination with ISO-NE and affected parties (D.P.U. 24-10, Exhs. DPU-Common 11-9; DPU-Common 11-10; DPU-Common 11-11; D.P.U. 24-11, Exhs. DPU-Common 11-9; DPU-Common 11-10; DPU-Common 11-11; D.P.U. 24-12, Exhs. DPU-Common 11-9; DPU-Common 11-10; DPU-Common 11-11). The record includes adequate descriptions of transmission-level upgrades associated with each company's proposed ESMP investment portfolios as well as its transmission planning processes (D.P.U. 24-10, Exh. AG 7-4; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 301-311; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 140-143). Based on the information above, the Department determines that the Companies employ a coordinated approach to distribution and transmission system planning and that the Companies have sufficiently identified the transmission system upgrades associated with their ESMP investments. Accordingly, the Department concludes that the ESMPs comply with Section 92B's requirements applicable to transmission system upgrades.

Given the Department's limited authority over transmission systems, our inquiry into transmission system upgrades with respect to these ESMPs must end here. The Department notes that upgrades to the transmission system infrastructure, including the siting and permitting of such infrastructure, falls squarely within the EFSB's jurisdiction and the Department's authority is limited to certain types of proceedings, such as approvals of construction and operation of transmission lines and zoning exemptions. See G.L. c. 164, §§ 69G to 69S, 72 to 75H; G.L. c. 40A § 3; G.L. c. 166, § 28. As such, we decline to require that subsequent ESMP filings contain greater detail on proposed transmission investments, particularly given that our review of the ESMPs is at the strategic planning level. Nevertheless, for transparency, the Department directs the Companies to provide status updates on transmission upgrades necessitated by ESMP investments in their biannual reports. Requiring such status updates in the biannual reports will allow stakeholders to obtain all ESMP-related information in a single location.

F. DER Interconnection Planning and Cost Allocation

1. Introduction

Pursuant to Section 92B(a)(ii), the Companies must file ESMPs to proactively upgrade the distribution system to "enable increased, timely adoption of renewable energy and distributed energy resources," among other things. Further, Sections 92B(b)(iv) and (ix) require a detailed description of "improvements to the distribution system that will enable customers to express preferences for access to renewable energy resources" and "alternative approaches to financing proposed investments, including, but not limited to, cost allocation arrangements between developers and ratepayers," respectively. As we noted in our Order closing our initial investigation of a LTSPP, Section 92B effectively codifies a long-term system planning requirement for enabling DER development to increase timely adoption of renewable energy and DERs. D.P.U. 20-75-C at 3-4.

2. Description of Company Proposals

a. Long-term System Planning Program

Following the completion of the Department's adjudication of the ESMPs, the Companies propose to work with stakeholders during 2024 and the beginning portion of the 2025 through 2029 ESMP term on the long-term cost allocation methodology for proactive infrastructure upgrades (D.P.U. 24-10, Exh. ES-Policy/Solutions-2, at 16-19; D.P.U. 24-11, Exh. NG-Policy/Solutions-2, at 16-19; D.P.U. 24-12, Exh. UN-Policy/Solutions-2, at 16-19). The Companies propose to submit the methodology to the Department for review in a generic proceeding, with the goal to incorporate the Department's feedback in the 2030 through 2034 ESMPs (D.P.U. 24-10, Exh. ES-Policy/Solutions-2, at 16-19; D.P.U. 24-11, Exh. NG-Policy/Solutions-2, at 16-19; D.P.U. 24-12, Exh. UN-Policy/Solutions-2, at 16-19).

b. Provisional Program Extension

The Companies propose to extend the cost allocation methodology and process that the Department proposed in D.P.U. 20-75-B to additional CIPs submitted during the 2025 through 2029 ESMP term (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 35; ES-Policy/Solutions-1, at 144; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 37, 371; NG-Policy/Solutions-1 (Corrected) at 29).[104] Given the timing constraints for this initial ESMP process, the Companies proposed to defer the review of additional alternative approaches to financing CIPs to a generic proceeding (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 35; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 37; D.P.U. 24-12,

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104 Although Unitil does not have existing or proposed CIPs, the company supports NSTAR Electric's and National Grid's proposal to extend the D.P.U. 20-75-B cost allocation paradigm to additional CIPs proposed during the 2025 through 2029 ESMP term (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 27). If Unitil identifies a need to conduct a Group Study during the 2025-2029 timeframe, the company proposes to apply the CIP framework as approved in D.P.U. 20-75-B (D.P.U. 24-12, Exh. UN-Policy/Solutions-1, at 92).

Exh. UN-ESMP-1 (Corrected) at 34). NSTAR Electric states that the alternative to extending the cost allocation methodology and D.P.U. 20-75-B process would be to revert to the previous methodology of funding interconnections using the principles of cost causation (D.P.U. 24-10, Exh. ES-Policy/Solutions-1, at 144-145).

Following completion of its ongoing Group Studies,[105] NSTAR Electric plans to submit seven new CIP proposals to the Department for review and approval as individual filings, much like previously docketed CIPs (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 104, 133, 153, 180; DPU 1-1). In addition to interconnecting the Group Study projects, NSTAR Electric states that CIP upgrades enable future DER interconnections and help address potential electrification and load growth needs in the identified areas (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 374, 415, 417, 419, 422-423). NSTAR Electric's proposed CIPs are summarized in Section VII.C.2.b.iii.(F).

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105 The Standards for Interconnection of Distributed Generation ("DG Interconnection Tariff") defines a "Group Study" as a single study that may be performed at the same time for a Group of proposed DG projects seeking to interconnect with the EPS, instead of each proposed DG project separately filing an Interconnection Application (either sequentially or in parallel as determined by the company). The company may elect to commence a Group Study before or after the Preceding Study, if any, is completed. The Group Study will produce an estimate for the cost of System Modifications to the Company's EPS within +/- 25 percent or, to the extent a Group unanimously requests an extended Group Study ("Extended Group Study"), the Group Study will produce an estimate for the cost of System Modifications to the Company's EPS within +/- 15 percent. An Extended Group Study will be performed only to the extent that a Group requests such a study by unanimous consent using the Extended Group Study Consent Form at Exhibit J. NSTAR Electric, M.D.P.U. No. 55A at § 1.2; National Grid, M.D.P.U. No. 1468 at § 1.2; Unitil, M.D.P.U. No. 375 at § 1.2.

Similarly, National Grid plans to submit three new CIP proposals to the Department for review and approval as individual filings following the completion of its ongoing Group Studies (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 371; DOER 1-2). National Grid's proposed CIPs are summarized in Section VII.C.2.c.iii.(F). National Grid further proposes to submit additional CIP proposals, at its discretion, including investments in distribution substations and feeders, for Group Studies finalized during the 2025 through 2029 ESMP term (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 371; NG-Policy/Solutions-1 (Corrected) at 21-22).

3. Positions of the Parties[106]

a. Long-Term System Planning Program

i. Attorney General

The Attorney General argues that the Department should open a proceeding to investigate and adopt an export tariff framework as the basis for a long-term cost allocation framework for DG interconnection instead of the CIP cost allocation framework established in D.P.U. 20-75-B (Attorney General Brief at 35-37; Attorney General Reply Brief at 8-9).

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106 The Attorney General, DOER, and the Coalition first raise their proposal for a Forecast and Needs Assessment Process ("FNAP") in their reply briefs, which is procedurally deficient. As such, since arguments and comments filed on brief are not evidence in a case inasmuch as there is no opportunity for cross-examination of such comments or for provision of rebuttal testimony and evidence, we do not summarize or address the FNAP in this Order. Boston Gas Company, D.P.U. 23-GSEP-03, at 23 (April 30, 2024); Aquarion Water Company of Massachusetts, D.P.U. 17-90, at 15-16 (2018); Boston Gas Company and Colonial Gas Company, D.P.U. 17-170, at 11 (2018); New England Gas Company, D.P.U.10-114, at 7-8 (2011).

She avers that an export tariff framework would allocate costs to DG customers similarly to how such costs are assessed for distribution system load, and doing so would integrate DG capacity into the grid planning process and facilitate DG growth (Attorney General Brief at 35-36). She argues that an export tariff framework would create a contractual agreement whereby system upgrade costs are allocated to and recovered from exporting facilities, similar to tariffs governing load (Attorney General Brief at 36-37). An export tariff could charge exporting customers for the costs they cause and compensate them for grid services they provide (Attorney General Brief at 37). The Attorney General argues that this export tariff proceeding should begin after the long-term proactive planning process for DG interconnection has concluded (Attorney General Reply Brief at 8-9).

The Attorney General also argues that the Companies should modernize their grid operations in such a manner that prioritizes flexibility (Attorney General Brief at 17-18). She avers that, in particular, flexible interconnection will defer or avoid system upgrades and/or improve usage of the existing distribution system, which could allow the Companies to curtail DG exports to reduce grid congestion (Attorney General Brief at 18). While the Attorney General notes that each company supports flexible interconnection, she argues that the Companies' proposals differ in types of interconnection, control approaches, and timeline (Attorney General Brief at 18-19). She continues that the Companies should collaborate and iterate on their proposals to form a uniform, flexible interconnection plan (Attorney General Brief at 18-19). Such a plan, she contends, should include: (1) standard options across the Companies; (2) flexible interconnection for both load and generation; (3) dynamic hosting capacity; (4) third-party control options; and (5) flexible options regardless of system capacity constraints (Attorney General Brief at 19).

The Attorney General maintains that standard flexible options should include naming conventions, standard analysis granularity, and control strategies in service of providing three types of interconnection offerings: (1) timed connections; (2) export limitation schemes; and (3) load managed connections (Attorney General Brief at 19). She also contends that while flexible interconnection options for generation have been standard, the Companies should plan to enable flexible interconnection options for both generation and EV charging load, particularly because EV load growth will be the primary cause of system upgrades through 2035 (Attorney General Brief at 20-21). Further, the Attorney General asserts that flexible interconnection should account for dynamic hosting capacity ("DHC")[107] and advocates that the Companies collaborate with stakeholders to develop a "DHC roadmap" including different granularities and resolutions for DHC for generation and load facilities, and appropriate third-party control options and technical standards to enable such options (Attorney General Brief at 21-23). She continues that the Companies should provide opportunities for load and generation customers to use their own controls to participate in flexible interconnection, arguing that delegating such options away from the Companies will permit developers to participate more quickly and cheaply (Attorney General Brief at 24). Finally, the Attorney General maintains that the Companies should offer such flexible

[107] DHC accounts for how hosting capacity on the distribution system varies across time (Attorney General Brief at 21-22).

interconnection options regardless of whether there are current constraints on a given feeder or substation (Attorney General Brief at 25). She avers that such an approach is important to fully use the capacity of the distribution system, and that examples in Australia and California prove the concept's worth (Attorney General Brief at 25-26).

On reply, the Attorney General notes the similarities between her recommendations for a long-term system planning process and DOER's Long-Term Forecast and System Plan ("LTFSP") (Attorney General Reply Brief at 7).

ii. DOER

DOER asserts that the Companies failed to provide a long-term planning solution for DG interconnection, contrary to direction from the Department in D.P.U. 20-75-C and disregarding one of the central statutory purposes of the ESMPs, i.e., to increase timely adoption of renewable energy and DERs (DOER Brief at 28-29). DOER stresses that the delays for DG interconnection pose a significant challenge for the Commonwealth to meet its goals for DG deployment, which are critical to achieve GHG emissions reductions (DOER Brief at 28). Therefore, DOER requests that the Department provide clear direction in its ESMP Order to move forward quickly with a long-term planning solution for DG interconnection using the existing body of evidence and stakeholder process (DOER Brief at 29). Further, DOER believes the future process should expand beyond DG interconnection and include new load electrification (e.g., transportation and building electrification loads), and recommends the Department take a broad view when it establishes the scope for a long-term system planning program (DOER Brief at 29-30).

As such, DOER supports the establishment of an LTFSP based on the existing broad stakeholder-supported ideas posed in prior proceedings, including D.P.U. 11-75, D.P.U. 19-55, and D.P.U. 20-75 (DOER Brief at 29-30). DOER recommends that the LTFSP be defined as a ten-year, rolling forecast updated annually to reflect policy development, changing technology costs, and interconnection requests (DOER Brief at 30). DOER further requests that the LTFSP serve as the foundation for all filings seeking recovery of infrastructure decisions and expenses for DG and electrification load interconnection (DOER Brief at 30). DOER requests that the LTFSP fully replace the Provisional Program (DOER Brief at 30, 32).

DOER suggests the following steps to develop the LTFSP framework: (1) commence monthly meetings for a limited time between the Companies' stakeholders through a subcommittee of the GMAC, inclusive of non-GMAC members, providing updates to the Department every six months; (2) establish an annual process and schedule for forecasting interconnection need that includes an opportunity for stakeholder feedback and incorporates quarterly meetings with the GMAC; and (3) incorporate the LTFSP in each ESMP filing and exclude further proposals for recovery through CIPs proposed under the Provisional Program (DOER Brief at 31).

DOER contends that this methodology is consistent with stakeholders' and intervenors' proposals in prior proceedings and argues the process can and should be guided by the GMAC in collaboration with the Companies (DOER Brief at 31-32; DOER Reply Brief at 9). Further, DOER asserts that the initial briefs show strong consensus among intervenors regarding the recommendations for a long-term planning process (DOER Reply Brief at 9).

DOER supports the requests that the Companies develop flexible interconnection options as key strategies within the next ESMP, citing their importance in reducing grid infrastructure investment costs and realizing the Commonwealth's clean energy goals (DOER Reply Brief at 12-13). In particular, DOER highlights the enablement of inverter functionality to address hosting capacity problems cost-effectively and to support dynamic monitoring and control (DOER Reply Brief at 13). DOER also agrees with the Attorney General's recommendation regarding collaboration across the Companies in developing flexible interconnection programs for EVs, citing expedited fleet interconnection and significant load management potential (DOER Reply Brief at 13-14).

iii. Clean Energy Coalition

The Coalition states the proposed ESMPs did not include a proactive, long-term planning process for DG interconnection, in violation of the ESMP statute (CEC Brief at 5; CEC Reply Brief at 6). To remedy this, the Coalition recommends that the Department establish a procedural path for the ESMPs to include proposals for the proactive construction of infrastructure upgrades to enable hosting capacity for DG interconnection (CEC Brief at 6-7). The Coalition requests that the Department direct the Companies, within six months of this Order, to submit proposals for a uniform long-term planning process, including an associated cost allocation methodology, for DG interconnection for Department review and approval (CEC Brief at 11, 15). Additionally, the Coalition asks the Department to direct the Companies, during the six months prior to filing, to work with the Coalition and other key stakeholders (e.g., the Attorney General and DOER) to develop the components of the DG interconnection process and a cost allocation methodology based on the beneficiary pays principle (CEC Brief at 15). Further, the Coalition asks the Department to direct the Companies, within 18 months of this Order, to file proposals for capital investments necessary to enable DG hosting capacity to meet the CECP mandates consistent with the approved long-term system planning process (CEC Brief at 15). Finally, the Coalition asserts that the long-term system planning process, once established, should be used and incorporated into all future ESMP proceedings (CEC Brief at 16).

iv. Companies

In response to the Attorney General's recommendation for the Companies to develop export tariffs as the future model for cost allocation, the Companies argue that cost allocation arrangements for long-term DER integration should be deferred to a generic proceeding (Companies' Joint Reply Brief at 57). In support of their position, the Companies cite to the Department's findings that it was premature to consider any cost allocation arrangements within the seven-month review of the ESMPs (Companies' Joint Reply Brief at 57, citing Interlocutory Order on Scope at 19). Additionally, the Companies disagree with the Coalition's allegations that the Companies did not include a long-term planning process for DG interconnection in violation of the ESMP statute (Companies' Joint Reply Brief at 58). On the contrary, the Companies argue that they included recommendations for a long-term planning process with expanded stakeholder participation (Companies' Joint Reply Brief at 58). As evidence of the expanded stakeholder process, the Companies point to their proposal to arrange small-group meetings with stakeholders in the DG developer community to revise elements of the Group Study process that will inform the long-term planning process (Companies' Joint Brief at 85, citing Tr. 6, at 902-903; D.P.U. 24-10, Exh. DPU-Common 11-1; D.P.U. 24-11, Exh. DPU-Common 11-1; D.P.U. 24-12, Exh. DPU-Common 11-1). As part of developing their proposals for a revised Group Study framework and methodology, the Companies also plan to include the additional factors from the GMAC recommendations identified as driving development of DER and align their proposals where possible (Companies' Joint Brief at 85, citing D.P.U. 24-10, Exh. DPU-Common 11-1; D.P.U. 24-11, Exh. DPU-Common 11-1; D.P.U. 24-12, Exh. DPU-Common 11-1).

b. Provisional Program Extension

i. Attorney General

The Attorney General argues against extending the Provisional Program created under D.P.U. 20-75-B because the Companies provide an isolated, piecemeal approach to what the Attorney General avers should be an equitable, stable, and scalable long-term system plan (Attorney General Brief at 33). She argues that the Companies have not addressed an alternative cost allocation framework, but rather continue to propose CIPs using the cost allocation paradigm propounded through the D.P.U. 20-75-B docket (Attorney General Brief at 34). The Attorney General renews her arguments from D.P.U. 20-75-B that the Companies' CIP cost allocation methodology inappropriately shifts costs to ratepayers and exposes them to undue risk (Attorney General Brief at 35). Finally, the Attorney General reiterates her argument that the CIPs do not possess a clear framework that is transparently, efficiently, and consistently replicable (Attorney General Brief at 35). Therefore, the Attorney General opposes continuation of the CIP cost allocation paradigm (Attorney General Reply Brief at 8).

ii. DOER

DOER emphasizes the "unacceptable delays" in interconnection of DG in the Commonwealth (DOER Brief at 28). DOER argues that the CIP process is time intensive for all parties, is reactive, and was never intended as a long-term solution (DOER Brief at 61). DOER asserts that the extension of the Provisional Program should not be considered because the Companies excluded a proposal for a long-term solution in their ESMPs, which is contrary to the Department's direction in Order D.P.U. 20-75-C (DOER Brief at 28-29, 61). However, DOER does not oppose continuation of the Provisional Program if the Department deems it the best approach on a short-term basis to interconnect the DG projects currently waiting in the queue of Group Studies (DOER Brief at 61-62). If the Provisional Program is extended, DOER stresses that the Department should simultaneously ensure rapid progress on a long-term system planning process, including DG interconnection (DOER Brief at 28, 62). In addition, DOER requests the Department include measures in its ESMP Order that would streamline the process under the Provisional Program to reduce participants' administrative burdens and expedite the review process for each new CIP (DOER Brief at 62).

iii. Clean Energy Coalition

The Coalition recommends the Department extend the Provisional Program on an interim basis until the long-term planning process for DG interconnection is implemented (CEC Brief at 7). While the Coalition opposes the use of the Provisional Program paradigm as the basis for the long-term proactive planning process, the Coalition asserts that extending the Provisional Program in these proceedings to accommodate additional CIPs is an essential interim step to preserve the viability of the DG industry in Massachusetts (CEC Brief at 8). Absent an extension, the Coalition contends, the interconnection process will default to cost causation principles and cause projects to lose their financial viability (CEC Brief at 8-9).

Additionally, the Coalition requests that the Provisional Program extension include a streamlined submission and review process to avoid delays (CEC Brief at 10). Specifically, the Coalition recommends including the following as part of the streamlined CIP process: (1) the maximum CIP fee should continue to be $500 per kW; (2) the Department should continue to adjudicate CIP proceedings, proposals should be filed simultaneously, and proceedings should be consolidated; (3) the Department should establish a procedural approach and standards of review that avoid repeated litigation of issues; (4) any upgrades proposed in a Group Study and approved by the Group Study members should be presumed reasonable, subject to rebuttal; (5) if a proposed cost allocation methodology has been previously approved by the Department, it should be presumed reasonable, subject to rebuttal; (6) if no evidence is presented to rebut the presumptions described above, the Department should approve the CIP as soon as reasonably possible; (7) if evidence is presented that merits further adjudication of the rebuttable presumptions described above, the Department should set an expedited procedural schedule; (8) the Department should require the Companies to file any eligible CIP proposal in the extended Provisional Program within 40 business days of the completion of a distribution and transmission (if applicable) impact study for the associated Group Study;[108] (9) a CIP in the extended Provisional Program should include all eligible electric power system ("EPS") upgrades identified for a single Group Study and any reasonable additional infrastructure upgrades needed to expand the enabled DG hosting capacity of the interconnection solution for the Group Study for the benefit of the Commonwealth in meeting its clean energy objectives; and (10) in extending the Provisional Program, the Department should elaborate on requirements for streamlining interconnection of future enabled DG for all approved CIPs, consistent with the Marion-Fairhaven Order (CEC Brief at 11).

iv. Companies

The Companies agree with the Coalition's recommendation to extend the Provisional Program on a streamlined, interim basis until the long-term planning process is implemented (Companies' Joint Reply Brief at 60). In the absence of an extension, the Companies assert that ending the Provisional Program without another regulatory construct in place would effectively halt DG interconnections in Massachusetts (Companies' Joint Reply Brief at 60).

108 The Coalition also recommends that the Department clearly define the completion dates for any applicable impact studies (CEC Brief at 11).

4. Analysis and Findings

a. Introduction

Pursuant to Section 92B, the Companies are required to include a proactive, long-term system planning process for DER[109] interconnection as part of their ESMP filings. However, the Department determined that pre-approval of costs and any proposed cost allocation methods for CIPs is beyond the scope of the Department's seven-month review of the ESMPs. Interlocutory Order on Scope at 19. As such, the Department clarified that any CIPs proposed as components of a company's planning solutions in their ESMP would be analyzed in these proceedings in the context of the company's particular forecasting methods and net benefits analysis only. Interlocutory Order on Scope at 19. Further, consistent with the strategic plan framework discussed above (see Section IV.C.3.), the Department reviews whether and to what extent the Companies have considered alternative approaches to financing their proposed and future CIPs, including cost allocation arrangements and the potential benefits of those alternatives, as part of their overall planning solutions. Interlocutory Order on Scope at 19-20. Accordingly, below, we address the Companies'

109 The Department uses the term DER rather than DG throughout our analysis and findings sections of this Order for the sake of consistency, since DER appears more frequently throughout Section 92B. However, we intend for DER to have the same meaning as DG in the CIP context consistent with NSTAR Electric's and National Grid's testimony in past CIP proceedings where witnesses for both Companies testified that DG and DER are used interchangeably. See, e.g. NSTAR Electric Company, D.P.U. 22-47 (Marion-Fairhaven), Tr. 2, at 255-256; National Grid, D.P.U. 22-61 (Shutesbury), Tr. 2, at 267-270. In the positions of the parties sections of this Order, we refer to the terms used by the parties.

proposals to defer the review of additional alternative approaches to financing the long-term integration of DER to a generic docketed proceeding and to extend the Provisional Program.

b. LTSPP for the Interconnection of DERs

In D.P.U. 20-75, the Department investigated the possibility of establishing an optimal long-term system planning framework (or LTSPP) to serve the public interest, provide benefits to ratepayers, enable effective interconnection of DER, support the Companies' infrastructure investment in a safe, reliable, and resilient EPS, and promote the Commonwealth's energy policies. D.P.U. 20-75-C at 3-4. Upon passage of the 2022 Clean Energy Act, however, the Legislature enacted a new process and requirements for long-term system electric planning that effectively replaced the Department's investigation in D.P.U. 20-75. St. 2022, c. 179, § 53; G.L. c. 164, § 92B(a). In consideration thereof, the Department determined our investigation of an LTSPP moot, and therefore suspended our investigation, and closed the proceeding. D.P.U. 20-75-C at 3. For the reasons discussed below, the Department finds that the Companies have complied with the statutory requirements applicable to the LTSPP for the interconnection of DERs.

Pursuant to Section 92B(a)(ii), the Companies are required to file ESMPs that proactively upgrade the distribution and, where applicable, transmission systems to enable increased, timely adoption of renewable energy and DERs, among other things. In recognition of this statutory requirement, the GMAC recommended that, as part of their ESMP filings, the Companies propose a proactive LTSPP process for the interconnection of DERs, utilizing the analysis process proposals and subsequent comments submitted in

D.P.U. 20-75 (D.P.U. 24-10, Exh. ES-Policy/Solutions-2, at 2; D.P.U. 24-11, Exh. NG-Policy/Solutions-2, at 2; D.P.U. 24-12, Exh. UN-Policy/Solutions-2, at 2). While the Companies' ESMPs contain recommendations for process to develop LTSPPs, the ESMPs do not include detailed proposals for LTSPPs themselves (D.P.U. 24-10, Exhs. ES-Policy/Solutions-2, at 16-19; DPU-Common 11-1; DPU-Common 11-2; DPU-Common 11-3; D.P.U. 24-11, Exhs. NG-Policy/Solutions-2, at 16-19; DPU-Common 11-1; DPU-Common 11-2; DPU-Common 11-3; D.P.U. 24-12, Exhs. UN-Policy/Solutions-2, at 16-19; DPU-Common 11-1; DPU-Common 11-2; DPU-Common 11-3). D.P.U. 20-75-C at 3-4. Multiple intervenors contend that the Companies' ESMPs comply with neither Section 92B nor the GMAC's recommendation given their failure to include detailed LTSPP proposals (Attorney General Brief at 33; CEC Brief at 5-7, 12-13; DOER Brief at 28-29). The Companies respond that the seven-month statutory deadline[110] would prove difficult for the development of a proactive distribution system planning process and for the subsequent review and adjudication by the Department (Tr. 6, at 902-903; D.P.U. 24-10, Exh. ES-Policy/Solutions-2, at 16-19; D.P.U. 24-11, Exh. NG-Policy/Solutions-2, at 16-19; D.P.U. 24-12, Exh. UN-Policy/Solutions-2, at 16-19). Instead, the Companies propose to work with interested stakeholders to develop LTSPP proposals utilizing the analysis, process, proposals, and comments submitted in D.P.U. 20-75 (D.P.U. 24-10, Exh. ES-Policy/Solutions-2; D.P.U. 24-11,

[110] Section 92B(d) states in pertinent part that "[t]he department shall approve, approve with modifications or reject the plan within [seven] months of submittal."

Exh. NG-Policy/Solutions-2; D.P.U. 24-12, Exh. UN-Policy/Solutions-2; D.P.U. 24-10/ D.P.U. 24-11/D.P.U. 24-12, Exh. ES-Policy/Solutions-2/NG-Policy/Solutions-2/ UN-Policy/Solutions-2, at 16-19).

Given the extensive information required in the ESMPs coupled with the limited time between the passage of the 2022 Clean Energy Act and the Companies' corresponding ESMP submissions—in addition to the seven-month statutory deadline—we find the Companies' recommendation to develop LTSPP proposals following the initial seven-month ESMP process to be reasonable. Notwithstanding, the Department emphasizes the need for the Companies to develop LTSPP proposals following the issuance of this Order in a timely manner so as not to delay progress towards accomplishing the Commonwealth's energy and climate goals. D.P.U. 20-75-C at 1 (among the goals of that proceeding was development of "optimal solutions for enhancing system planning to meet the Commonwealth's energy and climate goals"); 2025/2030 CECP at 68; 2050 CECP. Understanding additional stakeholder engagement and collaboration may cause a short-term delay in the filing of the Companies' LTSPP proposals with the Department, such a successful collaboration will lead to an informed and comprehensive filing, allowing the Department to conduct a more efficient review of the Companies' LTSPP proposals. Cf., Establishing Guidelines for Municipal Aggregation Proceedings, D.P.U. 23-67-A (July 9, 2024) (approving Municipal Aggregation Guidelines negotiated and filed by joint petitioners following an extensive stakeholder process). Further, among the parties that addressed the concept of an LTSPP stakeholder process on brief, there is unanimous support that such a process will aid in the development of the Companies' LTSPP proposals (Attorney General Brief at 49-50; CEC Brief at 14-15; Companies' Joint Reply Brief at 84-85; DOER Brief at 28-32). To that end, the Department directs the Companies to convene a stakeholder working group and to facilitate a stakeholder process consistent with the directives outlined herein.

c. LTSPP Stakeholder Process

The Department directs the Companies to coordinate an LTSPP stakeholder group no later than October 1, 2024. The Companies shall organize a six-month process (i.e., beginning in October 2024 and concluding in March 2025) with bi-monthly stakeholder meetings, at a minimum (Attorney General Brief at 9; CEC Brief at 15; Companies' Joint Brief at 98; DOER Brief at 31). By February 3, 2025, the Companies shall submit an interim status report to the Department that summarizes: (1) a list of stakeholder meetings and attendees; (2) the status of any discussions with stakeholders and the process by which such discussions occurred; and (3) a summary of all issues on which the Companies and stakeholders have reached consensus. See Second Grid Modernization Plans (Track 2) at 325-329. The Companies shall submit to the Department a final status report, along with final consensus proposals and a detailed summary of areas of disagreement by April 4, 2025. The Department will then, as soon as practicable after our review of the final report, direct next steps.

To ensure an effective and efficient process, the Companies shall: (1) designate company personnel to be responsible for oversight and management of the LTSPP stakeholder process; (2) recognize members of the GMAC and all entities on the service list for these ESMP proceedings as invitees to the stakeholder working group; (3) ensure each stakeholder participant receives all correspondence related to the stakeholder working group and process; and (4) maintain a stakeholder participant distribution list and ensure that all company communications related to the LTSPP Stakeholder Process are circulated to that list (Attorney General Brief at 9; CEC Brief at 15; Companies' Joint Brief at 98; DOER Brief at 31). See Second Grid Modernization Plans (Track 2) at 325-329.

Further, the Department identifies the following topics for consideration in the LTSPP stakeholder process: (1) factors identified by the GMAC and the Companies that drive development of DG by enabling hosting capacity in specific locations that benefit the Commonwealth as a whole and further the state's clean energy objectives (e.g., availability of technically developable land for solar,[111] land cost, proximity to existing transmission and distribution infrastructure, upgrade costs, and forecasted electrification demand to co-optimize infrastructure deployment for solar and electrification enablement, where feasible) (D.P.U. 24-10, Exh. DPU-Common 11-1, D.P.U. 24-11, Exh. DPU-Common 11-1; D.P.U. 24-12, Exh. DPU-Common 11-1); (2) the role of flexible interconnection in deferring or negating the need for certain system upgrades and/or improving the operations of the current distribution system (Attorney General Brief at 18-29; CEC Brief at 13 n.49; DOER Reply Brief at 12-14); (3) cost-allocation methodology (e.g., a Common System Modification

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[111] DOER published the Massachusetts Technical Potential of Solar Study on July 6, 2023. See Massachusetts Technical Potential of Solar Study (July 6, 2023), available at https://www.mass.gov/doc/technical-potential-of-solar-in-massachusetts-report/download (last visited August 29, 2024).

fee, export tariff, etc.) (Attorney General Brief at 10-17; Attorney General Reply Brief at 8-9; CEC Brief at 15 n.53; D.P.U. 20-75, Hearing Officer Memorandum, Discussion 3 (June 15, 2022)); and (4) the process for changing or updating the LTSPP over time (D.P.U. 20-75, Hearing Officer Memorandum, Discussion 2 (June 15, 2022)).

