The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

November 30, 2022

D.P.U. 21-80-B

Petition of NSTAR Electric Company d/b/a Eversource Energy for approval by the Department of Public Utilities of its Grid Modernization Plan for calendar years 2022 to 2025.

D.P.U. 21-81-B

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 Grid Modernization Plan for calendar years 2022 to 2025.

D.P.U. 21-82-B

Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval by the Department of Public Utilities of its Grid Modernization Plan for calendar years 2022 to 2025.

ORDER ON NEW TECHNOLOGIES AND ADVANCED METERING INFRASTRUCTURE PROPOSALS

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I. INTRODUCTION AND PROCEDURAL HISTORY

On July 1, 2021, 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 of Public Utilities ("Department") a proposed 2022-2025 Grid Modernization Plan and advanced metering infrastructure ("AMI") implementation proposals. The Companies submitted these filings pursuant to Grid Modernization – Phase II, D.P.U. 20-69-A (2021). The Department docketed these matters as D.P.U. 21-80, D.P.U. 21-81, and D.P.U. 21-82, respectively.[1]

On July 28, 2021, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed notices of intervention in D.P.U. 21-80, D.P.U. 21-81, and D.P.U. 21-82, pursuant to G.L. c. 12, § 11E(a). Additionally, the Department granted full intervenor status to each of the following entities: the Massachusetts Department of Energy Resources ("DOER") (D.P.U. 21-80; D.P.U. 21-81; D.P.U. 21-82); The Energy Consortium ("TEC") (D.P.U. 21-80; D.P.U. 21-81; D.P.U. 21-82); Green Energy Consumers Alliance ("GECA") (D.P.U. 21-80; D.P.U. 21-81); Cape Light Compact JPE ("CLC") (D.P.U. 21-80); Conservation Law Foundation ("CLF") (D.P.U. 21-80; D.P.U. 21-81; D.P.U. 21-82); Utilidata, Inc. ("Utilidata") (D.P.U. 21-80; D.P.U. 21-81;

[1] These cases have not been consolidated and remain separate proceedings.

D.P.U. 21-82); Acadia Center (D.P.U. 21-80; D.P.U. 21-81; D.P.U. 21-82); and the NRG Retail Companies (NRG Home, Direct Energy Services, LLC, Direct Energy Business, LLC, Green Mountain Energy Company, Energy Plus Holdings, LLC, and XOOM Energy Massachusetts, LLC) ("NRG") (D.P.U. 21-80; D.P.U. 21-81).

On September 1, 2021, the Department bifurcated its investigation of the filings into two separate, parallel tracks. D.P.U. 21-80/D.P.U. 21-81/D.P.U. 21-82, Procedural Notice at 2 (September 1, 2021). The Department designated Track 1 to review proposed investments identified as having been previously deployed and/or preauthorized grid modernization investments and technologies under the Companies' first grid modernization plan term ("continuing investments"), and Track 2 to review proposed investments identified as new grid modernization investments and those investments proposed as part of each company's AMI implementation plan. D.P.U. 21-80/D.P.U. 21-81/D.P.U. 21-82, Procedural Notice at 2 (September 1, 2021). See also D.P.U. 20-69-A at 37. Pursuant to notices duly issued, the Department conducted a joint public hearing and procedural conference in these proceedings on September 9, 2021. On October 7, 2022, the Department issued an Order on the proposed Track 1 investments. D.P.U. 21-80-A/D.P.U. 21-81-A/ D.P.U. 21-82-A, Order on Previously Deployed Technologies (October 7, 2022) ("Track 1 Order").[2]

[2] For additional background and procedural history for these proceedings, refer to the Track 1 Order at 1-9.

The Department held four days of joint evidentiary hearings, April 5, 2022 through April 8, 2022, on the Companies' proposed Track 2 investments and established a staggered briefing schedule for the three dockets on these proposed investments. For D.P.U. 21-80, the Attorney General, DOER, Acadia Center, CLC, CLF, NRG, GECA, TEC, and Utilidata submitted initial briefs on May 16, 2022;[3] NSTAR Electric submitted an initial brief on June 1, 2022; the Attorney General, CLC, GECA, and NRG submitted reply briefs on June 13, 2022;[4] and NSTAR Electric submitted a reply brief on June 28, 2022. For D.P.U. 21-81, the Attorney General, Acadia Center, CLF, NRG, and TEC submitted initial briefs on May 18, 2022; National Grid submitted an initial brief on June 1, 2022; the Attorney General and NRG submitted reply briefs on June 15, 2022; and National Grid submitted a reply brief on June 29, 2022. For D.P.U. 21-82, the Attorney General and CLF submitted initial briefs on May 20, 2022; Unitil submitted an initial brief on June 3, 2022; the Attorney General submitted a reply brief on June 17, 2022; and Unitil submitted a reply brief on July 1, 2022.

During the course of the Track 2 investigation, each company sponsored witness testimony. In D.P.U. 21-80, NSTAR Electric sponsored the testimony of the following

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3 On May 16, 2022, DOER and Utilidata each submitted a single initial brief for all three proceedings, and GECA submitted a single initial brief for D.P.U. 21-80 and D.P.U. 21-81.

4 On June 13, 2022, GECA submitted a single reply brief for D.P.U. 21-80 and D.P.U. 21-81.

witnesses, all employees of Eversource Energy Service Company: (1) Jennifer A. Schilling, vice president, grid modernization; (2) Robert W. Frank, director, Massachusetts revenue requirements; (3) Jessica Brahaney Cain, vice president, customer operations; (4) Douglas Horton, vice president, distribution rates and regulatory requirements; (5) Penelope Conner, executive vice president, customer experience and energy strategy; and (6) Ashley Botelho, acting director, revenue requirements for Massachusetts. In D.P.U. 21-81, National Grid sponsored the testimony of the following witnesses, all employees of National Grid USA Service Company, Inc.: (1) Wajiha A. Mahmoud, vice president, future of electric; (2) William F. Jones, director, transmission and distribution grid modernization New England; (3) Samer Arafa, principal engineer, electric strategy activation, future of electric; (4) Rashmi Dani, director, information technology ("IT") grid modernization; (5) Stephen Lasher, director, electric markets integration, future of electric; (6) Kathleen Hammer, principal analyst, New England revenue requirements; (7) Mindy Rosen, lead analyst, New England electric pricing, New England regulatory; (8) Kris Kiefer, assistant general counsel and director, New York regulatory; (9) Melissa Little, director, New England revenue requirements; (10) Pamela Viapiano, vice president, New England regulation; and (11) Sharon Daly, lead analyst, regulatory strategy. In D.P.U. 21-82, Unitil submitted the testimony of Kevin E. Sprague, vice president, engineering.[5]

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5 The Companies sponsored the testimony of additional witnesses during the Track 1 investigation. See Track 1 Order at 8-9.

The Attorney General sponsored the testimony of the following witnesses in each proceeding: (1) Paul J. Alvarez, Wired Group; and (2) Dennis D. Stephens, consultant, Wired Group. Additionally, the Attorney General sponsored the testimony of Timothy Newhard, financial analyst, Office of Ratepayer Advocacy, in D.P.U. 21-80 and D.P.U. 21-81. CLF sponsored the testimony of Christopher R. Villareal, president, Plugged In Strategies, in each proceeding. GECA sponsored the testimony of Kaya Salem, policy coordinator, GECA, in D.P.U. 21-80 and D.P.U. 21-81. TEC sponsored the testimony of James D. Bride, principal, Energy Tariff Experts, in D.P.U. 21-80. Utilidata sponsored the testimony of the following witnesses in each proceeding: (1) Dr. Marissa Hummon, chief technology officer, Utilidata; and (2) Jess Melanson, president and chief operating officer, Utilidata.

The evidentiary record in each docket includes the company's initial filing exhibits and corresponding revisions to those exhibits, responses to all information requests issued during these proceedings, and record request responses from both the Track 1 and Track 2 evidentiary hearings.[6] In D.P.U. 21-80, NSTAR Electric responded to 369 information requests and 16 record requests. In D.P.U. 21-81, National Grid responded to 292 information requests and 11 record requests. In D.P.U. 21-82, Unitil responded to

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[6] During the Track 2 evidentiary hearings, all exhibits filed in each docket were moved into the evidentiary record for that docket (D.P.U. 21-80/D.P.U. 21-81/D.P.U. 21-82, Tr. 6, at 1125-1127).

123 information requests and 4 record requests.

Additionally, on January 14, 2022, NSTAR Electric submitted AMI-specific proposals in its base distribution rate proceeding, D.P.U. 22-22 (D.P.U. 21-80, Exh. DPU 15-4; see also NSTAR Electric Company, D.P.U. 22-22, Exhs. ES-REVREQ-1, at 200-209; ES-AMI-1 through ES-AMI-3; ES-CAH/DPH-1, at 109-110). The company's AMI-related proposals in its base distribution rate proceeding assumed approval of its AMI Implementation Plan and cost recovery proposals in D.P.U. 21-80, and a company-specific AMI tariff in D.P.U. 22-22 (D.P.U. 21-80, Exh. DPU 15-4; Tr. 4, at 657-658, 663, 669-671; D.P.U. 22-22, Exhs. ES-AMI-1, at 16-17; DPU 7-1; DPU 40-1). The Department issues the instant Order on Track 2 investments concurrent with the final Order in D.P.U. 22-22 and addresses elements of NSTAR Electric's AMI-related proposals in both Orders. See D.P.U. 22-22, at 339-354 (November 30, 2022).[7]

II. BACKGROUND

In D.P.U. 20-69-A at 28-39, the Department directed each company to submit a 2022-2025 Grid Modernization Plan consistent with the Department's directives on the form and content established for these plans. The Department required that each plan include: (1) a five-year strategic plan that incorporated a plan for the full deployment of advanced metering functionality; (2) a separate four-year, short-term investment plan each for

[7] Pursuant to 220 CMR 1.10(3), the Department incorporates by reference from D.P.U. 22-22 into D.P.U. 21-80, the exhibits, discovery responses, testimony, and briefs pertaining to NSTAR Electric's AMI-related proposals.

grid-facing and customer-facing[8] technologies; and (3) a composite business case in support of both short-term investment plans. D.P.U. 20-69-A at 28, 38-39, citing Grid Modernization, D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, at 109-110 (2018) ("Grid Modernization Order"); Modernization of the Electric Grid, D.P.U. 12-76-B at 15-34 (2014). The Department directed the Companies to categorize proposed grid-facing investments in their short-term investment plans as either (1) previously deployed and/or preauthorized technologies, or (2) new technologies. D.P.U. 20-69-A at 31-32.

Further, the Department directed that each company address all proposed customer-facing investments needed to support the company's longer-term strategic plan for full AMI deployment. D.P.U. 20-69-A at 34. The Department explained that it would review the short-term investment plans to determine which proposed investments and technologies were appropriate for preauthorization. D.P.U. 20-69-A at 30. The Department also explained that, where certain conditions are met, the Companies may seek short-term targeted cost recovery of grid modernization investments preauthorized by the Department, and that the Department would consider the appropriate method to recover costs associated

[8] By "grid-facing," we mean technologies that automate grid operations and allow distribution companies to monitor and control grid conditions in near real time. Modernization of the Electric Grid, D.P.U. 12-76-A at 2 n.4 (2013). "Customer-facing" technologies primarily include customer metering and related infrastructure and may include any of the following technologies: meters; two-way communications systems (fixed, wireless, and home area networks ("HANs")); internet-based information portals; wireless applications; direct load control technologies (e.g., in-home energy devices and programmable communicating thermostats); and smart appliances and electronics. D.P.U. 12-76-A at 2 n.4.

with the various categories of proposed investments. D.P.U. 20-69-A at 31, 34, citing Grid Modernization Order at 115-116; D.P.U. 12-76-C at 24-25 (2014); D.P.U. 12-76-B at 17, 29-20.

III. GRID MODERNIZATION INVESTMENTS AND COST RECOVERY

A. Description of Proposals

1. Introduction

In their 2022-2025 Grid Modernization Plan filings, NSTAR Electric, National Grid, and Unitil each identified several categories of new grid-facing technology investments and submitted proposals relating to the deployment of AMI (D.P.U. 21-80, Exhs. ES-JAS-1, at 14-16; ES-JAS-2, at 31, 35-36, 46-52; ES-AMI-1, at 7-41; ES-AMI-2; D.P.U. 21-81, Exhs. NG-GMP-1, at 11-13; NG-GMP-2 (Rev. 2) at 15-16; NG-AMI-1, at 6-41; NG-AMI-2; D.P.U. 21-82, Exhs. Unitil-KES-1, at 16-22; Unitil-GMP[9] at 13-14, 72-79, 82-84, 86-109).[10] NSTAR Electric and National Grid each submitted composite business cases in support of their proposals, and Unitil provided a summary business case with additional supporting documentation (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.); DPU 1-1; DPU 1-2; D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 129-157; NG-GMP-3 (Rev.); NG-AMI-5; NG-AMI-Rebuttal-2; D.P.U. 21-82, Exhs. Unitil-GMP at 100-103; DPU 1-1 & Atts.;

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9 For ease of reference to this exhibit, the Department cites to Unitil's 2022-2025 Grid Modernization Plan as "Unitil-GMP."

10 The instant Order addresses the Companies' proposals involving: (1) new grid-facing investments, i.e., investment categories that represent new technologies beyond those previously deployed and/or preauthorized in the Track 1 Order and the Grid Modernization Order; and (2) AMI.

DPU 1-3 & Atts.). The Companies requested that the Department preauthorize costs for multiple categories of new grid-facing investments for recovery through their existing GMF tariffs (D.P.U. 21-80, Exhs. ES-JAS-1, at 14-16; ES-JAS-2, at 35-36; D.P.U. 21-81, Exhs. NG-GMP-1, at 11; NG-GMP-2 (Rev. 2) at 16; D.P.U. 21-82, Exhs. Unitil-KES-1, at 16-22; Unitil-GMP at 12-14). See also NSTAR Electric, M.D.P.U. No. 73F, §§ 1.0, 2.6; National Grid, M.D.P.U. No. 1497, §§ 1.0, 2.6; Unitil, M.D.P.U. No. 379, §§ 1.0, 2.6.

The Companies also requested Department preauthorization and/or approval of their customer-facing proposals (D.P.U. 21-80, Exhs. ES-AMI-1, at 37-40; ES-AMI-2; ES-AMI-5; D.P.U. 21-81, Exhs. NG-AMI-1, at 4, 8-11; NG-AMI-2; NG-AMI-6; D.P.U. 21-82, Exhs. Unitil-KES-1, at 18-19, 20-22; Unitil-GMP at 86-92). In their initial filings, NSTAR Electric and National Grid sought approval rather than preauthorization of their customer-facing proposals outlined in their AMI Implementation Plans, including a jointly proposed model AMI tariff and reconciling cost recovery mechanism framework specific to their proposed AMI investments (D.P.U. 21-80, Exhs. ES-AMI-1, at 37-40; ES-AMI-2; ES-AMI-5; DPU 2-5; D.P.U. 21-81, Exhs. NG-AMI-1, at 4, 8-11; NG-AMI-2; NG-AMI-6; DPU 2-5). Both companies indicated their intent to request both preauthorization of customer-facing (i.e., AMI-related) investments and approval of cost recovery through company-specific AMI tariffs in a subsequent filing (D.P.U. 21-80, Exhs. ES-AMI-1, at 40; DPU 2-5; DPU 15-4; D.P.U. 21-81, Exhs. NG-AMI-1, at 27-28; DPU 2-5).

During the course of these proceedings, NSTAR Electric in its base distribution rate case, D.P.U. 22-22, requested both preauthorization and approval for cost recovery for particular categories of its planned customer-facing investments, submitted a proposal for approval involving legacy automatic meter reading ("AMR") meter costs, and a company-specific AMI tariff for Department approval, and it noted that its proposals in D.P.U. 22-22 were dependent on the Department's approval in D.P.U. 21-80 (D.P.U. 21-80, Exh. DPU 15-4; Tr. 4, at 657-658, 663, 669-671). In D.P.U. 21-81, National Grid requested preauthorization and approval for cost recovery for the entirety of its customer-facing investments, approval of a company-specific AMI tariff, and submitted a more refined business case (D.P.U. 21-81, Exhs. NG-AMI-Rebuttal at 59-65; NG-AMI-Rebuttal-2; Tr. 4, at 650-651, 672-676, 750).

Unitil requested both preauthorization and approval for cost recovery for its proposed customer-facing investments through its 2022-2025 Grid Modernization Plan and existing GMF tariff (D.P.U. 21-82, Exhs. Unitil-KES-1, at 20-22; AG 1-9; Tr. 4, at 658-659).