Finally, the Coalition requests that the Department direct the Companies to file proposals for a uniform long-term planning process within six months of this Order, proposals for capital investments necessary to enable DER hosting capacity to meet the Commonwealth's CECP mandates within 18 months, and to direct the incorporation of a long-term planning process into all future ESMP proceedings (CEC Brief at 15-16). The Department anticipates addressing these future process recommendations upon conclusion of the six-month LTSPP Stakeholder Process.

d. Provisional Program Extension

i. Extension

As an initial matter, the Department did not review the proposed ESMP CIPs for the purposes of pre-approval of costs or for approval of any cost allocation methods; such review is beyond the scope of this seven-month proceeding. Interlocutory Order on Scope at 19. Rather, the Department focused its review on whether and to what extent the Companies have considered alternative approaches to financing their proposed and future CIPs, including cost allocation arrangements and the potential benefits of those alternatives, as part of their overall planning solutions. Interlocutory Order on Scope at 19-20. The Department considers the Companies' proposal to extend the Provisional Program to be an integral component of this review.

To determine whether an extension of the Provisional Program is warranted, we first examine the requirements of Section 92B. Per the statute, the Companies are required to include detailed descriptions of (1) improvements to the distribution system that will enable customers to express preferences for access to renewable energy resources, (2) improvements to the transmission or distribution system to facilitate achievement of the statewide GHG emissions limits under Chapter 21N, and (3) alternative approaches to financing proposed investments including, but not limited to, cost allocation arrangements between developers and ratepayers, among other things. G.L. c. 164, § 92B(b)(iv), (vi), (ix). The purpose of the Provisional Program is to create a pathway for DER projects currently in the interconnection queue that may not be able to take service due to significantly higher than historical interconnection costs. D.P.U. 20-75-B at 2. The provisional framework allows the Companies to file certain EPS infrastructure upgrade proposals with the Department that will enable DERs to safely and reliably interconnect to the company EPS while limiting the costs allocated to affected Interconnecting Customers. D.P.U. 20-75-B at 2. Both NSTAR Electric and National Grid included descriptions of CIPs in their respective ESMPs that, if approved, would enable customers to express preferences for access to renewable energy resources, facilitate the interconnection of DER, which would help to achieve statewide GHG emissions limits under Chapter 21N of the General Laws, and result in alternative cost allocation arrangements between developers and ratepayers, thus satisfying the requirements of Section 92B(b)(iv), (vi), and (ix) (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 374-378, 399-402, 415-425; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 320-321, 332-333, 339-340).[112]

Next, we examine the effects of not extending the Provisional Program. Without extending the Provisional Program to allow for CIP proposals to be filed beyond the original Affected Group Studies,[113] financing Common System Modifications[114] triggered by DERs seeking to interconnect to the Companies' EPS would be the sole responsibility of the interconnecting Group Study members; in other words, the cost causation principle would

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112 The quantity and size of the DER interconnections on Unitil's distribution system have not driven the need for Group Studies or the implementation of a CIP under the Provisional Program. In the future, however, in the event Unitil needs to conduct a Group Study that results in significant capital investment, the company proposes to apply the CIP approach approved by the Department in D.P.U. 20-75-B (D.P.U. 24-12, Exh. UN-Policy/Solutions-1, at 90).

113 The following Affected Group Studies were identified in Provisional System Planning Program:

For National Grid: (1) Ayer-Clinton; (2) Barre-Athol; (3) Gardner-Winchendon; (4) Millbury-Grafton; (5) MPL-East; (6) MPL-Northwest; (7) Shutesbury; (8) Spencer-Rutland; and (9) Webster-Southbridge- Charlton.

For NSTAR Electric: (1) Marion-Fairhaven; (2) Plymouth; (3) Cape Cod; (4) Freetown; (5) Dartmouth-Westport; (6) New Bedford; and (7) Plainfield-Blandford.

D.P.U. 20-75-B at 26-27 n.27

114 Per the DG Interconnection Tariff, "Common System Modification" shall mean any System Modification that is required for more than one Interconnecting Customer's Facility as determined by the Company. NSTAR Electric, M.D.P.U. No. 55A at § 1.2; National Grid, M.D.P.U. No. 1468 at § 1.2; Unitil, M.D.P.U. No. 375 at § 1.2

apply (D.P.U. 24-10, Exh. DPU-Common 8-1; D.P.U. 24-11, Exh. DPU-Common 8-1).[115] Group Study members throughout National Grid's and NSTAR Electric's service territories continue to be presented with Common System Modification costs that are significantly higher than historical costs (D.P.U. 24-10, Exh. DPU-Common 8-1; D.P.U. 24-11, Exh. DPU-Common 8-1). As such, the Department reiterates its concern that without an alternative to the cost causation model, large-scale DER development will stall and, as a result, limit our ability to achieve the Commonwealth's clean energy goals and the statutory objectives of Section 92B (D.P.U. 24-10, Exh. DPU-Common 8-1; D.P.U. 24-11, Exh. DPU-Common 8-1). See D.P.U. 20-75 (providing a history of the Department's investigations into interconnection of DER). Given that the establishment of any future LTSPP will take time and that there are DER projects currently in the queue that are unable to interconnect due to prohibitively high interconnection costs, we view the Companies' proposal to extend the Provisional Program as a necessary policy bridge to the establishment

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115 In setting rates for utility service and otherwise providing for the recovery of costs by utilities, the Department applies the cost causation principle (i.e., cost responsibility must follow cost incurrence). See, e.g., Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 167 (2009); Gas Unbundling, D.T.E. 98-32-B at 31 (1999); Boston Gas Company, D.P.U. 96-50 (Phase I), at 133-134 (1996); Electric Industry Restructuring, D.P.U. 96-100, at 51 (1996); Boston Gas Company, D.P.U. 93-60, at 331-337, 410, 432 (1993); Boston Edison Company, D.P.U. 1720, at 114 (1984); Generic Investigation of Rate Structures, D.P.U. 18810, at 14 (1977). In instances of public policy or where other discernable beneficiaries are identified, costs might be assigned and recovered from ratepayers other than just the entity responsible for the cost incurrence. D.P.U. 20-75, at 3 (2020); see, e.g., transition costs, G.L. c. 164, § 1G, energy efficiency, G.L. c. 25, § 19(a), renewable energy, G.L. c. 25, § 20(a), or net metering, G.L. c. 164, § 139(c).

of an LTSPP. Therefore, upon review and consideration of the record, including Section 92B requirements and the Provisional Program objectives, the Department finds that the Companies' proposal to extend the Provisional Program is reasonable.

While the Department shares the Attorney General's desired outcome for a long-term solution, which we address above, we are not persuaded by her opposition to a Provisional Program extension. We disagree that the CIP framework is not replicable (Attorney General Brief at 35). On the contrary, the Department's adjudication of eleven CIPs demonstrates the process is reproducible. See D.P.U. 22-47, D.P.U. 22-51 through D.P.U. 22-55, D.P.U. 22-170, D.P.U. 23-06, D.P.U. 23-09, and D.P.U. 23-12. The Department, therefore, extends the Provisional Program, subject to the directives outlined below such that the Companies may file the proposed CIPs identified in NSTAR Electric's and National Grid's ESMPs, as well as any potential future proposed CIPs, until the establishment of an LTSPP or as otherwise directed by the Department.

As part of our decision, the Department finds it necessary to establish certain parameters for the continuation of the Provisional Program to provide clarity and direction on the transition to an LTSPP. Additionally, based on our experience adjudicating CIP proposals, our desire to make those proceedings more efficient, and in response to recommendations to streamline the review of any future CIPs, the Department finds it necessary to clarify the existing eligibility criteria and provide guidance expanding the filing requirements.

ii. Eligibility Criteria for CIPs

With the goal of providing regulatory certainty, minimizing administrative burden, and preventing unnecessary delay, the Department identified five criteria in our establishment of the Provisional Program. D.P.U. 20-75-B at 34. Specifically, CIP proposals must: (1) be limited in scope to specific EPS upgrades and Affected Group Studies; (2) enable the interconnection of multiple DER facilities; (3) include a maximum CIP Fee of $500 per kW; (4) identify the specific geographic area served by the EPS upgrades constructed as part of a CIP and demonstrate that the amount of Enabled DER likely will be interconnected in that geographic area within the proposed Rate Recovery Period; and (5) demonstrate that aspects of the construction timeline within the Distribution Company's control can be completed within a maximum of four years from the conclusion of the Department's adjudicatory process. D.P.U. 20-75-B at 34-39.

The Department now supplements the existing eligibility criteria based on significant experience gained through CIP adjudications.[116] In doing so, the Department seeks to provide additional guidance regarding criteria (3), maximum CIP Fee of $500 per kW, and (5), construction timeline, rather than direct substantive changes. Specifically, for criterion (3), we expect that future CIP proposals will include a maximum CIP Fee of $500 per kW,

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[116] The eleven Provisional Program CIP dockets are D.P.U. 22-47 (Marion-Fairhaven); D.P.U. 22-51 (Freetown); D.P.U. 22-52 (Plainfield-Blandford); D.P.U. 22-53 (Dartmouth-Westport); D.P.U. 22-54 (Plymouth); D.P.U. 22-55 (Cape Cod); D.P.U. 22-61 (Shutesbury); D.P.U. 22-170 (Monson-Palmer-Longmeadow East); D.P.U. 23-06 (Gardner-Winchendon); D.P.U. 23-09 (Barre-Athol); and D.P.U. 23-12 (Spencer-Rutland).

unless otherwise accompanied by sufficient documentation demonstrating (a) an explanation for and the factors responsible for a CIP Fee in excess of $500 per kW, and (b) the willingness of developers to proceed with their projects at the higher CIP Fee. The Department finds that the $500 per kW CIP Fee threshold continues to be a reasonable limit. Further, for eligibility criterion (5), we expect that future CIP proposals will demonstrate that aspects of the construction timeline within the Distribution Company's control, including use of commercially reasonable efforts where practicable, can be completed within a maximum of four years from the conclusion of the Department's adjudicatory process. D.P.U. 22-52 through D.P.U. 22-55 at 98; D.P.U. 22-47 at 70; D.P.U. 20-75-B at 39.

iii. CIP Proposals Expected Process and Filing Requirements

To facilitate an efficient and timely review of CIP proposals, the Department established minimum filing requirements in the Provisional Program. As provided in D.P.U. 20-75-B at 31-32, 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; (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; (4) projected bill impacts; (5) a description of how the CIP will benefit ratepayers and aligns with cost-efficiently meeting the Commonwealth's clean energy policies; and (6) explanation of how the CIP will affect low-income and EJ populations, including describing any projects in the CIP that will be constructed in an EJ population. D.P.U. 20-75-B at 31-32.

To further streamline and promote the efficient and timely review of CIPs, the Department seeks to provide further guidance on the minimum filing requirements (CEC Brief at 13). The Department has identified a need to expand upon the filing requirements with the aim to provide for an accelerated procedural schedule that meets stakeholders' expectations and satisfies the Department's need for a comprehensive evidentiary record (CEC Brief at 13). As such, the Department directs the Companies to include the information indicated in the Provisional Program Extension Filing Checklist attached to this Order as Appendix A, in addition to a completed copy of the checklist itself, with any future CIP proposal filing. In advance of future filings before the Department, we request that the Companies consult this guidance, including conferring with DER applicants, where relevant, in the development of their CIP proposals. Along with our clarifications to the eligibility criteria, the Department expects these updates to the Provisional Program filing requirements will allow for a more efficient and timely process.

Further, we appreciate the intervenors' recommendations for streamlining the CIP process and address those not already discussed above (DOER Brief at 62; CEC Brief at 12-13). First, the Coalition recommended that the Department encourage simultaneous filings of CIP proposals, to the extent practicable (CEC Brief at 12-13). The Department encourages the Companies to file CIP proposals simultaneously to the greatest extent possible so that proceedings can be consolidated, consistent with the past two simultaneous filings made by National Grid and NSTAR Electric. See, e.g. D.P.U. 22-52 to D.P.U. 22-55 and D.P.U. 22-170, D.P.U. 23-06, D.P.U. 23-09, and D.P.U. 23-12. Second, while this is not the appropriate forum to establish an alternative standard of review or rebuttable presumption, we will consider these recommendations in the adjudication of any forthcoming CIP proposal filed pursuant to the Provisional Program extension and will otherwise continue to seek additional ways to further streamline our review of CIP proposals (CEC Brief at 12-13). Third, the Department agrees with the Coalition's recommendation to clearly define the Completion Date for any Group Study with impact studies completed prior to issuance of the Department's Order in the instant proceedings (CEC Brief at 13). As such, September 19, 2024, the day after the end of the appeal period of this Order, shall serve as the Completion Date for any Group Study with impact studies completed prior to the issuance of this Order.

Consistent with Provisional System Planning Program, the Companies have ten business days from the Completion Date to determine if any EPS upgrades identified for a Group Study will be the subject of a CIP and to inform the Group Study members and the Department. D.P.U. 20-75-B at 30-31. Further, the Companies have 40 business days from the Completion Date to file any such eligible CIP proposals with the Department for review. D.P.U. 20-75-B at 31. However, if one or more Group Study impact studies have not concluded but are nearing completion and the Company determines that submitting the CIP proposals after the 40-business day deadline will allow for a more efficient and consolidated process, the Company may file a letter with the Department prior to the 40-business day deadline seeking a reasonable extension. Such a letter shall be filed in the relevant Company ESMP docket and shall include: (1) the date the Company expects to make the consolidated filing; (2) the expected date the impact study or studies will be completed; (3) the Group Studies to be included in the consolidated filing; (4) evidence that the Company has communicated its plan to seek a filing extension with Group Study members; and (5) reasoning to support the need for the extension. Finally, consistent with our findings in D.P.U. 22-47 and D.P.U. 22-52 to D.P.U. 22-55, a CIP filed pursuant to the Provisional Program extension should consist of eligible EPS upgrades identified for a single Group Study and reasonable additional infrastructure upgrades that are necessary to fully utilize the enabled DER hosting capacity, beyond that of the original Group Study, in furtherance of meeting the Commonwealth's energy objectives (CEC Brief at 13).

Thus, the Department extends the Provisional Program such that the Companies may file CIP proposals for Group Studies until the establishment of an LTSPP, or otherwise directed by the Department, so long as the proposals meet the eligibility criteria, as supplemented in this Order, include the information detailed in Appendix A, and are accompanied by a completed checklist.

G. Alternatives to Financing Proposed Investments

1. Introduction

The Companies' alternatives to financing their proposed ESMP investments include developer fees collected through the Provisional Program as well as state and federal grants, loans, and tax incentives (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 441-442; ES-Policy/Solutions-1, at 143; DP.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 370; NG-Policy/Solutions-1 (Corrected) at 117; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 168; UN-Policy/Solutions-1, at 91). The Department addresses the Companies' proposals regarding the Provisional Program in Section VII.F.4. In this Section, the Department reviews the Companies' proposals to leverage government financing opportunities and the intervenors' positions regarding the alternatives to financing included in the Companies' ESMPs.

NSTAR Electric, National Grid, and Unitil each: (1) propose to pursue state and federal funding for ESMP investments, such as federal grants available through the IIJA; and (2) describe its efforts to obtain alternative financing for the current plans (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 441-442; ES-Policy/Solutions-1, at 143; DP.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 370; NG-Policy/Solutions-1 (Corrected) at 117; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 168; UN-Policy/Solutions-1, at 91). Specifically, in cooperation with federal and state partners, NSTAR Electric applied for a federal grant to incorporate NSTAR Electric's existing 24.9 MW ESS in Provincetown with 7.5 MW of existing, aggregated, and dispatchable behind-the-meter assets to create an advanced microgrid (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 442; ES-Policy/Solutions-1, at 143). In addition, National Grid received a $49.6 million federal grant for a smart grid technology project, $23.5 million of which will support platform investments, job training, and community benefits in Massachusetts (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 37, 261, 371). National Grid also proposes to apply for federal low-interest loans available through the Inflation Reduction Act, P.L. 117-169 (2022) ("IRA") to reduce cost burdens on ratepayers (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 371). Lastly, Unitil states that it received a grant award from MassCEC for its Townsend substation ESS project and that it will continue to review federal and state funding opportunities (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 121, 168).

2. Positions of the Parties

a. GECA

GECA maintains that Section 92B requires the Companies' ESMPs to include a cogent depiction of costs associated with investments that have been reviewed, are under consideration, or have been approved by the Department previously, including alternative approaches to financing said investments (GECA Brief at 8). GECA argues that the Companies did not provide this information in their ESMPs in contravention of Section 92B (GECA Brief at 8).

b. Companies

The Companies restate their commitment to pursue federal and state funding opportunities for ESMP investments as they become available (Companies' Joint Brief at 87). The Companies aver that any federal or state funding awarded to the Companies will accelerate benefits to customers consistent with their ESMPs (Companies' Joint Brief at 87).

3. Analysis and Findings

As discussed elsewhere in this Order, the costs of the programs necessary to further the Commonwealth's critical energy policy goals are expected to increase significantly in the near term and beyond. The Companies identify opportunities to mitigate the cost increases borne by ratepayers by applying for federal and state grants, low interest loans, and tax incentives (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 441-442; ES-Policy/Solutions-1, at 143; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 370; NG-Policy/Solutions-1 (Corrected) at 117; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 168; UN-Policy/Solutions-1, at 91). We find that the Companies' ESMPs include some information on alternatives to financing their proposed ESMP investments in compliance with Section 92B. With five years to prepare for the next ESMP filings, the Department expects the Companies to submit a far more robust presentation of alternatives to financing ESMP investments than the Companies sought and secured during the 2025-2030 ESMP term and will seek during the 2030-2035 ESMP term,[117] as well as calculations of the actual and estimated ratepayer benefits resulting from those efforts. The Department directs the Companies to proactively submit applications for available grants, tax incentives, and low-cost financing programs, which requires investigation and tracking of funding availability and deadlines, allocating sufficient resources to develop and submit applications, and planning for cost-share requirements. The Department's approval of the Companies' ESMPs is based on the understanding that the Companies will aggressively seek to minimize ESMP costs for ratepayers through diligent pursuit of these alternative approaches to financing investments.

The Department also takes notice of the time-sensitive requirements of the federal grant, loan, and tax funding made available through the federal IIJA and IRA. These funds

[117] In Section VII.A.4., above, the Department established the first ESMP term for the period July 1, 2025, through June 30, 2030, and the second ESMP term for the period July 1, 2030, through June 30, 2035.

are subject to recurring application cycles, and their future availability depends on continued support from Congress. Further, coordinated applications from the Companies, state and local agencies, and other for-profit and not-for-profit entities have proven likelier to win awards. In sum, competing effectively for these federal funds requires concerted, coordinated action by the Companies and their partners in Massachusetts. Accordingly, in each of their biannual reports, the Department directs the Companies to include summaries of federal grant, loan, and tax funding the Companies have sought during the preceding reporting period and their planned funding sources during the following reporting period. These summaries shall describe the Companies' efforts to coordinate with the partner entities noted above and any impediments to such efforts. Further, the Companies shall identify any barriers encountered by the Companies to obtaining funds and recommend ways the Department can support receipt of grants, loans, and tax incentives.

Regarding GECA's position, we find that the Companies' ESMPs include summaries of investments that have been reviewed, are under consideration, or have been approved by the Department previously, including alternative financing for Provisional Program projects through CIP fees and grants that the Companies have applied for and/or received (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 300-311, 442; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 370-371; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 121, 168). Accordingly, we disagree with GECA's contention that the information was not provided. To promote administrative efficiency and allow for informed participation in future ESMP proceedings, the Department directs the Companies to ensure that their summaries of the alternative approaches to financing investments that have been reviewed, are under consideration, or have been approved by the Department previously are clear and conspicuous in future ESMPs. G.L. c. 164, § 92B(c).

H. Stakeholder Engagement and Equity

1. Introduction

The Massachusetts Clean Energy and Climate Plan for 2025 and 2030, released three months prior to the 2022 Clean Energy Act establishing the electric sector modernization plan requirements, names equity as a key consideration in the implementation of the state's clean energy policies. Section 92B(c)(iii) requires each company to conduct technical conferences and a minimum of two stakeholder meetings. The Companies maintain that they complied with the requirements of Section 92B(c)(iii), and also propose to incorporate into their distribution system planning an equity framework applicable to ESMP and non-ESMP investments to guide stakeholder engagement efforts and assist in addressing the needs and concerns of their customers and the communities they serve (Tr. 7, at 1029, 1035-1036; D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 36-58; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 38-58; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 36-46). The Companies propose a common overall equity framework and additional company-specific elements.

2. Description of Company Proposals

a. Common Equity Framework

The Companies' equity framework defines equity as engaging all stakeholders, including its customers and communities, with respect and dignity while working toward fair and just outcomes, especially for those burdened with economic challenges, racial inequality, negative environmental impacts, and justice disparities (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 38; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 41; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 37). For the three primary components of the Companies' equity framework, namely, procedural, distributional, and structural equity, the Companies propose to adopt the American Council for an Energy-Efficient Economy's definitions (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 38; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 41; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 37-38). Specifically, the Companies propose to define: (1) procedural equity as creating transparent, inclusive, and accessible processes for engagement, such that stakeholders and communities impacted by energy projects and programs are given necessary information and opportunity to participate in processes to inform project siting, development, and implementation; (2) distributional equity as enabling a more equitable distribution of the benefits and burdens associated with the clean energy transition; and (3) structural equity as developing processes and decisions that are informed by historical, cultural, and institutional dynamics and structures that have led to inequities (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 38; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 41; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 37-38).

To inform stakeholder engagement efforts involving proposed electric distribution system infrastructure projects (e.g., new substations and substation expansions) brought before the Department and/or the EFSB,[118] the Companies propose to develop a CESAG, with membership consisting of three representatives from the electric distribution companies, five representatives from various CBOs, and one representative from an environmental or equity advocacy organization, for a total of nine members, and co-chaired by an electric distribution company representative and a CBO representative both of whom are elected by CESAG members (Tr. 7, at 972-973; D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 36-37, 53, 56, 664; ES-Stakeholder-1, at 10-11; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 24, 39, 56; NG-Stakeholder-1, at 12; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 43-44; UN-Stakeholder-1, at 9). The CESAG charter and by-laws would be developed by the electric distribution company representatives and CBO representatives, with input from the environmental or equity representative (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 53; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 56; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 44). The Companies propose to engage a professional

118 The EFSB has jurisdiction to approve, approve with conditions, or deny proposals to construct and operate major energy infrastructure in Massachusetts. Such facilities include large power plants, electric transmission lines, ancillary facilities, intrastate natural gas and oil pipelines, and storage facilities for natural gas (over 25,000 gallons) and fuel oil (over 500,000 barrels). G.L. c. 164, §§ 69G, 69H.

facilitator for CESAG meetings to be held twice per month for the first four months of its inception to develop a statewide community engagement framework to be employed prior to the filing of electric distribution system infrastructure projects with the Department and/or the EFSB (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 7-8, 36-37, 54, 56; DPU-Common 2-6; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 24, 39, 56-57; DPU-Common 2-6; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 44; DPU-Common 2-6). The Companies recommend that the Department open a generic proceeding to consider reasonable compensation for CBO members of the CESAG (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 54; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 57; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 44).

To ensure direct benefits for communities that host electric distribution system infrastructure, the Companies propose to enter into community benefits agreements ("CBAs") with host communities on a case-by-case basis (Tr. 7, at 975-979, 1025, 1037-1038; D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 55; DPU-Common 2-7; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 58; DPU-Common 2-7; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 46; DPU-Common 2-7). The Companies propose to coordinate with the CESAG on enhancements to their CBA approaches based on stakeholder feedback and lessons learned (Tr. 7, at 973; D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 55; DPU-Common 2-7; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 58; DPU-Common 2-7; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 46; DPU-Common 2-7).

b. NSTAR Electric

To increase the company's engagement and communication with historically marginalized communities and to ensure equitable outcomes for all of the company's customers, NSTAR Electric proposes to establish the following four stakeholder engagement principles: (1) proactively solicit and value stakeholder input and engagement through routine incorporation into projects and services; (2) collaborate with stakeholders to achieve mutually positive outcomes; (3) work to achieve fair and just outcomes for all stakeholders and ensure reasonable mitigation of any potential negative community outcomes that may arise from its activities; and (4) ensure that stakeholders and the communities that it serves feel respected and that the work supports their dignity (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 39, 42-43, 49-50). The company proposes a firm commitment to apply these principles to any investment project of $20 million or more (Tr. 7, at 1033-1034; D.P.U. 24-10, Exhs. ES-Stakeholder-4, at 4; DOER 3-2). The company also proposes to apply these principles to investment projects of less than $20 million on a case-by-case basis, depending on the direct impact of the project on a community (Tr. 7, at 1033-1034; D.P.U. 24-10, Exh. DOER 3-2).

NSTAR Electric states that its newly formed Equity and Environmental Justice team will serve as the primary contact for its employees seeking advice or support on equity and EJ matters and will assist the company in integrating EJ principles into its employees' daily work practices (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 40). Further, NSTAR

Electric states that it will continue momentum on a new online equity and EJ training module for its employees (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 40).

As part of its stakeholder outreach initiative, NSTAR Electric plans to increase engagement with its customers, with a specific focus on underserved communities, such as EJ populations (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 50-52). The company also states that it will regularly assess its stakeholder outreach approach to be responsive to feedback and the needs of the communities and customers that it serves (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 50, 58).

NSTAR Electric plans to use its Voice of the Customer organization[119] and to conduct surveys to develop a baseline understanding of customers' preferences and attitudes towards the company's programs and initiatives (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 44). NSTAR Electric will also use the initial customer outreach survey that it developed in consultation with GMAC members and other CBOs to inform the company about its customers' current understanding of the clean energy transition and to help shape the company's future education and outreach materials (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 44).

With respect to municipal outreach, NSTAR Electric states that it will provide host municipalities with transparent information on its planned ESMP investments in their

[119] NSTAR Electric's Voice of the Customer organization is focused on designing and executing strategies to obtain customer insights and communicating those insights to the company's internal business partners (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 44).

communities (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 45). The company also states that it will engage in direct dialogue with municipal leaders, including individual mayors and energy managers (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 45).

c. National Grid

National Grid used existing data and customer research to identify key priorities and customer concerns related to the clean energy transition (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 40).[120] National Grid states that its public engagement team will use this information to help address stakeholder concerns related to electric distribution system infrastructure projects (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 40). National Grid also states that it will provide stakeholders with opportunities for feedback, connection with project team members, and engagement with the company during the development of electric distribution system infrastructure projects (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 40).

National Grid represents that it will engage with stakeholders through various communication channels, facilitated forums, one-on-one settings, and through the CESAG, and will use research to better understand the needs of different customer segments (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 40, 43). National Grid also notes that it is

120 To gain insight into the needs and expectations of its customers, the company engaged with the National Grid Customer Council, which consists of 6,500 residential and 450 business customers and provides feedback to the company on new product innovations, programs, and rate changes (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 40, 44).

working with businesses, community organizations, and local chambers of commerce to engage with specific customer segments (e.g., retail, restaurants, hospitals, and academic institutions) to develop targeted communication materials for these customer groups and their members (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 44). National Grid states that it collects customer feedback through in-person events, focus groups, customer satisfaction surveys, the National Grid Customer Council, and targeted research (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 44). The company also proposes to continue tracking each discrete stakeholder engagement and any relevant feedback and to develop best practices to inform stakeholder engagement strategies, with a particular focus on engagement with EJ populations and the development of community benefit plans (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 46).

For larger capital infrastructure projects, National Grid dedicates a team to focus on community and municipal outreach and to refine its education and engagement strategies (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 46). National Grid also has direct dialogue with municipal leaders, including mayors, energy managers, and municipal organizations, and the company proposes to expand its municipal outreach, focusing initially on municipalities that will host electric distribution system infrastructure projects over the next ten years (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 48-49).

Finally, National Grid proposes several strategies and initiatives specific to its engagements with EJ populations (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 51). First, National Grid proposes to partner with municipalities with significant EJ populations to conduct in-person customer energy savings events to share relevant information, including available assistance for low-income customers (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 51). Second, for communities with a significant non-English speaking resident population, National Grid proposes to translate into multiple languages all pertinent publications, including those related to electric distribution system infrastructure projects, affordability, energy conservation, and bill management (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 51). National Grid also proposes to collaborate with community members, leaders, and trusted third-party partners from these communities to ensure that its communication is culturally sensitive (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 51). Third, the company proposes to collaborate with trusted community partners, faith-based groups, and individuals and use targeted outlets to reach minority populations (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 52). Finally, the company developed an Equity and EJ Policy and Engagement Framework to help guide its interactions with EJ populations and the National Grid Indigenous Peoples Initiative to help guide its interactions with Indigenous communities (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 54).

d. Unitil

Unitil proposes to establish the following five stakeholder engagement principles: (1) engage proactively with stakeholders through trusted community partners early on and throughout the planning process; (2) increase education about the need for future infrastructure, the company's potential investment plans, and the customer benefits those plans may provide; (3) engage with customers through communication channels that are conducive to ongoing dialogue, open discussion, and clear and timely information sharing while reducing communication barriers; (4) broaden the company's understanding of community and customer concerns and priorities that also consider historical inequities within the community; and (5) strive to directly support economic advancement in the communities that it serves, in part, by mitigating adverse impacts of proposed electric distribution system infrastructure projects (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 37).

Unitil states that a significant portion of its service territory is designated as an EJ population and, therefore, effective communication with these communities is paramount (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 41-42). To that end, Unitil proposes to consider factors, such as notice, location, accessibility, and scheduling, in a manner that encourages community participation and addresses the language and translation needs of that community (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 42). The company also proposes to coordinate with longstanding community partners, such as Making Opportunities Count, the United Way, and Fitchburg Housing Authority, on logistical arrangements that may be needed to encourage public participation and to increase the accessibility of its written materials (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 42-43). In addition, Unitil proposes to review all of its public-facing written materials for plain-spoken language, visualizations, clarity, transparency, and completeness as part of its drafting and production process (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 43). Unitil proposes to enhance and improve its stakeholder engagement process over time through lessons learned (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 43).

Unitil also proposes to educate municipal officials on electric distribution system projects that will be located within or impact the municipality (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 43). Specifically, the company proposes to hold one-on-one meetings with town officials, as needed, to educate them on the need, scope, and impact of the project (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 43).

3. Positions of the Parties

a. DOER

DOER makes three recommendations related to equity. First, DOER recommends that the Department direct National Grid and Unitil to develop similar equity initiatives to those established by NSTAR Electric (e.g., employee trainings on equity fundamentals and the creation of an EJ team) to operationalize equity within their respective organizations (DOER Brief at 64). Second, DOER urges the Department to direct the Companies to make all high-level, public-facing materials publicly accessible and to translate those materials into the top ten languages spoken in the Commonwealth (DOER Brief at 66). Finally, DOER recommends that the Department require the Companies to either perform distributional equity analyses in their future ESMPs or establish a mechanism for identifying and evaluating the localized impacts of CIPs on EJ populations, with filing requirements that include an explanation of how the CIP will affect low-income residents and EJ populations (DOER Brief at 67-68; DOER Reply Brief at 14-15).

a. Acadia Center

Acadia Center urges the Department to direct the Companies to clarify their CBA proposals (Acadia Center Brief at 4). At a minimum, Acadia Center argues that the Department should establish baseline principles for CBAs and to also: (1) provide guidance on the proper source and mix of funding for CBAs; (2) establish clear thresholds for projects that are assumed to require a CBA; and (3) provide guidance regarding the measures that are appropriate for CBAs (Acadia Center Brief at 22). In addition, Acadia Center contends that CBA costs should be shared between ratepayers and other sources, such as the Companies' shareholders (Acadia Center Brief at 22-23). Acadia Center requests that the Department clarify which CBA costs the Companies can recover from ratepayers and which CBA cost are not eligible for cost recovery (Acadia Center Brief at 23). Acadia Center also recommends that the Department develop a formula or establish a cap for CBA costs that are eligible for recovery from ratepayers (Acadia Center Brief at 23). Finally, Acadia Center contends that there should be a presumption of need for CBAs for projects that meet certain thresholds (Acadia Center Brief at 24).

a. Cape Light Compact

CLC provides two recommendations on the Companies' equity proposals. First, CLC requests that the Department clarify that NSTAR Electric can enter into CBAs with host communities only within the context of an EFSB and/or Department proceeding (CLC Brief at 3, 17). Second, CLC recommends that the Department direct NSTAR Electric to include a provision in CBAs that explains that CBA costs will ultimately be borne by all NSTAR Electric ratepayers, including ratepayers of the host community (CLC Brief at 3, 17).

b. CLF

CLF argues that the Companies should be required to develop a distributional equity analysis (CLF Brief at 11-12). CLF also recommends that: (1) the Companies consider EJ principles in their electric distribution system infrastructure siting decisions; (2) the Department clarify that its approval of the ESMPs does not eliminate the Companies' burden to demonstrate that their ESMPs comply with permitting requirements and EJ laws; (3) the Companies incorporate EJ considerations into their future electric distribution system infrastructure siting petitions; and (4) the Companies provide needs and alternatives assessments with their petitions to the EFSB for approval of proposed major infrastructure projects (CLF Brief at 11, 15, 17).

c. Companies

The Companies contend that their equity framework and related proposals ensure a just and equitable clean energy transition because: (1) the CBAs will be the byproduct of meaningful and proactive community engagement with the host community and that, as CBAs are developed with host communities, the Companies will convey feedback and lessons learned to the CESAG to formulate new methods and approaches to ensure an equitable clean energy transition; (2) they will engage with customers and communities on ESMP projects to ensure that their decision-making process appropriately balances affordability with the provision of safe and reliable service; (3) they will take deliberate steps to increase community engagement and communication and to identify the specific benefits and burdens that a project may have on a host community; and (4) the CESAG will develop a community engagement framework for the Companies to increase stakeholder engagement, provide transparency into their ESMP investments, and ensure that stakeholders feel respected, understood, and heard (Companies' Joint Brief at 13-14, 62-65; Companies' Joint Reply Brief at 52). The Companies also contend that their ESMP program offerings, coupled with a more formalized stakeholder engagement process, will provide enhanced opportunities for customers in EJ populations to benefit from ESMP investments and to participate in the clean energy transition (Companies' Joint Reply Brief at 50).

Next, the Companies contend that the Department should reject Acadia Center's recommendations that baseline principles be established for CBAs and that the Department provide guidance on the eligibility of CBA costs for recovery from ratepayers in these proceedings (Companies' Joint Reply Brief at 53-54). First, the Companies argue that CBAs are intended to be flexible to meet the needs of individual communities (Companies' Joint Reply Brief at 53-54). According to the Companies, a uniform set of principles for CBAs presupposes the wants or needs of a community and undermines the host community's voice which, in turn, could result in a lack of trust between the Companies and relevant stakeholders (Companies' Joint Reply Brief at 54). The Companies also argue that CBAs are project-specific and that the EFSB will review CBAs as part of its review of the Companies' electric distribution system infrastructure siting petitions (Companies' Joint Reply Brief at 54). In addition, the Companies contend that whether and to what extent CBA costs are eligible for recovery from ratepayers is outside the scope of these proceedings, but that CBA costs should be recoverable in the same manner that project mitigation costs are recovered (Companies' Joint Reply Brief at 54). Further, the Companies argue that compelling them to undertake certain CBA costs without an opportunity for recovery would be confiscatory (Companies' Joint Reply Brief at 54). Therefore, the Companies request that the Department reject Acadia Center's recommendations related to CBAs (Companies' Joint Reply Brief at 53-54).

The Companies oppose a requirement to establish a distributional equity analysis, as proposed by DOER and CLF, because the parameters for such an analysis are undefined, and no party provided evidence to explain or support such a requirement (Companies' Joint Reply Brief at 21). As such, the Companies contend that the Department has no record to justify a requirement for the Companies to develop a distributional equity analysis that is not required by Section 92B and that was raised for the first time on brief without an opportunity for the parties to present evidence on the appropriateness of such an analysis in the context of Section 92B (Companies' Joint Reply Brief at 21). Additionally, the Companies argue that ESMP costs are socialized to all customers, so EJ populations will not bear a disproportionate share of ESMP investment costs, and that the burdens associated with specific ESMP projects on a community will be identified and addressed through the siting and permitting process (Companies' Joint Reply Brief at 21-22). Further, the Companies contend that the Department has stated that it will review the ESMPs as strategic plans (i.e., the Department will not approve specific ESMP investments in these proceedings), and the final siting of potential ESMP projects will occur in the future, at which time the likely benefits and burdens of the project can be assessed and addressed through engagement with the host community (Companies' Joint Reply Brief at 22). Therefore, the Companies argue that an assessment of the benefits and burdens of specific ESMP projects on host communities is outside the scope of the ESMPs as strategic plans and that an evaluation of the benefits and burdens of specific ESMP projects on host communities is more appropriately addressed through the siting and permitting process (Companies' Joint Reply Brief at 21-22).

4. Analysis and Findings

a. Introduction

Section 92B does not specifically address equity as a consideration in distribution system planning. Nevertheless, equity is a Department priority with respect to itself and the entities we regulate. G.L. c. 25 § 1A. The Department is committed to an equitable clean energy transition. Accordingly, the Department reviews the Companies' proposed equity framework for consistency with the Commonwealth's public policy goals and Department policies.

In these proceedings, the Companies propose an equity framework to guide stakeholder engagement efforts and collaborations with communities that host electric distribution system infrastructure (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 36-58; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 38-58; D.P.U. 24-12, Exh. UN-ESMP-1

(Corrected) at 36-46). Generally, intervenors support approval of the Companies' equity framework but recommend certain modifications.

Below, the Department first addresses whether the Companies have complied with the requirements set forth in Section 92B(c)(iii). Next, the Department determines whether the Companies' equity framework is consistent with the Commonwealth's public policy goals and Department policies. Finally, the Department addresses modifications to the Companies' equity framework.

b. Compliance with Statute

Section 92B(c)(iii) requires an electric distribution company to conduct technical conferences and a minimum of two stakeholder meetings. The Companies maintain that they actively engaged with the GMAC and stakeholders to develop their ESMPs, stakeholder outreach and community feedback are woven into the fabric of their ESMPs, and they have complied with the requirements set forth in Section 92B(c)(iii) (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 7-8, 28, 31, 46, 664; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 8, 18-19, 24, 30, 33, 45, 54, 477; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 5, 30, 290). No intervenor addressed this issue.

The Companies held two stakeholder workshops in November 2023, a technical conference in December 2023, and other meetings to engage stakeholders on their ESMPs (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 31, 46-48; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 33, 39-40, 44-45; D.P.U. 24-12, Exh. UN-ESMP-1

(Corrected) at 30, 39-41). Accordingly, the Department finds that the Companies have complied with the requirements of Section 92B(c)(iii).

c. Equity Framework

For more than 20 years, the Commonwealth and the EEA have sought to promote EJ considerations in regulatory decision-making. In 2002, EEA issued its first EJ Policy requiring EEA and the agencies under its purview to make EJ an integral consideration in the implementation of its programs and develop strategies to proactively promote EJ in all neighborhoods. EEA EJ Policy at 4, 7 (October 9, 2002).[121] In 2014, Governor Deval Patrick affirmed EJ as priority for the Executive Branch including all secretariats.[122] In 2021, Governor Charles Baker signed into law the 2021 Climate Act, which, among other things, requires the Department to prioritize equity alongside the more traditional considerations of safety, security, and reliability of service. G.L. c. 25, § 1A. Moreover, EEA updated its EJ Policy in 2021 to make EJ principles an integral consideration in the implementation of all EEA programs.[123] EEA EJ Policy at 5 (June 24, 2021).

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121 Available at https://www.mass.gov/doc/2002-environmental-justice-policy/download. (lasted visited August 29, 2024). EEA updated its EJ Policy in 2017, and most recently in 2021, which is available at https://www.mass.gov/doc/environmental-justice-policy6242021-update/download (last visited August 29, 2024).

122 Exec. Order No. 552, Executive Order on Environmental Justice (2014), available at https://www.mass.gov/doc/executive-order-552/download (last visited August 29, 2024).

123 EJ principles are defined as principles that support protection from environmental pollution and the ability to live in and enjoy a clean and healthy environment, regardless of race, color, income, class, handicap, gender identify, sexual orientation,

Separately, the Department has also sought to promote EJ considerations in its proceedings. In February 2024, the Department established an EJ strategy with practices and principles consistent with statutes and regulations to promote EJ considerations across the Department's proceedings involving EJ populations. EEA Environmental Justice Strategy at 124-130 (February 15, 2024).[124] On February 23, 2024, the Department established the necessary notice and outreach requirements for Department proceedings aimed at increasing public awareness of and involvement in its proceedings. Tiering and Outreach Policy, D.P.U. 21-50-A (February 23, 2024). The Department is also working with EEA on finalizing a Language Access Plan to ensure all members of the public, including those with limited English proficiency, have an equal opportunity to participate in Department proceedings.[125]

In the present proceedings, the Companies maintain that their equity framework will: (1) help ensure that all of their customers, especially those in historically underserved communities, have a voice in the clean energy transition; (2) provide a framework that they

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national origin, ethnicity or ancestry, religious belief or English language proficiency, which includes: (i) the meaningful involvement of all people with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies, including climate change policies; and (ii) the equitable distribution of energy and environmental benefits and environmental burdens. EEA EJ Policy at 4 (June 24, 2021).

[124] Available at https://www.mass.gov/doc/february-2024-environmental-justice-strategy-english/download (last visited August 29, 2024).

[125] Available at https://www.mass.gov/info-details/eea-and-dpu-language-access-plans-laps (last visited August 29, 2024).

can use to rethink and formulate new methods and approaches to drive the benefits of the clean energy transition across the Commonwealth; and (3) help support the Commonwealth's public policy goals (Tr. 7, at 979, 1025; D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 40-41, 43, 50, 669; DPU-Common 2-7; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 24, 27, 49-50; DPU-Common 2-7; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 25, 289; DPU-Common 2-7). No intervenor specifically addressed the consistency of the Companies' equity framework with the Commonwealth's public policy goals or Department policies, but all intervenors urged the Department to approve the Companies' equity framework with some modifications. For the reasons discussed below, the Department finds that the Companies' equity framework is consistent with the Commonwealth's public policy goals and Department policies.

At the outset, the Department notes that the Companies' equity framework represents their first comprehensive strategy to incorporate equity principles into their distribution system planning processes. The Department acknowledges the Companies collaboration to develop a joint framework. This equity framework, however, is only the first step in an ongoing process to engage, educate, and respond to stakeholders as well as to address inequities by mitigating the negative impacts on those communities that bear the burden of hosting electric distribution system infrastructure that provides benefits that often extend well beyond the impacted communities. Turning to the specifics of the equity framework, the Department determines that the Companies' equity framework has the potential to increase stakeholder knowledge and participation in the clean energy transition in a manner that supports the Commonwealth's public policy goals as well as the Department's EJ and Language Access policies (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 36-58; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 38-58; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 36-46). Specifically, the equity framework commits each company to translate pertinent written publications into multiple languages for communities with a significant number of non-English speaking residents which, in turn, will decrease barriers for customers with limited English proficiency to meaningfully engage with the Companies on a variety of important matters related to the Companies' implementation of their ESMPs (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 51; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 51; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 42). In addition to translated materials directly related to Department proceedings pursuant to the Department's Tiering and Outreach and Language Access policies, the materials to be translated under the equity framework also include materials on matters indirectly related to a specific Department proceeding, such as affordability, energy conservation, and bill management (D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 51). Further, under the equity framework, Unitil proposes to consider factors, such as notice, location, accessibility, and scheduling, to encourage community participation and address the language needs of that community (D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 42). These practices, among others including interpretation services to ensure opportunities for multilingual verbal communications, will help to educate and engage the Companies' customers in support of the Commonwealth's and the Department's policies.

Additionally, the Department determines that the Companies' equity framework builds upon the recommendations from the GMAC, the GMAC's Equity Working Group, and other stakeholders to help address the disproportionate environmental burdens borne by EJ populations (D.P.U. 24-10, Exh. ES-ESP-1 (Corrected) at 7-8; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 8, 18-19, 24, 30; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 39-41; D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, Exh. ES-Stakeholder-2/ NG-Stakeholder-2/UN-Stakeholder-2). For example, the CESAG and the to-be-developed statewide community engagement framework represent not only a viable approach to increase stakeholder engagement with the Companies' distribution system planning processes, but also an opportunity for the Companies to acquire in-depth knowledge and understanding of the negative impacts, historical inequities, and ongoing disparities associated with distribution system infrastructure (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 53-54; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 56-57; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 43-44). Importantly, the CESAG will provide the Companies the opportunity to explore how best to mitigate those impacts, inequities, and disparities, and to improve upon their equity strategies and approaches based on stakeholder feedback and lessons learned (Tr. 7, at 973; D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 55; DPU-Common 2-7; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 58; DPU-Common 2-7; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 34-44; DPU-Common 2-7). Further, the Department determines that the increased collaboration envisioned by the equity framework between the Companies and the communities that host electric distribution system infrastructure, as well as the resulting CBAs that would directly benefit the communities where electric distribution system infrastructure is sited, would help balance the benefits and burdens of hosting infrastructure (Tr. 7, at 979, 1025; D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 55; DPU-Common 2-7; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 58; DPU-Common 2-7; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 46; DPU-Common 2-7).

In sum, the Department determines that the equity framework will support the Commonwealth's and the Department's goal to ensure the equal protection and meaningful involvement of all people and communities with respect to the development, implementation, and enforcement of energy, climate change, and environmental laws, regulations, and policies and the equitable distribution of energy and environmental benefits and environmental burdens. EEA Environmental Justice Policy at 3 (2021); Environmental Justice Strategy at 126. Notwithstanding the findings above and as discussed below, the Department determines it appropriate to require certain modifications to specific elements of the equity framework.

i. Procedural Equity

(A) Public-Facing Materials

The Companies propose to translate pertinent materials into multiple languages for communities with a significant number of non-English speaking residents (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 51; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 51; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 42). DOER urges the Department to direct the Companies to make all high-level, public-facing materials publicly accessible, to translate those materials into the top ten languages spoken in the Commonwealth, and to use clear, plain-spoken language in their public-facing materials (DOER Brief at 66). The Companies state that they are committed to making their high-level, public-facing materials accessible, understandable, and beneficial to all of their customers, including their customers that reside in EJ populations, but request that the Department allow them flexibility to adopt practices that are appropriate to each unique circumstance and that are tailored to the needs of their respective service territories (Companies' Reply Brief at 52-53).

The Department recognizes the importance of translated materials and messaging that uses plain language and is clear and easy to understand to increase public awareness of and engagement with the Companies on matters related to their ESMPs. See D.P.U. 21-50-A at 25-26, 28-31, 35 (discussing the importance of translated materials and the use of plain language in public-facing materials). The Department notes, however, that DOER's recommendation to require the Companies to translate all high-level, public-facing materials into the top ten languages spoken in the Commonwealth may differ from the Department's forthcoming Language Access Plan and exceeds the translation requirements we recently established for the Companies in relation to Tier 1 proceedings[126] with a service territory-wide impact in D.P.U. 21-50-A at 29; that Order directed the Companies to translate prefiling materials relating to specific proceedings (e.g., base distribution rate cases,

[126] The Department's Tiering and Outreach Policy defines Tier 1 proceedings as proceedings that involve significant policy changes or fundamental changes to process. D.P.U. 21-50-A, Appendix A at 1.

company mergers, and petitions for zoning exemptions) into the top three language spoken in the Commonwealth and, to the extent feasible, any additional languages upon request. The materials referenced by DOER are high-level public facing materials, which may include materials about bill management options, what to do when an outage occurs, or energy efficiency programs, and could differ from information related to a particular proceeding. There is no evidence in the record of the costs or implications associated with DOER's expanded translation recommendation that would allow us to consider the reasonableness or cost-effectiveness of such a requirement. Therefore, the Department rejects DOER's recommendation to require the Companies to translate all high-level, public-facing materials into the top ten languages spoken in the Commonwealth. Notwithstanding, the Department encourages the Companies to provide meaningful opportunities for limited English proficient customers to gain written and verbal access to high-level information and directs the Companies to comply with the Department's Language Access Plan and Orders in D.P.U. 21-50, including any future decisions in that docket. The Department finds that any language access practices developed by the CESAG may exceed language access requirements in the Department's Language Access Plan and D.P.U. 21-50.

Additionally, the Department expects the Companies to coordinate with the CESAG to develop clear and cohesive policies and practices in relation to when and how the Companies will translate materials into other languages and when to provide interpretation services during verbal interactions between each Company and its customers. To the extent feasible, the Department expects the Companies to accommodate requests from their customers and stakeholders to translate materials into other languages. The Department also encourages the Companies to post public-facing materials on platforms likely to be used by their customers and stakeholders (e.g., the Companies' websites, community centers, social media platforms, etc.).

Next, the Department agrees with DOER that all public-facing materials include clear and plain language. The Department expects the Companies to coordinate with the CESAG to develop a policy on best practices for incorporating plain language into their public-facing materials.

These directives are intended to help the Department and the Companies achieve their mutual goal of increased public awareness of the Companies' ESMP activities and increased stakeholder engagement. The Department acknowledges that improvements to the Companies' equity policies and practices will need to be made over time based on stakeholder input and lessons learned. The Department expects the Companies to make appropriate efforts to invite stakeholder feedback on their ESMP approaches and to engage with the CESAG on improvements to their equity strategies and policies based on stakeholder feedback and lessons learned.

(B) Equity Initiatives

DOER recommends that the Department direct National Grid and Unitil to develop similar equity initiatives to those established by NSTAR Electric (e.g., employee trainings on equity fundamentals and the creation of an EJ team) to operationalize equity within their respective organizations (DOER Brief at 64). The Companies do not specifically address this recommendation on brief.

To the extent feasible, the Department expects each of the Companies to take steps to operationalize equity within its respective organization. The Department recognizes the significant value of regular employee trainings on equity, EJ, and language access and the benefits that a dedicated EJ team within each company's organization may provide but the Department also recognizes that the Companies need flexibility to determine how to operationalize equity within their respective organizations to address the unique needs of their customers and the communities that they serve. The Department expects each of the Companies to develop equity policies, including EJ and language access policies, in coordination with the CESAG, and to provide regular trainings for their employees on these policies after they are finalized. The Department encourages, but does not require, National Grid and Unitil to create an EJ team to serve as the primary contact for their employees on equity and EJ-related matters within their respective organizations. Each of the Companies is directed to provide information about its progress on developing equity policies, providing trainings on the policies, and staffing assigned to these matters in its biannual reports further discussed in Section XI.D.

ii. Distributional and Structural Equity

(A) CBAs

The Companies propose to enter into CBAs with individual host communities on a case-by-case-basis (Tr. 7, at 979, 1025; D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 55;

DPU-Common 2-7; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 58; DPU-Common 2-7; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 46; DPU-Common 2-7). Acadia Center recommends that, due to the lack of detail, the Department require the Companies to provide more specificity on their CBA proposals and, at a minimum: (1) provide guidance on the proper source and mix of funding for CBAs; (2) establish clear thresholds for projects that are assumed to require a CBA; and (3) provide guidance regarding the measures that are appropriate for CBAs (Acadia Center Brief at 21-25). CLC urges the Department to clarify that NSTAR Electric can enter into CBAs with host communities only within the context of an EFSB and/or Department proceeding and to direct NSTAR Electric to include a provision in CBAs that explains that CBA costs will ultimately be borne by all NSTAR Electric ratepayers, including ratepayers of the host community (CLC Brief at 3, 17). The Companies argue that the Department should reject Acadia Center's recommendation to establish baseline principles for CBAs because CBAs must be flexible to meet the needs of individual host communities and that Acadia Center's recommendation for the Department to provide guidance on the eligibility of CBA costs for recovery from ratepayers is outside the scope of these proceedings (Companies' Joint Reply Brief at 53-54).

The Department recognizes the value that CBAs may provide to communities that host electric distribution system infrastructure and that CBAs would provide a level of assurance that host communities directly benefit from the infrastructure that they host (Tr. 7, at 979, 1025; D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 55; DPU-Common 2-7;

D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 58; DPU-Common 2-7; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 46; DPU-Common 2-7). However, the Department agrees with Acadia Center that the record is unclear on certain aspects of the Companies' CBA proposals, including: (1) how the Companies will determine whether it is appropriate to enter into a CBA with a host community; (2) whether the Companies propose to implement a cap on CBA costs per CBA; (3) the types of community benefits and the associated costs that are appropriate for inclusion in CBAs; and (4) whether and how the Companies would seek to recover all costs associated with CBAs from ratepayers. These issues require a broader discussion, which should involve a broader set of stakeholders than the parties in these dockets. Furthermore, there is pending legislation that, if enacted, would direct EEA to establish guidelines for CBAs and require consideration of CBAs in the context of EFSB proceedings.[127] The Department will need to consider whether and how the Companies could recover costs associated with CBAs, but we find it premature to consider cost recovery for CBAs prior to commencing the conversations about siting and permitting changes that will result in the event that pending legislation is enacted. Regardless of pending legislation, the Department intends to coordinate with the EFSB to clarify each agency's role regarding CBA oversight and we will consider CBA cost recovery at a later time in a subsequent phase of this proceeding or in a new proceeding.

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[127] An Act Upgrading the Grid and Protecting Ratepayers, 2024 S.2838, § 127; An Act Accelerating a Responsible, Innovative and Equitable Clean Energy Transition, 2024 H.4884, § 86.

(B) Electric Distribution System Infrastructure Siting

CLF urges the Department to direct the Companies to consider EJ principles in their electric distribution system infrastructure siting decisions and to provide needs and alternatives assessments with their petitions to the EFSB for approval of proposed major infrastructure projects (CLF Brief at 17). CLF also requests that the Department clarify that its approval of the ESMPs does not eliminate the Companies' burden to demonstrate that their ESMPs comply with permitting requirements and EJ laws (CLF Brief at 17). The Companies do not address these arguments on brief.

Distribution system planning necessarily involves decisions associated with the siting of electric infrastructure. There is some ambiguity in the record as to whether the equity framework applies solely to proceedings before the EFSB or also encompasses large electric distribution system infrastructure projects that may come before the Department (Tr. 6, at 912-913; D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 7, 36-37; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 24, 57; DPU-Common 3-1; DPU-Common 9-11; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 45). Nonetheless, the Department determines that, where the potential for an imbalance in the benefits and burdens exists to host large electric distribution system infrastructure, the Companies shall apply the equity framework as modified herein to any large electric system distribution system infrastructure projects that may come before the Department. The Department acknowledges that the EFSB may have other or additional requirements for the equity framework that applies specifically to projects within its jurisdiction and declines to consider proposals to modify the requirements of filings that are under the purview of the EFSB. Concerns and recommendations regarding the EFSB's filing requirements should be directed to the EFSB. The Department intends to coordinate with the EFSB when appropriate. Nonetheless, the Department directs the Companies to coordinate with the CESAG to develop policies and practices related to integrating EJ principles into their decision-making with respect to the siting of electric distribution system infrastructure projects.

Next, we address CLF's concerns that Department approval of the ESMPs would modify or eliminate the Companies' burden to demonstrate that their respective ESMPs comply with permitting requirements and EJ laws. A Department approval of the Companies' ESMPs, and in particular, an approval of the ESMPs pursuant to the strategic plan framework we established for these proceedings, would not modify or eliminate the Companies' burden to demonstrate that their individual electric distribution system infrastructure projects comply with all applicable permitting requirements or Massachusetts laws.

(C) Distributional and Structural Equity Analyses

DOER and CLF argue that the Companies should be required to develop a distributional equity analysis (DOER Brief at 67-68; DOER Reply Brief at 14-15; CLF Brief at 11-12). Alternatively, DOER urges the Department to establish a mechanism for identifying and evaluating the localized impacts of CIPs on EJ populations, with filing requirements that include an explanation of how the CIP will affect low-income residents and EJ populations (DOER Reply Brief at 14-15). The Companies request that the Department reject DOER's and CLF's recommendation to direct the Companies to develop a distributional equity analysis because Section 92B does not require the Companies to establish a distributional equity analysis, and the record does not justify such a requirement (Companies' Joint Reply Brief at 21).

The Department recognizes the critical importance of clear and cohesive policies and practices related to distributional equity that focus on enabling a more equitable distribution of the benefits and burdens associated with the clean energy transition, and structural equity that focuses on developing processes and decisions that are informed by the historical, cultural, and institutional dynamics and structures that have led to inequities. Such policies and practices help to ensure the equal protection and meaningful involvement of all people and communities in the clean energy transition and the equitable distribution of ESMP benefits and burdens. While the Companies provided detailed explanations of their proposed actions and intentions regarding procedural equity, we agree with DOER and CLF that the distributional and structural equity components of the Companies' common equity framework lack adequate details. But, as noted above, the Companies' equity framework is only the first iteration of a policy that will continue to develop and improve over time. The Department expects that in their next ESMP term filings, and after the Companies gain experience with the CESAG and CBAs over the first ESMP term, the Companies' next iteration of the equity framework, and in particular the distributional and structural equity components of the framework, will include a more comprehensive and detailed description of those components of the framework that address EJ principles. In the interim, the

Department directs the Companies to provide updates in their biannual reports on how they are addressing distributional and structural equity in the implementation of their ESMPs, and distribution system planning generally, and to describe how any lessons learned could shape the next iteration of their equity framework. Additionally, the Department encourages the Companies to collaborate with the CESAG and GMAC, including the GMAC Equity Working Group, to gather stakeholder input on actions that could enhance and assist in fully implementing all aspects of the equity framework. The Companies must explain how they incorporated stakeholder feedback and lessons learned during the first term of their ESMPs, as well as any relevant recommendations from the CESAG, into the distributional and structural equity components of their framework for the second term of their ESMPs. The Department also encourages the Companies to review publicly available studies on distributional and structural equity analyses[128] and to consider incorporating elements of these studies into the distributional and structural equity components of their framework, as appropriate.

d. Conclusion

After review and consideration, the Department approves the Companies' equity framework, as modified above. As discussed above, the Companies must coordinate with the

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[128] See, e.g., National Equity Screening Project, available at https://www.nationalenergyscreeningproject.org/resources/energy-equity-and-bca/ (last visited August 29, 2024) (GMAC Report at 37 n.36); Distribution Equity Analysis for EE and Other DERs, available at https://www.energy.gov/sites/default/files/2024-05/bto-distributed-equity-analysis-guide_may2024.pdf (last visited August 29, 2024).

CESAG to develop clear and cohesive equity policies and practices, including policies and practices related to language access, EJ, and the equitable siting of electric distribution system infrastructure. In addition, the Companies must provide updates in their biannual reports on how they are addressing distributional and structural equity in the implementation of their ESMPs, training their staff on equity matters, and allocating staff resources, and describe how any lessons learned could shape the next iteration of their equity framework. Finally, as we noted in the Interlocutory Order on Scope at 22-23, the Department intends to address metrics in a subsequent phase of this proceeding. As part of our metrics review, we will consider the sufficiency of the equity-related metrics proposed as well as possible modifications of or additions to those metrics.

I. Net Benefits

1. Introduction

To be approved by the Department, an ESMP must provide net benefits for customers. G.L. c. 164, § 92B(d). Additionally, for all proposed investments and alternative approaches to those investments, electric distribution companies must identify customer benefits associated with the investments and alternatives including, safety, grid reliability and resiliency, facilitation of the electrification of buildings and transportation, integration of DERs, avoided renewable energy curtailment, reduced GHG emissions and air pollutants, avoided land use impacts, and minimization or mitigation of impacts on the ratepayers of the Commonwealth. G.L. c. 164, § 92B(b). The Department explained that we would review the costs and benefits of each company's proposed planning solutions in the context of viewing these inaugural ESMPs as strategic planning documents. Interlocutory Order on Scope at 2, 14, 16, 23-24.