2. New Grid-Facing Investments

a. NSTAR Electric

i. Overview

In its 2022-2025 Grid Modernization Plan, NSTAR Electric estimated approximately $44.4 million in costs for the following four categories of new grid-facing investments, inclusive of operation and maintenance ("O&M") costs: (1) advanced load flow ("ALF") program ($10 million), involving an interconnection automation platform ($3 million), probabilistic power flow modeling ($2 million), and an analytics platform ($5 million); (2) communications, involving modernization of data transmission infrastructure ($14 million); (3) distributed energy resource management systems ("DERMS"), involving a dynamic distributed energy resource ("DER") interface ($6 million) and a DERMS software platform ($10 million); and (4) measurement, support, and verification ($4.4 million), involving systems support and maintenance (D.P.U. 21-80, Exhs. ES-JAS-1, at 9, 14-16; ES-JAS-2, at 36, 46-52, 89-124, 139-143; RR-DPU-13).[11] NSTAR Electric described the new investments as a continuation of its grid modernization efforts to date while also creating further pathways to grid optimization (D.P.U. 21-80, Exh. ES-JAS-2, at 47).

ii. Advanced Load Flow

For its ALF program, NSTAR Electric proposed new investments in an interconnection automation platform, probabilistic power flow modeling, and an analytics platform (D.P.U. 21-80, Exhs. ES-JAS-1, at 9, 14-15; ES-JAS-2, at 94-113). The company's planned investment in interconnection automation seeks to integrate its existing distributed generation ("DG") tools, including its modeling and simulation tools (i.e., Synergi, PSCAD) and customer interconnection portal (i.e., Power Clerk) into a single

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11 NSTAR Electric also identified Track 1 investments in the investment categories of communications and measurement, verification, and support (D.P.U. 21-80, Exhs. ES-JAS-1, at 14; ES-JAS-2, at 36, 44-45, 134-139). The Department preauthorized the Track 1 communications investment but deferred a decision on the Track 1 measurement, verification, and support investment until the instant Order. Track 1 Order at 64-65, 77.

software platform (D.P.U. 21-80, Exhs. ES-JAS-2, at 95, 98-99; DPU 13-1, at 2). In doing so, the company anticipates improvements to the DG interconnection process through a reduction in the time and engineering resources needed to process DG applications and complete interconnection studies, which the company stated have increased significantly in recent years (D.P.U. 21-80, Exh. ES-JAS-2, at 95-96, 100).

In combination with other grid modernization investments in modeling and forecasting, NSTAR Electric's proposed probabilistic power flow modeling studies project seeks to enable forecasting for long-term system planning scenarios related to locational changes in load and generation (D.P.U. 21-80, Exhs. ES-JAS-1, at 15; ES-JAS-2, at 107-109). As part of the project, the company proposed to utilize the Monte Carlo method, which creates a simulation environment that analyzes thousands of randomized scenarios based on the probability distribution of what the company identifies as "uncertain input variables" that impact the distribution system, including customer behavior, energy market prices, and asset locations on the grid (D.P.U. 21-80, Exh. ES-JAS-2, at 109, 111). The company anticipates that the probabilistic modeling project will merge and expand upon existing processes into an advanced automated approach to system modeling, leveraging the company's 2018-2021 term investments in ALF (D.P.U. 21-80, Exhs. ES-JAS-2, at 110, 113; DPU 14-6, at 2). NSTAR Electric stated that the probabilistic power flow modeling investment represents the final phase of its ALF category (D.P.U. 21-80, Exh. DPU 13-1).

NSTAR Electric's proposed analytics platform would enable the company's proposed interconnection platform and establish cloud infrastructure, including data storage and web services, and a cloud intelligence platform that will enable advanced analysis of large data sets and support large scale automated machine learning (D.P.U. 21-80, Exhs. ES-JAS-1, at 15-16; ES-JAS-2, at 94, 103-104). The company stated that this proposed investment would enable engineers to combine data from multiple data sources, such as the outage management system ("OMS"), geographic information system ("GIS"), and customer systems, and reduce the time and resources currently required to prepare data for analysis (D.P.U. 21-80, Exh. ES-JAS-2, at 103-104). The company estimated that the analytics platform would enable it to support 500 new computational models per year (D.P.U. 21-80, Exh. DPU 14-6). Approximately 20 percent of these models would be used to support real-time operations in the company's control rooms, and the remaining 80 percent would be used for on-demand analysis for engineering use cases to improve reliability, increase system efficiency, and focus system planning (D.P.U. 21-80, Exh. DPU 14-6).

iii. Communications

NSTAR Electric's proposed communications system modernization investment would involve the transition to an internet protocol ("IP") communications network on its field area network ("FAN"), from field device to its enterprise energy control system/control center ("ECS"), based on industry standard protocols (D.P.U. 21-80, Exhs. ES-JAS-1, at 15; ES-JAS-2, at 48-49, 89). The company stated that this project would ensure that investments in its FAN will be supported and enable interoperability with its remote terminal units

("RTUs") (D.P.U. 21-80, Exhs. ES-JAS-1, at 15; ES-JAS-2, at 48-49, 89; DPU 14-3; DPU 14-6). The proposed investments include migration of existing distribution field devices from a serial-based connection to an IP-based connection and work in the control room to align with the new configuration being implemented in the remote devices (D.P.U. 21-80, Exhs. ES-JAS-2, at 92-93; DPU 14-3). The company stated that the serial-to-IP conversion process involves replacement of the existing serial communications cable with an ethernet IP cable, reconfiguration of settings for the device and at the supervisory control and data acquisition ("SCADA") front-end processor, and testing and verification (D.P.U. 21-80, Exh. DPU 13-2).

Over the period of the 2022-2025 Grid Modernization Plan term, NSTAR Electric plans to convert 1,350 field devices to IP-based communications as part of its communications system modernization project (D.P.U. 21-80, Exh. DPU 15-2). The company stated that the remaining population of approximately 2,650 devices will be migrated to IP-based communications as part of its business as usual capital plan beginning in 2026 (D.P.U. 21-80, Exh. DPU 13-2).[12] The company stated that the investment would increase operational efficiency and enable faster troubleshooting of communications disruptions to improve system availability, increasing the value of assets in the field to support real-time system functions such as distributed management systems ("DMS"), volt/volt-ampere reactive optimization ("VVO"), and DERMS (D.P.U. 21-80,

[12] In its plan, NSTAR Electric identified the need to replace or convert over 4,000 devices (D.P.U. 21-80, Exhs. ES-JAS-2, at 93; DPU 13-2).

Exh. DPU 14-6, at 2). The IP-based connection would be used with the company's FAN, which will allow for remote monitoring, configuration, and troubleshooting of IP-connected devices (D.P.U. 21-80, Exh. ES-JAS-2, at 93).

iv. DERMS

For its DERMS investment category, NSTAR Electric proposed two investments: dynamic DER interface and DERMS (D.P.U. 21-80, Exh. ES-JAS-2, at 36, 114-118). During the 2022-2025 Grid Modernization Plan term, the dynamic DER interface investment would connect 24 large, inverter-based front-of-the-meter DER facilities to the company's distribution system, enabling integration with its ECS/DMS/DERMS control platform, to demonstrate dynamic dispatching capabilities of the inverter-based resources (D.P.U. 21-80, Exhs. ES-JAS-2, at 121-122; DPU 14-14). The company identified its Southampton DER facility as the first location for this investment (D.P.U. 21-80, Exhs. ES-JAS-2, at 121; DPU 3-17). The company would select the remaining 23 sites, including company- and customer-owned sites, to reflect a range of locations, facility attributes, and interconnection types (e.g., solar only or solar with energy storage) (D.P.U. 21-80, Exh. DPU 14-14).

To connect the DER interface to its distribution system, NSTAR Electric proposed to install the following equipment at each site: (1) a programmable controller, such as an RTU, and associated panel equipment for controlling the point of interconnection between the utility grid and the inverter generation resources; (2) communications equipment including a modem and router; and (3) a digital recloser capable of communicating with the programmable controller using the required communications protocol (D.P.U. 21-80, Exhs. ES-JAS-2, at 122; DPU 12-9). The programmable controller hosts ready-to-use programmable modules (e.g., voltage, VAR, power factor) that are available depending on the desired control scheme (D.P.U. 21-80, Exhs. ES-JAS-2, at 122; DPU 12-8). As part of this project, the company would assess the feasibility of adopting this equipment as a standardized interconnection interface (D.P.U. 21-80, Exh. ES-JAS-2, at 122). In addition, NSTAR Electric will explore integrating the 24 facilities into its DERMS platform (D.P.U. 21-80, Exh. ES-JAS-2, at 123).

The company also proposed to procure and implement a new DERMS platform through a phased deployment, including IT infrastructure, operational control software, and forecasting tools, to enable the monitoring and control of all DERs on its distribution system, with initial deployment planned at its New Bedford control center/ECS during the 2022-2025 Grid Modernization Plan term (D.P.U. 21-80, Exhs. ES-JAS-2, at 115, 117; DPU 12-4; DPU 13-1, at 4). By the end of the term, the company anticipates that 456 circuits would be enabled with DERMS capability (D.P.U. 21-80, Exh. DPU 14-6, at 4). The company stated that its proposed DERMS is closely linked to the DMS grid modernization investments and will deliver a tool for use by distribution system operators that integrates with its ECS and DMS, allowing the platform to dispatch resources based on the as-operated power flow model of the distribution system (D.P.U. 21-80, Exhs. DPU 7-3, at 2; DPU 13-1, at 4). In addition to real-time monitoring and control, the company's proposed DERMS would include near-term forecasting capability in system operations that will predict load and generation on the distribution system in the day to week ahead time frame (D.P.U. 21-80, Exhs. ES-JAS-2, at 114-115; DPU 7-3, at 2). The proposed integration with DMS will further facilitate coordination with advanced applications such as VVO (D.P.U. 21-80, Exh. DPU 7-3, at 2). As part of this project, NSTAR Electric stated that it would assess how to consolidate the company's existing, stand-alone DERMS solution used for energy efficiency demand response programs into one set of DER assets available for monitoring and control in its proposed DERMS (D.P.U. 21-80, Exhs. ES-JAS-2, at 118; DPU 7-3, at 2).[13]

v. Measurement, Verification, and Support

As part of its measurement, verification, and support investment, NSTAR Electric proposed to hire six full-time engineers to provide systems support and maintenance for new grid modernization investments during the 2022-2025 Grid Modernization Plan term to support each of the following three investment categories: (1) DMS model maintenance, including daily support and oversight of the DMS power flow model; (2) optimization support, including implementation of optimization functions such as VVO schemes; and (3) system forecasting, including development of detailed long-term forecast of load, energy storage, demand response, and DG to support probabilistic modeling activities (D.P.U. 21-80, Exhs. ES-JAS-1, at 16; ES-JAS-2, at 141-142). The company stated that its investments in planning tools, including advanced forecasting and probabilistic modeling, require support from engineers trained in data analytics and power systems (D.P.U. 21-80, Exhs. ES-JAS-1, at 16; ES-JAS-2, at 141; DPU 14-6, at 4). According to the company,

[13] According to NSTAR Electric, its existing DERMS is a stand-alone system that is not integrated with the company's operational tools (D.P.U. 21-80, Exh. DPU 7-3, at 2).

inclusion of these labor resources would allow it to dedicate resources to capturing the full value of engineering and system operations technologies deployed as a part of NSTAR Electric grid modernization plan at a level that would not be feasible without corresponding cuts to its existing O&M budget necessary to maintain other tools and systems (D.P.U. 21-80, Exh. DPU 13-1, at 5).

b. National Grid

i. Overview

In its 2022-2025 Grid Modernization Plan, National Grid estimated approximately $31.0 million in costs for the following two categories of new grid-facing investments, inclusive of O&M costs: (1) DERMS ($24.6 million), involving implementation of a DERMS software platform and associated products[14] ($15.7 million) and advanced short-term load forecasting ("ASTLF") capabilities ($7.0 million), with an initial investigation/study to inform the platform's implementation ($1.9 million); and (2) demonstration projects ($6.4 million), involving one project to assess active resource integration ($6.2 million) and a second project to evaluate local export power control ($0.2 million) (D.P.U. 21-81, Exhs. NG-GMP-1, at 11-13; NG-GMP-2 (Rev. 2) at 16, 85-101, 112-123). Additionally, National Grid proposed $4.4 million for program management and third-party measurement

[14] The associated products include: (1) advanced short-term load forecasting capabilities; (2) grid edge control; and (3) a centralized DER dispatch engine (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 88, 93; DPU 12-8; DPU 13-4; Tr. 3, at 448). National Grid proposed to develop the grid edge control and centralized DER dispatch products in coordination with its demonstration projects (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 94; DPU 13-1).

and verification (D.P.U. 21-82, Exh. NG-GMP-2 (Rev. 2) at 127-128).[15] National Grid stated that its 2022-2025 Grid Modernization Plan contains the company's proposals to advance the capabilities of its 2018-2021 plan investments, while continuing to enable a clean energy transition for its customers and a resilient and cost-effective electric system (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 4).

ii. DERMS

For its DERMS strategy, National Grid proposed a three-year study to assess the business needs and technical capabilities required to implement a phased deployment of the DERMS platform and individual products within the platform (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 85-90, 93-94; DPU 13-4; Tr. 3, at 448; Tr. 4, at 578-579). The DERMS study would define business and functional requirements, identify data interfaces required for integration with other utility enterprise systems (e.g., meter data management system ("MDMS"), ADMS), and inform the procurement plan for associated software systems and budgets for the DERMS product implementation (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 87, 89-90). As part of the DERMS study, National Grid proposed to test software tools to integrate customer-controlled DERs with grid operations,

15 National Grid's cost estimates for program management and third-party measurement and verification includes components applicable to both Track 1 and Track 2 investments (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 127-128). Because the record did not include a disaggregated budget for each track, the Department stated it would address this investment category as part of Track 2. Track 1 Order at 82.

including optimal economic dispatch of DER while maintaining distribution system security (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 11).

Following the DERMS study, National Grid proposed to implement the DERMS platform and additional associated products in a phased approach (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 11, 91, 94). In the first phase, National Grid proposed to prioritize: (1) ASTLF to forecast in real-time short-term load and supply and DER impacts on the distribution system that will enable the company to develop, plan, and execute system reconfiguration and switch orders, and to ensure the security of the distribution system; (2) a centralized DER dispatch engine to optimize DER dispatch based on financial factors and physical grid considerations; and (3) grid edge control to manage requests from utility systems to dispatch DERs and transmit DER dispatch signals (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 11, 93, 97-101; DPU 12-8). The company proposed to deploy ASTLF capabilities to support its ADMS deployment and provide near-term benefits to improve distribution system operations, with planned integration into its enterprise-wide DERMS implementation to follow in the longer term (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 93). In the second phase of DERMS deployment, projected to begin in the fourth quarter of 2024, National Grid plans to deliver a market platform that facilitates stakeholder trading of energy services (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 93-94; DPU 13-4). The company identified several benefits resulting from its DERMS investments, including that DERMS, in part, would enable load optimization and reduce costs and other barriers to DG interconnection (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 95; DPU 13-3).

iii. Demonstration Projects

National Grid stated that the proposed active resource integration demonstration project is designed to field test a new flexible interconnection option that could enable the company to accelerate DG interconnections and increase the energy production of DGs per unit of system capacity (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 5, 11, 114, 116). The company explained that the project would test an interconnection solution in Risingdale, Massachusetts, by exploring the ability to interconnect on existing infrastructure up to 15 megawatts ("MW") of actively managed solar projects by curtailing output from the solar projects during periods of high generation and low load (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 114, 116; DPU 13-1). National Grid would monitor real-time system constraints and automatically adjust export limits for each participating solar project through a curtailment management system when real-time loading of system constraints nears system ratings (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 119; DPU 12-1). National Grid would telemeter the export limit direction to the DG facility for a response through a secure communications gateway and telecommunications infrastructure connected to the company's backend software-based curtailment management system (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 112; DPU 12-5). National Grid stated that it would also assess the fail-safe provisions of the management scheme to ensure system reliability and safety (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 116). The development and implementation of the advanced DG control and active management solutions required for the active resource integration demonstration project would inform the company's DERMS platform roadmap, and completion of the active resource integration demonstration project would serve as the minimum viable product ("MVP") of the centralized DER dispatch engine and grid edge control capabilities deployed in the DERMS platform (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 94, 114; DPU 13-1).[16]

For its local export power control demonstration project, National Grid proposed to use a certified controller[17] with real-time local power management control to maintain a net-export limit at a school in the town of Orange that plans to install behind-the-meter solar and storage in order to explore the net zero thermal impact capabilities of a power control system in a DG facility (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 5, 12, 123; DPU 12-9; DPU 12-11). For this project, National Grid proposed to investigate the ability to connect behind-the-meter DG facilities more quickly and cost-effectively in areas of high DG saturation (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 124). Specifically, National Grid would explore the use of a power control system at a solar/battery energy storage installation

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16 The active resource integration project's curtailment management system would serve as the centralized DER dispatch engine MVP while the secure communication DER gateway to facilitate dispatch instructions from the curtailment management system would serve as the grid edge control MVP (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 94; DPU 13-1). Additionally, the company explained that the DERMS implementation budget accounts for further scaling out of these MVPs from the demonstration project so that application of these products can expand to wider use cases and DER types (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 94; DPU 13-1).