2. Description of Company Filings

a. Overview of Method

The Companies jointly proposed a standard of review for the Department to use in determining whether their ESMPs provide net benefits and jointly hired a third-party consultant, West Monroe, to develop a net benefits analysis method. In addition to the eight benefits required by Section 92B(b) identified above, the Companies also proposed that the Department consider impact to EJ populations and workforce and economic benefits (D.P.U. 24-10, Petition at 11-12, 14; Exhs. ES-ESMP-1 (Corrected) at 449-450; ES-Net-Benefits-1, at 10-12; ES-Net Benefits-3 (Corrected) at 14; D.P.U. 24-11, Petition at 11, 14; Exhs. NG-ESMP-1 (Corrected) at 372-373; NG-Net Benefits-1 (Corrected) at 10-13; NG-Net Benefits-3 (Corrected) at 14; D.P.U. 24-12, Petition at 11, 14; Exhs. UN-ESMP-1 (Corrected) at 175; UN-Net Benefits-1 (Corrected) at 7-10; UN-Net Benefits-3 (Corrected) at 14). The Companies explained that qualitative benefits have a level of complexity that make them difficult to quantify but have substantial value nonetheless for a holistic evaluation of the program’s outcomes and, thus, merit inclusion in the net benefits analysis (D.P.U. 24-10, Exh. ES-Net Benefits-1, at 24; D.P.U. 24-11, Exh. NG-Net Benefits-1 (Corrected) at 24; D.P.U. 24-12, Exh. UN-Net Benefits-1 (Corrected) at 21). Each company bases the net benefits of its ESMP on the estimated costs and benefits of its proposed ESMP investments (D.P.U. 24-10, Exhs. ES-ESMP-1

(Corrected) at 432-438, 449-450; ES-Net Benefits-1, at 20; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 356-362, 372-373; NG-Net Benefits-1 (Corrected) at 20; D.P.U. 24-12, UN-ESMP-1 (Corrected) at 13-19, 175; UN-Net Benefits-1 (Corrected) at 17).

The Companies jointly hired West Monroe to develop a method to analyze the net benefits of the ESMPs (D.P.U. 24-10, Petition at 11; Exh. ES-Net Benefits-1, at 7-8; D.P.U. 24-11, Petition at 11; Exh. NG-Net Benefits-1 (Corrected) at 8; D.P.U. 24-12, Petition at 11; Exh. UN-Net Benefits-1 (Corrected) at 5). West Monroe adopted the principles using a "regulatory perspective" outlined in the National Standard Practice Manual and the U.S. DOE's Modern Distribution Grid documents, which state that net benefits should account for state regulatory and policy goals, account for all relevant costs and benefits (including those that are hard-to-quantify), apply a full life-cycle analysis, and assess investments as bundles and portfolios instead of separate measures (D.P.U. 24-10, Exh. ES-Net Benefits-1, at 10-11; D.P.U. 24-11, Exh. NG-Net Benefits-1 (Corrected) at 11; D.P.U. 24-12, Exh. UN-Net Benefits-1 (Corrected) at 8). As a result, each company's net benefits analysis considers the proposed projects as a territory-wide, single portfolio, does not utilize locational values, and aggregates the net benefits, based on the assumption that all ESMP projects and programs are implemented as an integrated whole with interrelated functions (Tr. 4, at 419-425; D.P.U. 24-10, Exhs. ES-Net Benefits-1, at 21; AG 2-14; D.P.U. 24-11, Exhs. NG-Net Benefits-1 (Corrected) at 21; AG 1-24; D.P.U. 24-12, Exh. UN-Net Benefits-1 (Corrected) at 18; AG 1-14). The model provided by each company identifies the costs and benefits for each investment category, and each company discounted all costs and benefits to obtain present values and net present values of costs and benefits using its weighted average cost of capital ("WACC") (D.P.U. 24-10, Exh. ES-Net Benefits-1, at 17, 20-21; D.P.U. 24-11, Exh. NG-Net Benefits-1 (Corrected) at 17, 20-21; D.P.U. 24-12, Exh. UN-Net Benefits-1 (Corrected) at 14, 17-18).

The Companies submitted preliminary estimates of ESMP investment costs, both capital and O&M, based on subject matter expert analysis and costs for similar projects (D.P.U. 24-10, Exh. DPU-1-1; D.P.U. 24-11, Exh. DPU-1-1; D.P.U. 24-12, Exh. DPU-1-1). At a future date, the Companies state that each investment will be subject to detailed engineering analysis and will follow the company's competitive procurement and project approval processes (D.P.U. 24-10, Exhs. DPU 1-1; DPU-Common 10-2; D.P.U. 24-11, Exhs. DPU 1-1; DPU-Common 10-2; D.P.U. 24-12, Exhs. DPU 1-1; DPU-Common 10-2). For consistency with the duration of the benefits assessment, the model also includes estimates of the ongoing operational costs of proposed investments over the lifetime of each asset or out to 2050, whichever occurs sooner, for those investments that would be in service by 2029 (D.P.U. 24-10, Exh. ES-Net Benefits-1, at 21-22; D.P.U. 24-11, Exh. NG-Net Benefits-1 (Corrected) at 21-22; D.P.U. 24-12, Exh. UN-Net Benefits-1 (Corrected) at 18-19).

For each company, West Monroe monetized outcomes for the customer benefits listed in Section 92B(b) based on the non-monetized values of those benefits, including those attributed to GHG and air pollutant emissions reductions, i.e., total reductions by metric tons of carbon dioxide, nitrogen oxides, and particulate matter, total EVs enabled, total heat pumps enabled, total distributed generation enabled (MW), demand reduction (kW), energy savings (MWh), CMI reductions, and all-in SAIDI improvement (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 455-456; ES-Net Benefits-1, at 22-24; ES-Net Benefits-3 (Corrected) at 29; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 376-379; NG-Net Benefits-1 (Corrected) at 22-24; NG-Net Benefits-3 (Corrected) at 29; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 180-182; UN-Net Benefits-1 (Corrected) at 19-21; UN-Net Benefits-3 (Corrected) at 28). West Monroe calculated monetized benefits by using certain assumptions, such as the dollar value of avoided emissions (i.e., social cost of carbon) (D.P.U. 24-10, Petition at 12; Exh. ES-Net Benefits-1, at 20-24; D.P.U. 24-11, Petition at 12; Exh. NG-Net Benefits-1 (Corrected) at 20-24; D.P.U. 24-12, Petition at 11; Exh. UN-Net Benefits-1 (Corrected) at 17-21).

The Companies each stated that, to the extent possible, West Monroe used values and methodologies, such as the social cost of carbon and net benefits methods, that have been utilized, scrutinized, and accepted in past Department proceedings (D.P.U. 24-10, Exh. ES-Net Benefits-1, at 11, 17; D.P.U. 24-11, Exh. NG-Net Benefits-1 (Corrected) at 11, 17; D.P.U. 24-12, Exh. UN-Net Benefits-1 (Corrected) at 8, 14). The Companies each pointed to the recent grid modernization and AMI implementation plans (D.P.U. 21-80, D.P.U. 21-81, and D.P.U. 21-82), and the 2022 through 2024 Three-Year EE Plans (D.P.U. 21-120 through D.P.U. 21-129) as examples of proceedings with similar cost-benefit models and analyses (D.P.U. 24-10, Exh. ES-Net Benefits-1, at 17; D.P.U. 24-11, Exh. NG-Net Benefits-1 (Corrected) at 17; D.P.U. 24-12, Exh. UN-Net Benefits-1 (Corrected) at 14). Each company also stated that, while they coordinated to drive alignment where reasonable on issues such as common inputs, adoption of standard assumptions, and approaches to information gathering, the net benefits results are primarily driven by the company-specific scope, schedule, and benefits of the ESMP investments proposed (D.P.U. 24-10, Exh. ES-Net Benefits-1, at 16; D.P.U. 24-11, Exh. NG-Net Benefits-1 (Corrected) at 16; D.P.U. 24-12, Exh. UN-Net Benefits-1 (Corrected) at 13).

Finally, West Monroe separately modeled workforce and economic benefits associated with the investments and included corresponding benefit totals in the holistic net benefits summary (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 452, 457; ES-Net Benefits-3 (Corrected) at 8; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 375, 379; NG-Net Benefits-3 (Corrected) at 8; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 182; UN-Net Benefits-3 (Corrected) at 8). West Monroe used the Regional Input-Output Modeling System II ("RIMS-II") model developed by the U.S. Department of Commerce's Bureau of Economic Analysis to quantify these economic benefits (D.P.U. 24-10, Exh. ES-Net Benefits-1, at 11, 19; D.P.U. 24-11, Exh. NG-Net Benefits-1 (Corrected) at 11-12, 18-19; D.P.U. 24-12, Exh. UN-Net Benefits-1 (Corrected) at 9, 15-16). The RIMS-II model estimates the region-specific economic benefits of capital investments and considers the direct impacts of the investment, such as hiring workers and purchasing materials, as well as the indirect impacts of the investment, such as business for logistics companies that deliver the materials (D.P.U. 24-10, Exh. ES-Net Benefits-1, at 19;

D.P.U. 24-11, Exh. NG-Net Benefits-1 (Corrected) at 19; D.P.U. 24-12, Exh. UN-Net Benefits-1 (Corrected) at 16).

b. Definitions of Statutory Benefits

Each company evaluated the eight benefits categories outlined in Section 92B(b) (D.P.U. 24-10, Exh. ES-Net Benefits-3 (Corrected) at 13; D.P.U. 24-11, Exh. NG-Net Benefits-3 (Corrected) at 13; D.P.U. 24-12, Exh. UN-Net Benefits-3 (Corrected) at 13). The Companies classified safety benefits as those that increase safety and security for the public and utility workers, which the Companies stated are typically achieved by improving the risk profiles of current assets and/or replacing them with more reliable and secure technology. The Companies classified grid reliability and resiliency benefits as those resulting from upgrades to infrastructure, grid hardening, and implementing technology to reduce the occurrence or impact of outage events and improve system performance and provide savings for customers. The Companies classified facilitation of the electrification of buildings and transportation benefits as those resulting from investments in transmission/ distribution infrastructure meant to alleviate barriers to adoption of technologies such as EVs and heat pumps. The Companies classified integration of DER benefits as those associated with improving interconnection and enabling DERs. The Companies classified avoided renewable energy curtailment benefits as those achieved through system investments aimed at alleviating capacity constraints and, in turn, eliminating the need to curtail renewable energy generation on the system. The Companies classified reduced GHG emissions and air pollutants benefits as those arising from investments that directly produce or enable reduction of GHGs and other air pollutants such as carbon dioxide, nitrogen oxides, and particulate matter. The Companies classified avoided land use impacts benefits as those achieved through deploying infrastructure that has a smaller physical footprint than traditional utility infrastructure upgrades. Finally, the Companies classified minimization or mitigation of impacts on the ratepayers of the Commonwealth benefits as those resulting from the minimization of future utility costs (D.P.U. 24-10, Exh. ES-Net Benefits-3 (Corrected) at 13; D.P.U. 24-11, Exh. NG-Net Benefits-3 (Corrected) at 13; D.P.U. 24-12, Exh. UN-Net Benefits-3 (Corrected) at 13).

c. Overview of Results

Utilizing the net benefits model discussed above, the Companies and West Monroe analyzed the costs and benefits of their proposed incremental ESMP investments for the first five years of spending from 2025 through 2029 (D.P.U. 24-10, Exh. ES-Net Benefits-1, at 21-22; D.P.U. 24-11, Exh. NG-Net Benefits-1 (Corrected) at 21-22; D.P.U. 24-12, Exh. UN-Net Benefits-1 (Corrected) at 18-19). The Companies each identified the following quantitative and qualitative benefits in their net benefits analysis for the proposed categories of investments summarized in the following two tables below (D.P.U. 24-10, Exh. ES-Net Benefits-1, at 24; D.P.U. 24-11, Exh. NG-Net Benefits-1 (Corrected) at 24; D.P.U. 24-12, Exh. UN-Net Benefits-1 (Corrected) at 21). Altogether, each company identified net benefits for its proposed ESMP investments based on the method jointly developed with West Monroe (D.P.U. 24-10, Petition at 11; Exh. ES-Net Benefits-1, at 7-8, 10-11; D.P.U. 24-11, Petition at 11; Exh. NG-Net Benefits-1 (Corrected) at 8, 11; D.P.U. 24-12, Petition at 11; Exh. UN-Net Benefits-1 (Corrected) at 5, 8).

Summary of Quantitative Benefits by Investment Category

Investment Category	Grid Reliability and Resiliency*	Facilitation of the Electrification of Buildings and Transportation*	Reduced GHG Emissions and Air Pollutants*	Minimization or Mitigation of Impacts on Ratepayers*	Economic Benefits
Network Investments	NG, UN	UN	NG, UN	NG, UN	NG, UN
Customer Investments					All
Platform Investments			All		All
Resiliency	ES, UN			ES	ES, UN
CIPs			ES, NG		ES, NG
EV Program		UN	All	NG	All
Solar			ES	ES	ES

*Indicates that benefit is required for inclusion in the net benefits analysis, per Section 92B(b). ES refers to NSTAR Electric, NG refers to National Grid, UN refers to Unitil.

(D.P.U. 24-10, Exh. ES-Net Benefits-1, at 25; D.P.U. 24-11, Exh. NG-Net Benefits-1 (Corrected) at 25; D.P.U. 24-12, Exh. UN-Net Benefits-1 (Corrected) at 22).

Summary of Non-Monetized Qualitative Benefits by Investment Category

Investment Category	Safety*	Grid Reliability and Resiliency*	Facilitation of the Electrification of Buildings and Transportation*	Integration of DERs*	Avoided Renewable Energy Curtailment*	Reduced GHG Emissions and Air Pollutants*	Avoided Land Use Impacts*	Minimization or Mitigation of Impacts on Ratepayers*	EJP Impact	Economic Benefits
Network Investments	NG, UN	NG, UN	NG, UN	NG, UN	NG, UN	NG, UN		NG, UN	NG, UN	NG, UN
Customer Investments		All	All	All	All	All	All	All	All	All
Platform Investments	All	ES		All	All	All	All		All	All
Resiliency	ES, UN	ES, UN					ES, UN	ES	ES, UN	ES, UN
CIPs	ES, NG	ES, NG	ES, NG	ES, NG	ES, NG	ES, NG		ES, NG	ES, NG	ES, NG
EV Program			All	All		All		All	All	All
Solar				ES	ES	ES		ES	ES	ES

*Indicates that benefit is required for inclusion in the net benefits analysis, per Section 92B(b). ES refers to NSTAR Electric, NG refers to National Grid, UN refers to Unitil.

(D.P.U. 24-10, Exh. ES-Net Benefits-1, at 25; D.P.U. 24-11, Exh. NG-Net Benefits-1 (Corrected) at 25; D.P.U. 24-12, Exh. UN-Net Benefits-1 (Corrected) at 22).

The table below summarizes the monetized quantitative net benefits for the first five years of expenditures on the Companies' proposed ESMP investments, from 2025 to 2029, accounting for monetized benefits and capital costs as well as any ongoing O&M costs associated with these investments:

Summary of Net Quantitative Benefits
by Investment Category ($ Millions, Nominal) and Estimated Job Impact

Investment Category	NSTAR Electric	National Grid	Unitil[129]
Network Investments	n/a	$4,182	$77.6
Customer Programs and Investments	($59)	($259)	($1.2)
Platform Investments	($41)	($470)	($2.2)
Resiliency	$380	n/a	($3.9)
CIPs	$1,091	Grouped with Network Investments	n/a
EV Program	$491	$1,541	$3.6
Solar	$68	n/a	n/a
ESMP Program Administration	n/a	($89)	($0.38)
Economic Benefits from ESMP Investments (RIMS-II Model)	$149	$502	$12.1
Total	**$2,077**	**$5,406[130]**	**$85.6**
Total Number of Indirect Jobs Created from Proposed ESMP Investments (estimated 2025-2029)	**1,169**	**3,945**	**96**

(D.P.U 24-10, Exh. ES-Net Benefits-3 (Corrected) at 18-19, 26, 32, 37, 39, 40, 44, 46; D.P.U 24-11, Exh. NG-Net Benefits-3 (Corrected) at 18-19, 26, 32, 35, 40, 42, 44; D.P.U 24-12, Exh. UN-Net Benefits-3 (Corrected) at 18-19, 26, 31, 34, 39, 40, 41, 43).

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129 Discrepancy between category subtotals and total are due to rounding.

130 Discrepancy between category subtotals and total are due to rounding.

The Companies explained that the quantitative benefits are largely driven by estimated GHG emissions and air pollutant reductions associated with the enablement of capacity to electrify transportation and buildings and assumes customer adoption of clean energy solutions (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 455; ES-Net Benefits-1, at 22-23; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 377; NG-Net Benefits-1 (Corrected) at 22-23; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 180; UN-Net Benefits-1 (Corrected) at 19-20). The table below summarizes the overall estimated net monetized benefits and costs for the proposed portfolio of incremental ESMP investments:

Summary of Monetized Benefits and Costs ($ Millions, Nominal)

Investment Category	NSTAR Electric	National Grid	Unitil
Benefits	**$2,912**	**$8,588**	**$139**
Reduced GHG Emissions and Air Pollutants	$2,045	$7,843	$114
Grid Reliability and Resiliency	$385	$122	$2.8
Minimization or Mitigation on Ratepayers	$333	$121	$10
Economic Benefits (RIMS-II Model)	$149	$502	$12.1
Costs	**$835**	**$3,182**	**$53.4**
Capital (5-year ESMP)	$609	$2,055	$49.7
O&M (5-year ESMP)	$211	$470	$2.5
Total Ongoing O&M	$15	$657	$1.2
Total	**$2,077**	**$5,406**	**$85.6**

(D.P.U 24-10, Exh. ES-Net Benefits-1, at 22; D.P.U 24-11, Exh. NG-Net Benefits-1 (Corrected) at 22; D.P.U 24-12, Exh. UN-Net Benefits-1 (Corrected) at 19).

3. Positions of the Parties

a. Attorney General

The Attorney General argues that the Companies' net benefits analyses are inadequate and fail to meet the requirements established in Section 92B (Attorney General Brief at 40, 44-45). Overall, the Attorney General asserts that the analyses lack sufficient detail, are inconsistent amongst the Companies, and fail to account for uncertainty regarding assumptions and inputs (Attorney General Brief at 40, citing Exh. AG-BF-1, at 32-44). As a result, the Attorney General argues that stakeholders and policymakers cannot clearly identify the burdens that ratepayers will be asked to bear in support of decarbonization (Attorney General Reply Brief at 15-16). To address these concerns, the Attorney General recommends that the Department require the Companies to provide additional support for their benefits calculations as part of a compliance filing (Attorney General Brief at 42, 45; Attorney General Reply Brief at 16).

The Attorney General raises several concerns with the Companies' net benefit analyses. First, the Attorney General contends that the calculation of economic benefits is over-simplified (Attorney General Brief at 41). In support of its contention, the Attorney General refers to the RIMS-II model the Companies use to calculate economic benefits, asserting that the model yields the same economic benefit for any dollar of incremental capital expenditure, i.e., economic benefits equal 24 percent of capital expenditure (Attorney General Brief at 41, citing D.P.U. 24-10, Exhs. ES-Net Benefits-1, at 11, 19; AG 2-6 & Att.; D.P.U. 24-11, Exhs. AG 1-16 & Att.; D.P.U. 24-12, Exhs. UN-Net Benefits-4, Summary Tab; AG 1-7, Att.). The Attorney General suggests that capital investments differ by type and location, and accordingly, should result in different amounts of economic benefits (Attorney General Brief at 41, citing Exh. AG-BF-1, at 37). The Attorney General also cites to negative net benefits calculations for customer and platform investments as warranting closer scrutiny of individual or groups of investments (Attorney General Brief at 41 n.29, citing Exh. AG-BF-1, at 35-36). To remedy its concerns, the Attorney General recommends that the Companies each conduct a more detailed analysis as part of the net benefits methodology and further justify its investments (Attorney General Brief at 41). The Attorney General also recommends that the Department require the Companies to explain and justify their investments with negative net benefits in future ESMP filings, and that such investments only be permitted for foundational or enabling investments (Attorney General Brief at 41 n.29).

In addition, the Attorney General argues that the Companies' benefits calculations lack any scenario or sensitivity analysis to account for inherent uncertainty in the calculations (Attorney General Brief at 41, citing Exh. AG-BF-1, at 38-39, 43-44). Specifically, the Attorney General highlights the following concerns relating to assumptions incorporated by the Companies into the benefits calculations: rates of growth of customer demand (e.g., baseline, step, EV, heat pumps, etc.); project timelines that are planned despite several risks, including siting, permitting, supply chain, and workforce challenges; static state and federal policies; and a lack of examination of the impact on benefits from adding or removing individual projects (Attorney General Brief at 42, citing Exh. AG-BF-1, at 38-39). The

Attorney General argues that the lack of sensitivity analysis regarding assumptions is magnified when analyzing the reduced GHG emission and air pollutants calculations (Attorney General Brief at 42, citing Exh. AG-BF-1, at 41-43). The Attorney General contends that with benefits calculated out to 2050 based on assumed EV and peak heat pump loads (MW), there is great uncertainty regarding the variation in potential benefits (Attorney General Brief at 42, citing Exh. AG-BF-1, at 43). The Attorney General observes that the Companies' assumptions, if incorrect, would substantially change the projected benefits (Attorney General Brief at 43, citing Exh. AG-BF-1, at 44). To address these concerns, the Attorney General recommends that the Department require the Companies to provide additional support incorporating sensitivities into their benefits calculations as part of a compliance filing, since the benefits calculations could be useful in the context of a strategic plan if the weaknesses in the calculations were addressed (Attorney General Brief at 42-43, citing Exh. AG-BF-1, at 39, 44).

Finally, the Attorney General argues that the net benefits analyses are inadequate due to the inconsistent approaches amongst the Companies (Attorney General Brief at 43). The Attorney General suggests that different approaches to cost recovery creates confusion and complicates the interpretation of benefits included in the ESMP (Attorney General Brief at 43, citing Exh. AG-BF-1, at 39). The Attorney General contends that the net benefits analyses should consider all energy sector modernization investments equally regardless of the cost recovery approach (Attorney General Brief at 44, citing Exh. AG-BF-1, at 40). The Attorney General also highlights differences over the treatment of resiliency investments as core investments versus ESMP investments as a problematic division between the Companies (Attorney General Brief at 43-44 (citations omitted)). The Attorney General further asserts that the ESMP statute requires the calculation of net benefits for projects needed to meet the Commonwealth's energy goals, which includes core investments that are necessary for ESMP investments (Attorney General Brief at 44).

b. DOER

DOER contends that, in future ESMP filings, the Department should require that the Companies describe and connect all their ongoing programs and investments to their strategic plan and identify how such programs will be optimized to maximize net benefits (DOER Brief at 12). As part of future ESMP filings, DOER further argues that the Companies should demonstrate substantial efforts in stakeholder outreach and consideration of stakeholder feedback for their ESMPs, including in calculating net benefits (DOER Brief at 13).

DOER asserts that the Companies presented investment amounts and categories differently and that this presentation hindered review of the ESMPs (DOER Brief at 38, citing Exh. DOER-1, at 42; GMAC Consultant Comments at 3, 5-6). Specifically, DOER points to variation in the Companies' inclusion of resiliency investments and network investments as part of the proposed ESMP investments (DOER Brief at 38, citing D.P.U. 24-10, Exh. ES-ESMP-1, at 435; D.P.U. 24-11, Exh. NG-ESMP-1, at 358, 431; D.P.U. 24-12, Exh. UN-ESMP-1, at 159-160). DOER suggests that the varied application of ESMP versus non-ESMP categorization of investments poses challenges for holistically evaluating and comparing the ESMPs across the Companies (DOER Brief at 39, citing GMAC Consultant Comments at 139). DOER further contends that the bifurcation of investments into ESMP and non-ESMP categories creates a separation in the net benefits analysis between (1) ESMP investments that are analyzed and (2) non-ESMP investments that are summarized (DOER Brief at 39).

DOER contends that the Department should require the ESMPs to include distributional equity and net benefits analyses that specifically address customers in EJ populations, pointing to recommendations made by the GMAC's Equity Working Group (DOER Brief at 67, citing GMAC Report at 29, 37). DOER argues that customer benefits and burdens will vary by community and customer, and the Companies need to provide more detailed information on the effects and benefits as they apply to customers in EJ populations (DOER Brief at 67). DOER cites to the Department's findings in D.P.U. 22-52 through D.P.U. 22-55 as example of an equity analysis that the Companies could consider for identifying and evaluating impacts on customers in EJ populations for localized areas (DOER Reply Brief at 15, citing D.P.U. 22-52 through D.P.U. 22-55, at 141-146). Specifically, DOER recommends that the Department direct the Companies to generate qualitative and quantitative tables of benefits and costs to customer in EJ populations in the current ESMPs (DOER Brief at 67). DOER recommends that the Companies supplement their net benefits analyses in the current and future ESMPs to include a distributional equity analysis to fully represent the outcomes of all customers (DOER Brief at 67-68; DOER Reply Brief at 14-15). In response to the Companies' argument that calculating localized benefits such as for

EJ populations as part of a net benefits analysis is inconsistent with industry standards because it would lead to false precision and inaccuracies, DOER counters that conducting a distributional equity analysis would be one way of conducting an energy equity analysis and should complement the net benefits analyses of future ESMPs (DOER Reply Brief at 14, citing GMAC Report at 37).

c. Acadia Center, CLF, and GECA

Acadia Center, CLF, and GECA argue that the net benefits analyses have multiple shortcomings, including the exclusion of non-ESMP investments (Acadia Center Brief at 26, citing GMAC Consultant Comments at 7; GECA Brief at 14-15, citing D.P.U. 24-10/D.P.U. 24-11, Exh. GECA-LC-1, at 5-6; GMAC Consultant Comments at 69; Joint Intervenor Reply Brief at 2-3). According to the Joint Intervenors, the Companies failed to comply with requirements to account for alternative investments and their corresponding benefits (GECA Brief at 14, citing Exh. GMAC Consultant Comments at 74; Joint Intervenor Reply Brief at 3). To address these concerns, the Joint Intervenors recommend the Department require the Companies to revise their net benefit analyses through a compliance filing and include both ESMP and non-ESMP investments to provide a more comprehensive assessment (Acadia Center Brief at 26; Joint Intervenor Reply Brief at 2-3).

Acadia Center asserts that the cost-benefit analysis is critically flawed by focusing only on incremental ESMP investments, making it difficult to understand the benefits and costs of the proposed plans from the broader energy sector modernization context (Acadia

Center Brief at 26). Acadia Center also raises concerns that the Companies did not file a cost-benefit analysis with their draft ESMP or at any point prior to filing their final ESMPs (Acadia Center Brief at 26, citing DOER-1, at 12-13). Finally, Acadia Center argues that because of these shortcomings in the net benefits analysis, they are not able to assess whether the ESMPs maximize net benefits or minimize rate impacts, which Acadia Center notes is flagged by the GMAC Consultants as a requirement of the statute (Acadia Center Brief at 26, citing GMAC Consultant Comments at 7).

CLF similarly argues that the cost-benefit analyses included with the ESMPs are inadequate to assess the net benefits to customers (CLF Brief at 11, citing GMAC Equity Working Group Memo at 6 (November 3, 2023); GMAC Consultant Comments at 2). CLF states that the analyses are deficient for several reasons, including the: (1) choice of the discount rate; (2) bifurcation of proposed expenditures into ESMP and non-ESMP categories; (3) selection of costs and benefits; (4) interrelated functions across investment categories; (5) lack of consideration of alternative investments that could reduce GHG emissions; and (6) exclusion of macroeconomic impacts created by changes in electric rates (CLF Brief at 11-12, citing GMAC Consultant Comments at 69-73 (additional citations omitted)). As a result of the stated deficiencies, CLF contends that the Department should not rely on the Companies' cost-benefit analyses to assess the benefits to the Commonwealth and ratepayers (CLF Brief at 12). In addition, to provide a more holistic accounting of the impacts of grid modernization, CLF asserts that the cost-benefit analyses should include a distributional equity analysis (CLF Brief at 12, citing GMAC Report at 37). Finally, CLF requests that the Department articulate a standard of review that requires the ESMPs to provide net benefits to all customers, including EJ populations (CLF Brief at 15). In doing so, CLF contends that such clarification will help guide future ESMP filings and proceedings while providing consistency across the Companies and their service territories (CLF Brief at 15).

d. Companies

The Companies argue that, in assessing net benefits, the Department considers a wide range of quantitative and qualitative benefits, including savings, impact on energy systems, reliability, environmental impacts, employment, and economic development (Companies' Joint Brief at 23-24, citing Long-Term Contracts for the Mayflower Wind Offshore Wind Energy Project, D.P.U. 20-16/D.P.U. 20-17/D.P.U. 20-18, at 51-52 (2020); Sheffield Water Company/Mountain Water Systems, D.P.U. 16-37, at 7-8 (2016); NSTAR Electric Company/Northeast Utilities, D.P.U. 10-170, Interlocutory Order on Standard of Review at 21 (March 10, 2011)). According to the Companies, the net benefits analysis should include an assessment of all monetized, quantified, and qualitative benefits, which is not a cost-effectiveness analysis like that used to evaluate EE programs under G.L. c. 25, § 21 (Companies' Joint Brief at 79, citing Second Grid Modernization Plans (Track 2) at 272-232). Based on this standard, the Companies maintain that their analyses demonstrate that their plans provide substantial quantitative and qualitative benefits that outweigh the costs (Companies' Joint Brief at 71, citing D.P.U. 24-10, Exhs. ES-Net Benefits-3 (Corrected); ES-Net Benefits-4 (Corrected); D.P.U. 24-11, Exhs. NG-Net Benefits-3 (Corrected);

NG-Net Benefits-4 (Corrected); D.P.U. 24-12, Exhs. UN-Net Benefits-3 (Corrected); UN-Net Benefits-4 (Corrected)).

The Companies contend that they developed reasonable cost estimates for their proposed ESMP investments and programs and that the budgets reflect reasonable and robust cost estimates based on the best available information at the time of drafting the ESMPs (Companies' Joint Brief at 71, 73). In general, the Companies developed cost capital and O&M cost estimates based on subject matter expertise with historical costs for similar projects adjusted as necessary (Companies' Joint Brief at 71, citing D.P.U. 24-10, Exh. DPU 1-1; D.P.U. 24-11, Exh. DPU 1-1 D.P.U. 24-12, Exh. DPU 1-1). For purposes of the net benefits assessment, based on the scale and incremental nature of the investments, each company assessed whether ongoing maintenance would be delivered through existing company resources and, if not, each company estimated additional ongoing O&M costs required to sustain the proposed ESMP investments (Companies' Joint Brief at 72, citing D.P.U. 24-10, Exhs. DPU-Common 1-9; DPU-Common 11-6; D.P.U. 24-11, Exhs. DPU-Common 1-9; DPU-Common 11-6; D.P.U. 24-12, Exhs. DPU-Common 1-9; DPU-Common 11-6).

In addition to reasonable cost estimates, the Companies argue that the net benefits model is based on reasonable assumptions and consistent with best practices (Companies' Joint Brief at 73). The Companies state they and their consultant analyzed each proposed ESMP investment to identify and, where reasonable, quantify benefits of the proposed investment (Companies' Joint Brief at 73, citing D.P.U. 24-10, Exh. ES-Net Benefits-3

(Corrected); D.P.U. 24-11, Exh. NG-Net Benefits-3 (Corrected); D.P.U. 24-12, Exh. UN-Net Benefits-3 (Corrected)). The Companies assert that the benefits analysis relies on guidance from Section 92B, industry best practices, nationally recognized methodologies used to evaluate similar types of electric utility investments, and conservative assumptions that have been previously reviewed and adopted by the Department (Companies' Joint Brief at 73 citing D.P.U. 24-10, Exh. ES-Net Benefits-1, at 10; D.P.U. 24-11, Exh. NG-Net Benefits-1, at 11; D.P.U. 24-12, UN-Net Benefits-1 (Corrected) at 8).

The Companies assert that the net benefits of each ESMP are robust (Companies' Joint Brief at 77). The Companies contend that their analyses show that customers will benefit from enhanced resiliency and reliability, minimization and mitigation of customer bills, reductions in GHG emissions and air pollution, and workforce and economic benefits (Companies' Joint Brief at 77). The Companies assert that the benefits are based on their best estimates, and that the estimates are presented in a reviewable and reliable manner along with the detailed assumptions used in the calculations (Companies' Joint Brief at 77 (citations omitted)). The Companies argue that the ESMP investments placed in service between 2025 and 2029 will yield substantial monetized net benefits before consideration of any qualitative benefits (Companies' Joint Brief at 78). Further, the Companies assert that their analyses rely on conservative benefit assumptions to ensure benefits are not overstated (Companies' Joint Brief at 78, citing D.P.U. 24-10, Exh. ES-Net Benefits-1, at 10, 34; D.P.U. 24-11, Exh. NG-Net Benefits-1 (Corrected) at 11-36; D.P.U. 24-12, Exh. UN-Net Benefits-1 (Corrected) at 8, 30).

The Companies recommend that the Department assess their ESMP investments as a portfolio, rather than by individual investment or investment category (Companies' Joint Brief at 79). The Companies emphasize that Section 92B requires that the *plan*, not individual investment(s), provide net benefits (Companies' Joint Brief at 79). If the Department were to assess net benefits by individual investment, the Companies argue that such interpretation would be contrary to Section 92B(d) and potentially limit the investments from fulfilling the objectives of the statute (Companies' Joint Brief at 79, citing Tr. 4, at 434-435, 441-445). For example, the Companies refer to platform investments, including monitoring and control systems for DERs, stating that they may result in less direct quantifiable and monetized net benefits but provide value in enhancing safety and reliability, and facilitate interconnection of DERs (Companies Joint Brief at 79, citing Tr. 4, at 443). Further, according to the Companies, these investments may also be critical enablers for future benefits beyond this initial ESMP and associated with greater integration of VPPs and flexibility into the Companies' planning and operations (Companies' Joint Brief at 79).

Additionally, the Companies recommend that the net benefits analysis apply only to incremental ESMP investments, rather than include non-ESMP investments (Companies' Joint Brief at 80). The Companies argue that including non-ESMP investments (i.e., planned and previously approved investments) in the net benefits analysis is flawed and would alter the definition, focus, and purpose of the net benefits analysis (Companies' Joint Brief at 80, citing D.P.U. 24-10, Exh. DPU-Common 11-20; D.P.U. 24-11, Exh. DPU-Common 11-20; D.P.U. 24-12, DPU-Common 11-20). The Companies contend that incorporating non-ESMP investments may significantly increase or decrease net benefits, reducing the utility of assessing ESMP investments required under Section 92B (Companies' Joint Brief at 80).

The Companies disagree with various issues raised by intervenors. In response to the Attorney General's claims that the net benefit analyses are inconsistent and inadequate, the Companies argue that the methodology and analyses are standardized across the Companies (Companies' Joint Reply Brief at 15 (citations omitted)). Furthermore, the Companies contend that a comparison of net benefits across the Companies is not a requirement of Section 92B, nor is it appropriate in determining whether a company's ESMP is designed to enable net benefits (Companies' Joint Reply Brief at 16). According to the Companies, variations in ESMP investments and the level of such investments should be expected due to the differences in size, location, and characteristics of the Companies' unique service territories (Companies' Joint Reply Brief at 15).

The Companies disagree with the Attorney General's assertion that their assumptions are flawed (Companies' Joint Reply Brief at 16). The Companies maintain that a net benefit analysis is inherently based on assumptions and the question to answer is whether the assumptions are reasonable (Companies' Joint Reply Brief at 16, citing D.P.U. 22-22, at 352; 2013-2015 Three-Year Plans, D.P.U. 12-100 through D.P.U. 12-111, at 49, 78 (2013); Western Massachusetts Electric Company, D.P.U. 91-44, at 129 (1991)). The Companies contend that their assumptions are reasonable and conservative and that they are based on customer adoption trajectories necessary to meet the state's climate goals (Companies' Joint Reply Brief at 16-17 (citations omitted)). The Companies note that the net benefits analysis incorporates qualitative benefits resulting from ESMP investments that are difficult to quantify (Companies' Joint Reply Brief at 17). The Companies assert that the Attorney General's consultant specifically identified only one assumption in the net benefits analysis involving reliance on the RIMS-II model to estimate economic benefits that it claimed was unreliable, and counter that this assumption and underlying model is in fact a reasonable, reliable industry standard practice addressing how each dollar of capital investment stimulates additional economic activity and job creation across various sectors of the local economy (Companies' Joint Reply Brief at 17-18, citing D.P.U. 24-10, Exhs. ES-Net Benefits-1, at 19; AG 2-12; D.P.U. 24-11, Exhs. NG-Net Benefits-1, at 19; AG 1-22; D.P.U. 24-12, Exhs. UN-Net Benefits-1 (Corrected) at 16; AG 1-12).

With regard to sensitivity analysis across various input assumptions included in the net benefits analysis, the Companies argue that they did conduct numerous sensitivity analyses, but that accounting for a broader range of scenarios as called for by the Attorney General would lack rigor and would not be responsive to the requirements of Section 92B(d) (Companies' Joint Reply Brief at 18-19, citing D.P.U. 24-10, Exh. AG 2-9; D.P.U. 24-11, Exh. AG 1-19; D.P.U. 24-12, Exh. AG 1-9). The Companies assert that Section 92B(c)(i) requires a single demand assessment, rather than multiple assessments, that projects demand based on the state's current policies (Companies' Joint Reply Brief at 20). The Companies reiterate their willingness to work with the GMAC to develop reasonable scenarios for sensitivity analyses for future long-term demand assessments, including a commitment to align forecasts as much as possible (Companies' Joint Reply Brief at 20, citing

D.P.U. 24-10, Exh. DPU-Common 7-5; D.P.U. 24-11, Exh. DPU-Common 7-5; D.P.U. 24-12, Exh. DPU-Common 7-5).[131]

Regarding distributional equity analysis in addition to a net benefit analysis, the Companies disagree with recommendations from DOER and CLF for the Department to direct the Companies to conduct such an analysis (Companies' Joint Reply Brief at 20-21). The Companies assert that such an analysis is undefined, the Department has no evidentiary record to justify mandating the use of such an analysis, and this issue was not raised until the briefing phase (Companies' Joint Reply Brief at 21). As part of the net benefits analysis, the Companies argue that they assessed the potential benefits of the ESMPs to EJ populations and found that their plans enable reductions in air pollutants in these communities (Companies' Joint Reply Brief at 21, citing D.P.U. 24-10, Exhs. ES-Net Benefits-3 (Corrected); DPU-Common 9-20; D.P.U. 24-11, Exhs. NG-Net Benefits-3 (Corrected); DPU-Common 9-20; D.P.U. 24-12, Exhs. UN-Net Benefits-3 (Corrected); DPU-Common 9-20). Regarding costs, the Companies contend that there are no specific costs to EJ populations because the ESMP costs are socialized to all customers (Companies' Joint Reply Brief at 21-22 (citations omitted)). The Companies argue that assessing the potential range of benefits and burdens on communities falls outside the scope of the ESMP as a strategic plan (Companies' Joint Reply Brief at 22). To the extent stakeholders are concerned with the potential infrastructure burden of ESMP investments on a community, the

131 The Department addresses arguments relating to the demand assessments in further detail in Section VI.C.

Companies contend that they will address these issues during ESMP implementation, including through the siting and permitting process (Companies' Joint Reply Brief at 22, citing D.P.U. 24-10, Exh. DPU 4-2; D.P.U. 24-11, Exh. DPU 4-3; D.P.U. 24-12, Exh. DPU 3-4).

Additionally, the Companies argue that conducting an economic benefit analysis at a more granular level as advocated by the Attorney General is not a best practice or typically done in such a net benefits analysis (Companies' Joint Reply Brief at 18, citing Tr. 4, at 494). According to the Companies, such an analysis leads to false precision and inaccuracies and will provide little additional value in a net benefits analysis (Companies' Joint Reply Brief at 18, citing Tr. 4, at 493-494). The Companies maintain that consideration should also be given to the administrative burden associated with conducting an atypical, complex exercise to establish a very localized economic impact analysis, rather than using an established, reliable tool (Companies' Joint Reply Brief at 18).

Finally, the Companies disagree with the Attorney General, Acadia Center, and DOER that their net benefits analyses are flawed for failure to include all potential investments that may occur over the next five years, arguing that these criticisms are misplaced in understanding the purpose of the analysis (Companies' Joint Reply Brief at 22-23). The Companies claim that the intervenors misunderstand the purpose of the ESMP under Section 92B (Companies' Joint Reply Brief at 23). Rather than a comprehensive distribution plan for all planned investments, the Companies argue that the ESMP is a five-year plan for incremental investments to achieve specific Section 92B objectives, including to proactively upgrade the distribution system (Companies' Joint Reply Brief at 23). The Companies disagree that the net benefits analysis should include all potential distribution investments (Companies' Joint Reply Brief at 23-24).

4. Analysis and Findings

a. Introduction

Section 92B sets forth the Department's authority to review and approve ESMPs and, as a condition for approval, requires that a plan "shall provide net benefits for customers[.]" Section 92B(b) identifies the following customer benefits that must be addressed by the Companies for all proposed investments and alternative approaches to those investments: (1) safety; (2) grid reliability and resiliency; (3) facilitation of the electrification of buildings and transportation; (4) integration of DERs; (5) avoided renewable energy curtailment; (6) reduced GHG emissions and air pollutants; (7) avoided land use impacts; and (8) minimization or mitigation of impacts on the ratepayers of the Commonwealth. Evaluation of the net benefits of the Companies' ESMPs necessarily requires review of the Companies' cost estimates. Interlocutory Order on Scope at 16. For purposes of the ESMP net benefits analysis, the Department reviews the costs and benefits of the proposed planning solutions in the context of strategic planning documents only, i.e., not for purposes of cost recovery. Interlocutory Order on Scope at 2, 16, 18.

In preparation for their filings, the Companies coordinated on the net benefits method to be applied to their proposed ESMP investments and submitted documentation in their filings applying that method to those investments (D.P.U. 24-10, Exhs. ES-ESMP-1

(Corrected) at 450; ES-Net Benefits-3 (Corrected); ES-Net Benefits-4 (Corrected); AG 2-15; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 373; NG-Net Benefits-3 (Corrected); NG-Net Benefits-4 (Corrected); AG 1-25; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 175; UN-Net Benefits-3 (Corrected); UN-Net Benefits-4 (Corrected. AG 1-15). The method utilized by the Companies analyzed the benefits of their proposed investments based on the factors listed in Section 92B(b) and, via the RIMS-II model, economic benefits such as indirect job impacts and workforce development (D.P.U. 24-10, Exhs. ES-Net Benefits-1, at 11, 19-20, 22; ES-Net Benefits-3 (Corrected) at 8, 10, 14, 18-19; D.P.U. 24-11, Exhs. NG-Net Benefits-1 (Corrected) at 11, 19-20, 22; NG-Net Benefits-3 (Corrected) at 8, 10, 14, 18-19; D.P.U. 24-12, Exhs. UN-Net Benefits-1, at 9, 16-17, 19; UN-Net Benefits-3 (Corrected) at 8, 10, 14, 18). Altogether, each company calculated positive net benefits for its proposed ESMP investments collectively (D.P.U. 24-10, Exhs. ES-Net Benefits-1, at 22, 34; ES-Net Benefits-3 (Corrected) at 5; D.P.U. 24-11, Exhs. NG-Net Benefits-1 (Corrected) at 22, 37; NG-Net Benefits-3 (Corrected) at 5; D.P.U. 24-12, Exhs. UN-Net Benefits-1, at 19, 31; UN-Net Benefits-3 (Corrected) at 5).

Multiple intervenors critique the inputs and methods relied on by the Companies for purposes of calculating net benefits, including: (1) exclusion of non-ESMP and alternative investments, more granular locational data and data specific to EJ populations, macroeconomic impacts created by changes in electric rates, and a sensitivity analysis based on variations in input assumptions; (2) differing classifications of certain investments between investment categories; (3) method of calculating economic benefits; and (4) choice of the discount rate. The Attorney General points to negative net benefits calculations for particular investment categories as the reason for closer scrutiny of individual or groups of investments and recommends that the Companies each conduct a more detailed analysis as part of the net benefits methodology to further justify those investments. Acadia Center raised concerns involving the Companies' failure to file a net benefits analysis with the GMAC prior to the filing with the Department, and DOER urges that the Department require the Companies in future ESMP filings to obtain substantial outreach and feedback in calculating their net benefits. Several intervenors also request that the Department require the Companies to each submit a compliance filing to address perceived deficiencies in the Companies' net benefits analyses.

The Companies argue that their ESMPs provide net benefits based on reasonably identified costs and monetized, quantitative customer benefits, and as well as qualitative benefits, and that they utilized a standardized method and related inputs that are based on reasonable assumptions and consistent with best practices. The Companies maintain that reliance on proposed ESMP rather than non-ESMP investments as a portfolio in their analyses was appropriate and consistent with Section 92B, that assessing the potential range of benefits and burdens on communities falls outside the scope of the ESMPs as strategic plans, and that locational and EJ analyses will be addressed during ESMP implementation, including through the siting and permitting process.

For the reasons discussed below, the Department finds that NSTAR Electric, National Grid, and Unitil have established net benefits for their ESMPs using a reasonable method and inputs. Further, we address the intervenors' arguments on this issue.

b. Contested Inputs

i. Non-ESMP and Alternative Investments

In determining whether each company's proposed plans provide net benefits, the Department evaluates the method and inputs relied on by the Companies. As cases of first impression under Section 92B, the Department first looks to the statute and then our precedent in other matters where needed to guide our analysis. Accordingly, based on our review of the statute, as discussed in Section IV.C.2., we find reasonable and appropriate the Companies' omission of non-ESMP investments from their net benefits analyses. More specifically, a net benefits analysis to be conducted pursuant to Section 92B(d) involves only those "discrete, specific, enumerated investments" proposed by the Companies in accordance with Section 92B(e). As such, as well as for the reasons discussed in Section VII.D.4., we also decline to require that alternatives to proposed investments be incorporated into the net benefits analysis, with the exception of non-traditional investment alternatives, e.g., NWAs and ESS projects, submitted as part of the portfolio of proposed ESMP projects. Further, while the Section 92B(b) list of benefits appropriately informs the net benefits analysis required under Section 92B(d), Section 92B(d) does not direct a particular method or inputs in the Department's assessment of net benefits or, more specifically, require that the net benefits analysis also include inputs for alternatives to proposed investments. As a result, we find that the Legislature left largely to the Department's discretion how to analyze the net benefits of the proposed plans, and we decline to require that the ESMP net benefits analyses include non-ESMP or alternatives to proposed ESMP investments.

ii. Portfolio Approach

Regarding each company's use of a portfolio of investments in establishing net benefits, we find this approach reasonable and consistent with the express terms of the statute. In particular, Section 92B(d) expressly requires that a *plan*, rather than discrete investments, provide net benefits for customers to be approved by the Department. Although negative net benefits may be calculated for particular investments or categories of investments under the method utilized by the Companies, the Legislature clearly intended for the Department to review the net benefits of a plan as a whole.

This approach is also consistent with that taken by the Department in our prior grid modernization proceedings in analyzing the composite business case submitted by each company in those proceedings for purposes of preauthorization. D.P.U. 12-76-C ("we conclude that a composite business case will provide a more comprehensive view of the proposed [short-term investment plan] by examining the costs and benefits of the full package of grid modernization investments"); see generally Second Grid Modernization Plans (Track 2) at 155, 174, 189, 222-232, 244-253, 265-272; Grid Modernization Order at 115-116, 137, 149-153, 156-162, 165-171. The Department has observed that stand-alone projects may be interrelated to such an extent that these projects are more appropriately examined as part of a single analysis and that many technologies that are required to enable grid modernization functionalities can be leveraged to achieve improvements in multiple objectives and, similarly, a business case is a composite analysis of interrelated categories of investments. Second Grid Modernization Plans (Track 2) at 298; D.P.U. 12-76-C at 6. Here, each company presents its plan and proposed investments (and corresponding net benefits analysis) as an interrelated whole (D.P.U. 24-10, Exh. ES-Net Benefits 1, at 10-11, 21; D.P.U. 24-11, Exh. NG-Net Benefits-1 (Corrected) at 11, 21; D.P.U. 24-12, Exh. UN-Net Benefits-1 (Corrected) at 8, 18). Thus, the Department declines to require the Companies to provide further support for categories of investments estimated to have negative net benefits, as suggested by the Attorney General, and the Department finds no deficiency in the interrelated functions across investment categories, as suggested by CLF, in the Companies' presentation of net benefits.

iii. Locational-Specific and Distributional Equity Considerations

Section 92B(b) provides a non-exclusive list of benefits that each company must identify for its proposed investments, and Section 92B(d) does not require a specific method by which the Department must analyze net benefits other than at the plan level. Because each company's net benefits analysis appropriately takes a holistic, service territory-wide approach to estimating the net benefits of the proposed ESMP investments consistent with the statutory framework and Department precedent, the Department declines to require each company to provide a locational-specific or distributional equity analysis, or to identify specific EJ population benefits, for its net benefits analysis as either a compliance filing in these proceedings or through the net benefits analysis in the next ESMP. Moreover, the record reflects that use of locational-specific values in a net benefits analysis is not industry practice and may result in false precisions or inaccuracies without further development (see Tr. 4, at 489-494). Further, for major infrastructure projects (e.g., CIPs and new substations) in particular, a distributional equity analysis[132] and impacts to specific EJ populations would be better addressed in the extended Provisional Program filings or the forthcoming LTSPP, similar to the requirements already applied to Provisional Program projects and projects submitted to the EFSB for review (see D.P.U. 24-10, Exh. DPU 4-2; D.P.U. 24-11, Exh. DPU 4-3; D.P.U. 24-12, Exh. DPU 3-4). See, e.g., Appendix A, § F (CIP Filing Checklist); D.P.U. 22-52 through D.P.U. 22-55, at 141-146; NSTAR Electric Company, EFSB 22-01, at 155-164 (2022) (assessing EJ and language access in reviewing requirements related to a new substation). Thus, requiring such an analysis at the strategic plan level for purposes of establishing net benefits could be duplicative. While we decline to require additional considerations to be included in the net benefits analysis at this time, we may revisit this issue, in particular distributional equity, in future iterations of ESMP filings if we determine it is warranted.

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[132] A distributional equity analysis could be presented in the form of a cumulative impacts analysis. The Legislature is considering language that could require an electric distribution company to conduct a cumulative impacts analysis as part of future EFSB proceedings. "An Act Upgrading the Grid and Protecting Ratepayers," 2024 S.2838, §§ 73, 82, 88, 94; "An Act Accelerating a Responsible, Innovative and Equitable Clean Energy Transition, 2024 H.4884, §§ 30, 39, 42, 51. The Department may find EFSB discussions relating to cumulative impacts analysis to be informative for matters within our jurisdiction.

To inform future analyses, however, the Department directs the Companies to provide a narrative in their next ESMP filings that discusses equity-specific benefits[133] for their planned and proposed investments, which the Department anticipates will be informed by the distributional equity framework[134] to be developed by each company. In the interim, the Department will also explore equity-related metrics and reporting requirements, as well as requirements on locational values and/or case studies on particular investments, in a subsequent phase of these proceedings. See Section X.D. and Section XI.D.

iv. Economic Benefits

Next, as noted above, the Companies incorporated estimated economic and workforce benefits into their net benefits analyses using the RIMS-II model developed by the U.S. Department of Commerce (D.P.U. 24-10, Exhs. ES-Net Benefits-1, at 11, 19; ES-Net Benefits-3 (Corrected) at 7-8, 10, 14, 18-19; D.P.U. 24-11, Exhs. NG-Net Benefits-1 (Corrected) at 11-12, 18-19; NG-Net Benefits-3 (Corrected) at 7-8, 10, 14, 18-19; D.P.U. 24-12, Exhs. UN-Net Benefits-1 (Corrected) at 9, 15-16; UN-Net Benefits-3 (Corrected) at 7-8, 10, 14, 18-19). The model leverages a region-specific capital multiplier for Massachusetts, which the Companies applied to their estimated capital expenses for their proposed ESMP investments, as well as separate estimates attributed to their core and other

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133 To be clear, the Department does not require this for the whole-of-plan net benefits analysis.

134 The Department discusses requirements relating to distributional equity in further detail in Section VII.H.4.

planned investments during the ESMP term (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 659-661; AG 2-12; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 473-475; AG 1-22; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 282-286; AG 1-12). Unlike the other estimated benefit breakdowns provided for each investment category, the Companies estimated the economic benefits at the plan level (see D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 659-660; ES-Net Benefits-3 (Corrected) at 8, 10, 26; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 473-474; NG-Net Benefits-3 (Corrected) at 8, 10, 26; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 282-284; UN-Net Benefits-3 (Corrected) at 8, 10, 26). The Attorney General argues that the Companies' economic benefits calculations are oversimplified in applying this model at the plan level (Attorney General Brief, citing Exh. AG-BF-1, at 36-37); however, neither the Attorney General nor other intervenors otherwise dispute the Companies' reliance on the RIMS-II model in calculating the workforce and economic benefits of their proposed plans. Accordingly, the Department finds the Companies' reliance on and application of the RIMS-II model for purposes of calculating economic and workforce benefits at the plan-level reasonable and appropriate for these inaugural ESMPs. For their next ESMP filings, however, we direct the Companies to also provide detail at the investment category (e.g., Network Investments, Customer Investments, etc.) level of any economic benefits identified with the proposed plans. To the extent there are any limitations or shortcomings to such an approach, the Companies shall identify such in their filings.

v. Investment Categorization

Intervenors also express frustration in analyzing the net benefits analyses based on how the Companies assign particular investments to different investment categories (Attorney General Brief at 43-44; DOER Brief at 38-39; Joint Intervenor Reply Brief at 2-3). For instance, NSTAR Electric and Unitil each include resiliency as a category in their incremental ESMP investments and net benefits analysis, and National Grid includes resiliency investments in its core spending to be recovered through base rates or its proposed Infrastructure, Safety, Reliability, and Electrification ("ISRE") mechanism addressed in its pending base distribution rate proceeding in Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 23-150 (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 435; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 374; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 160). Additionally, NSTAR Electric incorporates proposed integrated energy planning investments into its customer investments category while National Grid incorporates proposed integrated energy planning investments into its network investments category (D.P.U. 24-10, Exh. ES-Net Benefits-1, at 14; D.P.U. 24-11, Exh. NG-Net Benefits-1 (Corrected) at 13).

The Department recognizes that each company will propose ESMP investments that align with the unique needs of the distribution system and customers in the company's service territory. As such, and as discussed in Section VII.C.4.b.i., it is at the discretion of each company based on the unique needs of its system to decide whether to propose an investment as an ESMP investment in accordance with the requirements under Section 92B or to incorporate the investment into its core investments. Thus, the differing treatments by the Companies of resiliency investments in the current ESMPs is reasonable. At the same time, for future plan filings, to facilitate comparison and review between the Companies' plans, the Department has instructed the Companies to better coordinate[135] to ensure that proposed ESMP investments are consistently incorporated into the same investment categories, e.g., integrated energy planning. See Section VII.C.4.b.i. For purposes of a composite, plan-level net benefits analysis, however, whether an investment is more appropriately classified as one investment category over another does not change the final outcome of the overall analysis.

vi. Sensitivity Analysis

Regarding the Attorney General's argument that the Companies' benefits calculations lack any scenario or sensitivity analysis to account for inherent uncertainty in the calculations (Attorney General Brief at 41), the record reflects that, contrary to the Attorney General's assertions, West Monroe conducted a sensitivity analysis with "low," "base," and "high" case scenarios across a subset of assumptions in the net benefits model, which the Companies identified as meaningful drivers of the overall benefits (D.P.U. 24-10, Exh. AG 2-9 & Att.; D.P.U. 24-11, Exh. AG 1-19 & Att.; D.P.U. 24-12, Exh. AG 1-9 & Att.). Specifically, West Monroe assessed sensitivities involving: (1) the discount rate, namely, the WACC

[135] The Department acknowledges the limited time afforded by the Legislature to the Companies to coordinate and propose comprehensive ESMPs and anticipates that consistent categorization of proposed ESMP investments will be easily resolved ahead of the next term filings.

most recently approved for each company by the Department (low and base cases) versus a two percent discount rate recommended by the GMAC (high case); (2) the societal cost of carbon ("SCC") most recently included in the 2022 through 2024 EE plans (low and base cases) versus a more recent value released by the U.S. Environmental Protection Agency (high case); (3) EV and heat pump enablement, with estimated adoption rates ten percent lower than the base case estimate (low case) and ten percent higher than the base case estimate (high case) deriving from the Massachusetts CECP residential heating forecasts; and (4) an electric generation emissions factor, utilizing the emissions factors provided in the 2022 through 2024 EE plans (low case) against a dynamic emissions factor that decreases through 2050 (base and high cases) (D.P.U. 24-10, Exh. AG 2-9 & Att.; D.P.U. 24-11, Exh. AG 1-19 & Att.; D.P.U. 24-12, Exh. AG 1-9 & Att.). The sensitivity analyses conducted for the Companies are consistent with those envisioned and required in the grid modernization proceedings. See, e.g., D.P.U. 12-76-C, at 18 (determining that a company-specific WACC is the appropriate discount rate); D.P.U. 12-76-A at 21 (directing the grid modernization sensitivity analysis to include at least three separate case scenarios that would show how the benefit-cost analysis would change when the company alters key assumptions"). Accordingly, the Department finds reasonable the sensitivities used by the Companies and West Monroe in developing and examining the net benefits analyses.

The Department observes, however, that the Companies did not explicitly address in their initial filings the sensitivities performed for the net benefits analyses, other than a passing mention in response to a GMAC recommendation (D.P.U. 24-10/D.P.U. 24-11/

D.P.U. 24-12, Exhs. ES-Net Benefits-2/NG-Net Benefits-2/UN-Net Benefits-2, at 16 (GMAC Recommendation 85).[136] Rather, the Companies provided those details and performed additional related analyses during discovery, including impacts on net benefits assuming: (1) cost increases/decreases of ten and 25 percent for proposed ESMP investments; (2) service lives of investments plus-or-minus two, three, and four years; and (3) adjustments to SCC values and values attributed to EV program adoption rates (D.P.U. 24-10, Exhs. DPU-Common 1-11 & Att.; DPU-Common 9-9 & Att.; DPU-Common 11-15 & Att.; AG 2-9 & Att.; D.P.U. 24-11, Exhs. DPU-Common 1-11 & Att.; DPU-Common 9-9 & Att.; DPU-Common 11-15 & Att.; AG 1-19 & Att.; D.P.U. 24-12, Exhs. DPU-Common 1-11 & Att.; DPU-Common 9-9 & Att.; DPU-Common 11-15 & Att.; AG 1-9 & Att.). To limit the need for discovery on this issue in future ESMP filings, the Department directs the Companies to address and provide summaries of the sensitivity analyses conducted for all inputs that significantly affect the results of the model. At a minimum, each company should include a sensitivity analysis on the discount rate, the estimates for the proposed costs of the ESMP investments, the service lives of proposed ESMP investments, the SCC, amount of carbon reduction achieved through ESMP investments, and percentage of the EV forecast attributable to a company's EV program, in addition to other elements deemed appropriate by the Companies (see D.P.U. 24-10, Exhs. ES-Net Benefits-1 (Corrected) at 23; DPU-Common 1-11,

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136 The Companies did, however, discuss the sensitivity analyses performed in relation to their forecasts and demand assessments addressed in Section VI.

DPU-Common 9-9, DPU-Common 11-15; D.P.U. 24-11, Exhs. NG-Net Benefits-1 (Corrected) at 23; DPU-Common 1-11, DPU-Common 9-9, DPU-Common 11-15; D.P.U. 24-12, Exhs. UN-Net Benefits-1 (Corrected) at 20; DPU-Common 1-11, DPU-Common 9-9, DPU-Common 11-15).

vii. Additional Considerations

DOER urges the Department to require the Companies to describe and connect all their ongoing programs and investments to their strategic plan and identify how such programs will be optimized to maximize net benefits (DOER Brief at 12). The Department declines to make such a finding, i.e., to direct the Companies to optimize their non-ESMP investments to maximize the net benefits of their ESMP investments. While the statute requires ESMP investments to provide net benefits for customers, it does not require the Companies to select or plan investments to maximize net benefits. Indeed, other priorities, such as mitigating the cost to ratepayers or ensuring system needs to provide safe and reliable service, may be equally as or more important when the company plans its investments. Regarding the suite of ESMP investments proposed by each company, however, the Department expects the Companies to maximize the benefits of their proposed investments, to the extent practicable.

c. Net Benefits Method

The Department now turns our attention to the overall net benefits analysis provided by the Companies in their filings. As noted above, to guide our own analysis, we first look to the statute and then to our precedent for guidance. Section 92B(d) does not prescribe the method or factors on which the Department should rely in determining whether a plan provides net benefits. The Department also found that the Companies' inclusion of the customer benefits identified in Section 92B(b) and the addition of economic benefits was appropriate and reasonable.

In assessing net benefits and similar standards, the Department has previously considered a wide range of qualitative and quantitative benefits in comparison to estimated costs. See Second Grid Modernization Plans (Track 2) at 222-232, 244-253, 265-272; D.P.U. 20-16/D.P.U. 20-17/D.P.U. 20-18, at 46, 48-52; Eversource Energy/Macquarie Utilities, D.P.U. 17-115, at 8-10 (2017); D.P.U. 12-76-C at 12-13, 24-25. The underlying assumptions and estimates relied upon must be reasonable. See D.P.U. 22-22, at 352; Second Grid Modernization Plans (Track 2) at 137, 223; D.P.U. 17-115, at 27. In the context of mergers, the Department has stated that projections of future events can be judged in terms of whether they are substantiated by past experience and supported by logical reasoning founded on sound theory. D.P.U. 10-170-B at 57 (2012); Boston Gas Company/Essex Gas Company, D.P.U. 09-139, at 19-20 (2010); National Grid/KeySpan Corporation, D.P.U. 07-30, at 27 (2010); NEES/EUA Merger, D.T.E. 99-47, at 50 (2000). In grid modernization, acknowledging the uncertainties inherent in planning estimates, the Department instructed that the electric distribution companies provide their best estimates of the costs and benefits at the time a short-term investment plan is submitted to the Department. Second Grid Modernization Plans (Track 2) at 223; D.P.U. 12-76-C at 13, 38.