17 Specifically, National Grid intends to demonstrate the use of a power controller certified to the Underwriters Laboratory, Inc. Standard UL 1741 CRD entitled "Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources, Certification Requirement Decision" (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 123).

in the Barre-Athol region to maintain net-export limits at the site and to monitor that project's impact on the distribution system (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 123-124). Since the net zero thermal impact would avoid requirements to conduct a full distribution impact study, National Grid anticipated the project to demonstrate lower interconnection costs and expedite interconnection timelines (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 12, 124).

Additionally, to implement the two demonstration projects and support their scaled deployment to a wider range of customers, National Grid proposed to hire a program manager and two full-time lead engineers (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 129; DPU 11-2 & Att.; DPU 12-10). According to National Grid, the two proposed demonstration projects would support and inform the investigation and implementation of DERMS (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 94, 99, 113, 120). To implement the two demonstration projects and support their scaled deployment to a wider range of customers, National Grid proposed to hire a full-time lead engineer (D.P.U. 21-81, Exh. DPU 12-10).

iv. Measurement, Verification, and Support

National Grid proposed to implement project management and third-party evaluation of its progress toward meeting the Department's grid modernization objectives (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 127-129). For project management, National Grid stated that it established its Grid Modernization Execution team in August 2018, which functions as a project management office and manages the overall delivery of Department-approved grid modernization investments, and that the costs proposed for recovery are for a subset of incremental employee costs or third-party services (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 127-128). Additionally, National Grid identified estimated costs for an anticipated evaluation and services to be conducted by a third-party consultant (D.P.U. 21-81, Exh. NG-GMP-2 (Rev.) at 127).

c. Unitil

i. Overview

In its 2022-2025 Grid Modernization Plan, Unitil estimated approximately $1.2 million in costs for the following two categories of new grid-facing investments, inclusive of O&M costs: (1) DERMS functionality integrated within its ADMS[18] ($162,000); and (2) DER mitigation ($1.04 million), involving substation overvoltage protection (D.P.U. 21-82, Exhs. Unitil-GMP at 13-14, 28, 74, 82-84; DPU 2-8; DPU 6-1, at 5). Additionally, Unitil proposed a budget of $300,000 for measurement, verification, and support, involving a third-party evaluation (D.P.U. 21-82, Exh. Unitil-GMP at 82). Unitil stated that its proposed investments are required to facilitate the distribution system as an enabling platform and are designed to be flexible to changes in technology, system needs, and customer service (D.P.U. 21-82, Exhs. Unitil-KES-1, at 8-9; Unitil-GMP at 63-64).

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18 In the Track 1 Order at 93, 98, the Department preauthorized Unitil's continuing investment in ADMS but deferred a decision on the DERMS portion of this project until the instant Order.

ii. DERMS

Unitil explained that its proposed DERMS project includes: (1) the DERMS module to be enabled within the ADMS; and (2) communications, monitoring, and control (i.e., SCADA) of the sites where DERMS is deployed (D.P.U. 21-82, Exhs. Unitil-GMP at 74; DPU 2-8; AG 3-8, at 2). Beginning in 2024 and after the initial ADMS deployment, the company intends to purchase and activate the DERMS license and configure and integrate the module into the ADMS SCADA through a multi-phase process (D.P.U. 21-82, Exhs. Unitil-GMP at 74; DPU 2-8; DPU 6-1, at 6). During its 2022-2025 Grid Modernization Plan term, Unitil plans to deploy DERMS on two company-owned DER facilities, one solar facility and one energy storage facility, to confirm that DERMS operates as expected before implementing it at other company-owned and customer-owned DER facilities (D.P.U. 21-82, Exhs. Unitil-GMP at 74; AG 2-2(c); DPU 6-1, at 2, 6).[19] The company stated it would first utilize DERMS to manage real and reactive power needs, but that the system would also have the capability to perform voltage management and be integrated into the VVO algorithm (D.P.U. 21-82, Exhs. Unitil-GMP at 74; DPU 6-1, at 6). The DERMS benefits identified by the company, in conjunction with the ADMS, include outage reductions, improvements to situational awareness, and an increased ability to

19 During discovery, the company clarified that it did not include costs with implementing DERMS at additional DERs in its proposals (D.P.U. 21-82, Exh. AG 2-2(c)).

integrate renewable energy sources and other DERs (D.P.U. 21-82, Exh. Unitil-GMP at 22, 27, 100-101).

iii. DER Mitigation

For its DER mitigation project, Unitil proposed to implement overvoltage protection improvements on three distribution substations by 2023 in order to mitigate the risk of ground-fault over-voltages, including through modifications to substation and sub-transmission line surge protection and the addition of voltage transformers and overvoltage relaying schemes where necessary (D.P.U. 21-82, Exhs. Unitil-GMP at 83; DPU 1-3; DPU 7-5). The company's proposal intends to address DER saturation on its system that is causing reverse power flow (D.P.U. 21-82, Exhs. Unitil-GMP at 82-83; DPU 7-1; DPU 7-3). Unitil stated that its DER mitigation project would support integration and interconnection of additional DERs, both large and small, on its system (D.P.U. 21-82, Exhs. DPU 7-1; DPU 7-2). The benefits identified by Unitil for this project include increased hosting capacity for renewable resources and other DERs (D.P.U. 21-82, Exh. Unitil-GMP at 102).

iv. Measurement, Verification, and Support

Unitil proposed to engage a third-party consultant to conduct an evaluation of the implementation of its grid modernization plan (D.P.U. 21-82, Exh. Unitil-GMP at 82).

3. Customer-Facing Investments

a. NSTAR Electric

i. Overview

NSTAR Electric projected approximately $668.2 million in capital and O&M costs incurred from 2022 through 2028 for the following customer-facing investment categories identified in its AMI Implementation Plan: (1) AMI electric meters ($232.1 million); (2) communications network ($43.2 million); (3) a new head-end system ("HES") and MDMS ($48.2 million); (4) customer information system ("CIS") replacements ($154.3 million);[20] (5) customer enablement products and services ($17.0 million); (6) analytics ($37.6 million); (7) operational system integrations and enhancements ($40.0 million); (8) cybersecurity ($13.9 million); (9) customer engagement and education ($7.3 million); (10) project management ($43.1 million); and (11) contact center and theft deterrence costs ($31.2 million) (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.) at 12-22; DPU 1-2, Att.). In support of its proposed customer-facing investments through its AMI Implementation Plan, NSTAR Electric included a business case and estimated bill impacts based on the costs identified (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.); AG 1-5).

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20 For NSTAR Electric, its CIS replacement proposals include replacement of its existing CIS system used for its eastern Massachusetts customers, and its C2 system used for its western Massachusetts customers (D.P.U. 21-80, Exhs. ES-AMI-1, at 26; ES-AMI-4 (Rev.) at 26; ES-Rebuttal at 9-10; AG 3-10; AG 5-18; D.P.U. 22-22, Exhs. DPU 9-2; DPU 36-7). For ease of reference, the Department utilizes the term "CIS" for both systems.

ii. Proposed Investments

NSTAR Electric proposed to replace the approximately 1.1 million AMR meters currently in place across its service territory with AMI meters (D.P.U. 21-80, Exhs. ES-AMI-1, at 32; ES-AMI-2, at 25; ES-AMI-4 (Rev.) at 12). The company also proposed to convert approximately 260,000 "bridge" meters to AMI mode (D.P.U. 21-80, Exhs. ES-AMI-1, at 23; ES-AMI-2, at 11, 25; ES-AMI-Rebuttal at 51-52; Tr. 3, at 538).[21] The company explained that it deployed the majority of its AMR meters during 2000 through 2006 and, thus, those meters will exceed their useful life of 20 years during 2023 through 2028 (D.P.U. 21-80, Exh. ES-AMI-1, at 23).[22]

Further, NSTAR Electric stated that its current AMR meters collect monthly usage data that communicate with AMR-equipped vans using the company's field collection system ("FCS") mobile collection system (D.P.U. 21-80, Exh. ES-AMI-1, at 23). The readings are then exported out of the FCS and sent to the company's respective CIS systems (D.P.U. 21-80, Exh. ES-AMI-1, at 23). In contrast, according to the company, AMI meters

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21 Bridge meters are AMR meters with remote turn-on and turn-off capability through the existing meter reading system (D.P.U. 21-80, Exh. ES-AMI-2, at 24-25). The company installed bridge meters as the result of its remote disconnect project starting in 2016, and bridge meter has become the company's standard practice when replacing meters (D.P.U. 21-80, Exh. ES-AMI-2, at 24-25). The company stated that it can switch these meters to AMI mode if a compatible wireless network is available (D.P.U. 21-80, Exhs. ES-AMI-2, at 24-25; ES-AMI-Rebuttal at 51-52).

22 Specifically, NSTAR Electric stated that approximately 740,000 of its existing 1.1 million meters will exceed their useful lives of 20 years during the proposed AMI deployment period (D.P.U. 21-80, Exh. ES-AMI-1, at 23, 41).

can collect data at specified intervals, transmit the data through the communications network, and receive control signals from the network (D.P.U. 21-80, Exh. ES-AMI-2, at 23-25). AMI meters can also provide a variety of functionalities such as distributed intelligence ("DI"), load disaggregation, connectivity model verification, and voltage monitoring (D.P.U. 21-80, Exhs. ES-AMI-1, at 24-25; ES-AMI-2, at 17-18, 23-26).

NSTAR Electric maintained that the deployment of AMI meters represents a "technology-driven evolution" that would enhance the services the company offers its customers and allow the company to best meet the Commonwealth's energy and environmental policies, including the Department's grid modernization goals (D.P.U. 21-80, Exh. ES-AMI-1, at 19). The company stated that, at the time of the Department's investigation in D.P.U. 12-76 and its subsequent order in D.P.U. 15-122, the transition to AMI was a very significant departure from the company's normal course of business (D.P.U. 21-80, Exh. ES-AMI-1, at 19). Further, the company specified that, currently, the ongoing evolution of technology has made the installation and use of AMI the only feasible operating alternative as compared to other technological solutions, with the potential to produce benefits for customers, and that as its AMR metering infrastructure nears the end of its useful life, AMI presents the only replacement solution that can ensure that the company is able to manage its distribution system effectively and safely for its customers. (D.P.U. 21-80, Exh. ES-AMI-1, at 19-20).

Additionally, NSTAR Electric proposed to deploy a two-way communications network for transmitting AMI data and control signals using wireless telecommunications

(D.P.U. 21-80, Exhs. ES-AMI-1, at 26; ES-AMI-2, at 16-18; ES-AMI-4 (Rev.) at 13). NSTAR Electric stated that, based on vendor responses to its request for information ("RFI"), it expected a hybrid approach utilizing a private wireless "mesh" network coupled with public carrier cellular networks to be the most effective technology for its communications needs (D.P.U. 21-80, Exhs. ES-AMI-1, at 26-27; ES-AMI-2, at 16-17; ES-AMI-4 (Rev.) at 13; AG 1-10). NSTAR Electric explained that AMI meters and its proposed communications network are foundational investments needed to enable all associated use cases tied to AMI (D.P.U. 21-80, Exh. ES-AMI-4 (Rev.) at 12).

Further, NSTAR Electric proposed to deploy a new HES and replace its existing MDMS and CIS systems (D.P.U. 21-80, Exhs. ES-AMI-1, at 24-25; ES-AMI-2, at 31-33, 38-46; ES-AMI-4 (Rev.) at 13-15). The company explained that the HES would serve as a hub for all meter data gathered from field devices and decrypt this data for use in other systems, including the MDMS, and encrypt outgoing meter commands,[23] ensuring that the AMI system is secured end-to-end (D.P.U. 21-80, Exhs. ES-AMI-2, at 28-29; ES-AMI-4 (Rev.) at 14). The function of the MDMS would be to house all the data collected from the meters, and process that data into information that can be used by other back-office systems such as the customer information and outage management systems (D.P.U. 21-80, Exhs. ES-AMI-1, at 27-28; ES-AMI-2, at 28-29; ES-AMI-4 (Rev.) at 14). The core MDMS

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23 Examples of outgoing meter commands include service switch reconnections and pinging of the meters to confirm outages or service restorations status (D.P.U. 21-80, Exh. ES-AMI-1, at 27).

functionalities include validating, estimating, and editing ("VEE") the AMI meter data before it is passed on to the CIS and other systems (D.P.U. 21-80, Exhs. ES-AMI-1, at 28; ES-AMI-2, at 29; ES-AMI-4 (Rev.) at 14). Additional functionalities for the proposed MDMS would include: (1) filtering power off/on notifications during large-scale outages so as to not overwhelm the OMS with thousands of individual meter outage notifications; (2) performing basic analytics; and (3) providing rudimentary reports around theft and tamper detection (D.P.U. 21-80, Exh. ES-AMI-2, at 29).[24] The company stated that its final MDMS solution would fully support the advanced functionalities enabled by the new generation of AMI meters, but added that, as a temporary solution to accelerate meter deployments in the field, it would assess opportunities to implement an interim MDMS solution that can provide core VEE functions and integrate with the company's existing CIS (D.P.U. 21-80, Exh. ES-AMI-2, at 29).

Regarding its CIS, NSTAR Electric explained that it currently utilizes two separate systems for collecting and managing billing and account information for the bulk of retail customers: (1) its CIS, which was launched in 1990 and is utilized for its eastern Massachusetts service territory; and (2) its C2 system, which was completed in 2008 and is

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24 NSTAR Electric explained that its current MDMS is an older system that processes interval data from its large commercial and industrial customer meters with very limited functionality and would be unable to handle the expected level of AMI data, and, thus, is "not comparable" to what is contemplated as an AMI MDMS (D.P.U. 21-80, Tr. 4, at 594-595). The company stated that the existing MDMS, which it deployed during 2011 through 2013, will be fully depreciated in 2023 (D.P.U. 21-80, RR-DPU-ES-3).

utilized for its western Massachusetts service territory (D.P.U. 21-80, Exhs. ES-AMI-1, at 26; ES-AMI-4 (Rev.) at 26; ES-AMI-Rebuttal at 9-10; AG 3-10; AG 5-18; D.P.U. 22-22, Exhs. DPU 9-2; DPU 36-7).[25] According to the company, these existing systems are not equipped to bill complex rates, such as time varying rates ("TVR"), and do not have the capability to capture AMI usage data, calculate bill impacts associated with that usage, or present that data to customers in near-real time (D.P.U. 21-80, Exhs. ES-AMI-1, at 26; ES-AMI-Rebuttal at 10; ES-AMI-4 (Rev.) at 15).[26] The company stated that modifying a legacy CIS to support TVRs would require a substantial and costly architectural overhaul and may not be possible in some cases (D.P.U. 21-80, Exh. ES-AMI-2, at 41, 42-43). In contrast, the proposed new CIS would enable the company to enhance customer offerings and better equip call center representatives with more granular information on customer bills, especially involving high bills and usage information, meter status, and outages while also increasing customer access to data (D.P.U. 21-80, Exhs. ES-AMI-1, at 26; ES-AMI-2,

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25 The company explained that both systems are fully depreciated, while software updates to the systems, which were implemented in 2019-2020, will be fully depreciated in 2025 (D.P.U. 21-80, RR-DPU-ES-3).

26 The company explained that, when the existing CIS were designed, the system did not contemplate the volume or frequency of data that would be provided by AMI meters, nor did it anticipate current clean energy policies and complex billing solutions (D.P.U. 21-80, Tr. 4, at 600-603). In particular, the existing CIS is limited to providing its customer service representatives with customer information such as monthly usage and meter read dates, and account information such as billing history (D.P.U. 21-80, Tr. 4, at 600-602). The company stated that adapting the existing CIS to current needs has required it to implement manual "workarounds" to ensure accurate billing, adding that it would continue with such workarounds absent AMI deployment (D.P.U. 21-80, Tr. 4, at 602-605, 611-613).

at 41-42; ES-AMI-Rebuttal at 9-10; ES-AMI-4 (Rev.) at 15). The company stated that the new CIS would also offer non-AMI benefits such as streamlined billing and faster error and issue resolution (D.P.U. 21-80, Exh. AG-AMI-4 (Rev.) at 15).

Additionally, NSTAR Electric submitted a proposed customer engagement plan, which is its plan to educate and inform customers on the benefits that AMI enables, as well as to answer common questions that customers may have regarding AMI technology, and includes consideration for low- and moderate-income customer segments and diverse groups (D.P.U. 21-80, Exhs. ES-AMI-1, at 30; ES-AMI-2, 36-38 & Appx. C; ES-AMI-4 (Rev.) at 20). The customer engagement plan as proposed includes four phases: (1) a customer awareness (pre-deployment) phase, during which the company would begin incorporating awareness and education on AMI meters into existing communications plans for customers;[27] (2) a meter deployment phase, during which the company would promote awareness about planned AMI meter installations;[28] (3) a new energy insights and ways-to-save phase, during which the company would provide customers with insight into their usage and actionable ways to save in key AMI-enabled areas, including detailed customer usage, detailed usage sharing with third parties, enhanced web and mobile app customer experience, customized

27 NSTAR Electric stated that, since these communications already address issues such as a clean energy future, grid modernization and energy efficiency priorities, it would be a natural fit to incorporate the topic of AMI meters into the communications (D.P.U. 21-80, Exh. ES-AMI-2, Appx. C at 6-7).