As an initial matter, the Department finds that the Companies were reasonable in their use of assumptions and inputs. As described above, the Companies jointly hired a third-party consultant, West Monroe, to develop a method to analyze the net benefits of the ESMPs, and the consultant used values and net benefits capture methods, where possible, that have been utilized and accepted in past Department proceedings (D.P.U. 24-10, Exhs. ES-Net Benefits-1, at 7-8, 11, 17; AG 2-4; AG 2-9 & Att.; D.P.U. 24-11, Exhs. NG-Net Benefits-1 (Corrected) at 8, 11, 17; AG 1-14; AG 1-19 & Att.; D.P.U. 24-12, Exhs. UN-Net Benefits-1 (Corrected) at 5, 8, 14; AG 1-4; AG 1-9 & Att.). 2022-2024 Three Year EE Plans at 167-176. Each company provided a composite net benefits analysis using a discount rate commensurate with the company's WACC, as well as comparisons of nominal and present value costs and benefits (D.P.U. 24-10, Exhs. ES-Net Benefits-1, at 17; ES-Net Benefits-3 (Corrected) at 26, 32, 34; D.P.U. 24-11, Exhs. NG-Net Benefits-1 (Corrected) at 17; NG-Net Benefits-3 (Corrected) at 26, 32, 34; D.P.U. 24-12, Exhs. UN-Net Benefits-1 (Corrected) at 14; UN-Net Benefits-3 (Corrected) at 26, 31, 33). The Companies submitted their best estimates of ESMP investment costs, both capital and O&M, based on subject matter expert analyses and costs for similar projects (D.P.U. 24-10, Exh. DPU-1-1; D.P.U. 24-11, Exh. DPU-1-1; D.P.U. 24-12, Exh. DPU-1-1).[137] For

[137] At a future date, assuming the company moves forward on the proposed investments, each investment would be subject to a detailed engineering analysis and follow the company's competitive procurement and project approval processes, as appropriate for the category of investment (D.P.U. 24-10, Exhs. DPU 1-1; DPU-Common 10-2; D.P.U. 24-11, Exhs. DPU 1-1; DPU-Common 10-2; D.P.U. 24-12, Exhs. DPU 1-1; DPU-Common 10-2).

consistency with the duration of the benefits assessment, the model also includes estimates of the ongoing operational costs of proposed investments over the lifetime of each asset or out to 2050, whichever occurs sooner, for those investments that would be in service by 2029 (D.P.U. 24-10, Exh. ES-Net Benefits-1, at 21-22; D.P.U. 24-11, Exh. NG-Net Benefits-1 (Corrected) at 21-22; D.P.U. 24-12, Exh. UN-Net Benefits-1 (Corrected) at 18-19). Additionally, the Companies included monetized quantitative and qualitative benefits in their net benefits analyses derived from each category of benefits identified in Section 92B(b) and the addition of an economic benefits consideration using the RIMS-II model (D.P.U. 24-10, Exhs. ES-Net Benefits-1, at 11, 19-24; ES-Net Benefits-3 (Corrected) at 29; D.P.U. 24-11, Exhs. NG-Net Benefits-1 (Corrected) at 11-12, 18-24; NG-Net Benefits-3 (Corrected) at 29; D.P.U. 24-12, Exh. UN-Net Benefits-1 (Corrected) at 9, 15-21). Further, the consultant conducted a sensitivity analysis with "low," "base," and "high" case scenarios across a subset of assumptions in the net benefits model, involving meaningful drivers of the overall benefits (D.P.U. 24-10, Exh. AG 2-9 & Att.; D.P.U. 24-11, Exh. AG 1-19 & Att.; D.P.U. 24-12, Exh. AG 1-9 & Att.).

As the Department has found previously, this type of analysis is valid for evaluating the net benefits to customers of proposed investments. See Grid Modernization Order, at 224-232; Grid Modernization Order at 141; D.P.U. 12-76-C at 6-7, 11-12. Accordingly, because the net benefits analysis methods the Companies used to support their proposed investments rely upon established and appropriate methods, the Department finds that the net benefits analysis produces reasonable estimates of costs and benefits.

For the Department to determine that the proposed ESMP investments will provide net benefits to customers, the Department must compare their estimated costs and benefits. Based on the results of the net benefits model, the Companies estimate that monetized, quantitative benefits will exceed the total costs of the investments, with a nominal value of $2.08 billion for NSTAR Electric, $5.41 billion for National Grid, and $85.6 million for Unitil (D.P.U. 24-10, Exh. ES-Net Benefits-1, at 22; D.P.U. 24-11, Exh. NG-Net Benefits-1 (Corrected) at 22; D.P.U. 24-12, Exh. UN-Net Benefits-1 (Corrected) at 19). To determine whether ESMP investments provide net benefits for customers, the Department also considers whether additional qualitative benefits will accrue to the Companies' ratepayers over the lifetime of each asset or out to 2050, whichever occurs sooner. As described above, the Companies have identified numerous qualitative benefits accruing to ratepayers over the term of the proposed investments, including: safety, grid reliability and resiliency, facilitation of the electrification of buildings and transportation, integration of DERs, avoided renewable energy curtailment, reduced GHG emissions and air pollutants, avoided land use impacts, minimization or mitigation of impacts on ratepayers, EJ population impacts, and economic benefits (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 443-461, 652-663; ES-Net Benefits-3 (Corrected) at 14; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 372-384, 466-476; NG-Net Benefits-3 (Corrected) at 14; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 168-187, 275-287; UN-Net Benefits-3 (Corrected) at 14). Based on these considerations, the Department finds that the Companies have demonstrated there are net benefits to customers, considering both quantitative and qualitative benefits, associated with their proposed ESMP investments. Accordingly, the Department finds that each company has established the net benefits of its proposed ESMP in accordance with Section 92B(d) and in the context of strategic plans.

Finally, as noted above, the net benefits analyses use preliminary cost estimates (D.P.U. 24-10, Exhs. DPU 1-1; DPU-Common 10-2; D.P.U. 24-11, Exhs. DPU 1-1; DPU-Common 10-2; D.P.U. 24-12, Exhs. DPU 1-1; DPU-Common 10-2), and these values may change significantly over time. Additionally, proposals for particular investments, including those applicable to the CIPs to be filed as part of the Provisional Program extension or filings to extend each company's EV program, will be subject to further analysis and review. As such, the Department reiterates that we are not pre-approving or preauthorizing any proposed ESMP costs or investments identified in these proceedings. Interlocutory Order on Scope at 2, 17, 18-19, 23. Further, our finding of net benefits here, and the costs identified therein, should not be relied on in any future filings seeking pre-approval of investments or budgets relating to these investments or for subsequent prudency reviews.

d. GMAC Review

In developing a plan, Section 92B(c)(iii) requires each electric distribution company to solicit input, such as planning scenarios and modeling, from the GMAC. In their ESMP filings with the Department, each electric distribution company must submit a demonstration of the GMAC's review, input, and recommendations. G.L. c. 164, § 92B(d). During the process of reviewing the draft plans, the GMAC did not have the opportunity to review each company's finalized net benefits model or analyses, which the Companies attribute to timing constraints between the 2022 Clean Energy Act's enactment and the September 1, 2023, draft filing deadline to analyze the new statutory framework, receive initial stakeholder feedback, develop the required forecasts and demand assessments, and analyze and compile potential projects to meet the anticipated demand within an as yet to be defined net benefits framework (D.P.U. 24-10, Exh. AG 2-4; D.P.U. 24-11, Exh. AG 1-14; D.P.U. 24-12, Exh. AG 1-4; GMAC Report at 9). The Companies do not anticipate the same challenges for the next ESMP filings (D.P.U. 24-10, Exh. AG 2-4; D.P.U. 24-11, Exh. AG 1-14; D.P.U. 24-12, Exh. AG 1-4).

The record reflects, however, that the Companies sought and received input from the GMAC in developing their net benefits method, and the GMAC provided overall recommendations in the development of the net benefits method and inputs (D.P.U. 24-10/ D.P.U. 24-11/D.P.U. 24-12, Exh. ES-Net Benefits-2/NG-Net Benefits-2/UN-Net Benefits-2; D.P.U. 24-10, Exhs. ES-Net Benefits-3 (Corrected) at 7; AG 2-4; D.P.U. 24-11, Exhs. NG-Net Benefits-3 (Corrected) at 7; AG 1-14; D.P.U. 24-12, Exhs. UN-Net Benefits-3 (Corrected) at 7; AG 1-4). The Department also observes that the timeframes afforded to the Companies, the GMAC, and the Department in consideration of the scale and breadth of factors to be considered under Section 92B were incredibly compressed and all parties, including the Department, have worked diligently to meet the statutory requirements. Accordingly, the Department finds that the Companies have complied with the statutory requirements in seeking GMAC input on their net benefits model. For future ESMP filings, the Department directs the Companies to include the details of their net benefits model, method, and analysis, including assumptions relied upon and sensitivities conducted in their draft plans provided to the GMAC.

e. Framework for Review for Future Plans

The Department finds the current net benefits model useful for informational purposes, particularly as it highlights the ways in which each investment category drives quantitative benefits. As described above, the Department finds reasonable and approves the use of values and method used by the Companies, the portfolio-level analysis of investments, and the omission of non-ESMP and alternatives to proposed investments from inclusion in the net benefits analysis. The Department directs the Companies to retain a similar framework for future net benefits analyses which, due to the consistent approach used by the Companies, facilitates comparisons between plans. However, the Department directs the Companies to include additional details and considerations to their future net benefits analyses as described above, namely: the analysis of economic benefits by investment category and the inclusion of the results of sensitivity analyses incorporating variations in assumptions and inputs into the net benefits analysis. The Companies shall also include a narrative with qualitative and quantitative data on equity benefits within their plans.

f. Conclusion

The Department finds that each plan provides net benefits for customers in accordance with Section 92B(d). The Department also directs the Companies to make certain changes to future net benefits analyses and to include certain benefits narratives in their plans, as described above.

J. Conclusion

Section 92B(d) states that the Department shall approve, approve with modification, or reject each electric distribution company's ESMP within seven months of submittal. To be approved, a plan must meet the criteria enumerated in Section 92B(a) and provide net benefits for customers. Based on our review above, the Department determines that each company has satisfied the criteria enumerated in Section 92B(a) and demonstrated that its proposed ESMP will provide net benefits to customers. Additionally, the Department finds that each company has complied with the remaining provisions of Section 92B. Accordingly, the Department approves each company's ESMP with modification as indicated above. In particular, the Department modifies the term of each company's ESMP and established a term of July 1, 2025, through June 30, 2030. Additionally, the Department extends the Provisional Program and provides a revised CIP proposal checklist. The Department also requires the Companies to coordinate an LTSPP stakeholder group no later than October 1, 2024, and to conduct and report on a six-month LTSPP stakeholder process with a final report due no later than April 4, 2025. Further, the Department approves the Companies' equity framework, as modified above, and identifies several items to be included in the Companies' biannual reports. Finally, the Department emphasizes that our approval with modification of each company's ESMP is not preapproval or preauthorization of any investments, or their associated budgets, included in the ESMPs. Nevertheless, our approval with modification of each company's ESMP, and the strategic planning processes included therein, is a significant first step towards equitably achieving the Commonwealth's GHG emissions reduction targets.

VIII. COST RECOVERY FRAMEWORK

A. Introduction

In their petitions, each of the Companies requested the Department's approval of a budget cap on total ESMP expenditures for the five-year term (D.P.U. 24-10, Petition at 12-13, 15-16; D.P.U. 24-11, Petition at 12-13, 15-16; D.P.U. 24-12, Petition at 12-13, 15). In the Interlocutory Order on Scope at 15-16, we determined that we would not adjudicate the Companies' requests for approval of a budget cap in these inaugural ESMP proceedings. The Department stated that we would investigate and address the appropriate cost recovery framework for ESMP costs (i.e., through base distribution rates and/or reconciling mechanisms) in this Order. Interlocutory Order on Scope at 16. Further, we stated that if we found it appropriate in this Order for recovery of ESMP costs to occur outside of base distribution rates, then the parameters of the ESMP cost recovery mechanisms would be determined in a subsequent phase of these proceedings. Interlocutory Order on Scope at 16.

B. Description of Company Proposals

NSTAR Electric proposed to recover incremental ESMP expenditures through existing cost recovery mechanisms, including its grid modernization tariff, EV program tariff, provisional system planning tariff for CIP costs, resiliency tree work program for certain resiliency investments, and solar cost recovery factors or residential assistance adjustment clause for costs associated with the ASAP (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 434-438; ES-Bill Impacts-1, at 7-9, 17-22). For CIP investments included in its ESMP or proposed in the future, NSTAR Electric requested to recover the associated costs from ratepayers and interconnecting DG customers consistent with the cost allocation method approved in D.P.U. 20-75-B (D.P.U. 24-10, Exhs. ES-Bill Impacts-1, at 18; ES-Policy/Solutions-1, at 33, 144).

National Grid proposed to recover its proposed ESMP expenditures, except CIP-related costs, through the ISRE mechanism proposed in its pending base distribution rate proceeding, D.P.U. 23-150 (D.P.U. 24-11, Petition at 12-13; Exh. DPU-Common 9-7). For EE, grid modernization, AMI, EV, and CIP costs previously approved by the Department, National Grid proposed to continue cost recovery from ratepayers through the established reconciling mechanisms (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 359, 362; NG-Bill Impacts-1 (Rev.) at 11). For CIP investments included in its ESMP or proposed in the future, National Grid also requested to recover the associated costs from ratepayers and interconnecting DG customers consistent with the cost allocation method approved in D.P.U. 20-75-B (D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 37, 87, 112, 308, 315, 327, 359, 371; NG-Bill Impacts-1 (Rev.) at 8).

Unitil proposed to recover ESMP expenditures through its grid modernization factor (D.P.U. 24-12, Petition at 22; Exhs. UN-ESMP-1 (Corrected) at 2, 27, 152; UN-Bill Impacts-1, at 6, 12; UN-Policy/Solutions-1, at 24, 26). As such, Unitil filed proposed illustrative revisions to its grid modernization factor tariff to reflect collection of incremental ESMP expenditures through the effective period of the ESMP term (D.P.U. 24-12, Exhs. UN-Bill Impacts-1, at 6, 12; UN-Bill Impacts-5).

C. Positions of the Parties

1. Attorney General

The Attorney General maintains that the 2022 Clean Energy Act makes no changes to the Department's ratemaking authority (Attorney General Brief at 48). The Attorney General contends that the Department should assert strong leadership in ratepayer protection and reject unjust and unreasonable rates for electric distribution service (Attorney General Brief at 48). To that end, the Attorney General argues that the Companies should not be granted an ESMP-specific reconciliation mechanism without: (1) a convincing demonstration that such cost recovery treatment is merited; and (2) the development of ratepayer safeguards from the financial risk of premature ESMP investments (Attorney General Brief at 48-49). Further, she asserts that the Department must require the Companies to establish that the actual deployment of their investments was prudent and that all plant additions included in rates are used and useful before the Companies recover ESMP costs in rates (Attorney General Reply Brief at 5).

2. DOER

DOER asserts that the Department should require the Companies to recover ESMP costs primarily through base distribution rates (DOER Brief at 57; DOER Reply Brief at 17-19). DOER contends that the Companies' proposals to implement different cost recovery approaches for incremental ESMP investments (i.e., targeted cost recovery) and core investments (i.e., base distribution rates) are inconsistent with the strategic plan approach to reviewing the ESMPs and ignore the fact that many of the Companies' proposed ESMP investments support their core business functions of providing safe and reliable service (DOER Brief at 58, 59; DOER Reply Brief at 17). DOER argues that when economic growth or new technologies lead to load growth, the Companies are expected to invest in and justify new infrastructure to support a reliable system, even if the load growth is policy driven (DOER Brief at 59). Further, DOER claims that the Department's prior grid modernization orders made clear that grid modernization investments would eventually become a part of the Companies' normal course of business (DOER Brief at 59, citing Second Grid Modernization Plans (Track 2) at 290; Second Grid Modernization Plans (Track 1) at 111; D.P.U. 20-69-A at 35; Grid Modernization Order at 235; D.P.U. 12-76-B at 19; D.P.U. 12-76-A at 9); DOER Reply Brief at 17-18).

DOER avers that the Companies each propose to recover the costs of ESMP investments through targeted reconciling mechanisms through at least 2034, which will disincentivize electrification by exacerbating the rate impacts associated with the additional investments (DOER Brief at 60; DOER Reply Brief at 18). Further, DOER maintains that the Companies' position casts doubt on their commitment to considering ESMP investments as an integral part of their ongoing, routine investment and operational plans (DOER Brief at 60).

DOER contends that Section 92B leaves the Department broad discretion to determine the appropriate cost recovery framework for ESMP investments (DOER Reply Brief at 18).

DOER maintains that the statutory language suggests it was the Legislature's intent for the ESMPs to be an avenue to propose investments that are recovered in other proceedings, not an avenue to recover investments (DOER Reply Brief at 19). In sum, DOER argues that the Department should prioritize cost recovery primarily through base distribution rates to emphasize that ESMP investments must become a part of the Companies' normal course of business and planning process (DOER Brief at 60; DOER Reply Brief at 18-19).

3. Acadia Center, CLF, and GECA

The Joint Intervenors argue that the Department must require a vastly improved ESMP process as a prerequisite to a cost recovery framework premised on the preauthorization of costs (GECA Brief at 14-15; Joint Intervenor Reply Brief at 4). The Joint Intervenors assert that without such improvements to the ESMP process, preauthorization of investments may lead to excessive expenditures because alternative investments were neither considered nor incorporated into the ESMPs (GECA Brief at 15, citing D.P.U. 24-10/D.P.U. 24-11, Exh. GECA-LC-1, at 8-9; GMAC Consultant Comments; Joint Intervenor Reply Brief at 4).

4. Companies

The Companies maintain that they require adequate revenue support and flexibility to proactively upgrade their distribution systems and that base rate recovery is inadequate to support the significant capital investment needed to achieve the Commonwealth's energy policy goals (Companies' Joint Brief at 68; Companies' Joint Reply Brief at 32). The Companies argue that if the Department directs base rate recovery for ESMP investments, then the Companies will lack the necessary revenue support to execute fully on the incremental ESMP projects (Companies' Joint Brief at 68-69, citing Exhs. D.P.U. 24-10, DPU-Common 1-12; DPU-Common 9-4; DOER-Common 1-3; D.P.U. 24-11, DPU-Common 1-12; DPU-Common 9-4; DOER-Common 1-3; D.P.U. 24-12, DPU Common 1-12; DPU-Common 9-4; DOER-Common 1-3). For example, the Companies assert that they may proceed on certain ESMP projects at a reduced scope and timeline or not move forward at all, especially for non-capital projects (Companies' Joint Brief at 68, citing D.P.U. 24-10, Exh. DPU-Common 9-4; D.P.U. 24-11, Exh. DPU-Common 9-4; D.P.U. 24-12, Exh. DPU-Common 9-4; Companies' Joint Reply Brief at 30-32).

In addition, the Companies claim that Section 92B does not require the Companies to recover ESMP costs through base distribution rates (Companies' Joint Brief at 70; Companies' Joint Reply Brief at 27). The Companies maintain that Section 92B does not impose any directive, limitation, or modification of the Department's broad ratemaking authority to allow cost recovery through another mechanism (Companies' Joint Brief at 70).

The Companies argue that a reconciling mechanism is necessary to provide revenue support for their proposed ESMP investments and consistent with the purpose and language of Section 92B (Companies' Joint Reply Brief at 27, 31, citing Exhs. D.P.U. 24-10, DPU-Common 1-12; DPU-Common 9-4; D.P.U. 24-11, DPU-Common 1-12; DPU-Common 9-4; D.P.U. 24-12, DPU-Common 1-12; DPU-Common 9-4). Therefore, the

Companies maintain that the Department should adopt the Companies' proposed cost recovery framework as filed (Companies' Joint Reply Brief at 32-33).

D. Analysis and Findings

As these proceedings are cases of first impression, the Department must first determine whether the language of Section 92B explicitly requires a particular means of cost recovery. Olmstead, 466 Mass. at 588; City of Worcester v. College Hill Properties, LLC, 465 Mass. 134, 138 (2013) ("[w]here the language of a statute is clear and unambiguous, it is conclusive as to legislative intent"); Providence and Worcester Railroad Company v. Energy Facilities Siting Board, 453 Mass. 135, 141 (2009); NSTAR Gas Company, D.P.U. 19-120, at 464 (2020). The Attorney General, DOER, and Companies maintain that the statute neither requires the Department to implement a specific means of cost recovery for ESMP costs nor changes the Department's broad discretion to determine the appropriate cost recovery framework (Attorney General Brief at 48; DOER Reply Brief at 18; Companies' Joint Brief at 70). We agree.

Section 92B expressly permits the Companies to include Department-approved plant additions in base distribution rates but does not expressly require the Companies to include EMSP costs in base distribution rates or prohibit the Department from approving cost recovery outside of base distribution rates. G.L. c. 164, § 92B. Our determination that the Legislature intended to afford the Department the discretion to determine the appropriate cost recovery framework for ESMP costs is informed by the fact that the Legislature has prescribed specific methods of cost recovery for other statutory programs overseen by the

Department, such as the gas system enhancement program and EE program, but chose not to do so in Section 92B. G.L. c. 25, § 19, 21; G.L. c. 164, § 145; Fernandes v. Attleboro Housing Authority, 470 Mass. 117, 129 (2014) ("the omission of particular language . . . is deemed deliberate where the Legislature included such omitted language in related or similar statutes"); Interlocutory Order on Scope at 15.

We must next determine which of the proposed cost recovery frameworks (i.e., base distribution rates or annual reconciling mechanisms) would better serve the purpose of Section 92B. The Department gives careful consideration to the formation of any new cost reconciling mechanisms. See, e.g., D.P.U. 23-80/D.P.U. 23-81, at 301-305; Boston Gas, Company, Essex Gas Company, and Colonial Gas Company, D.P.U. 10-55, at 66 n.43 (2010); Bay State Gas Company, D.T.E. 05-27, at 183-186 (2005); NSTAR Pension, D.T.E. 03-47-A at 25-28 (2003), 36-37; Eastern Enterprises/Essex County Gas Company, D.T.E. 98-27, at 6, 28 (1998). Such consideration is warranted because certain cost recovery mechanisms can lessen the incentive of a utility to control its costs. Under conventional ratemaking practice, there is a time gap between when a utility incurs a cost and when the utility recovers its costs through new rates. This time gap is referred to as "regulatory lag," and it provides a strong incentive for companies to control costs and to invest wisely in capital. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 09-39, at 80 (2009). Cost reconciling mechanisms, because they allow for dollar-for-dollar recovery from ratepayers, substantially reduce, or in some cases eliminate, benefits to ratepayers that would accrue as a result of regulatory lag. See, e.g., D.P.U. 23-80/D.P.U. 23-81, at 302; D.P.U. 15-120-F/D.P.U. 15-121-F/D.P.U. 15-122-F at 8-9 (2022); Fitchburg Gas and Electric Light Company, D.P.U. 13-90-A at 10 (2014); Boston Gas Company, D.P.U. 96-50 (Phase I) at 81 (1996).

The Department has long held that grid modernization investments should become the Companies' normal business practice over time and, as a result, cost recovery for grid modernization should transition from short-term, targeted cost recovery to base distribution rates to restore the benefits of regulatory lag to ratepayers. Second Grid Modernization Plans (Track 2) at 289-290; Second Grid Modernization Plans (Track 1) at 110-112; D.P.U. 20-69-A at 35; Grid Modernization Order at 235; D.P.U. 12-76-B at 19; D.P.U. 12-76-A at 9. Nevertheless, the evidence before us demonstrates that applying our existing standards for base distribution rates to ESMP costs would not provide sufficient revenues to support the step change needed to achieve the Commonwealth's GHG emissions targets in the current operating environment (Tr. 3, at 315-347; D.P.U. 24-10, Exhs. DPU-Common 1-12; DPU-Common 9-4; D.P.U. 24-11, Exhs. DPU-Common 1-12; DPU-Common 9-4; D.P.U. 24-12, Exhs. DPU-Common 1-12; DPU-Common 9-4). Consequently, directing ESMP costs to flow through base distribution rates at this time could drive the Companies to delay, scale down, or even decline to make the investments and implement the programs outlined in the ESMPs; diminish or eliminate the associated net benefits to ratepayers; and jeopardize the Commonwealth's GHG emissions reduction targets in contravention of the purpose of Section 92B (Tr. 3, at 315-347; D.P.U. 24-10, Exhs. DPU-Common 1-12; DPU-Common 9-4; D.P.U. 24-11, Exhs. DPU-Common 1-12; DPU-Common 9-4; D.P.U. 24-12, Exhs. DPU-Common 1-12; DPU-Common 9-4).

For the reasons stated above and to avoid delay in the achievement of the Commonwealth's GHG emissions reductions targets, the Department finds that it is appropriate at this time to allow short-term targeted cost recovery for ESMP costs. Accordingly, we will determine the parameters of an ESMP cost recovery mechanism in the second phase of these proceedings. In addition, the Department intends to investigate in a separate proceeding how innovative approaches to cost recovery through base distribution rates can further the purpose of Section 92B, optimally balance our priorities, and promote efficiency. An investigation of that scale, however, will likely require a lengthy inquiry to identify, analyze, and resolve many complex ratemaking issues. Therefore, Department will establish a short-term reconciling mechanism for ESMP costs before our investigation into a long-term cost recovery framework proceeds. To ensure an efficient and orderly investigation in phase two of these proceedings, the Department provides the guidance below.

We have considered NSTAR Electric's and Unitil's proposals to recover ESMP costs through their existing grid modernization factors (D.P.U. 24-10, Exh. ES-Bill Impacts-1, at 17-22; D.P.U. 24-12, Petition at 12-13; Exh. UN-Bill Impacts-1, at 11). Recovery through the current grid modernization factors is limited to the approved, second term grid modernization plan investments. Second Grid Modernization Plans (Track 2) at 289; Second Grid Modernization Plans (Track 1) at 77, 89, 98, 111. We have determined that including ESMP costs in a new ESMP mechanism rather than extending the grid modernization factors, which are subject to specific standards of review that may not apply to ESMP costs, will allow for a more efficient and orderly review process and avoid confusion among stakeholders. Therefore, the current grid modernization plan terms will end, as previously determined, on December 31, 2025. Other than carry-over costs, the Department will not permit cost recovery for additional investments through the grid modernization factors, and the Companies shall maintain their grid modernization factors until such time those investments are incorporated into base distribution rates in their next base distribution rate cases. Second Grid Modernization Plans (Track 2) at 289; Second Grid Modernization Plans (Track 1) at 77, 89, 98, 111.

As discussed above, National Grid proposed to recover ESMP costs through the ISRE mechanism. The Department will issue its decision on National Grid's proposed ISRE mechanism in its pending base distribution rate case, D.P.U. 23-150, on or before September 30, 2024, and initiate the phase of this proceeding on the ESMP cost recovery mechanism for NSTAR Electric, Unitil, and, if necessary, National Grid, soon thereafter.

Additionally, in Section VII.F.4., the Department allows the Companies to continue their Provisional Programs until the Department finalizes an LTSPP to replace them. We have considered whether Provisional Program costs should remain in the existing recovery mechanisms or move to the forthcoming ESMP reconciling mechanisms and determined that recovery of Provisional Program costs should continue through the existing recovery mechanisms to promote transparency. The Department will consider the appropriate recovery mechanism for the LTSPP at a later date.

As discussed above, the Companies' ESMPs also include proposals to extend their EV programs (see Section VII.C.2.). In Electric Vehicles 2022 Order at 168-169, the Department approved NSTAR Electric's Phase II EV program, National Grid's Phase III program, and Unitil's EV program.[138] The Companies shall continue to recover their current EV program costs through the mechanisms previously approved by the Department. Regarding the ESMP EV program proposals, we have considered whether our review of these proposals should continue to occur in dedicated proceedings. Consistent with our recent determination that the size and scope of NSTAR Electric's Phase II EV program warranted a devoted cost recovery mechanism to increase transparency and enable a more focused review, we have concluded that it is appropriate to retain a separate review process and tariff for NSTAR Electric's ESMP EV program costs. Electric Vehicles 2022 Order at 168. Therefore, NSTAR Electric may petition the Department for approval to continue its EV program beyond its current term. As Unitil currently recovers its EV program costs through its grid modernization factor that will expire at the end of 2025, the Department directs Unitil to petition the Department for approval of a stand-alone EV program mechanism, separate from its grid modernization provision, for recovery of any future EV program investments incurred after December 31, 2025. Future company proposals relating

[138] The Department approved the following budget caps and terms: (1) $188 million and four years for NSTAR Electric's Phase II EV program; (2) $206 million and four years for National Grid's Phase III EV program; and (3) $998,000 and five years for Unitil's EV program. Electric Vehicles 2022 Order at 168-169.

to EV programs shall be submitted as separate filings and subject to the precedent and tariffs for those existing mechanisms.[139]

The development of short- and long-term cost recovery frameworks for ESMP costs will involve a balancing of the need to provide sufficient certainty to the Companies and their investors regarding recovery of the revenues necessary to support the ramp up in clean energy investments associated with achieving the Commonwealth's GHG emissions targets, versus the Department's equally important obligations to ratepayers to preserve affordability through rigorous oversight of utility expenditures to ensure that costs are minimized and the Companies are giving due consideration to alternative, lower cost solutions. The Department's investigation in the second phase of these proceedings may include, but need not be limited to: (1) definitions of costs eligible for recovery; (2) cost containment provisions such as budget or revenue caps; (3) documentation required to support cost recovery; (4) the Companies' processes for evaluating alternatives and addressing changed circumstances during the five-year ESMP terms; (5) consideration of possible mechanisms to encourage innovative approaches designed to minimize costs for ratepayers; and (6) planned obsolescence of the ESMP mechanism.

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139 The Department will issue its decision on National Grid's proposal to recover new EV program costs through the proposed ISRE mechanism in its pending base distribution rate case in D.P.U. 23-150.