28 NSTAR Electric specified that it would undertake these activities multiple times; specifically, 90 days prior to deployment, 60 days prior to deployment, and 30 days prior to deployment (D.P.U. 21-80, Exh. ES-AMI-2, Appx. C at 8-9).

high bill alerts, delivered energy insights, and enhanced outage alerts; and (4) a TVR (post-deployment) phase, during which the company would build awareness and educate customers on TVR (D.P.U. 21-80, Exh. ES-AMI-2, 36-38 & Appx. C at 6-13). NSTAR Electric also proposed a new customer portal and to provide customers with new enablement tools such as usage insights and alerts through mobile and web-based channels, as well as tools that would enable third-parties to gain access to AMI usage data in order to offer value-added services such as TVR to customers (D.P.U. 21-80, Exhs. ES-AMI-1, at 28, 29-30; ES-AMI-4 (Rev.) at 16, 20, 37).

NSTAR Electric proposed to deploy a data analytics platform to allow it to perform descriptive and predictive analytics on AMI data to enhance internal decision making and provide customers with additional insights and alerts (D.P.U. 21-80, Exhs. ES-AMI-1, at 28, 31; ES-AMI-2, at 46; ES-AMI-4 (Rev.) at 17). The company would also enhance its outage management and VVO systems to allow for the integration of AMI data, in particular, with the proposed MDMS in order to: (1) enable more accurate reporting of outages and estimated time of response communications to customers; and (2) support more aggressive, feeder specific, VVO programs, thus providing an incremental increase to the efficiency of the grid already achieved by its existing VVO program (D.P.U. 21-80, Exhs. ES-AMI-1, at 25, 33; ES-AMI-2, at 46-49; ES-AMI-4 (Rev.) at 18).

Further, NSTAR Electric submitted a proposed grid modernization cybersecurity plan setting forth the initiatives it would use to protect its AMI system and customer data (D.P.U. 21-80, Exhs. ES-AMI-1, at 25, 28-29; ES-AMI-2, Appx. B at 5; ES-AMI-4 (Rev.)

at 19). The company explained that cybersecurity would overlay each component of its AMI investments, and it would include cybersecurity technical requirements in the request for proposals ("RFP") of each component of the AMI system and evaluate every component of the AMI system based on its capability to meet or exceed the company's cybersecurity technical requirements (D.P.U. 21-80, Exhs. ES-AMI-1, at 25; ES-AMI-2, at 34-35). Under the company's cybersecurity plan, any new system procured by the company would go through a formal questionnaire as part of the contract negotiations for each selected vendor and their component(s) (D.P.U. 21-80, Exh. ES-AMI-2, at 35). In addition, if the system or component includes third-party access to data storage, process, or transmission of non-public information, the third party would be required to complete a due diligence questionnaire (D.P.U. 21-80, Exh. ES-AMI-2, at 35).

According to the company, due to the transformational nature of its proposed AMI plan, it proposed to establish an AMI program management office ("PMO") and change management office that would be responsible for: (1) managing risks; (2) ensuring adherence to budgets and timelines; (3) monitoring work quality; (4) reporting on progress; (5) tracking benefits realization; and (6) ensuring that leadership and employees are aligned with the overall program vision (D.P.U. 21-80, Exhs. ES-AMI-2, at 12-14; ES-AMI-4 (Rev.) at 21). The company stated that it drew upon its experience managing programs and projects of various sizes and complexities, as well as industry best practices, for the expected program management outlined in its AMI Implementation Plan (D.P.U. 21-80, Exh. ES-AMI-2, at 12).

NSTAR Electric also anticipated that the deployment of AMI would require it to hire additional customer contact center staff to respond to increased customer calls, and calls of greater duration, both during and after meter deployment (e.g., customer calls pertaining to the new energy insights and rate options) (D.P.U. 21-80, Exh. ES-AMI-4 (Rev.) at 22). In addition, the company expected a need for incremental resources dedicated to electricity theft investigation, since leads would be enhanced through the data and tamper alerts provided by the meters (D.P.U. 21-80, Exh. ES-AMI-4 (Rev.) at 22).

iii. Deployment Timeline

The company anticipated commencing deployment of AMI meters during the first half of 2025, with full deployment completed by mid-year 2027 (D.P.U. 22-22, Exh. DPU 46-4, Att.). To minimize stranded costs, the company would initiate AMI meter deployment in its western Massachusetts service territory, where the existing AMR meters are closest to the end of their useful lives (D.P.U 21-80, Exhs. ES-AMI-4 (Rev.) at 12; ES-AMI-2, at 11; Tr. 5, at 865-866). The company explained that, prior to AMI meter deployment in an area, it first needed to deploy the communications, HES, and MDMS infrastructure necessary to transmit, process, and store meter-related data (D.P.U 21-80, Exhs. ES-AMI-1, at 32-34; DPU 17-5; Tr. 5, at 802-803). In addition, the company expected the new CIS to be sufficiently operational to allow its customer service representatives to provide customers with information on their AMI metered data as soon as the AMI meters are deployed (D.P.U 21-80, Exhs. ES-AMI-1, at 32-33; ES-AMI-2, at 32; DPU 17-5; AC 1-9; Tr. 5, at 802-803). According to NSTAR Electric, the proposed deployment timeline: (1) is intended to minimize stranded costs associated with its existing AMR meters; (2) takes into account the necessary dependencies and required predecessor activities; and (3) is designed to enable benefit realization as soon as possible in the deployment period (e.g., integration of AMI data into the company's existing OMS will begin as soon as possible following the completion of the necessary investments in the MDMS) (D.P.U. 21-80, Exh. ES-AMI-1, at 32-33; ES-AMI-2, at 8).

iv. Business Case

NSTAR Electric provided a net present value ("NPV") comparison of costs and benefits over a 20-year timeframe for its customer-facing investments, using a discount rate commensurate with the company's cost of capital (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.) at 7-9; ES-Rebuttal at 48; DPU 1-2, Att.; AG 1-24(b); AG 8-9(a)). The company identified the NPV of benefits and costs equal to $667 million and $655 million, respectively, for a benefit-to-cost ratio of 1.02 (D.P.U. 21-80, Exh. ES-AMI-4 (Rev.) at 9).

For AMI electric meters, NSTAR Electric projected costs for purchase of meters and deployment labor expenses incurred during those years (D.P.U. 21-80, Exh. ES-AMI-4 (Rev.) at 12). The company based its projections on responses to an RFI it issued for AMI meters (D.P.U. 21-80, Exh. DPU 2-6, at 1). The company explained that it would rely on its established competitive procurement process for final selection of its AMI meter vendor and would develop a meter deployment strategy utilizing internal and outsourced labor resources as appropriate to install and test each AMI meter in the field, and repair and maintain AMI meters on an on-going basis (D.P.U. 21-80, Exh. ES-AMI-2, at 26-27).

For the communications network, NSTAR Electric projected costs associated with: (1) AMI IT, technical support, and equipment replacement labor; (2) management, design, support, and testing; (3) physical infrastructure, installations, and replacement; (4) communications tester hardware; and (5) network fees (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.) at 13; DPU 2-6, at 1). For HES and MDMS, NSTAR Electric projected costs associated with: (1) annual product support; (2) O&M expenses; (3) MDMS configuration, hardware, and software; (4) AMI system integration, configuration, and testing; and (5) billing (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.) at 14; DPU 2-6, at 1-2). For CIS replacements, NSTAR Electric projected costs associated with: (1) CIS configuration, hardware, and software; (2) O&M; and (3) billing (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.) at 15; DPU 2-6, at 2). The projections for the communications network and HES were based on responses to the same RFI it utilized for the AMI meters; while the cost projections for the CIS replacements and MDMS were developed by a consultant working in partnership with the company's subject matter experts, as well as historical costs from previous MDMS and CIS deployments (D.P.U. 21-80, Exh. DPU 2-6, at 1-2). The company explained that it planned to collaborate with other electric utilities in the Commonwealth to explore a possible shared AMI communications network infrastructure agreement to lower costs, for example by expanding the existing shared telecommunications network agreement to include AMI data backhaul (D.P.U. 21-80, Exh. ES-AMI-2, at 18-19).

For customer engagement and education, NSTAR Electric projected costs associated with customer outreach and early awareness efforts related to meter deployment, TVR, and energy insights (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.) at 20; DPU 2-6, at 2-3). For customer enablement products and services, the company projected costs associated with: (1) the configurations of data sharing solutions; (2) web/app development for visuals and alerts; (3) system integrations; and (4) annual maintenance (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.) at 16; DPU 2-6, at 2). The company based these cost projections on internal subject matter experts' experience from historical AMI deployments, as well costs from historical projects (D.P.U. 21-80, Exh. DPU 2-6, at 2-3).

For analytics and operational system integrations and enhancements, NSTAR Electric projected costs associated with: (1) hardware for data storage and data processing; (2) development; (3) systems integrations; (4) software licensing fees; and (5) annual maintenance (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.) at 17-18; DPU 2-6, at 2). The company calculated these costs with input from its internal data scientists and IT subject matter experts based on their previous experience, as well as from costs from historical projects (D.P.U. 21-80, Exh. DPU 2-6, at 2). Similarly, for cybersecurity, NSTAR Electric projected costs associated with: (1) hardware; (2) system integrations; (3) software licensing fees; and (4) annual maintenance (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.) at 19; DPU 2-6, at 2). The company calculated these costs with input from its internal cybersecurity subject matter experts, based on their previous experience, as well as costs from historical projects (D.P.U. 21-80, Exh. DPU 2-6, at 2).

For project management, NSTAR Electric projected costs associated with: (1) project management labor; (2) training; (3) quality assurance; and (4) RFP development for the AMI system components (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.) at 21; DPU 2-6, at 3). The company based the cost projections on its current labor rates for project management and estimates of full-time employee ("FTE") requirements provided by a consultant with experience with AMI project management (D.P.U. 21-80, Exh. DPU 2-6, at 3).

Finally, for contact center and theft deterrence costs, NSTAR Electric projected costs associated primarily with: (1) contact center enhancements; (2) training; (3) quality assurance; (4) RFP development for the AMI system components; and (5) cost increases for notices and disconnects enabled through AMI in relation to non-payment, as well as the cost of incremental resources for theft investigation resulting from enhanced AMI data and tamper alerts (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.) at 22; DPU 2-6, at 3).[29] The company based the cost projections on its current labor rates for contact/credit center representative and theft investigators and estimates for FTE requirements from its subject matter experts (D.P.U. 21-80, Exh. DPU 2-6, at 3).

NSTAR Electric quantified benefits associated with customer-facing investments for the following: (1) TVR, associated with cost savings that would result from customers reducing usage or shifting usage from peak to off-peak hours due to the availability of AMI data; (2) the reduction/elimination of end-of-life AMR meter replacement costs; (3) the

29 NSTAR Electric anticipated the need for an additional 120 FTEs by 2028 to accommodate the increase in call volumes and "handle times" as AMI meters are installed in customer locations, and the new CIS is implemented with upgraded functionality (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.) at 22; DPU 1-2, Att.; NRG 2-1, Att. at 38; D.P.U. 22-22, Exhs. ES-AMI-3, at 2; AG 29-3 & Att.).

reduction/elimination of metering and billing costs that support the current systems; (4) bad debt reductions, associated with cost savings that would result from increased efficiencies in the disconnection process; (5) theft and remote disconnect cost savings due to energy savings anticipated to result from reductions in energy theft and more timely remote disconnections; (6) no trouble found and connectivity survey cost savings due to the ability of operators to utilize the AMI system to conduct remote diagnostics to confirm a reported outage or service issue, and provide connectivity insights; (7) meter reading and field operation cost savings associated with the reduction of AMR drive-by work; (8) outage restoration cost savings due to staff duration reductions during major outage events resulting from the company's improved ability to identify nested outages at the tail end of restoration; (9) asset analytics, associated with the improved ability of NSTAR Electric to better predict system conditions such as blown fuses and transformer overloads; (10) conservation voltage reduction ("CVR")/VVO and voltage sensor cost savings, associated with (i) additional energy and demand reduction provided by AMI data beyond that of the existing CVR/VVO benefits, and (ii) the reduced need for additional line sensors and their associated cellular charges; and (11) reduced energy carbon emissions due to anticipated reductions in energy usage (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.) at 12-22; DPU 1-2, Att.).

Additionally, NSTAR Electric identified several customer and operational qualitative benefits related to AMI deployment (D.P.U. 21-80, Exh. ES-AMI-4 (Rev.) at 37). In particular, the company identified customer benefits associated with improved customer satisfaction due to anticipated: (1) increases to awareness of usage; (2) online tools to control usage; (3) enhanced rate options; and (4) improved outage status safety (D.P.U. 21-80, Exh. ES-AMI-4 (Rev.) at 37). The company identified operational benefits associated with: (1) storm restoration efficiencies; (2) more accurate information being available to customer service representatives; (3) improved tracking of momentary outages; (4) more effective marketing; and (5) improvements to existing field operation safety (D.P.U. 21-80, Exh. ES-AMI-4 (Rev.) at 37).

b. National Grid

i. Overview

National Grid's customer-facing investments are set forth in its AMI Implementation Plan, for which the company projected $487.1 million in capital and O&M costs incurred from 2023 through 2027 for the following categories: (1) AMI electric meter equipment and installations ($273.4 million); (2) communications network and equipment and installation ($12.4 million); (3) a new HES and MDMS ($25.0 million); (4) enhancements to its existing CIS ($7.1 million); (5) customer enablement products and services ($8.1 million); (6) analytical tools and system integrations ($46.5 million); (7) cybersecurity ($0.9 million); (8) customer engagement and education ($41.5 million); and (9) a PMO ($72.3 million) (D.P.U. 21-81, Exhs. NG-AMI-Rebuttal-1, at 61; NG-AMI-Rebuttal-2). In support of its proposed customer-facing investments, National Grid included a business case and estimated bill impacts based on the costs identified (D.P.U. 21-81, Exhs. NG-AMI-Rebuttal-1, at 59-64; NG-AMI-Rebuttal-2; NG-AMI-Rebuttal-5).

ii. Proposed Investments

National Grid proposed to replace the approximately 1.4 million AMR meters currently installed across its service territory with AMI meters (D.P.U. 21-81, Exh. NG-AMI-2, at 45). National Grid states that its current AMR meters collect monthly usage data that communicate via radio signal to a fleet of service vans as they drive by to collect monthly meter reads (D.P.U. 21-81, Exhs. NG-AMI-1, at 11; NG-AMI-2, at 14). National Grid specified that three compelling needs drive the proposed transition to AMI meters: (1) an operational need created by the current fleet of AMR metering assets reaching the end of their estimated useful life; (2) evolving customer expectations; and (3) a shared commitment to achieving ambitious clean energy goals (D.P.U. 21-81, Exhs. NG-AMI-1, at 13-16; NG-AMI-2, at 6-7). The company explained that approximately 900,000 of its AMR meters are electro-mechanical meters with an AMR retrofit that will reach the end of their estimated life within the next few years, increasing the risk of meter failures for the company and its ability to accurately perform a core business function as time progresses (D.P.U. 21-81, Exhs. NG-AMI-1, at 11-12; NG-AMI-2, at 8-10). National Grid stated that the electro-mechanical portion of these meters would reach the end of their estimated useful life within the next three years, while the AMR retrofits portion would reach the end of their estimated useful life in early 2023 (D.P.U. 21-81, Exhs. NG-AMI-1, at 11-12; NG-AMI-2, at 8-10). Further, the company maintained that as the penetration of AMI meters in the country's households reach levels of 75 to 80 percent, indications exist that manufacturers are producing far fewer AMR meters, thus presenting the risk that there will be a scarcity of

AMR technology in the market to replace failed meters (D.P.U. 21-81, Exhs. NG-AMI-1, at 12, citing Edison Foundation Institute for Electric Innovation, Electric Company Smart Meter Deployments: Foundations for a Smart Grid (2021 update); NG-AMI-2, at 8-10).

Additionally, National Grid proposed to deploy a two-way communications network and related IT to transmit data from the AMI meters and control signals back to the meters using radio frequency and, where necessary, cellular communications technology (D.P.U. 21-81, Exhs. NG-AMI-1, at 12, NG-AMI-2, at 19). More specifically, the company indicated that its communications infrastructure would primarily use radio frequency technology, but, in limited instances where insufficient meter density exists (e.g., in a rural area) to allow the mesh network to support the use of such technology, it would rely on cellular technology to communicate the metered data to its offices (D.P.U. 21-81, Tr. 4, at 584). The company stated that it would deploy an HES to process the data from the communications network, and a new MDMS to collect, validate, store, and manage the meter data, thus converting the data into a form suitable for billing and advanced analytics (D.P.U. 21-81, Exhs. NG-AMI-1, at 12-13, NG-AMI-2, at 19; NG-AMI-4, at 6). The company explained that MDMS is one of the four key elements of the proposed AMI system (D.P.U. 21-81, Exh. NG-AMI-1, at 12-13). Further, the company stated that Massachusetts will be the second state where the company is implementing the full suite of AMI technology solutions based on the need of full deployment of AMI (D.P.U. 21-81, Exh. NG-AMI-2, at 56-57). The company previously deployed both HES and MDMS on a limited scale as part of its Worcester Smart Energy Solution pilot, and the HES and MDMS costs for which it is seeking cost recovery in this proceeding do not include the costs of the previously deployed systems (D.P.U. 21-81, Tr. 4, at 590-592, 598-599).