IX. BILL IMPACTS

A. Introduction

On August 7, 2023, the Department directed the Companies' ESMP filings to comply with certain filing requirements, which included the submission of projected one-year, three-year, and five-year bill impacts[140] associated with implementing the ESMPs as proposed (Hearing Officer Memorandum at 4 (August 7, 2023)). Each of the Companies provided illustrative bill impact calculations for the estimated costs of the investments and expenses associated with the proposed ESMPs and supporting testimony with their petitions (D.P.U. 24-10, Exhs. ES-Bill Impacts-1, at 4-5; ES-Bill Impacts-4; ES-Bill Impacts-5; D.P.U. 24-11, Exhs. NG-Bill Impacts-1 (Rev.), at 15-16; NG-Bill Impacts-4; NG-Bill Impacts-5; D.P.U. 24-12, Exhs. UN-Bill Impacts-1, at 4; UN-Bill Impacts-4). Several Intervenors criticized the Companies' bill impacts calculations and requested that the Department direct the Companies to change their methods for calculating illustrative bill impacts related to grid modernization. Below, we clarify the Department's review of bill impacts in the context of a strategic plan approach. Interlocutory Order on Scope at 14.

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[140] A bill impact analysis shows: (1) the existing charges; (2) the proposed charges; (3) the percentage change in the charges; (4) the total dollar change in total monthly bill at various consumption levels; and (5) the percentage change in the total bill per month at various consumption levels. D.P.U. 12-76-C, at 29 n.15.

B. Description of Company Bill Impacts

1. NSTAR Electric

For year one, NSTAR Electric states that the illustrative bill impacts associated with the incremental ESMP investments and expenses for a typical residential customer range from 0.1 percent to 0.2 percent, or $0.27 per month to $0.29 per month (D.P.U. 24-10, Exhs. ES-Bill Impacts-1, at 24; ES-Bill Impacts-4). For commercial and industrial customers, the company states that illustrative bill impacts range from 0.1 percent to 0.2 percent dependent on specific rate class and location (D.P.U. 24-10, Exh. ES-Bill Impacts-4). For year two, NSTAR Electric states that the illustrative bill impacts associated with the incremental ESMP investments and expenses for a typical residential customer range is 0.3 percent or $0.51 per month to $0.52 per month[141] (D.P.U. 24-10, Exh. ES-Bill Impacts-4). For commercial and industrial customers, the company states that illustrative bill impacts range from 0.1 percent to 0.3 percent dependent on specific rate class and location (D.P.U. 24-10, Exh. ES-Bill Impacts-4). For year three, the company states that the illustrative bill impacts associated with the incremental ESMP investments and expenses for a typical residential customer range from 1.1 percent to 1.2 percent, or $2.12 per month to $2.18 per month (D.P.U. 24-10, Exhs. ES-Bill Impacts-1, at 24; ES-Bill Impacts-4). For commercial and industrial customers, the company states that illustrative bill impacts range from 0.4 percent to 1.2 percent dependent on

141 The estimated bill impacts of $0.51 per month and $0.52 per month both amount to 0.3 percent after rounding.

specific rate class and location (D.P.U. 24-10, Exh. ES-Bill Impacts-4). For year four, NSTAR Electric states that the illustrative bill impacts associated with the incremental ESMP investments and expenses for a typical residential customer range from 0.4 percent to 0.5 percent, or $0.84 per month to $0.85 per month (D.P.U. 24-10, Exh. ES-Bill Impacts-4). For commercial and industrial customers, the company states that illustrative bill impacts range from 0.1 percent to 0.5 percent dependent on specific rate class and location (D.P.U. 24-10, Exh. ES-Bill Impacts-4). Finally, for year five, NSTAR Electric states that the illustrative bill impact associated with the incremental ESMP investments and expenses for a typical residential customer is 0.5 percent, or $0.91 per month to $0.94 per month (D.P.U. 24-10, Exhs. ES-Bill Impacts-1, at 25; ES-Bill Impacts-4). For commercial and industrial customers, the company states that illustrative bill impacts range from 0.2 percent to 0.5 percent dependent on specific rate class and location (D.P.U. 24-10, Exh. ES-Bill Impacts-4).

2. National Grid

National Grid states that there will be no bill impacts associated with the incremental ESMP investments and expenses for year one because the ESMP revenue requirement for year one will not be billed to customers until year two, or October 1, 2025 (D.P.U. 24-11, Exhs. NG-Bill Impacts-1, at 15; NG-Bill Impacts-3 (Rev.)). For year two, National Grid states that the illustrative bill impacts associated with the incremental ESMP investments and expenses for a typical residential customer range is 0.1 percent or $0.19 per month (D.P.U. 24-11, Exh. NG-Bill Impacts-4 (Rev.)). For commercial and industrial customers, the company states that the illustrative bill impact is 0.1 percent (D.P.U. 24-11, Exh. NG-Bill Impacts-4 (Rev.)). For year three, the company states that the illustrative bill impacts associated with the incremental ESMP investments and expenses for a typical residential customer is 0.3 percent, or $0.66 per month (D.P.U. 24-11, Exhs. NG-Bill Impacts-1, at 16; NG-Bill Impacts-5 (Rev.)). For commercial and industrial customers, the company states that illustrative bill impacts range from 0.2 percent to 0.3 percent dependent on specific rate class and location (D.P.U. 24-11, Exh. NG-Bill Impacts-5). For year four, National Grid states that the illustrative bill impacts associated with the incremental ESMP investments and expenses for a typical residential customer is 0.6 percent, or $1.20 per month (D.P.U. 24-11, Exh. NG-Bill Impacts-6 (Rev.)). For commercial and industrial customers, the company states that illustrative bill impacts range from 0.3 percent to 0.6 percent dependent on specific rate class and location (D.P.U. 24-11, Exh. NG-Bill Impacts-6 (Rev.)). Finally, for year five, National Grid states that the illustrative bill impact associated with the incremental ESMP investments and expenses for a typical residential customer is 2.2 percent, or $4.79 per month (D.P.U. 24-11, Exhs. NG-Bill Impacts-1, at 16; NG-Bill Impacts-7). For commercial and industrial customers, the company states that illustrative bill impacts range from 1.3 percent to 2.2 percent dependent on specific rate class and location (D.P.U. 24-11, Exh. NG-Bill Impacts-7).

3. Unitil

For year one, Unitil states that the illustrative bill impact associated with the incremental ESMP investments and expenses for a typical residential customer is 0.4 percent, or $1.03 per month (D.P.U. 24-12, Exhs. UN-Bill Impacts-1, at 17; UN-Bill Impacts-4). For commercial and industrial customers. the company states that illustrative bill impacts range from 0.2 percent to 0.4 percent when assuming class average usage (D.P.U. 24-12, Exhs. UN-Bill Impacts-1, at 17; UN-Bill Impacts-4). For year two, Unitil states that the illustrative bill impacts associated with the incremental ESMP investments and expenses for a typical residential customer range is 1.15 percent or $3.03 per month (D.P.U. 24-12, Exh. UN-Bill Impacts-4). For commercial and industrial customers, the company states that illustrative bill impacts range from 0.6 percent to 1.0 percent dependent on specific rate class and location (D.P.U. 24-12, Exh. UN-Bill Impacts-4). For year three, the company states that the illustrative bill impact associated with the incremental ESMP investments and expenses for a typical residential customer is 1.2 percent, or $3.12 per month (D.P.U. 24-12, Exhs. UN-Bill Impacts-1, at 17; UN-Bill Impacts-4). For commercial and industrial customers, the company states that illustrative bill impacts range from 0.6 percent to 1.1 percent when assuming class average usage (D.P.U. 24-12, Exhs. UN-Bill Impacts-1, at 17; UN-Bill Impacts-4). For year four, Unitil states that the illustrative bill impacts associated with the incremental ESMP investments and expenses for a typical residential customer is 1.39 percent, or $3.78 per month (D.P.U. 24-12, Exh. UN-Bill Impacts-4). For commercial and industrial customers, the Unitil states that illustrative bill impacts range from

0.7 percent to 1.2 percent dependent on specific rate class and location (D.P.U. 24-12, Exh. UN-Bill Impacts-4). Finally, for year five, the illustrative bill impact associated with the incremental ESMP investments and expenses for a typical residential customer is 1.3 percent, or $3.48 per month (D.P.U. 24-12, Exhs. UN-Bill Impacts-1, at 17; UN-Bill Impacts-4). For commercial and industrial customers. the company states that illustrative bill impacts range from 0.6 percent to 1.2 percent when assuming class average usage (D.P.U. 24-12, Exhs. UN-Bill Impacts-1, at 17; UN-Bill Impacts-4).

C. Positions of the Parties

1. Attorney General

The Attorney General emphasizes that the breadth of the Companies' planned ESMP expenditures is a sobering challenge to ratemaking and to affordability for ratepayers (Attorney General Brief at 8). With that in mind, the Attorney General urges the Department to be cognizant that the Companies will ultimately ask their customers to pay for all planned investments though some combination of future base distribution rates and surcharges (Attorney General Brief at 9).

2. Acadia Center

Acadia Center asserts that the Companies failed to provide clear ratepayer bill impacts in their ESMPs (Acadia Center Brief at 14). Acadia Center argues that the bill impacts provided by the Companies are misleading because they cover only the incremental investments proposed in the ESMPs (Acadia Center Brief at 15, citing D.P.U. 24-10, Exh. ES-Bill Impacts-1, at 24-25). Acadia Center contends that the total impacts on ratepayers related to the ESMPs will be significantly higher (Acadia Center Brief at 15). Finally, while Acadia Center acknowledges that the approach to potential bill impacts may be in line with past precedent, Acadia Center maintains that absent clear bill impact information, intervenors are unable to argue for or against the ESMPs without knowing the combined impacts on ratepayers (Acadia Center Brief at 16, citing D.P.U. 24-10, Exh. GECA-Common 1-4, at 1-2; D.P.U. 24-11, Exh. GECA-Common 1-4, at 1).

3. Cape Light Compact

CLC asserts that NSTAR Electric's bill impacts reflect only a small portion of its total grid modernization plan costs because they exclude core investments, AMI, CIP, solar, EV, EE, and transmission upgrade costs (CLC Brief at 25, citing D.P.U. 24-10, Exh. ES-Bill Impacts-1, at 735, 738; RR-GECA-ES-1; RR-CLC-ES-2). CLC argues that the ESMP should account for all efforts to meet the 2050 climate goals, so that the true cost of meeting this goal can be known and evaluated (CLC Brief at 26). CLC maintains that the Department should require bill impacts for the total cost of incremental and non-incremental investments and require the Companies to include a comprehensive bill impact analysis in the next ESMPs (CLC Brief at 26-27; CLC Reply Brief at 16).

4. CLF

CLF claims that the Department should identify specific factors for inclusion in the Companies' bill impacts analyses and require compliance filings within one year of issuance of the Department's Order (CLF Brief at 11). As with other intervenors, CLF asserts that the Companies' bill impacts underestimate the actual overall impact that the proposals will have on ratepayers (CLF Brief at 16, citing Acadia Comments at 2).

5. GECA

GECA asserts that the bill impacts associated with grid modernization are unclear and difficult to assess (GECA Brief at 7-8). Specifically, GECA argues that because ESMP investments are only a small portion of the total costs of grid modernization, bill impacts, particularly for low and middle-income customers, cannot be meaningfully examined (GECA Brief at 7-8, citing D.P.U. 24-10/D.P.U. 24-11, Exh. GECA-LC-1, at 2).

6. Companies

The Companies contend that they have each provided bill impact analyses consistent with Department requirements (Companies' Joint Reply Brief at 33). The Companies further argue that the Intervenors raise the same arguments that the Department addressed in D.P.U. 12-76-C at 29 (Companies' Joint Reply Brief at 33-34). The Companies allege that the Intervenors' arguments are based on the false assumption that the ESMP is an overarching distribution planning document that encompasses all investments that the Companies may implement within a five-year period (Companies' Joint Reply Brief at 34, citing D.P.U. 12-76-C at 29; Acadia Brief at 15-16; CLC Brief at 24-27; CLF Brief at 16-17; GECA Brief at 7-11). Further, the Companies claim that a full bill impact analysis of all investments and programs would require the estimation of many factors and assumptions and, therefore, that such bill impact analysis has limited efficacy (Companies' Joint Reply Brief at 34). The Companies maintain that a bill impact analysis of the proposed

ESMP investments provides the most transparency regarding the impact of the Department's decision in this proceeding (Companies' Joint Reply Brief at 34-35, citing D.P.U. 24-10, Exh. GECA-Common 1-4; D.P.U. 24-11, Exh. GECA-Common 1-4; D.P.U. 24-12, Exh. GECA-Common 1-4).

Finally, the Companies assert that the Department should give no weight to the bill impact analysis provided in response to GECA's information request (Companies' Joint Reply Brief at 35). The Companies maintain that GECA confuses bill impacts with rate impacts (Companies' Joint Reply Brief at 36, citing GECA Brief at 17). Further, the Companies contend that CLF's proposal of bill impacts illustrating what customers can expect if they electrify during the five-year term is not appropriate (Companies' Joint Reply Brief at 35-36). The Companies argue that such analysis would require assumptions on electrification adoption rates and customer behavior that could mislead customers (Companies' Joint Reply Brief at 35-36).

D. Analysis and Findings

The Department reviews bill impacts to ensure that the potential impact to ratepayers of the proposals under consideration, if approved, do not frustrate the Department's goal of rate continuity. Energy Efficiency Guidelines, D.P.U. 08-50-D at 4 (2012); D.P.U. 12-76-C at 29. As discussed earlier in this Order, the Department has determined that it is appropriate and consistent with the legislative intent of Section 92B to review the ESMPs as strategic plans and to analyze the net benefits of the Companies' proposed ESMP investments and programs rather than the Companies' total planned investments and spending. Further, the Department is not approving the Companies' request for an approved budget cap based on the Companies' estimated ESMP expenditures; however, the Department will determine the parameters of the ESMP cost recovery mechanism, which shall include robust ratepayer protection and cost control, in the next phase of these proceedings. See Section VIII.D. Consistent with these decisions, we find that it is appropriate to consider the illustrative bill impact analyses limited to the Companies' proposed ESMP investments in our review of the ESMPs as strategic plans, so that the illustrative bill impacts inform the Department and stakeholders on the potential impact of the Department's decisions in this Order.

The Department acknowledges the intervenors' concerns about the ratepayer impacts of the proposed ESMPs. The Department is mindful of the magnitude of the estimated ESMP costs and their potential effects on rate continuity and affordability for the Commonwealth's customers. This concern is heightened when considering the combined effect of future expected rate impacts (e.g., given the planned GHG emissions reductions targets, the Department fully expects that the EE budgets will increase significantly in the upcoming 2025-2027 Three-Year Plan term).[142] Fitchburg Gas and Electric Light Company, D.P.U. 24-47-A at 13 (June 28, 2024). For these reasons, the Department will continue to

142 See Letter from the Secretary, EEA, to the Program Administrators Establishing GHG Emissions Reduction Requirements for 2025-2027 (March 1, 2024) (establishing a goal of one million metric tons of carbon dioxide equivalent GHG emissions reductions, up from 845,000 metric tons in the current Three-Year Plans); and 2025-2027 Statewide EE Plan, at 2 (Draft) (April 1, 2024) (proposing $4.99 billion in spending as compared to $4.0 billion in the current Three-Year Plans). D.P.U. 24-47-A at 13 n.12.

prioritize affordability in accordance with G.L. c. 25, § 1A as we carry out the correlated investigations that we have announced in this and other Orders, including the investigations of: (1) energy burdens in D.P.U. 24-15; (2) the ESMP cost recovery mechanism; (3) innovative approaches to base distribution rates; and (4) changes in rate design enabled by the full deployment of AMI.

Although we have determined that a comprehensive estimate of ratepayer bill impacts for all costs related to the Commonwealth's clean energy goals is neither required by Section 92B nor appropriate to consider in our strategic plan approach, the intervenors' requests to see such analysis has merit. As we recently stated in an Order on EE reconciliation factors, the ESMPs are only one of several initiatives overseen by the Department to further the Commonwealth's critical energy policy goals and to deliver substantial benefits to its residents (e.g., EE, net metering, the SMART Program, offshore wind and hydroelectric procurements, EV initiatives, grid modernization, CIPs, and the ESMPs). These initiatives are largely funded through reconciling mechanisms that allow the Companies to recover program costs directly from ratepayers. The Department fully expects that the costs of these programs will increase significantly in the near term and beyond. Accordingly, we continue to see value in a process where policymakers, stakeholders, and the Department can work together to comprehensively address the cumulative effect of these essential policy programs on customer bills now and in the future. D.P.U. 24-47-A at 18.

After review, the Department finds that the Companies correctly calculated their estimated bill impacts and that the estimated bill impacts resulting from the proposed ESMP costs are within the range of reasonableness in light of the anticipated benefits that the proposed ESMPs may provide (D.P.U. 24-10, Exhs. ES-Bill Impacts-1, at 4-5; ES-Bill Impacts-4; ES-Bill Impacts-5; D.P.U. 24-11, Exhs. NG-Bill Impacts-1 (Rev.), at 15-16; NG-Bill Impacts-4; NG-Bill Impacts-5; D.P.U. 24-12, Exhs. UN-Bill Impacts-1, at 4; UN-Bill Impacts-4). When the Companies propose to include ESMP costs in rates, the Department will consider the actual proposed bill impacts in our decision on whether to allow the proposed rate changes consistent with G.L. c. 25, § 1A, Section 92B, the Department's authority to regulate rates, and well-established precedent.

X. METRICS

A. Introduction

Section 92B(e) requires each company to submit two reports per year to the Department and the Legislature's Joint TUE Committee on the deployment of approved investments in accordance with any performance metrics included in the approved ESMP plans. In their ESMP filings, the Companies jointly proposed three new ESMP stakeholder engagement performance metrics and five proposed metrics for incremental ESMP investments (D.P.U. 24-10, Exh. ES-Metrics-1, at 4; D.P.U. 24-11, Exh. NG-Metrics-1, at 6; D.P.U. 24-12, Exh. UN-Metrics-1, at 4). In Interlocutory Order on Scope at 22-23, however, the Department found that it would be premature and unproductive to establish final performance metrics in our August 29, 2024 Order and determined that we would address any initial performance metrics in a separate phase of the current proceedings. On brief, CLC requests that the Department clarify the subsequent process for deferred issues, including metrics.

B. Description of Company Proposals

The Companies jointly proposed three new ESMP stakeholder engagement performance metrics (D.P.U. 24-10, Exh. ES-Metrics-1, at 4; D.P.U. 24-11, Exh. NG-Metrics-1, at 6-7; D.P.U. 24-12, Exh. UN-Metrics-1, at 4-5). Specifically, the Companies proposed reporting on the number of: (1) outreach and involvement meetings with stakeholders, including EJ populations, municipal leaders, and community-based organizations and customers, about (a) the ESMP filings, and (b) plan-specific infrastructure projects; and (2) the number and category of requests made as part of stakeholder feedback on specific ESMP infrastructure projects (D.P.U. 24-10, Exh. ES-Metrics-1, at 4; D.P.U. 24-11, Exh. NG-Metrics-1, at 6-7; D.P.U. 24-12, Exh. UN-Metrics-1, at 4-5).

Additionally, the Companies proposed five metrics related to incremental ESMP investments (D.P.U. 24-10, Exh. ES-Metrics-1, at 4; D.P.U. 24-11, Exh. NG-Metrics-1, at 6; D.P.U. 24-12, Exh. UN-Metrics-1, at 4). Specifically, the Companies proposed to report on: (1) the achievement dates of "ready-for-load" for major ESMP infrastructure projects; (2) the percentage of customers covered by/benefiting from incremental resiliency investments outlined in the ESMP; (3) the increase in (a) DER hosting capacity, and (b) load serving capacity by substation demonstrated by an increase in transformer rating installed; (4) a measure of GHG reduction impact of investments enabled in alignment with statewide GHG reduction targets; and (5) for DERMS, beginning in 2026, the (a) number of participating sites, (b) amount of non-company-owned dispatchable assets that the utility can control, measured in kW, and (c) number of instances that sites are dispatched (D.P.U. 24-10, Exh. ES-Metrics-1, at 5; D.P.U. 24-11, Exh. NG-Metrics-1, at 7-9; D.P.U. 24-12, Exh. UN-Metrics-1, at 5-6).

C. Positions of the Parties

1. Cape Light Compact

CLC requests that the Department clarify the subsequent process for deferred issues, including metrics (CLC Brief at 31-32). CLC argues that the separate phase should allow stakeholders to propose additional metrics and to consider whether any current grid modernization metrics should be carried over into the ESMP metrics (CLC Brief at 32). In particular, CLC argues that the Department should require NSTAR Electric to report on any increase in double poles related to ESMP system improvements either in its annual report or as a specific, reporting-only metric (CLC Brief at 3, 19; CLC Reply Brief at 11, 16).

2. Companies

The Companies maintain that they fully support the creation of metrics to measure progress and performance of ESMP-related investments (Companies' Joint Brief at 88). The Companies request that the Department, however, defer consideration of performance metrics to a different phase of these proceedings, to be commenced after the Department's review of the ESMPs, where proposed metrics can be considered and developed more extensively (Companies' Joint Brief at 82-83). The Companies commit to working with interested stakeholders to address performance metrics in a future phase of the ESMP dockets (Companies' Joint Brief at 88-89).

D. Analysis and Findings

As discussed above, the Department determined in Interlocutory Order on Scope at 22-23, that it was premature and unproductive to establish final performance metrics in the August 29, 2024 Order for these proceedings and that it would address performance metrics in a separate phase of the current proceedings. The Department intends to fully address the Companies' proposed metrics, including whether modifications of or additions to those metrics are appropriate. The Department also intends to consider whether any current grid modernization or EV performance metrics should be carried forward and applied to proposed ESMP investments identified in the plans. Consistent with the decision to defer consideration of performance metrics until a later date, the Department will not determine at this time whether or not CLC's proposed metrics are appropriate, but the Department affirms that it will consider stakeholder proposals, including CLC's, in this later process. The Department will provide further guidance on the performance metrics phase of these proceedings at a later date.

XI. REPORTING REQUIREMENTS

A. Introduction

Section 92B(e) requires each company to submit two reports per year to the Department and the Legislature's Joint TUE Committee on the deployment of approved investments in accordance with any performance metrics included in the approved ESMP plans. The Companies propose filing reports on April 1 and October 1 beginning in 2026 (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 665; DPU-Common 7-8; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 481; DPU-Common 7-8; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 295; DPU-Common 7-8). The Companies propose to provide in the initial report information on the progress over the prior ESMP plan year and, in the second report, information on the first half of the current plan year (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 665; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 481; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 295). The Attorney General requests that the Department direct each company to establish a data sharing platform to share information on each company's ESMP progress. DOER and CLC recommend that the Department direct the Companies to include certain additional information in the biannual reports and to hold public listening sessions to summarize relevant updates regarding implementation of the ESMPs.

B. Description of Proposals

The Companies' proposed ESMP term is for the period January 1, 2025 through December 31, 2029 (D.P.U. 24-10, Petition at 1; D.P.U. 24-11, Petition at 1; D.P.U. 24-12, Petition at 1). The Companies propose filing reports on April 1 and October 1 each year (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 665; DPU-Common 7-8; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 481; DPU-Common 7-8; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 295; DPU-Common 7-8). The Companies state that these deadlines best align with existing dockets and annual reporting deadlines for grid modernization, EVs, service quality, and

ARRs (D.P.U. 24-10, Exh. DPU-Common 7-8; D.P.U. 24-11, Exh. DPU-Common 7-8; D.P.U. 24-12, Exh. DPU-Common 7-8).

The Companies propose that the April 1 report would provide information on the prior plan year's progress on incremental ESMP investments, including results relative to performance metrics, and replace the current grid modernization annual report (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 665; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 481; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 295). The Companies propose that the October 1 report would provide information on the first six months of the current year, January through June, and a higher-level interim review of year-to-date progress (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 665; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 481; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 295). The Companies state that they support developing a common reporting template for biannual reports that would include, at a minimum, progress related to implementation, stakeholder engagement, and benefit realization (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 665; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 481; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 295). Additionally, the Companies propose performance metrics as discussed in Section X.B. The Companies recommend that the first biannual report be filed in 2026, the second year of the ESMP, to give them time to deploy and realize benefits of any approved investments (D.P.U. 24-10, Exh. DPU-Common 7-8; D.P.U. 24-11, Exh. DPU-Common 7-8; D.P.U. 24-12, Exh. DPU-Common 7-8).

C. Positions of the Parties

1. Attorney General

The Attorney General contends that ongoing access to data on the state of the Companies' distribution systems is necessary to provide a transparent and accessible grid planning process that allows the GMAC, stakeholders, and the Department to: (1) assess the Companies' progress towards achieving the ESMP goals; (2) provide stakeholders sufficient information to make future recommendations on each utility function; (3) independently verify the reasonableness of ESMP investments; (4) identify opportunities for market-driven clean energy solutions; and (5) propose future performance metrics (Attorney General Brief at 29-31, citing Exh. AG-NBC-1, at 19-20). To do so, the Attorney General urges the Department to direct each company to establish a dedicated data sharing platform that consolidates information on the current and ongoing status of the company's distribution system and operations (Attorney General Brief at 29-33; Attorney General Reply Brief at 9-11). The Attorney General recommends that the data platform include information on each company's progress toward achieving ESMP goals, modeling data, and the performance of existing programs such as AMI, interconnection programs, EE, EV make-ready programs, and demand response programs (Attorney General Brief at 32). The Attorney General argues that such a platform is necessary for the GMAC and other stakeholders to effectively monitor the Companies' progress in implementing the ESMPs, collaborate in post-ESMP processes, and evaluate future ESMPs (Attorney General Brief at 31, citing Exh. AG-NBC-1, at 19-24; Attorney General Reply Brief at 9-11). The Attorney General recommends that the

Department open a new proceeding to establish statewide data access guidelines and uniform requirements for these data sharing platforms (Attorney General Brief at 29, 33; Attorney General Reply Brief at 10-11).

2. DOER

DOER recommends that the Department direct each company to submit a publicly accessible biannual report on: (1) its ESMP-related activities and progress since its last report; (2) a description of the activities planned in the next six months; (3) a summary of electric distribution system infrastructure investments planned and under construction in its service territory, with geographic specificity, and an explanation of each investment's contribution to the company's clean energy and DER goals; (4) the availability of new residential and commercial programs or technologies to support electrification and DERs; (5) an update on coordination efforts with the local gas distribution companies to transition customers from natural gas to electric service, including any planned pilot programs for strategic electrification; (6) updates on the company's relevant regulatory proceedings; (7) a timeline for the development of the company's next ESMP; (8) opportunities for the public to provide feedback for incorporation into the ESMP planning process; and (9) a description of how the company incorporated public feedback into its ESMP (DOER Brief at 68-71). DOER argues that such publicly accessible reports would improve transparency and accessibility of the ESMPs (DOER Brief at 68). DOER also encourages the Department to direct the Companies to hold public listening sessions on their biannual reports (DOER Brief at 69-70). DOER supports the Companies' proposal to have one of the biannual reports replace the Grid Modernization Plan Annual Report (DOER Brief at 71). In addition, DOER supports the Attorney General's recommendation that the Department open a statewide data access proceeding (DOER Reply Brief at 15-17).

3. Cape Light Compact

CLC requests that the biannual report include: (1) NSTAR Electric's progress on IEP planning; (2) testing on alternative use parameters on ESS; (3) increases in double poles related to ESMP system improvements (if not otherwise included in the ESMP metrics); and (4) progress on and timelines for developing ESMP performance metrics, alternative rate design in the Interagency Rates Working Group, TVR in the AMI Stakeholder Group, and dispatch energy storage technologies in D.P.U. 23-126 (CLC Brief at 29-31; CLC Reply Brief at 8-9, 11, 15). CLC argues that including this information in the biannual report would ensure that stakeholders are kept apprised of NSTAR's progress on its ESMP (CLC Brief at 30-31). CLC strongly supports DOER's proposal for the Companies to make the biannual reports publicly available and have public listening sessions to summarize relevant updates regarding the implementation of the ESMP that would likely be of interest to stakeholders (CLC Reply Brief at 11-12, citing DOER Brief at 69-70).

4. Companies

The Companies recommend April 1 and October 1 each year as the filing dates for the biannual reports and urge the Department to approve their proposed biannual reporting timelines because they align with existing dockets and other annual reporting timelines (Companies' Joint Brief at 96-97). Because information to be reported in the first year of the

ESMPs would be minimal, the Companies recommend beginning the biannual reporting in the second year of the ESMP implementation, i.e., 2026 (Companies' Joint Brief at 97). The Companies also request an opportunity to develop a common reporting template to ensure that all reports are valuable, actionable, and support transparency among the GMAC, stakeholders, regulators, and policy makers (Companies' Joint Brief at 97). Additionally, the Companies propose to make the biannual reports publicly available and will consider having public presentations on the progress of ESMP implementation, provided the GMAC does not require or provide similar presentations at public meetings (Companies' Joint Reply Brief at 65).

The Companies oppose establishing dedicated data sharing platforms because the Companies have already provided a significant amount of information and data in their ESMPs and to the GMAC as well as in their ARRs and annual service quality reports (Companies' Joint Reply Brief at 56). Further, the Companies maintain that the Attorney General did not describe with specificity the data to be shared on the data sharing platforms and that any information sought that is critical energy infrastructure information cannot be shared with stakeholders without increasing the risk of data leaks, exposures, and virtual and physical damage to utility infrastructure (Companies' Joint Reply Brief at 56-57). The Companies argue that public safety concerns regarding critical energy infrastructure information outweigh the public's interest in transparency and information (Companies' Joint Reply Brief at 57).

Finally, the Companies oppose the Attorney General's, DOER's, and CLC's recommended reporting requirements, arguing that such requirements are beyond the scope of the biannual reporting requirement established by the Legislature or are irrelevant to these proceedings (Companies' Joint Reply Brief at 62-66). Moreover, the Companies argue that CLC's recommended biannual reporting requirements would impermissibly broaden the scope of these proceedings, or are unnecessary because, in the case of EE and double poles, are addressed in other dockets (Companies' Joint Reply Brief at 9).

D. Analysis and Findings

1. Introduction

Section 92B(e) requires each company to submit two reports per year to the Department and the Joint TUE Committee on the deployment of approved investments in accordance with any performance metrics included in the approved ESMP plans. The Companies identify information they propose to include in the biannual reports and a submission timeline. Intervenors recommend additional reporting as well as a dedicated data sharing platform for ongoing access to data on the Companies' distribution systems.