National Grid proposed enhancements to its CIS in order to accommodate the integration of AMI data, stating that the enhancements would allow the company to: (1) bill for TVR options; (2) provide improved information to customers regarding their energy usage; and (3) send AMI usage data to the customer energy management platform ("CEMP"), through which customers can gain greater insights into energy cost drivers and their personal usage, take actions to control their usage, and access new products and offerings (D.P.U. 21-81, Exhs. NG-AMI-1, at 28; NG-AMI-2, at 5, 19; Tr. 4, at 599-600).

National Grid submitted a customer engagement plan, which sets forth the company's proposed plan to educate customers on: (1) AMI implementation and the benefits of AMI meters; (2) increasing acceptance of the new meters; (3) increasing participation in future innovative rate structures that align customer benefits with clean energy objectives; and (4) empowering customers to use new insights and services to be provided by AMI (D.P.U. 21-81, Exhs. NG-AMI-1, at 32-33; NG-AMI-3, at 16). National Grid identified three phases for this plan: (1) Phase I (Awareness) to occur prior to AMI meter installation and build an internal foundation of resources to support communications and engagement activities, educate and train employees, and initiate a territory-wide customer and stakeholder outreach effort to build awareness of the AMI program, generate interest and support, and proactively address customer concerns prior to meter installation; (2) Phase II (Deployment) to build on the education initiated in Phase I and narrow the focus of communications toward individual customers with information that would guide customers through the day-of AMI meter installation by explaining, in part, the anticipated timeline of events, what to expect, and available alternatives including the option to opt-out of an AMI meter;[30] and (3) Phase III (Empowerment and Enablement) to (i) provide access to the company's proposed new online CEMP, (ii) educate customers early and often about CEMP functionality and other tools and options that would be available after meter installation, (iii) encourage customers to interact with CEMP functionality to better understand energy usage and modify energy consumption, (iv) provide follow-up communications on new features to customers, and (v) introduce and educate customers on new TVR plans, when available (D.P.U. 21-81, Exhs. NG-AMI-1, at 33-34; NG-AMI-3, at 16-17, 31-42).

National Grid explained that the anticipated CEMP is a critical component of its proposed customer enablement products and services investments intended to serve as the contact point for customers and authorized third parties to access energy consumption data, energy insights, and service offerings (D.P.U. 21-81, Exhs. NG-AMI-1, at 36-37; NG-AMI-3, at 41). National Grid stated that, among other things, the CEMP would provide customers with access to the Green Button Connect My Data platform, through which they could voluntarily share their energy usage data with authorized third parties (D.P.U. 21-81, Exh. NG-AMI-2, at 19-20). National Grid also stated that customers would be able to access

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30 National Grid explained that, during this phase, targeted customer communications will be rolled out 90, 60, and 30 days prior to installation of the AMI meter and will be locally timed to the Company's meter installation schedule (D.P.U. 21-81, Exh. NG-AMI-3, at 35-40).

their usage data in real-time through home area networks ("HANs") that customers may deploy to communicate directly with the AMI meters (D.P.U. 21-81, Exh. NG-AMI-2, at 20).

National Grid proposed analytical tools and systems and grid integration activities, which the company stated are key to maximizing the effectiveness of the overall AMI platform (D.P.U. 21-81, Exhs. NG-AMI-1, at 28; NG-AMI-2, at 25, 55-56). The company specified that enabling data exchanges between the MDMS and its back-office systems would provide: (1) improved outage response time and performance; (2) lower labor costs and increased operational efficiency; and (3) compatibility across system devices and software (D.P.U. 21-81, Exh. NG-AMI-2, at 55-56).

National Grid's proposed cybersecurity investments include an AMI data governance plan setting forth a framework comprised of policies, standards, and guidelines to ensure that AMI data is collected, managed, stored, transferred, and protected in a way that preserves customer privacy, consistent with its existing cybersecurity requirements, and that facilitates data access to further operational requirements as well as grid modernization and clean energy objectives (D.P.U. 21-81, Exhs. NG-AMI-1, at 40-41; NG-AMI-4). The company explained that the plan addresses protections for both customer energy usage data (i.e., customer electric usage as recorded at the meter in kilowatt-hours ("kWh") and system data (i.e., grid-facing information such as planning documents that address grid impacts, load-flow models, DER forecasting, and voltage information) (D.P.U. 21-81, Exhs. NG-AMI-1, at 40-41; NG-AMI-4, at 3-4).

Finally, National Grid proposed to establish a PMO to serve as the conduit between the project front line and a steering committee to be comprised of business and IT program sponsors as well as senior leadership (D.P.U. 21-81, Exhs. NG-AMI-1, at 25; NG-AMI-2, at 51). The company explained that the PMO would be composed of company employees and experienced third-party consultants (D.P.U. 21-81, Exhs. NG-AMI-1, at 25; NG-AMI-2, at 51). The PMO would provide oversight and direction to overall program activities, as well as manage project spending, local resolution, critical updates to stakeholders, and the integrated project schedule with defined milestones (D.P.U. 21-81, Exhs. NG-AMI-1, at 25; NG-AMI-2, at 51).

iii. Deployment Timeline

National Grid proposed a four-and-one-half year deployment schedule for its primary customer-facing capital infrastructure investments (e.g., meters, communications infrastructure, HES, MDMS, and CIS) to commence in 2023 (D.P.U. 21-81, Exhs. NG-AMI-1, at 19-20; NG-AMI-2, at 5, 43-44). During the initial 18 months, the company anticipated: (1) addressing design details; (2) building and testing solutions; (3) conducting procurements; (4) developing procedures for organization, implementation, and training; and (5) installing and upgrading the back-office systems, including the CIS enhancements, MDMS, and HES (D.P.U. 21-81, Exhs. NG-AMI-1, at 19-20; NG-AMI-2, at 5, 43). The company would also initiate its customer engagement plan during this period (D.P.U. 21-81, Exh. NG-AMI-1, at 19-20). During the second year, the company would begin deployment of its proposed communications network (D.P.U. 21-81, Exhs. NG-AMI-1, at 19-20; NG-AMI-2, at 5, 43-44). Finally, after the completion of the back-office work, anticipated in 2024, the company would commence replacement of its AMR meters (D.P.U. 21-81, Exhs. NG-AMI-1, at 19-20; NG-AMI-2, at 5, 43, 45; Tr. 5, at 795-796).[31] According to National Grid, it structured its AMI deployment proposals to align with the end-of-life of a large portion of existing AMR meters, thus minimizing stranded costs (D.P.U. 21-81, Exhs. NG-AMI-1, at 20; NG-AMI-2, at 45). National Grid stated that it would further minimize stranded costs by reducing non-required meter replacements and using refurbished AMR meters in anticipation of AMI deployment (D.P.U. 21-81, Exhs. NG-AMI-2, at 45; NG-AMI-Rebuttal-1, at 18).

iv. Business Case

National Grid provided an NPV comparison of costs and benefits over a 20-year timeframe based on costs incurred through 2027 for its customer-facing investments, using a discount rate equal to its after-tax weighted average cost of capital ("WACC") (D.P.U. 21-81, Exhs. NG-AMI-2, at 23, 26; NG-AMI-Rebuttal-1, at 59-64; NG-AMI-Rebuttal-2; AG 1-19, Att.). The company identified the NPV of benefits and costs equal to $708.2 million and $483.7 million, respectively, for a benefit-to-cast ratio of 1.46 (D.P.U. 21-81, Exh. NG-AMI-Rebuttal-1, at 59-63).

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[31] National Grid stated that it expects to install approximately 30 percent of the AMI meters during the first twelve-month period, 40 percent during the second twelve-month period, and the final 30 percent during the subsequent twelve-month period (D.P.U. 21-81, Exh. NG-AMI-1, at 20-21; Tr. 5, at 795-797).

National Grid developed its initial customer-facing investment cost estimates based on the work previously completed by its affiliates in New York and Rhode Island,[32] which included an RFI to qualify potential AMI vendors, followed by a request for solutions ("RFS") (D.P.U. 21-81, Exhs. NG-AMI-1, at 26; NG-AMI-2, at 56; DPU 2-6.).[33] Subsequent to its filing in the instant proceeding, its New York affiliate entered into a contract with an AMI vendor, based on the responses to the RFI and RFS, and the contract includes an exhibit with Massachusetts-specific pricing (D.P.U. 21-81, Exhs. NG-AMI-Rebuttal-1, at 59-62; NG-AMI-Rebuttal-2; DPU 2-6; Tr. 4, at 770). As a result, the company updated its cost estimates during the course of the proceeding to reflect these Massachusetts-specific cost components, as well as to incorporate lessons learned from the back-office design and integration work currently underway as part of the New York affiliate's AMI deployment (D.P.U. 21-81, Exhs. NG-AMI-Rebuttal-1, at 59-62; NG-AMI-Rebuttal-2; DPU 2-6; Tr. 4, at 770).

National Grid quantified benefits associated with AMI implemention and deployment for the following: (1) avoided O&M costs attributed to reductions or elimination of (i) the need for meter reading vehicles, personnel, and annual software and maintenance, (ii) meter

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32 Effective May 25, 2022, National Grid's Rhode Island affiliate, The Narragansett Electric Company, was sold to PPL Rhode Island Holdings, LLC. See National Grid USA, D.P.U. 21-60, at 1-2 (2021); D.P.U. 21-60, Compliance Filing Letter at 2 (June 24, 2022).

33 The company explained that its affiliates undertook this work as part of their AMI processes and filings in their respective states (D.P.U. 21-81, Exhs. NG-AMI-1, at 26; NG-AMI-2, at 56).

investigations, (iii) meter visits required to connect and disconnect service, (iv) damage claims, (v) outages, (vi) the FCS for AMR meter reading, and (vii) the MV-90 interval meter system; (2) avoided AMR costs associated with eliminating the need to replace aging AMR meters nearing the end of their estimated useful life, as well as avoided truck rolls for AMR meter reading and labor costs savings; (3) customer benefits associated with (i) reduced energy loads from VVO beyond that of the existing VVO, (ii) customer response to energy insights/bill alerts, (iii) energy and demand savings associated with customers shifting usage from on-peak to off-peak periods in response to electric vehicle ("EV") charging, (iv) shifting customer energy to TVR rates, and (v) reduced loss of customer load due to shorter duration outages; (4) societal benefits associated with carbon dioxide reductions due to the decreased truck rolls and anticipated load shifting and energy conservation; and (5) revenue benefits involving improvements to meter-reading accuracy, reductions in theft, and reductions in bad-debt write-offs (D.P.U. 21-81, Exh. NG-AMI-2, at 29-36).

Additionally, National Grid identified two qualitative benefits associated with its proposed customer-facing investments; namely, facilitating the ability of DERs to participate fully in the wholesale market in compliance with Federal Energy Regulatory Commission ("FERC") Order 2222, and leveraging the AMI communications network and back-office systems over time to integrate other end-point devices (D.P.U. 21-81, Exhs. NG-AMI-1, at 31; NG-AMI-2, at 37-41; AC 1-9). The company also identified potential future benefits that rely on grid-edge computing capabilities including: (1) grid mapping/locational awareness; (2) real-time load disaggregation; (3) bypass theft detection; (4) intelligent voltage monitoring; (5) distributed outage detection; (6) temperature monitoring; (7) arc sensing; (8) high impedance detection; (9) broken neutral detection; and (10) active demand response (D.P.U. 21-81, Exh. NG-AMI-1, at 21). The company did not quantify the benefits for these functionalities, because these functionalities are in various stages of development and testing by AMI vendors (D.P.U. 21-81, Exh. NG-AMI-1, at 21).

c. Unitil Proposal

i. Overview

Unitil projected approximately $13.6 million in capital-only[34] customer-facing costs incurred through 2025 for the following investment categories: (1) AMI meter replacements ($11.2 million); (2) customer engagement and experience ($1.8 million); and (3) a data sharing platform ($0.5 million) (D.P.U. 21-82, Exhs. Unitil-KES-1, at 18; Unitil-GMP at 88, 91, 99). In support of its proposed customer-facing investments, Unitil included a summary business case and modeled bill impacts based on the costs identified (D.P.U. 21-82, Exhs. Unitil-KES-1, at 24; Unitil-GMP at 100-104). Unlike NSTAR Electric and National Grid, Unitil has already deployed AMI meters in its service territory, and accordingly does not need to develop many of the AMI data process and storage and customer billing functionalities.

[34] These estimated costs include capitalized labor (see D.P.U. 21-82, Exhs. Unitil-GMP at 88; DPU 1-3, Att. (8)).

ii. Proposed Investments

Unitil proposed to accelerate replacement of its 29,107 existing TS2 meters, which are an older-generation AMI technology, with new PLX AMI meters (D.P.U. 21-82, Exh. Unitil-KES-1, at 20). According to Unitil, PLX meters can provide interval metering functionality beyond that of its existing meters, thus allowing the company to: (1) accommodate TVR rate structures that would provide its customers with the ability to achieve the full benefit of their changes in customer user patterns; (2) provide more frequent and timely meter read information to customers and the company; and (3) support 15-minute load profile information (D.P.U. 21-82, Exhs. Unitil-KES-1, at 20-21; Unitil-GMP at 87-88). Unitil indicated that it does not require additional communications infrastructure to accommodate the new PLX meters but would instead continue use of its existing powerline carrier technology to communicate commands to the meters and transmit data from the meters back to the company's HES (D.P.U. 21-82, Exh. Unitil-GMP at 86; Tr. 4, at 587-588; Tr. 5, at 807-808).[35] Similarly, Unitil stated that it does not require additional investments in its existing CIS or MDMS to accommodate the PLX meters (D.P.U. 21-82, Exh. Unitil-GMP at 87; Tr. 4, at 592-593; Tr. 5, at 807-808).

Unitil represented that its proposal to accelerate the transition to modern AMI meters is driven both by an operational and a technology need (D.P.U. 21-82, Exhs. Unitil-KES-2,

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[35] Unitil stated that it recently completed an upgrade of the substation collectors that will allow interval meter readings to be transmitted once the PLX meters are installed (D.P.U. 21-82, Exh. Unitil-GMP at 86; Tr. 5, at 807-808).

at 11; Unitil-GMP at 86-87; AG 1-3; AG 1-6; AG 6-6, at 2; AG 6-7; DPU 10-1; Tr. 3, at 516-520). From an operational perspective Unitil stated that approximately one half of its existing TS2 meters are reaching the end of their useful life in the next few years, and the manufacturer no longer produces the TS2 meters (D.P.U. 21-82, Exhs. Unitil-KES-2, at 11; Unitil-GMP at 87-88; AG 6-7). As a result, the company began replacing its existing meters with new PLX meters at a business as usual pace (D.P.U. 21-82, Exhs. Unitil-KES-2, at 11; Unitil-GMP at 87-88). From a technology perspective, Unitil explained that, while its existing meter technology was considered state of the art at the time of deployment over a decade ago, the meters have been outpaced by new technology that can provide more granular and timely usage information (D.P.U. 21-82, Exh. Unitil-GMP at 35-36, 86).

Additionally, Unitil proposed the following customer engagement and experience investments: (1) a customer experience management solution to provide customers with a single location to better manage their energy usage, and a notification engine to proactively alert them to payment activity, increases in usage, outage notifications, and the status of scheduled appointments; (2) a customer engagement marketplace for customers to find personalized rate plans, education, data products and services, and home energy management systems made available through partnerships between the company and trusted vendor alliances; (3) artificial intelligence ("AI") to allow the company to better understand how consumers use energy in their homes in order to develop future products and service offerings; (4) a utility bill redesign that includes personalized messaging by customer class, location, and interests; and (5) a work order job scheduler to allow the company and customers to coordinate appointments in real time and improve communications on available dates and times, status, and outcome (D.P.U. 21-82, Exhs. Unitil-KES-1, at 21-22; Unitil-GMP at 89-92).

Finally, Unitil proposed a data sharing platform intended to allow customers and interested third parties the ability to use AMI data to inform behaviors, products, and programs (D.P.U. 21-82, Exhs. Unitil-KES-1, at 21; Unitil-GMP at 99-100). Unitil explained that it would use the Green Button Download My Data platform to allow customers to: (1) download their energy usage data directly from the company's customer engagement platforms; and (2) voluntarily provide access to their energy usage data to third parties (D.P.U. 21-82, Exhs. Unitil-KES-1, at 22; Unitil-GMP at 92-100; AG 5-1; Tr. 5, at 884-885).

iii. Deployment Timeline

Unitil anticipated replacing all of its existing TS2 meters with new PLX meters by 2025, contingent on receiving Department approval sufficiently in advance (D.P.U. 21-82, Exhs. Unitil-KES-1, at 20; Unitil-GMP at 87-88; Tr. 5, at 800). Unitil anticipated finalizing work on most components of its proposed customer engagement and experience project by 2025, with work associated with the customer engagement marketplace and AI components continuing through at least 2030 (D.P.U. 21-82, Exhs. Unitil-KES-1, at 21; Unitil-GMP at 91). Unitil anticipated finalizing work on its proposed data sharing platform by 2023 (D.P.U. 21-82, Exhs. Unitil-KES-1, at 18; Unitil-GMP at 99).

iv. Business Case

Unitil submitted with its 2022-2025 Grid Modernization Plan a summary business case for its proposed customer-facing investments (D.P.U. 21-82, Exh. Unitil-GMP at 89, 91, 100, 102-103). During the course of the proceeding, Unitil explained that it based its cost estimates on the business case it submitted in D.P.U. 15-121, updated by information gathered through its business as usual PLX meter deployments and existing customer web portal, as well as from its affiliate activities related to the proposed investments (D.P.U. 21-82, Exhs. Unitil-KES-2, at 3-4, 9-10; Unitil-GMP at 86, 89, 91-92, 99; DPU 1-3, at 2; DPU 10-1; CLF-U 1-6; CLF-U 1-8; AG-WG-Surrebuttal at 16; Tr. 3, at 517-520; Tr. 4, at 702-704).

The anticipated benefits identified by the company involving meter replacement include the ability to provide customers with the opportunity to lower their energy bills through changes in their usage patterns, with lowered usage enabling deferral of the construction of fossil fuel or nuclear power plants, and reduced need for investments in transmission and distribution system infrastructure (D.P.U. 21-82, Exh. Unitil-GMP at 89, 91-92, 102). The company also identified benefits involving improvements in outage and circuit monitoring due to the increased speed of response from the meters to the company's back-office systems (D.P.U. 21-82, Exh. Unitil-GMP at 89, 102). For its proposed customer engagement and experience investments, Unitil identified benefits associated with facilitating customer access to and control of their energy usage (D.P.U. 21-82, Exh. Unitil-GMP at 91-92, 102-103). For its proposed data sharing platform, in coordination with meter replacement and customer engagement and experience investments, the company identified potential improvements to and facilitation of third-party access to customer usage data, thus increasing opportunities for customers to take active involvement in their energy usage (D.P.U. 21-82, Exh. Unitil-GMP at 100).

4. Cost Recovery Proposals

For their proposed new grid-facing investments, the Companies requested cost recovery through their existing GMF tariffs (D.P.U. 21-80, Exhs. ES-JAS-1, at 14-16; ES-JAS-2, at 35-36; D.P.U. 21-81, Exhs. NG-GMP-1, at 11; NG-GMP-2 (Rev. 2) at 16; D.P.U. 21-82, Exhs. Unitil-KES-1, at 16-22; Unitil-GMP at 12-14). See also NSTAR Electric, M.D.P.U. No. 73F, §§ 1.0, 2.6; National Grid, M.D.P.U. No. 1497, §§ 1.0, 2.6; Unitil, M.D.P.U. No. 379, §§ 1.0, 2.6. For its proposed customer-facing investments (i.e., AMI-related investments) preauthorized by the Department, Unitil also requested cost recovery through its existing GMF tariff (D.P.U. 21-82, Exhs. Unitil-KES-1, at 20-22; AG 1-9; Tr. 4, at 658-659). However, NSTAR Electric and National Grid each requested that the Department approve recovery of customer-facing investments through a new AMI tariff (D.P.U. 21-80, Exhs. ES-AMI-1, at 37-40; ES-AMI-5; DPU 2-2; DPU 2-5; DPU 15-4; Tr. 4, at 657, 663, 666-671, 746; D.P.U. 21-81, Exhs. NG-AMI-1, at 4, 8-11; NG-AMI-6; NG-AMI-Rebuttal at 59-65; DPU 2-2; DPU 2-5; Tr. 4, at 650-651, 672-676). NSTAR Electric and National Grid jointly proposed a model tariff for the Department's consideration (D.P.U. 21-80, Exhs. ES-AMI-1, at 37-38; ES-AMI-5; D.P.U. 21-81, Exhs. NG-AMI-1, at 8-9; NG-AMI-6). If approved, each company would derive a company-specific tariff based on the model tariff (D.P.U. 21-80, Exh. ES-AMI-1, at 37-38; D.P.U. 21-81, Exh. NG-AMI-1, at 8-9).[36] The proposed tariff would establish a new reconciling cost recovery mechanism for NSTAR Electric and National Grid, the AMI factor ("AMIF"), that would allow for the accelerated recovery of eligible costs outside of base distribution rates, subject to Department prudency reviews and approvals (D.P.U. 21-80, Exh. ES-AMI-1, at 37-38; D.P.U. 21-81, Exh. NG-AMI-1, at 8-9).

As proposed, the tariff would allow NSTAR Electric and National Grid to recover through the AMIF an annual AMI revenue requirement associated with the company's AMI-related plant-in-service for each AMI investment year prior to the recovery year, as well as recoverable O&M expense (D.P.U. 21-80, Exh. ES-AMI-5; D.P.U. 21-81, Exh. NG-AMI-6; D.P.U. 22-22, Exhs. ES-AMI-1, at 19; ES-AMI-2; ES-RDC-6, at 556-561). The AMI revenue requirement would be calculated to recover: (1) the monthly revenue requirement for eligible AMI investments recorded as in-service in the AMI investment year immediately prior to the recovery year; (2) the average annual revenue requirement for the calendar year ending December 31 of the AMI investment year two years prior to the recovery year, for cumulative eligible investments placed into service in the two years prior to the recovery year; (3) the annual revenue requirement for the recovery year on eligible investments recorded as in-service in the AMI investment year immediately prior to

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36 As noted above in Section III.A.1, NSTAR Electric requested approval of the model tariff in D.P.U. 21-80 and a company-specific tariff in D.P.U. 22-22, while National Grid requested approval of a company-specific tariff during the course of the instant proceedings.

the recovery year; and (4) actual monthly AMI-related O&M expenses incurred in the AMI investment year prior to the recovery year (D.P.U. 21-80, Exh. ES-AMI-5; D.P.U. 21-81, Exh. NG-AMI-6; D.P.U. 22-22, Exhs. ES-REVREQ-1, at 200-201; ES-AMI-1, at 19-20; ES-AMI-2, at 1-5; ES-RDC-6, at 556-560). Each company would submit an annual cost recovery filing that includes project documentation of all eligible AMI investments, documentation supporting non-recurring O&M expense as part of recoverable O&M expense, an AMI reconciliation calculation based on prior-year collections, and estimated bill impacts (D.P.U. 21-80, Exh. ES-AMI-1, at 39; D.P.U. 21-81, Exh. NG-AMI-1, at 9-10; D.P.U. 22-22, Exhs. ES-REVREQ-1, at 201; ES-AMI-1, at 20; ES-AMI-2, at 1, 5-6; ES-RDC-6, at 559-561). The annual AMIF filing and effective dates would align with the filing and effective dates associated with each company's annual GMF filings (D.P.U. 21-81, Tr. 4, at 649-650; D.P.U. 22-22, Exh. ES-AMI-2, at 5-6).

NSTAR Electric and National Grid explained that when their AMR meters reach the end of their estimated useful lives in the coming years, they will continue to replace AMR meters with AMR meters annually until AMI is completely implemented, and those legacy AMR replacement costs are included in base distribution rates (D.P.U. 21-80, Exh. ES-AMI-1, at 23, 40-41; D.P.U. 21-81, Exhs. NG-AMI-1, at 7, 10-11, 20; NG-AMI-Rebuttal-1, at 18; Tr. 3, at 501). NSTAR Electric submitted a proposal in its base distribution rate case, D.P.U. 22-22, to address the unrecovered investments in AMR meters (D.P.U. 22-22, Exhs. ES-REVREQ-1, at 202-204; ES-AMI-1, at 18-22; ES-JJS-1, at 19). In particular, NSTAR Electric proposed accelerated recovery of the appropriate remaining book value of its AMR meters for depreciation purposes, intended to align with its AMI deployment plans, and the establishment of a regulatory asset to recover any non-fully depreciated AMR meters at the time of full AMI deployment (D.P.U. 21-80, Exhs. ES-AMI-1, at 40-41; ES-Rebuttal at 25-26; DPU 15-4, at 2; Tr. 3, at 506-511; D.P.U. 22-22, Exhs. ES-REVREQ-1, at 202-204; ES-AMI-1, at 18-22; ES-JJS-1, at 19).[37]

Similarly, National Grid and Unitil each stated that, if their customer-facing proposals are approved, there may be a resulting unrecovered investment from the legacy metering assets (D.P.U. 21-81, Exh. NG-AMI-1, at 7, 10-11, 20; Tr. 3, at 502-503; Tr. 4, at 718; D.P.U. 21-82, Exh. AG 1-2(a)-(b)). As a result, both National Grid and Unitil proposed to address the unrecovered investment as part of their next base distribution rate case (D.P.U. 21-81, Exhs. NG-AMI-1, at 7, 10-11, 20; AG 1-8(b); Tr. 3, at 502-503; Tr. 4, at 718-719; RR-DPU-NGrid-2, at 2; D.P.U. 21-82, Exh. AG 1-2(c)).[38] NSTAR Electric and National Grid also specified that, once the recovery of their remaining investment in AMR assets is complete, it would be reasonable to provide a credit to customers for the amount of AMR asset recovery in base distribution rates that is no longer required (D.P.U. 21-80, Tr. 4, at 610-611, 700; D.P.U. 21-81, Tr. 4, at 719; RR-DPU-NGrid-2, at 2).

Finally, in D.P.U. 22-22, NSTAR Electric proposed to establish a cost-of-service benchmark for metering infrastructure to determine incremental O&M expense savings

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[37] The Department addresses this proposal in further detail in D.P.U. 22-22, at 339-351.

[38] National Grid stated that it was amenable to a proposal similar to NSTAR Electric's in D.P.U. 22-22 on the issue (D.P.U. 21-81, RR-DPU-NGrid-2, at 2).

related to AMI (D.P.U. 21-80, Exh. AG 8-14; Tr. 4, at 712-713; D.P.U. 22-22, Exh. ES-REVREQ-1, at 202-203, 205-209). The company proposed to measure incremental costs based on the test year level of costs for meter expenses, maintenance of meters, meter reading expenses, and miscellaneous customer accounts expenses as measured by FERC Account (D.P.U. 21-80, Exh. AG 8-14; Tr. 4, at 712-713; D.P.U. 22-22, Exh. ES-REVREQ-1, at 205-206). Using FERC Accounts 586, 597, 902, and 905, the company calculated $9.7 million in test year[39] metering costs (D.P.U. 22-22, Exhs. ES-REVREQ-1, at 206-207; ES-AMI-1, at 24; ES-AMI-3, at 1). This amount represents the baseline amount, adjusted each year for the annual change in gross domestic product price index ("GDP-PI"), that the company proposes to compare against to determine incremental cost recovery for AMI meter-related O&M (D.P.U. 22-22, Exhs. ES-REVREQ-1, at 206-207; ES-AMI-1, at 24-25). National Grid stated it was amenable to taking a similar approach in calculating O&M savings and anticipates that any O&M savings resulting from its AMI implementation investments can be reflected in rates to customers in a future base distribution rate case (D.P.U. 21-81, Exh. AG 1-4; Tr. 4, at 706-708).

[39] The test year used in D.P.U. 22-22 is calendar year 2020. D.P.U. 22-22, at 10-11.

B. Positions of the Parties

1. Intervenors

a. Attorney General

i. General Arguments

The Attorney General does not oppose full-scale deployment of AMI, but she urges the Department to revise the current grid modernization cost recovery structure (D.P.U. 21-80, Attorney General Brief at 1, 8-11, 29; D.P.U. 21-81, Attorney General Brief at 1, 8-11, 29; D.P.U. 21-82, Attorney General Brief at 1, 7-11). Specifically, the Attorney General requests that the Department reject the Companies' requests for expedited cost recovery of their proposed AMI-related investments, including NSTAR Electric's proposed CIS (D.P.U. 21-80, Attorney General Brief at 21-25; D.P.U. 21-81, Attorney General Brief at 22-25; D.P.U. 21-82, Attorney General Brief at 2, 22-31). The Attorney General maintains that NSTAR Electric and National Grid's AMI system investments can and should proceed under ordinary ratemaking for cost recovery through base distribution revenues and rates, and that any claims by either company that they cannot proceed without additional revenues from a capital tracker are exaggerated (D.P.U. 21-80, Attorney General Brief at 25; Attorney General Reply Brief at 9; D.P.U. 21-81, Attorney General Brief at 25; Attorney General Reply Brief at 8).

Additionally, the Attorney General argues that the cost recovery proposals through the existing GMF tariffs and the proposed AMIF tariffs would result in overcollections from ratepayers with no incentive for the Companies to deliver projected benefits to ratepayers

(D.P.U. 21-80, Attorney General Brief at 1, 9-10; D.P.U. 21-81, Attorney General Brief at 1, 8-9; D.P.U. 21-82, Attorney General Brief at 1, 8-9). Specifically, the Attorney General recommends that the Department: (1) create performance metrics or targets to measure the delivery of ratepayer benefits as projected by the Companies in their business cases; and (2) amend the Companies' tariffs to limit the return on grid modernization investments until after a showing that the projected level of benefit is achieved (D.P.U. 21-80, Attorney General Brief at 8-9, 10-11, citing Exh. AG-WG-1, at 32-33, 66-68; Attorney General Reply Brief at 2, 5-6; D.P.U. 21-81, Attorney General Brief at 8, 9-10, citing Exh. AG-WG-1, at 32-33, 37-38, 48-49; Attorney General Reply Brief at 2, 4-5; D.P.U. 21-82, Attorney General Brief at 7, 10-11, citing Exh. AG-WG-1, at 39; Attorney General Reply Brief at 2-3, 4-5). The Attorney General counters that accountability for delivering projected benefits is necessary because the Companies are not simply observers but must play an active role in making investment decisions that ensure the investments deliver the projected benefits (D.P.U. 21-80, Attorney General Reply Brief at 3; D.P.U. 21-81, Attorney General Reply Brief at 3; D.P.U. 21-82, Attorney General Reply Brief at 3).

In response to NSTAR Electric, the Attorney General argues that a prudence review protects ratepayers from cost overruns but affords no protection if the investments are on budget but fail to deliver projected benefits (D.P.U. 21-80, Attorney General Reply Brief at 3-4, citing NSTAR Electric Brief at 69-70, 83 n.15). Regarding NSTAR Electric's total resource cost arguments, the Attorney General argues that traditional utility investments in equipment such as poles, wires, and transformers create self-achieving benefits readily apparent after the items are placed in-service, whereas the proposed grid modernization investments provide incremental value only if their projected benefits are achieved (D.P.U. 21-80, Attorney General Reply Brief at 4). The Attorney General dismisses the company's argument that her recommendation is unfair because factors outside the company's control may affect benefits, arguing that the company is paid to manage its business in all operating conditions, including changes in weather and load, supply chain issues, and varying customer behavior, and that the company's management of such risks is the basis for its allowed rate of return (D.P.U. 21-80, Attorney General Reply Brief at 5, citing NSTAR Electric Brief at 76-77). The Attorney General maintains that it would be more unfair to impose 100 percent of the risks on ratepayers (D.P.U. 21-80, Attorney General Reply Brief at 5).

From a cost perspective, the Attorney General contends that each company's grid-facing and customer-facing investment cost estimates focus exclusively on the company's direct capital acquisition costs and ignores the total costs ratepayers would incur, including carrying charges (D.P.U. 21-80, Attorney General Brief at 11 n.11; D.P.U. 21-81, Attorney General Brief at 10 n.10; D.P.U. 21-82, Attorney General Brief at 11 n.10). According to the Attorney General, the customers' cost, which under cost-of-service regulation includes years of return on investment on undepreciated plant account balances, is far higher than the utility's acquisition cost, and when comparing these costs, rather than the Companies', against benefits, the difference is significant (D.P.U. 21-80, Attorney General Brief at 11 n.11, citing Exh. AG-WG-1, at 29-30, 45; D.P.U. 21-81, Attorney General Brief at 10 n.10, citing Exh. AG-WG-1, at 30-31, 41-42; D.P.U. 21-82, Attorney General Brief at 11 n.10, citing Exh. AG-WG-1, at 30-31, 41-42).