2. Data Access

For the following reasons, the Department declines to require each company to establish a dedicated data sharing platform for stakeholders to access company data on an ongoing basis. First, ongoing access by stakeholders to data on the Companies' distribution systems, whether provided through a consolidated data platform or another format, goes well beyond the two reports per year required by the Legislature in Section 92B. As discussed in

Section V.D., the Department concluded that the Legislature in Section 92B conferred on the GMAC an advisory role. While the Department has general regulatory authority over the Companies, that does not justify the Department substituting its own judgment for that of utility management. Attorney General v. Dep't of Public Utilities, 390 Mass. at 228. Nor is it our intent to oversee and manage the Companies' day-to-day planning and decision-making but, rather, to put in place a distribution system planning framework that enables achievement of the objectives of Section 92B. This framework includes informational filings to maintain accountability in the implementation of those plans and to allow the Department to monitor implementation progress and fulfill its regulatory oversight responsibilities in an efficient and effective manner. Grid Modernization Order at 113, citing Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines, D.P.U. 11-120-A (Phase II) at 2 (2013).[143]

The GMAC and other stakeholders have a legitimate interest in monitoring the implementation of the ESMPs and progress towards achieving the statutory objectives, but ongoing access to data on the Companies' distribution systems and planning processes is not necessary to advance this interest. Rather, in this Order, we establish the initial content to be included in the biannual reports and will finalize the content in a subsequent phase of these proceedings that will allow stakeholders the ability to monitor ESMP implementation

143 The Department, however, may formally investigate a company's performance during the ESMP term where we determine it is warranted. Grid Modernization Order at 112.

progress. We encourage intervenors to participate in that subsequent phase. Further, as part of that subsequent phase, we will consider, to the extent practicable, whether and how to streamline our reporting requirements to minimize duplicative data reporting.

Second, the record is unclear as to the potential security risk posed by a dedicated data sharing platform or associated implications relating to confidential critical energy infrastructure information ("CEII") (Tr. 6, at 881). See G.L. c. 4, § 7, cl. 26(a). As such, the Department is also disinclined to mandate establishing such a platform without a full understanding of those risks or CEII considerations. Nevertheless, we acknowledge that several other jurisdictions have implemented or are developing a data sharing platform (D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, Exh. AG-NBC-1, at 24-26), and we recognize the potential value and efficiency of doing so. The Department may therefore revisit in the future the feasibility, as well as the associated costs, of a data sharing platform and the extent of data to be shared on that platform.

3. Form and Content of Biannual Reports

The Companies and intervenors differ on the extent of information to be reported in the biannual reports. The Companies propose to include in their first biannual report information on the prior plan year's progress on incremental ESMP investments, including results relative to performance metrics, and to replace the current grid modernization plan annual report (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 665; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 481; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 295). The Companies propose that the subsequent biannual report would provide information on the first six months of the current ESMP plan year and an interim review of year-to-date progress (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 665; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 481; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 295). DOER and CLC recommend that the biannual reports include the Companies' ESMP-related activities and progress, summary of planned and in-progress electric distribution projects, new programs to support electrification and use of DERs, information on IEP planning, engagement with the general public and stakeholders, ESS, double poles, and progress on and timelines for developing alternative rate designs and, further, that the Companies conduct public listening sessions on implementation of their ESMPs (DOER Brief at 68-71; CLC Brief at 29-31; CLC Reply Brief at 8-9, 11, 15).

To begin, throughout this Order, the Department has directed specific information to be included in the biannual reports. That required information includes, but is not limited to, the following:

- Section IV.C.3. (Framework for Review): Changes and reprioritization of proposed ESMP investments.
- Section VI.C.3. (Forecasts and Demand Assessments): A comparison of the forecasted demand (according to the updated ARR) and actual demand, separated by component (baseload and DERs) for each completed year in the ESMP term; and identification of variances between five- and ten-year demand forecast components in the approved ESMP and the updated ARR ten-year demand forecast components.
- Section VII.B.3. (Integrated Energy Planning): Progress on IEP processes, including but not limited to updates on the Joint Working Group, data exchange, feasibility assessments, and targeted electrification projects.

- Section VII.C.4.b.iii. (Planned and Proposed Investments – Grid Services Study): Updates relating to the Grid Services Study and compensation framework being developed.

- Section VII.C.4.c.i. (Planned and Proposed Investments – Reliability, Resiliency, and Climate-Driven Impacts):
  - Updates on finalizing CVA frameworks
  - Updates on targeted resiliency investment identification and prioritization method
  - Identify and explain adjustments to proposed portfolio of targeted resiliency investments
  - Descriptions of company's planned targeted resiliency investments along with associated costs, regardless of core or ESMP classification

- Section VII.D.4. (Alternatives to Proposed Investments): Whether the company has conducted testing on company-owned ESS and any corresponding results, involving secondary use parameters.

- Section VII.E.4. (Transmission Investments): Updates on transmission upgrades necessitated by ESMP investments.

- Section VII.G.3. (Alternatives to Financing Proposed Investments): Summaries of federal grant, loan, and tax funding the company has sought during the preceding reporting period and its planned funding sources during the following reporting period; descriptions of company efforts to coordinate with partner entities and impediments to such efforts: and identification of barriers encountered in obtaining funds and recommendations for how the Department can support company receipt of grants, loans, and tax incentives.

- Section VII.H.4.c. (Stakeholder Engagement and Equity): Updates on how the company is addressing distributional and structural equity in the implementation of its ESMP, training its staff on equity matters, and allocating staff resources, and a description of how any lessons learned could shape the next iteration of their equity framework.

For purposes of transparency and to facilitate greater understanding of distribution system planning, the Department also sees value in the Companies reporting high-level data in the ESMP reports relating to non-ESMP investments, including summary lists of, for example, relevant Department proceedings, docketed and non-docketed filings, related stakeholder or working groups, and key metrics.[144] The Department determines that summaries of relevant Department proceedings and both docketed and non-docketed filings will provide stakeholders with the ability to preview in a single location all proceedings and filings before the Department that may inform implementation of ESMP investments.

The Department clarifies that in addition to this required data, the Department intends to further develop and finalize the form and content of the biannual reports in a subsequent phase of these proceedings. Regarding DOER's request for the Companies to conduct public listening sessions on the implementation of their ESMP investments, the Department declines to mandate such a requirement at this time. The Department does, however, encourage the Companies to conduct such sessions for interested stakeholders and to report on such activities in their biannual reports.

4. Biannual Report Filing Dates

The Companies propose filing reports on April 1 and October 1 each year, beginning in 2026, based on a five-year ESMP term with the first term beginning on January 1, 2025 and ending on December 31, 2029 (D.P.U. 24-10, Exhs. ES-ESMP-1 (Corrected) at 665; DPU-Common 7-8; D.P.U. 24-11, Exhs. NG-ESMP-1 (Corrected) at 481;

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[144] Prior to these proceedings, the Companies provided the GMAC with summaries of its pre-existing metrics, and the GMAC's consultant prepared a summary of ESMP-relevant proceedings and working groups. Both summaries, "Pre-Existing Metrics for EDCs" and "ESMP-Relevant Proceedings and Working Groups – Version 2" are available on the GMACs website at: https://www.mass.gov/info-details/electric-sector-modernization-plans-esmps-information-and-recommendations (last visited August 29, 2024). The Department finds the format and content of these summaries to be useful for stakeholder engagement.

DPU-Common 7-8; D.P.U. 24-12, Exhs. UN-ESMP-1 (Corrected) at 295; DPU-Common 7-8). The Companies also propose that the biannual report replace the current grid modernization annual report (D.P.U. 24-10, Exh. ES-ESMP-1 (Corrected) at 665; D.P.U. 24-11, Exh. NG-ESMP-1 (Corrected) at 481; D.P.U. 24-12, Exh. UN-ESMP-1 (Corrected) at 295). No intervenor addressed these issues.

The Department acknowledges that the Companies are subject to multiple reporting requirements, including ARRs, grid modernization annual reports, EV annual reports, EE annual reports, and annual interconnection time enforcement metric reports. Notice of Inquiry and Rulemaking, D.T.E. 98-84/EFSB 98-5 (2003); G.L. c. 164, § 146; Second Grid Modernization Plans (Track 2) at 302; Electric Vehicles 2022 Order at 188; Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines, D.P.U. 20-150-A, Guidelines, § 4.2 (2021); Department Investigation on Distributed Generation Interconnection, D.P.U. 11-75-F at 3 (2014). Thus, the Department finds it appropriate to the extent practicable to align the timing of the Companies' various reporting requirements. The Companies must each file ARRs annually on March 31 and in their ARRs must report on the reliability of their respective distribution and transmission systems, including demand forecasting, distribution system planning criteria and guidelines, lists of significant planned reliability and infrastructure improvement projects, planned projects to meet transmission needs, and other information as required by the Department. Annual Reliability Reports, D.P.U. 22-ARR-01/D.P.U. 22-ARR-02/D.P.U. 22-ARR-04, Hearing Officer Memorandum on 2023 ARR Reporting Requirements (February 6, 2023);

D.T.E. 98-84/EFSB 98-5; see also G.L. c. 164, § 146. The Department recognizes that certain data necessary to allow the Department and stakeholders to monitor ESMP implementation progress and to be reported in the ESMP biannual reports overlaps with the data that the Companies must report in the ARRs, and in particular demand forecasting, distribution system planning criteria and guidelines, and planned reliability and infrastructure improvement projects, among other data. Thus, consistent with the Companies' proposal, the biannual report filing dates should align with the ARRs. Accordingly, the Companies must file one of its biannual reports on March 31, and the other biannual report on September 30.

Further, the Department rejects the Companies' recommendation to begin ESMP biannual reporting in 2026. The Department acknowledges that time is necessary to mobilize and deploy ESMP investments but, in the first plan year of the ESMPs, the Department expects that updated forecasts as well as compliance with directives in this Order may require the Companies to reprioritize investments and/or deployment timelines and, in the interest of transparency, the Department, Joint TUE Committee, GMAC, and other stakeholders should be apprised of such developments. As discussed in Section VII.A.4., the Department established the first five-year ESMP term as beginning on July 1, 2025 and concluding on June 30, 2030. As such, the Companies first ESMP biannual report shall be filed on September 30, 2025, three months into the first ESMP term, and the second biannual report will be due on March 31, 2026.

Lastly, as noted above, in finalizing the content of the biannual reports, the Department will endeavor to streamline Department reporting requirements to minimize duplicative data reporting, to the extent practicable. However, as discussed below, the Department does not find it appropriate to eliminate the grid modernization annual report, as the Companies suggest, even if the contents of the grid modernization annual reports are incorporated into the ESMP biannual reports.

On principle, there is some merit to incorporating the grid modernization annual report into the ESMP biannual reports but, in practice, doing so would be inappropriate. The grid modernization annual reports allow the Department to monitor the progress of each company's implementation of preauthorized investments pursuant to its approved grid modernization plan. Second Grid Modernization Plans (Track 2) at 303; Grid Modernization Order at 112-113. As discussed in Section VII.A.4., the Department established the first five-year ESMP term as the period from July 1, 2025 through June 30, 2030. The four-year term of the grid modernization plans now in effect began on January 1, 2022, and will conclude on December 31, 2025. The two remaining grid modernization annual reports are due on July 1, 2025 and July 1, 2026 for calendar year ("CY") 2024 and CY 2025, respectively, with the July 1, 2026 filing also incorporating each company's final term report. D.P.U. 21-80/D.P.U. 21-81/D.P.U. 21-82, Stamp-Approved Compliance Tariffs (January 22, 2024); Second Grid Modernization Plans (Track 2) at 303. The Department, with input from stakeholders, developed a detailed reporting template and narrative report outline for the grid modernization annual reports. See, e.g., Grid Modernization Annual Reports, D.P.U. 24-40, Hearing Officer Memorandum & Atts. (April 3, 2024).

The CY 2022 through CY 2025 grid modernization term report forms the basis for the Department's prudence review of all preauthorized grid modernization plan investments deployed over the four-year term and, as such, must remain a separate and distinct filing from the ESMP biannual reports. Further, given that there is an established reporting template and narrative outline for the grid modernization annual reports, the effort to incorporate or modify the grid reporting templates and required narratives would be an inefficient use of time given that only the CY 2024 grid modernization annual report, currently due on July 1, 2025, would be incorporated into the ESMP biannual report. In sum, the Department rejects the Companies' recommendation to replace the filing of the grid modernization annual reports with the ESMP biannual reports.

XII. ORDER

After due notice, hearing, and consideration, it is

ORDERED: That the 2025 through 2029 electric sector modernization plan filed by NSTAR Electric Company d/b/a Eversource Energy is APPROVED WITH MODIFICATION, consistent with and subject to the directives contained herein; and it is

FURTHER ORDERED: That the 2025 through 2029 electric sector modernization plan filed by Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid is APPROVED WITH MODIFICATION, consistent with and subject to the directives contained herein; and it is

FURTHER ORDERED: That the 2025 through 2029 electric sector modernization plan filed by Fitchburg Gas and Electric Light Company d/b/a Unitil is APPROVED WITH

MODIFICATION, consistent with and subject to the directives contained herein; and it is

FURTHER ORDERED: That NSTAR Electric Company d/b/a Eversource Energy, Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, and Fitchburg Gas and Electric Light Company, d/b/a Unitil shall comply with all other directives contained in this Order.

By Order of the Department,

James M. Van Nostrand, Chair

Cecile M. Fraser

Cecile M. Fraser, Commissioner

Staci Rubin, Commissioner

An appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part. Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. G.L. c. 25, § 5.

APPENDIX A - PROVISIONAL PROGRAM EXTENSION: CIP FILING CHECKLIST

Instructions:

Per D.P.U. 20-75-B at 31-32, an electric distribution company ("Company") seeking to file a Capital Investment Project ("CIP") proposal for the interconnection of distributed energy resources ("DER") with the Department of Public Utilities ("Department") must include the following six items, at a minimum, in its initial filing:

A. Description of the CIP, including projected cost, equipment, permitting and licensing requirements, and construction timeline.

B. Demonstration that the CIP meets all eligibility criteria.

C. Detailed cost allocation proposal based on D.P.U. 20-75, Att. A ("Department's Methodology") that includes a proposed rate recovery period for the CIP through the reconciling charge.

D. Projected bill impacts.

E. Description of how the CIP will benefit ratepayers and aligns with cost-efficiently meeting the Commonwealth's clean energy policies.

F. 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 population.

Based on our experience adjudicating CIP proposals, the Department provides expanded guidance, in the form of a checklist for the six filing requirements, to further streamline our review of any future proposals. Also, to the extent practicable, the Department recommends that the electric distribution companies coordinate with the Group Study DER developers in advance of any filing to provide additional information (see Coordination with Group Study Developers) pertinent to the Department's review. In all sections, the Company must identify the page number or attachment reference in the petition where the information associated with each request may be found. If a request is not applicable, the Company should write "N/A" in the cell; cells should not be left blank.

A. Description of the CIP, including projected cost, equipment, permitting and licensing requirements, and construction timeline.

Request Number	Request	Page Reference
1.	Provide the most recent copy of the Company's Distribution Planning Criteria.	
2.	Provide the Distribution System Impact Studies ("SIS") for all DER facilities in the Group Study. Include all results, reports, analyses, documentation, and assumptions supporting each SIS provided in your response.	
3.	Provide a list of the unique DER projects in the Group Study, by substation, including: a) The name(s) of the Interconnecting Customer; b) Project location (city or town); c) Whether the project is standalone or behind-the-meter; d) Whether the project is rooftop or non-rooftop; e) Whether the project is solar, an energy storage system ("ESS"), or both; f) Nameplate, maximum export, and if applicable, curtailed export capacities in kilowatt ("kW") alternating current ("AC"); and g) The date on which the Company approved the interconnection application as complete. Do not include any personally identifiable information.	
4.	Provide a list of the unique, large DER projects, by substation, in the Company's interconnection queue that are not in the Group Study. Include the information requested in Question A.3. (a) through (g), above.	
5.	Provide an estimate of the range of additional, site-specific interconnection costs on top of those covered by the CIP fee. a) Discuss whether additional interconnection costs have been calculated for each Group Study project and whether the Group Study projects have been informed of the amount of additional costs. b) Indicate whether the all-in cost of interconnection, including additional site-specific interconnection costs, are expected to result in any Group Study project's failure to move forward with completing the interconnection process.	
6.	Discuss the full range of solutions considered and not selected in the process of determining the proposed CIP distribution system upgrades to be the optimal technical and viable solution.	
7.	Describe any thermal loading, voltage regulation, or other issues that add to the cost of the solution and explain why the chosen solution is justified.	

Request Number	Request	Page Reference
8.	List the factors considered when selecting each solution and describe how each factor is prioritized (e.g., controlling cost, secondary benefits of providing headroom for future DER, ease of implementation/construction, etc.).	
9.	Discuss whether there are any Group Study projects that, if not included, would significantly reduce necessary substation or distribution line upgrades, or reduce excess headroom created by the proposed project solution.	
10.	Provide a detailed budget breakdown for each CIP, in working Microsoft Excel format, including all supporting documentation, data, and assumptions used to develop the cost estimates.	
11.	Identify the source of and basis for such data and assumptions employed to develop each of the following key inputs (as applicable): a) Installed Capacity; b) Available Operational Capacity; c) Existing Maximum Gross Load; d) Installed Capacity, Group Study Solution; e) Reserved Operational Capacity; f) Enabled Rooftop DER Capacity; g) Existing Minimum Gross Load; h) Provisional Program DER Group Study; and i) Group Study DER Application after Provisional Program.	
12.	Discuss any impact on the Company's CIP proposals from the four-year construction timeline constraint.	
13.	Describe any impact that specific permitting processes may pose to the Company's CIP proposals, including delays and cost increases, and if these impacts are fully captured in any existing budget contingency.	
14.	Explain how the CIP proposal is bounded and provide the following information as part of the response: a) the relevant zip codes or geographic designation for each CIP; b) a description of how the geographic boundaries of the CIP area are determined; and c) the total land area included in the CIP area.	
15.	Explain whether the DER facilities enabled by the CIP Proposal may be served by distribution infrastructure (e.g., substations, feeders, etc.) outside of the CIP geographic area.	
16.	For existing DER facilities in the CIP Group Study area that seek to expand their DER facility, provide the following information:	

Request Number	Request	Page Reference
	a) Explain whether the Company would put on hold the application for any existing small facility whose capacity is below the CIP Fee size threshold that seeks to expand; b) Explain whether the Company would assess such an expanded DER facility a CIP Fee; c) If the Company would apply a CIP Fee, explain whether the CIP Fee would apply to the total combined kW of the existing and expanded DG facility or to just the incremental kW of the expansion; and d) Explain whether, once the Department approves a CIP Fee, the Company would assess a CIP Fee to any existing DER facility in the Group Study area that is already seeking to expand.	
17.	If the Department were to approve the CIP, explain when the Company would initiate the formulation and study of the next group(s) of Large DER projects in the queue behind the Group Study.	
18.	Identify and describe any transmission system upgrades associated with the proposed CIP that the Company proposes to recover separately through Local Network System rates. For each upgrade: a) State when the need for the upgrade was identified; b) Describe the need for the upgrade; c) Provide the cost for each proposed upgrade, broken out by the capital costs, operating expense, and removal cost components; and d) Describe the current status of the upgrade, including with respect to any stakeholder or regulatory review.	
19.	Discuss any indication that a Group Study participant may not move forward for any reason.	
20.	Curtailment. a) As applicable, explain why the Company proposes curtailment of DER from the Group Study facilities. Provide all analyses the Company has conducted to support its proposal to curtail the Group Study DER. b) For each CIP in which the Company proposes curtailment of DER, describe the Group Study applicants' continued request for and interest in agreeing to having the operations of their DER curtailed to reduce the proposed electric power system upgrades. c) Further, for each CIP in which the Company proposes curtailment of DER, explain:	

Request Number	Request	Page Reference
	i. How the Company will secure Group Study agreement to and implementation, monitor, and enforcement of curtailment of the DER in the Group Study; ii. If further capital or operating measures or investments relative to curtailment are necessary and whether their costs are included in each CIP; and iii. Whether DER projects seeking interconnection after the Group Study would similarly be subjected to curtailment.	
21.	Describe how the Company considered and/or incorporated flexible interconnection or non-wires alternatives options in its CIP proposal. Such alternatives include but are not necessarily limited to load management and other methods for reducing demand, enabling flexible demand, and supporting dispatchable demand response.	

B. Demonstration that the CIP meets all eligibility criteria.

Request Number	Request	Page Reference
1.	Without the Provisional Program, discuss how or when additional capacity would be constructed to accommodate future electrification needed to meet the Commonwealth's 2050 Decarbonization Goals. Explain if the Company would undertake any upgrades described in the CIP proposal in the absence of Group Study DER. Provide a calendar year[145] estimate for these upgrades, if applicable.	
2.	Discuss whether the proposed projects separately enable more capacity than is projected to be necessary to meet the Commonwealth's 2050 Decarbonization Goals in any one region, or cumulatively enable more capacity than is projected.	
3.	Discuss whether the Company conducted an analysis of peak shaving benefits attributable to the proposed CIPs. If so, discuss whether the potential peak shaving benefits could be estimated.	
4.	Clarify whether forecasted load growth in the CIP area, aside from electrification, was considered in the Company's analysis and development of its proposed solution. Explain whether the Reserved Operational Capacity is sufficient to accommodate non-DER load growth in the CIP area, aside from electrification.	
5.	Provide a summary table of the forecasted amount of DER capacity that the Company determines is likely to seek connection in the	

145 "Year" means calendar year, unless otherwise noted.

Request Number	Request	Page Reference
	CIP area, itemized by project type (e.g., rooftop or non-rooftop solar, ESS, or both, etc.) and expected year of completion.	
6.	Discuss whether the Company conducted any research or analyses to confirm that the amount of DER capacity that it determines is likely to connect in the CIP area is not limited by land availability or other siting restrictions. Specifically, explain whether the Company determined the amount of land that was developable for solar in the vicinity of each substation, up to the enabled capacity.	
7.	Explain whether and to what extent the Company used data from the Department of Energy Resources' ("DOER") Massachusetts Technical Potential of Solar Study ("MTPS")[146] in determining or confirming the total amount of forecasted DER capacity likely to seek interconnection in the CIP area. If not, explain why not.	
8.	Explain if the Company considered state or federal incentive programs when determining the amount and pace of forecasted DER capacity likely to seek interconnection in the CIP area.	
9.	Explain how the upgrades needed for reliable integration of DERs in the Group Study led to the enablement of additional DER above the Group Study DER. As part of this response, discuss how the use of standard sized equipment contributed to the enablement of additional DER, whether options other than standard size equipment could be used and, if so, provide the prescribed capacity in MVA that would be needed to enable the Group Study DER, and the associated change in costs for the proposed CIPs.	
10.	Explain whether and how the total amount of enabled DER would differ if DER other than solar are interconnected.	
11.	Specify the payment schedule that the Company proposes to include with the terms of the ISA to each Interconnecting Customer.	
12.	Specify the timeline for ISA issuance following a Department-issued approval of the CIP.	
13.	Explain the Company's process for managing Group Study project changes, including any differences from the Company's DG Interconnection Tariff. Indicate whether any Group Study members have communicated the need for project changes.	
14.	Explain which agreements and forms that appear in or as attachments to the DG Interconnection Tariff have been executed by Group Study members to date.	

146 DOER published the MTPS Study on July 6, 2023. Massachusetts Technical Potential of Solar Study (July 6, 2023), available at https://www.mass.gov/doc/technical-potential-of-solar-in-massachusetts-report/download (last visited August 29, 2024).

Request Number	Request	Page Reference
15.	Explain whether the Company has considered any type of alternative proposed commitment, not included in or as an attachment to the DG Interconnection Tariff, from Group Study projects before initiating procurement and construction.	

C. Detailed cost allocation proposals based on the Straw Proposal that includes a proposed rate recovery period for the CIP through the reconciling charge.

Request Number	Request	Page Reference
1.	Identify and explain any modifications and/or updates to the Company's cost allocation and recovery framework proposed for this CIP relative to previously filed CIPs.	

D. Projected bill impacts.

Request Number	Request	Page Reference
1.	In the Company's analysis of bill impacts, provide the calculation of the CIP factor for each rate class, including the supporting Excel documentation with all cell references and formulas intact.	
2.	Provide a cumulative bill impact analysis under the assumption that all CIPs are approved as proposed. Include a discussion of the year or years over which the bill impacts are analyzed and supporting documentation of all calculations, including of the calculation of the underlying CIP factors for each rate class.	
3.	Specify the year in which the Company expects the CIP Factor to first be applied to customer bills and explain the assumptions used for determining the years in which a capital project is placed into service.	
4.	Discuss how the proposed projects further the goal of affordability.	
5.	Discuss how ratepayers will be impacted if CIP costs are higher than estimated.	
6.	Explain whether the Company has considered scenarios, or conducted any sensitivity analyses demonstrating bill impacts, in which any number of Group Study projects are not ultimately interconnected and the resultant risk to ratepayers.	
7.	Explain how the Company will define CIP capital, including whether certain capital (i) will be in service prior to the full enablement of DER interconnection, and (ii) will be used and useful prior to the full enablement of DER interconnection.	

Request Number	Request	Page Reference
8.	Discuss whether a net metering customer that does not participate in the Solar Massachusetts Renewable Target ("SMART") program may be able to bypass the CIP Factor.	

E. Description of how the CIP will benefit ratepayers and aligns with cost-efficiently meeting the Commonwealth's energy policies.

Request Number	Request	Page Reference
1.	Explain how the average residential customer will experience improvements to reliability and voltage quality that result from the proposed projects and, to the extent feasible, quantify or further qualify any benefits (e.g., reduced outage minutes per year).	
2.	Explain how the average commercial or industrial customer will experience improvements to reliability and voltage quality that result from the proposed projects and, to the extent feasible, quantify or further qualify any benefits (e.g., reduced outage minutes per year).	

F. Explanation of how the CIP will affect low-income and environmental justice ("EJ") populations.

Request Number	Request	Page Reference
1.	Explain how the location of a parcel of land in an EJ population within the CIP area affects the Company's ranking analysis.	
2.	Discuss how both non-EJ population distribution customers and EJ population distribution customers in the CIP area will benefit from community shared solar or may receive other direct financial benefits from DER projects enabled by the CIP. Discuss whether any of the Group Study or other post-Group Study projects are intended to be community solar or low-income solar projects.	
3.	Explain whether the Company conducted any analyses of: a) quantitative or qualitative benefits to EJ populations from the CIP. If so, provide all analyses the Company conducted. b) quantitative or qualitative impacts or risks to EJ populations from the CIP. If so, provide all analyses the Company conducted.	
4.	Explain when the Company plans to complete the distribution line design plan. If completed or in progress, explain how the distribution line construction plan may impact any EJ populations in the CIP geographic area.	

Request Number	Request	Page Reference
5.	Discuss in additional detail how the Company will communicate and work with communities where distribution line construction is expected. Provide an example of an outreach plan.	
6.	Discuss and quantify the extent to which: a) location-relative-to EJ-populations is a factor in deciding where distribution lines will be located; b) substation construction is concentrated inside of EJ populations (e.g., the proportion of affected acres inside EJ populations); and c) overhead and underground work on distribution lines will impact EJ populations (e.g., the proportion of total miles of work on distribution lines that will occur in EJ populations).	
7.	Provide a detailed description of the environmental burdens of the CIP and underlying Group Study projects on EJ populations, including: a) Discussion of the disruption caused by construction, pollution impacts from construction vehicles, tree removal, or any other foreseeable short- or long-term impacts on EJ populations; and b) Explanation of the potential impacts to EJ populations caused by design decisions later in the process, such as distribution line construction or reconductoring through an EJ population based on substation upgrades.	
8.	Explain how the Company identifies EJ populations in the CIP geographic area and the census block group information associated with those EJ populations (e.g., minority population, median household income, etc.) and which EJ populations may be impacted by construction of distribution system upgrades to enable the CIP.	
9.	Provide the total number of distribution customers living in (a) the CIP area; and (b) within the CIP area, an EJ census block group by type of EJ criteria (i.e., minority status, income status, language isolation status, minority plus income status).	

The Department recommends that the Companies coordinate with the Group Study DER developers in advance of any filing to provide the following information.

G. Coordination with Group Study Developers.

Request Number	Request	Page Reference
1.	For each Group Study DER facility included in the CIP, provide in a table all anticipated permits and licensing requirements for the construction and operation of the facility and the corresponding federal, regional, state, or municipal permitting or licensing entities. This information may be based upon a preliminary permitting assessment. In your response, note which permitting or licensing requirements the Interconnecting Customers have already begun to pursue.	
2.	In instances where permitting of a facility is complete, please identify whether any party appealed or otherwise challenged the permitting decision. If so, provide the permit being challenged, the appellant, the forum in which the permitting decision has been appealed, whether the matter is active or resolved, and the outcome of any resolution.	
3.	For any permit that is in process, please further explain if the permit application has: a) been prepared and filed; b) been deemed complete by the permitting authority; c) been under review by the permitting authority; d) resulted in the issuance of a permit by the permitting authority and, if yes, whether the permit is awaiting finalization, recording, or any appeal period; or e) resulted in the issuance of a permit by the permitting authority and, if yes, whether the permit is under active appeal. If the permit is under active appeal, please explain the nature of the appeal, the appellant, and the forum in which the permitting decision has been appealed.	
4.	For each DER project that each CIP Proposal proposes to interconnect: a) Identify any public conversations with or guidance provided by federal, regional, state, or municipal officials regarding the siting, permitting, or licensing approvals; and b) Provide any meeting minutes, transcripts, presentations, or other materials regarding each of the DER projects in any public forum (e.g., Town Meetings, City Council Meetings, presentations to the public). Please include a list of all meetings of this nature.	
5.	For each DER project proposed to interconnect, provide a general estimate of costs expended to date, and if the developer intends to proceed with the project(s).	

Request Number	Request	Page Reference
6.	Explain whether the Group Study Developers support or oppose the CIP Fee proposed by the Company. Explain the reasons for the support or opposition. Provide any upper limit on the CIP Fee that would prevent Group Study Developers from developing DER projects in the CIP area.	
7.	Discuss how EJ population distribution customers in the CIP area will benefit from community shared solar or may receive other direct financial benefits from the DER Group Study developers' projects. As part of this response, discuss whether any of the Group Study developers intend to: a) Operate one or more of its projects as a community shared solar or low-income solar facility; b) Qualify any of their facilities as "Community Shared Solar Tariff Generation Unit" or "Low Income Community Shared Community Shared Solar Tariff Generation Unit" as defined in the SMART program regulations at 225 CMR 20.02 and provide benefits to EJ population distribution customers in the CIP area; c) Offer all or part of any net metering credits or alternative on-bill credits generated by one or more of its projects to offset electric bills or provide other benefits to the EJ population distribution customers in the CIP area; or d) Take any other steps through one or more of its projects to provide direct financial benefits of solar energy or distributed generation to EJ population distribution customers in the CIP area.	