Further, the Attorney General argues that the costs outweigh the claimed benefits in NSTAR Electric and National Grid's AMI business cases due to cost understatements and benefit overstatements by each company (D.P.U. 21-80, Attorney General Brief at 29-33; D.P.U. 21-81, Attorney General Brief at 29-31). The Attorney General identifies NSTAR Electric's 1.02 cost-benefit ratio as "razor-thin" and maintains that the company's business case likely results in negative net benefits (D.P.U. 21-80, Attorney General Brief at 29-30, 33, citing Exhs. ES-AMI-4 (Rev.) at 9; AG-WG-1, at 43). Similarly, the Attorney General points to the reduction in National Grid's projected cost-benefit ratio from 1.51 to 1.46 due to the company's refined cost estimates to argue that the projected AMI costs and benefits are subject to ongoing variability (D.P.U. 21-81, Attorney General Brief at 29, 31, & n.14, citing Exhs. NG-AMI-2, at 26, 30; NG-AMI-Rebuttal-1, at 61-63; AG-WG-Surrebuttal at 17). According to the Attorney General, the negative net benefits attributed to NSTAR Electric's business case and uncertain cost-effectiveness of National Grid's AMI Implementation Plan highlight the importance of holding each company accountable to provide benefits (D.P.U. 21-80, Attorney General Brief at 30, 33; D.P.U. 21-81, Attorney General Brief at 30, 31).

For instance, the Attorney General asserts that NSTAR Electric and National Grid each fail to address how stranded costs impact its AMI business case even though these costs are likely to be between \$116.9 million and \$219.9 million for the varying net book values attributed to NSTAR Electric's existing meters, and $44.9 million attributed to the net book value of National Grid's existing meters (D.P.U. 21-80, Attorney General Brief at 31, citing Exhs. ES-Rebuttal at 53; AG-WG-1, at 51-52; AG 3-1; D.P.U. 21-81, Attorney General Brief at 30, citing Exhs. AG 1-8, Att. (Supp.); AG-WG-Surrebuttal at 17). In response to NSTAR Electric's argument that its deployment strategy will mitigate stranded costs by replacing the oldest meters first, the Attorney General contends that this strategy will only be marginally successful because the company cannot avoid replacing meters that still have book value (D.P.U. 21-80, Attorney General Brief at 31 n.17, citing Exhs. AG-WG-Surrebuttal at 21; AG 8-4).

The Attorney General asserts that NSTAR Electric and National Grid each overstate avoided AMR replacement costs due to their false sense of urgency to replace existing meters (D.P.U. 21-80, Attorney General Brief at 31, citing Exhs. ES-AMI-4 (Rev.) at 25; AG-WG-Surrebuttal at 26; D.P.U. 21-81, Attorney General Brief at 30, citing Exh. NG-AMI-2, at 30). The Attorney General contends that the current average age of NSTAR Electric's existing meters is lower than the company projects, and the estimated remaining operating life of National's Grid's existing meters is higher than the company projects (D.P.U. 21-80, Attorney General Brief at 31-32, citing Exhs. ES-AMI-1, at 23; AG-WG-1, at 57-58; AG-WG-Surrebuttal at 26; DPU 1-2, Att.; D.P.U. 21-81, Attorney General Brief at 31, citing Exhs. NG-AMI-2, at 12, 30; NG-AMI-Rebuttal-2, at 31; AG-WG-1, at 45-46). According to the Attorney General, her witness rebutted NSTAR Electric and National Grid's assumptions that their existing fleets of AMR meters are at the end of their service lives (D.P.U. 21-80, Attorney General Brief at 22, citing Exh. AG-TN-1, at 6; D.P.U. 21-81, Attorney General Brief at 23, citing Exh. AG-TN-1, at 6). The Attorney General asserts that the average remaining life of the AMR meters appears to be eight or more years for NSTAR Electric and nine or more years for National Grid (D.P.U. 21-80, Attorney General Brief at 22, citing Exh. AG-TN-1, at 6; D.P.U. 21-81, Attorney General Brief at 23, citing Exh. AG-TN-1, at 6). The Attorney General contends that NSTAR Electric and National Grid's claims that they will avoid $152 million (NSTAR Electric) and $186 million (National Grid) in AMR replacement costs by installing AMI are overstated (D.P.U. 21-80, Attorney General Brief at 31, citing Exhs. ES-AMI-4 (Rev.) at 25; AG-WG-Surrebuttal at 26; D.P.U. 21-81, Attorney General Brief at 31, citing Exhs. NG-AMI-2, at 12, 30; NG-AMI-Rebuttal at 2, 31). The Attorney General states that at least 50 percent of meters last longer than their depreciation lives (D.P.U. 21-80, Attorney General Brief at 31-32, citing Exh. AG-WG-1, at 57-58; D.P.U. 21-81, Attorney General Brief at 31, citing Exh. AG-WG-1, at 45-46).

Further, the Attorney General maintains that an AMI system is now business as usual for utility operations in the United States, with NSTAR Electric and National Grid each acknowledging that AMI technology has become the de facto electric industry standard for retail service meters (D.P.U. 21-80, Attorney General Brief at 22, citing Exh. AG-TN-1, at 7; Attorney General Reply Brief at 6-7; D.P.U. 21-81, Attorney General Brief at 23, citing Exh. AG-TN-1, at 7; Attorney General Reply Brief at 5-6). The Attorney General states that NSTAR Electric and National Grid's investment in AMI simply brings each company's AMR system up to current industry standards (D.P.U. 21-80, Attorney General Brief at 22, citing Exh. AG-TN-1, at 7; D.P.U. 21-81, Attorney General Brief at 23, citing Exh. AG-TN-1, at 7). In addition, the Attorney General contends that the level of proposed costs does not justify a new cost recovery mechanism when projected spending above the current amounts spent on AMR meters by NSTAR Electric and National Grid is compared to the total annual investments for each company's combined operations (D.P.U. 21-80, Attorney General Brief at 24; D.P.U. 21-81, Attorney General Brief at 25).[40]

The Attorney General further argues that NSTAR Electric's proposed CIS costs and NSTAR Electric's and National Grid's AMI meter costs are presently factored into each company's base distribution rates by operation of the current performance-based ratemaking ("PBR") applied to each company in their most recent rate cases, NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05 (2017), and Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 18-150 (2019), respectively (D.P.U. 21-80, Attorney General Brief at 23-24; D.P.U. 21-81, Attorney General Brief at 23-25). Specifically, the Attorney General contends that the X-factor used in NSTAR Electric's and National Grid's PBR rate formulas reflect the combined cost of service of all electric distribution companies rather than just NSTAR Electric or National Grid

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[40] For NSTAR Electric, the Attorney General states that this equates to approximately \$43 million of incremental spending required of the \$700 million invested annually, and for National Grid, approximately \$62 million of incremental spending required of the \$300 million invested annually (D.P.U. 21-80, Attorney General Brief at 24, citing Exh. AG-TN-1, at 13; D.P.U. 21-81, Attorney General Brief at 25, citing Exh. AG-TN-1, at 12-13).

(D.P.U. 21-80, Attorney General Brief at 23; D.P.U. 21-81, Attorney General Brief at 24). Furthermore, the Attorney General alleges the percentage revenue increase exceeds the rate of inflation because the distribution industry is less productive than the US economy (D.P.U. 21-80, Attorney General Brief at 23; Attorney General Reply Brief at 7; D.P.U. 21-81, Attorney General Brief at 23-24; Attorney General Reply Brief at 6-7). As a result, the Attorney General contends that because the industry put AMI meters in service between the 2000s and each company's most recent base distribution rate proceeding, each company's PBR formula already captures the cost of AMI meter systems (D.P.U. 21-80, Attorney General Brief at 23-24, citing Exh. AG-TN-1, at 10-11; D.P.U. 21-81, Attorney General Brief at 24, citing Exh. AG-TN-1, at 10).

Allowing separate cost recovery under the proposed model AMI tariff, the Attorney General asserts, would result in double recovery (D.P.U. 21-80, Attorney General Brief at 24, citing Exh. AG-TN-1, at 11; D.P.U. 21-81, Attorney General Brief at 24-25, citing Exh. AG-TN-1, at 11). Examining the Total Factor Productivity ("TFP") study, the Attorney General alleges that the study was based on the number of customers for each utility company and not the number of companies (D.P.U. 21-80, Attorney General Reply Brief at 8; D.P.U. 21-81, Attorney General Reply Brief at 6). Because over 80 percent of customers have AMI capabilities, the Attorney General contends that NSTAR Electric and National Grid's claims that a portion of distribution companies had deployed AMI are inaccurate (D.P.U. 21-80, Attorney General Reply Brief at 8, citing Exh. AG-TN-Surrebuttal at 8-11; D.P.U. 21-81, Attorney General Reply Brief at 7, citing Exh. AG-TN-Surrebuttal at 4-5). The Attorney General also contends that because the PBR rate formula used by NSTAR Electric and National Grid increases base distribution revenues, which reflect an industry with AMI, their rates change as if NSTAR Electric and National Grid already implemented AMI (D.P.U. 21-80, Attorney General Brief at 24; Attorney General Reply Brief at 7; D.P.U. 21-81, Attorney General Brief at 25).

To the extent the Department approves NSTAR Electric's and National Grid's proposed AMI cost recovery mechanisms, the Attorney General recommends that the Department reduce each company's cost recovery revenue requirements by the amount of projected O&M savings and revenue assurance benefits by year, as identified in each company's business case, until the benefits are fully captured in a base distribution rate case (D.P.U. 21-80, Attorney General Brief at 27-28; Attorney General Reply Brief at 10-11; D.P.U. 21-81, Attorney General Brief at 28-29; Attorney General Reply Brief at 8). The Attorney General argues that shareholders, not customers, will otherwise secure O&M costs avoidance and revenue assurance benefits from AMI through 2027 and some to most of the benefits secured through 2032 as a result of the schedule on which each company projects it will realize these O&M cost reductions, each company's control over when it files for a change in base distribution rates, and the timing necessary for the reductions to actually be reflected in customers' rates (D.P.U. 21-80, Attorney General Brief at 28 & n.14, citing Exh. AG-WG-1, at 61-62; D.P.U. 21-81, Attorney General Brief at 28 & n.14, citing Exh. AG-WG-1, at 43-44). Noting NSTAR Electric's proposals in D.P.U. 22-22 to track and document AMI-related O&M costs and savings by corresponding FERC account and to recover only the net change from the test year amount (as calculated in D.P.U. 22-22), adjusted each year for the annual change in GDP-PI, the Attorney General maintains that these proposals are inadequate (D.P.U. 21-80, Attorney General Brief at 28-29, citing Exhs. AG-WG-1, at 61-62; ES-Rebuttal at 56; AG 8-14). Specifically, the Attorney General argues that the use of actual savings does not hold the company accountable for delivering the projected benefits, and the proposal leaves unaccounted for other rate case dependent benefits quantified in the business case, including bad debt expense ($128.9 million) and truck rolls from "no trouble found" incidents ($14.1 million) (D.P.U. 21-80, Attorney General Brief at 29, citing Exhs. ES-AMI-4 (Rev.) at 27, 29; AG-WG-Surrebuttal at 27; AG 8-14).[41]

In response to NSTAR Electric's and National Grid's oppositions to the O&M recommendation, the Attorney General argues that they cannot claim that the benefit projections are sufficient to obtain preferential rate treatment but so speculative that they should not flow through to ratepayers (D.P.U. 21-80, Attorney General Reply Brief at 11; D.P.U. 21-81, Attorney General Reply Brief at 8). Moreover, regarding NSTAR Electric's argument that the Department has previously rejected reducing cost recovery based on potential or projected savings benefits, the Attorney General counters that those decisions are not comparable and involved base distribution rate cost recovery (D.P.U. 21-80, Attorney General Reply Brief at 10-11, citing NSTAR Electric Brief 104-105).

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[41] The Department addresses the Attorney General's additional company-specific O&M arguments further below.

In addition, the Attorney General recommends that the Department address three issues involving meter-related functionality and hardware for the Companies: (1) HAN; (2) DI; and (3) for NSTAR Electric and National Grid, remote shut-off capabilities (D.P.U. 21-80, Attorney General Brief at 2, 39-44; D.P.U. 21-81, Attorney General Brief at 2, 37-41; D.P.U. 21-82, Attorney General Brief at 2, 36-39). The Attorney General identifies these technologies' capabilities but also argues that they raise questions regarding fair market competition and access to data, equity, cybersecurity and privacy, and cost-effectiveness (D.P.U. 21-80, Attorney General Brief at 39-41, 43-44, citing Exhs. ES-AMI-4 (Rev.) at 27-28; ES-Rebuttal at 62-63; AG-WG-1, at 50 n.1; AG-WG-Surrebuttal at 33-35; CLF-CV at 9-10; U-MH/JM at 4-5; Tr. 5, at 885, 888; D.P.U. 21-81, Attorney General Brief at 37-39, 40-41, citing Exhs. NG-AMI-1, at 13; AG-WG-Surrebuttal at 25-27; CLF-CV at 9, 15; U-MH/JM at 4-5; Tr. 5, at 885, 888, 934; D.P.U. 21-82, Attorney General Brief at 36-38, citing Exhs. AG-WG-Surrebuttal at 22-23; CLF-CV at 9, 15; U-MH/JM at 4-5; Tr. 5, at 885, 888). Additionally, the Attorney General recommends that the Department address the HAN- and DI-related concerns first, by carefully weighing the costs and benefits of these technologies and deciding whether NSTAR Electric and National Grid should include them in the AMI meters before the meters are procured, and whether Unitil is able to include HAN- and DI-enabling hardware in its existing TS2 and PLX meters; and second, through the separate data access stakeholder process (D.P.U. 21-80, Attorney General Brief at 41-42; D.P.U. 21-81, Attorney General Brief at 38-40; D.P.U. 21-82, Attorney General Brief at 37-39).

Regarding the anticipated remote shut-off capabilities for NSTAR Electric's and National Grid's AMI meters, the Attorney General urges that, given the cybersecurity risks for customers involving loss of service caused by improper acts or intrusions by bad actors, the Department should: (1) require AMI meters without remote shut-off capabilities; (2) require each company to guarantee that the remote shut-off function cannot be hacked and provide financial insurance for liabilities associated with any meter intrusion; and/or (3) at a minimum, order each company to allow customers to opt-out of meters with remote shut-off capabilities (D.P.U. 21-80, Attorney General Brief at 43-44; D.P.U. 21-81, Attorney General Brief at 40-41). The Attorney General contends that the cybersecurity risks can be mitigated by removing the ability to shut off customer service remotely and installing the meters without the switch to remotely shut off service (D.P.U. 21-80, Attorney General Brief at 44, citing Tr. 5, at 935-936; D.P.U. 21-81, Attorney General Brief at 41, citing Tr. 5, at 935-937). The Attorney General maintains that while such an option may come with some increased costs to customers to manually turn service on and off, customers are already incurring such costs, and the Companies are already required under the Department's regulations to be at the premises to shut off service to customers for nonpayment (D.P.U. 21-80, Attorney General Brief at 44, citing Tr. 5, at 939-940; 220 CMR 25.00; D.P.U. 21-81, Attorney General Brief at 41, citing Tr. 5, at 940-941; 220 CMR 25.00).

ii. Plan-Specific Arguments

(A) NSTAR Electric

The Attorney General argues that NSTAR Electric has not supported its proposed grid-facing investments (D.P.U. 21-80, Attorney General Brief at 20-21). According to the Attorney General, NSTAR Electric failed to identify or overstated the specific benefits associated with these investments by hundreds of millions of dollars, or to adequately provide an alternative analysis for its proposed communications upgrades (D.P.U. 21-80, Attorney General Brief at 2, 20-21, citing Exh. AG-WG-1, at 28, 32, 38). The Attorney General maintains that, instead, the company included benefits for the proposed grid-facing investments in the AMI business case, making them unavailable to offset the cost of the grid-facing investments (D.P.U. 21-80, Attorney General Brief at 20). The Attorney General also criticizes NSTAR Electric for only providing projected spending for the four years of the grid modernization plan, even though the company expects the projects to take longer than four years to complete (D.P.U. 21-80, Attorney General Brief at 20, citing Exh. AG-WG-1, at 28). As a result, the Attorney General contends that the Department is being asked to preauthorize spending without knowing either the total costs or benefits, which should be provided before any preauthorization occurs (D.P.U. 21-80, Attorney General Brief at 21, citing Exh. AG-WG-1, at 28).

Further, the Attorney General contends that NSTAR Electric demonstrates a bias toward owning and constructing its own grid-facing communications infrastructure and should have, instead, provided a “make vs. buy” analysis of communications upgrades to better understand and document its proposed spending on these upgrades (D.P.U. 21-80, Attorney General Brief at 21, citing Exh. AG-WG-1, at 38). The Attorney General asserts that public carrier networks have made great strides in features, including security, reliability, and backward compatibility, and that the Department should condition approval of communications upgrades on the company demonstration that constructing its own communications facilities is superior to obtaining public carrier services (D.P.U. 21-80, Attorney General Brief at 21).

Regarding NSTAR Electric's AMI-related proposal to replace its existing CIS, in addition to the PBR arguments, the Attorney General argues that the company's existing CIS already supports the AMI meters currently on its system, including capturing and processing TVR and demand information and computing and billing for demand and TVR rates, and the company already provides multichannel communication with customers to notify them of significant events on its system (D.P.U. 21-80, Attorney General Brief at 25, citing Exh. AG-TN-Surrebuttal at 5-6). Pointing to National Grid's proposal to modify its existing CIS to facilitate AMI, the Attorney General states that NSTAR Electric has failed to demonstrate why it cannot take the same approach (D.P.U. 21-80, Attorney General Brief at 25, citing Exh. AG-TN-Surrebuttal at 5-6). As a result, the Attorney General contends that it would be imprudent to replace the whole CIS platform when NSTAR Electric can achieve the same or similar results with less costly modifications (D.P.U. 21-80, Attorney General Brief at 25).

Regarding NSTAR Electric's projected O&M cost benefits for customer-facing investments, the Attorney General calculates that less than one-third, $93 million, is associated with labor cost reductions based on headcount reductions while the balance, $275 million, is based on reductions in the amount of activity required by employees (D.P.U. 21-80, Attorney General Brief at 32, citing Exhs. ES-AMI-4 (Rev.) at 29-32; AG-WG-1, at 59-60). The Attorney General argues that assumed headcount reductions associated with reductions in employee activity levels are never realized and, thus, do not provide benefits to customers (D.P.U. 21-80, Attorney General Brief at 32, citing Exh. AG-WG-1, at 59-60). The Attorney General estimates that approximately 90 headcount reductions among field staff would be required to achieve the average $18 million in annual reductions over 20 years projected by NSTAR Electric (D.P.U. 21-80, Attorney General Brief at 32, citing Exhs. AG-WG-1, at 60; AG 1-14). The Attorney General also argues that NSTAR Electric's business case makes questionable assumptions based on inconsistent numbers of bridge meters identified on its system (263,000 identified for the business case versus only 120,000 otherwise identified in the record) and regarding the company's ability to convert its bridge meters to AMI due to its not having successfully tested the upgrade of the bridge meters' communication software and, thus, likely increasing the company's potential costs (D.P.U. 21-80, Attorney General Brief at 30-31, citing Exhs. ES-AMI-2, at 11; AG 1-13(e); AG 5-7, Att. & Att. (Supp.); AG 8-12; AG 8-13; Attorney General Reply Brief at 11-12).

(B) National Grid

The Attorney General argues that National Grid has overstated its projected benefits for it proposed grid-facing investments, specifically, in relation to projected O&M savings and reliability improvements (D.P.U. 21-81, Attorney General Brief at 19-22). Regarding the projected O&M savings, the Attorney General argues that customers will not receive any of these benefits until the company realizes the savings and those savings are reflected in National Grid's revenue requirement incorporated into base rates in the company's next base distribution rate case (D.P.U. 21-81, Attorney General Brief at 21-22, citing Exh. AG-WG-1, at 42-44).

With regard to projected reliability improvements for its grid-facing investments, the Attorney General contends that National Grid's average frequency interruption performance has not improved between 2013 and 2020 despite significant investment growth, which casts doubt on the company's projected 17.5 percent reduction in outage duration and frequency resulting from its proposed grid modernization investments (D.P.U. 21-81, Attorney General Brief at 19, citing Exhs. AG-WG-1, at 31; AG-WG-Surrebuttal at 8). The Attorney General states that the company was unwilling to commit to achieving its projected benefits, belaying a lack of confidence by the company that such benefits will ultimately be realized (D.P.U. 21-81, Attorney General Brief at 19-20, citing Exh. AG-WG-1, at 31).

Additionally, the Attorney General argues that National Grid's reliability benefits identified for both its grid-facing and customer-facing investments are overstated due to the company's reliance on the Department of Energy's ("DOE's") Interruption Cost Estimator

("ICE") tool (D.P.U. 21-81, Attorney General Brief at 20, 30, citing Exhs. NG-AMI-2, at 35-36; AG-WG-1, at 42; AG-WG-5). The Attorney General asserts that the ICE tool systematically overstates the economic benefits of reducing outages and the societal costs of those outages (D.P.U. 21-81, Attorney General Brief at 20, citing Exh. AG-WG-5, at 2-3). As a result of the ICE tool's limitations, the Attorney General urges the Department to direct National Grid to undertake its own reliability improvement research by conducting "willingness to pay" customer research or through Massachusetts-specific econometric research by specialists in the field (D.P.U. 21-81, Attorney General Brief at 21, citing Exh. AG-WG-Surrebuttal at 10).

(C) Unitil

The Attorney General argues that Unitil has overstated its projected benefits for its proposed grid-facing investments, specifically, in relation to projected reliability improvements (D.P.U. 21-82, Attorney General Brief at 20-22). The Attorney General contends that Unitil's outage duration performance between 2016 through 2020 is already 38 percent better than the U.S. investor-owned utility average over this time period, therefore Unitil may be unable to achieve the company's further projected 17.9 percent reduction in outage duration from its proposed grid modernization investments (D.P.U. 21-82, Attorney General Brief at 20-21, citing Exh. AG-WG-1, at 30).

Additionally, the Attorney General argues that Unitil's reliability benefits for its grid-facing investments are overstated due to the company's reliance on DOE's ICE tool (D.P.U. 21-82, Attorney General Brief at 21). The Attorney General asserts that the

ICE tool systematically overstates the economic benefits of reducing outages and the societal costs of those outages due to how the tool aggregates outage costs incurred by surveyed customers and extrapolates them to all customers in the service territory (D.P.U. 21-82, Attorney General Brief at 21, citing Exhs. AG-WG-1, at 30-31; AG-WG-5, at 2). As a result of the ICE tool's limitations, the Attorney General urges the Department to direct Unitil to undertake its own reliability improvement research by conducting "willingness to pay" customer research or through Massachusetts-specific econometric research by specialists in the field (D.P.U. 21-82, Attorney General Brief at 22, citing Exh. AG-WG-Surrebuttal at 10).

Furthermore, the Attorney General maintains that Unitil failed to submit a business case for its customer-facing investments to justify its proposed spending, other than pointing to its 2015 business case in its initial brief,[42] and that its proposal suffers from several additional deficiencies (D.P.U. 21-82, Attorney General Brief at 2, 22-23, citing Exh. AG-WG-1, at 43-44; D.P.U. 20-69-A at 30-31; Attorney General Reply Brief at 5, citing Unitil Brief at 12, 22; Exh. Unitil-KES-2, at 9-10). First, the Attorney General argues that the company failed to demonstrate that the customer benefits from its proposal to accelerate replacement of TS2 meters would justify the costs (D.P.U. 21-82, Attorney General Brief at 23-28). According to the Attorney General, the cost to customers of

42 The Attorney General observes that the portion of the 2015 business case cited by Unitil concerns benefits associated with AMI/OMS integration, which the Attorney General identifies as a Track 1 investment in this proceeding (D.P.U. 21-82, Attorney General Reply Brief at 5-6, citing Unitil Brief at 12).

replacing all TS2 meters with PLX meters by 2025 would be $16.6 million, as compared to $9.9 million if Unitil replaced its meters at its current business as usual pace (D.P.U. 21-82, Attorney General Brief at 23, citing Exhs. AG-WG-1, at 44-45; AG 4-1, Att. 1, Sch. 1; AG 4-1, Att. 2, Sch. 1). The Attorney General contends that Unitil's argument, that accelerated deployment is prudent because failing TS2 meters will require an expedited replacement with a new PLX meter, is speculative (D.P.U. 21-82, Attorney General Reply Brief at 6, citing Unitil Brief at 11; Exh. DPU 10-1). Further, the Attorney General maintains that Unitil ignores that it already recovers the costs of its existing meter replacements and the costs of the PLX meters it currently installs on a business as usual pace through the capital tracker (D.P.U. 21-82, Attorney General Reply Brief at 6, citing Fitchburg Gas and Electric Light Company, D.P.U. 21-79 (2022); Fitchburg Gas and Electric Light Company, D.P.U. 20-71-A (2021); Fitchburg Gas and Electric Light Company, D.P.U. 19-130 (2020); Fitchburg Gas and Electric Light Company, D.P.U. 15-80/D.P.U. 15-81 (2016)). Thus, according to the Attorney General, there is no need to allow those costs to flow through the company's existing GMF (D.P.U. 21-82, Attorney General Reply Brief at 7).

Additionally, the Attorney General contends that the existing TS2 meters can implement simple, two-part TVR to calculate peak time rebates ("PTRs"), thus making the anticipated benefits slim relative to the estimated costs (D.P.U. 21-82, Attorney General Brief at 24-25 & n.15, citing Exhs. AG-WG-1, at 45-47; AG-WG-Surrebuttal at 17; AG 1-3; AG 3-4; Fitchburg Gas and Electric Light Company, D.P.U. 07-71, at 11, 38, 44 (2008)).

The Attorney General critiques Unitil's use of a study performed in 2012 to support its proposal, arguing that the company's reliance on the study exaggerates projected benefits because the study measured consumption reduction for a limited time, relied only on customers with central air conditioning, and included customers' use of programmable thermostats and in-home energy displays even though the company does not propose to employ either technology as part of its plan (D.P.U. 21-82, Attorney General Brief at 25-27, citing Exhs. AG 1-1 & Att. 1; AG-WG-1, at 48-52). The Attorney General contends that, like NSTAR Electric and National Grid, Unitil also fails to address how the stranded costs of prematurely replacing its existing meters, estimated at $6.4 million, will impact its proposal (D.P.U. 21-82, Attorney General Brief at 27, citing Exhs. AG-WG-1, at 52; AG 1-2; D.P.U. 12-76-C at 27-28).

Second, the Attorney General argues that the proposed data sharing platform and certain components of Unitil's proposed customer engagement and experience project spending (i.e., a mobile app, customer self-service, online chat with customer care, and customer alerts) are business as usual investments that are unrelated to PLX meter interval data capabilities (D.P.U. 21-82, Attorney General Brief at 23, 28-29, citing Exhs. Unitil-GMP at 89-91; Unitil-KES-2, at 13; AG-WG-1, at 54; AG-WG-Surrebuttal at 20; AG 6-7). The Attorney General asserts that these are routine service enhancements and represent standard practice necessary to support current day service obligations and system requirements (D.P.U. 21-82, Attorney General Brief at 28, citing Exhs. Unitil-GMP at 89-91; AG-WG-1, at 54; AG-WG-Surrebuttal at 20). The Attorney General also asserts that the value of these investments is directly related to the number of customers that will use them, but that the company failed to provide any customer usage projections or develop a customer engagement or education plan regarding these offerings (D.P.U. 21-82, Attorney General Brief at 29, citing Exhs. Unitil-GMP at 91; CLF 1-2).

Finally, the Attorney General argues that the benefits identified from the proposed AI/personalized selling and behind the meter work-order job scheduling components of Unitil's proposed customer engagement and experience project spending are unlikely to justify their $358,000 in estimated costs (D.P.U. 21-82, Attorney General Brief at 23, 30-31 & n.23, citing Exhs. Unitil-GMP at 91; AG-WG-Surrebuttal at 19; AG 4-9). The Attorney General maintains that, given Unitil's relatively small customer count, too few customers will utilize these features (D.P.U. 21-82, Attorney General Brief at 30, citing Exh. AG-WG-Surrebuttal at 19; Tr. 5, at 951). The Attorney General contends that the AI functions appear to provide services that could be provided by third parties through competitive markets, and, because customers can easily communicate with "external behind the meter partners" on their own, the value of adding Unitil as an intermediary in the work-order job scheduling capability is questionable (D.P.U. 21-82, Attorney General Brief at 30, citing Exhs. AG-WG-1, at 55-56; AG-WG-Surrebuttal at 19).

iii. Proposed AMIF Tariffs

The Attorney General argues that, to the extent the Department approves NSTAR Electric's and National Grid's AMI-related cost recovery proposals, the proposed tariff is flawed in several ways and should be modified to account for the following: (1) the AMI revenue requirement identified in Section 2.7 does not recognize or net out recovery of the meter system cost recovery that already exists in base rates and provides double recovery of the cost of plant placed in-service during the investment year; (2) the eligible investment identified in Section 2.10 should recognize and adjust for the meter investment, whether in-service or in the warehouse inventory, of newer AMR or bridge meters that can be repurposed for those customers who opt-out of AMI; (3) reductions in O&M expenses related to embedded meter investment or otherwise created by the investments; (4) the recoverable O&M expense identified in Section 2.16 should reflect only the appropriate and reasonable allocated share of service company costs and not any "charged" amount; (5) the property tax rate definition in Section 2.14 should reflect the total utility property tax paid for the year as a percentage of the total utility property valuation for that same tax year and not the net plant; (6) there is no indication that the tariffed charge provides for a fully reconciling charge; (7) there is no definition of "incremental" as it is used in Sections 1.0 and 2.16; (8) there is no provision for reconciliation or incorporation of the costs recovered through the charge with those recovered through base rates; and (9) there is no provision for termination of the tariff (D.P.U. 21-80, Attorney General Brief at 25-26, citing Exh. AG-TN-1, at 14-15; D.P.U. 21-81, Attorney General Brief at 25-26, citing (same)).

b. DOER

DOER urges the Department to approve the Companies' 2022-2025 Grid Modernization Plan and AMI proposals and model tariff because implementation of these investments will make measurable progress toward achieving the Department's grid modernization objectives, which are essential for the Commonwealth to achieve its clean energy and climate goals for 2030 and its net-zero emission goal in 2050 (DOER Brief[43] at 8, 9, citing Executive Office of Energy and Environmental Affairs ("EEA"), Interim 2030 Clean Energy and Climate Plan at 23 ("Interim 2030 CECP")).[44] DOER asserts that DERMS and AMI will allow the Companies to optimize system performance and integrate DERs, enabling the grid to be managed with more granularity in time and location while cost-effectively transitioning the economy to a decarbonized future (DOER Brief at 8, 9). DOER also contends that AMI technologies such as meters, communications, and data analytics have evolved substantially since the Department last reviewed AMI proposals, and will allow new tools such as TVR to manage load and DI to monitor and control large quantities of DERs to reduce distribution outages and costs (DOER Brief at 8-9).

DOER observes that electrification and DER proliferation change the nature of electricity consumption, and that the use of new grid modernization investments like DERMS and AMI is necessary to successfully integrate large quantities of DERs like rooftop solar (DOER Brief at 8). DOER points to the Interim 2030 CECP at 23-24, as outlining the importance and benefits of accelerated growth of DERs and the electrification of

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43 Because DOER submitted a single brief for all three dockets, the Department does not cite to the individual dockets for DOER's brief.

44 After briefs were submitted in these proceedings, EEA released its Massachusetts Clean Energy and Climate Plan for 2025 and 2030 (June 30, 2022), available at https://www.mass.gov/doc/clean-energy-and-climate-plan-for-2025-and-2030/download (last viewed November 30, 2022).

transportation and heating sectors as central to the Commonwealth's climate strategy and as identifying load management strategies such as managed charging for EVs and demand response as key to lower and shift load to less costly and lower-emitting times of day (DOER Brief at 8, 9). DOER submits that using grid modernization investments, inclusive of AMI, to enable emissions-reduction strategies and achieve climate goals is also consistent with the Department's legislative mandate to consider greenhouse gas ("GHG") emission reductions (DOER Brief at 11, citing G.L. c. 25, § 1A). Thus, according to DOER, a full-scale rollout of AMI should not be delayed (DOER Brief at 13). Moreover, DOER agrees that, as electrification increases and DERs are deployed, without these grid modernization plan and AMI investments, customers risk exposure to higher bill impacts due to cost-inefficient replacements of meter and communications systems and worsened reliability (DOER Brief at 11, citing D.P.U. 21-80, Exh. ES-AMI-1, at 9-19 through 10-2; D.P.U. 21-81, Exhs. NG-GMP-2, at 6; NG-AMI-3, at 63).

DOER submits that NSTAR Electric and National Grid have demonstrated that the investments in AMI have net benefits for ratepayers and are cost-effective (DOER Brief at 10, citing D.P.U. 21-80, Exh. ES-AMI-4, at 7; D.P.U. 21-81, Exh. NG-AMI-1, at 26-27). According to DOER, AMI benefits include TVR, reduced costs related to AMR meters, bad debt reductions, VVO savings, and operational benefits that help utilities to better manage the distribution system (DOER Brief at 10). Additionally, DOER argues that grid modernization and AMI investments will help manage costs and bill impacts through customers' ability to gain control over their energy bills, and that strategic investments will limit risks associated with power quality events, reliability degradation, and higher costs from increased peak demand (DOER Brief at 10, citing D.P.U. 21-80, Exh. ES-AMI-1, at 9-10; EEA, Energy Pathways to Deep Decarbonization: A Technical Report of the 2050 Decarbonization Roadmap Study at 71 (December 2020) ("2050 Decarbonization Roadmap")). DOER notes that additional cost savings for the proposed investments could be achieved through efficiencies created by NSTAR Electric and National Grid implementing AMI with their out-of-state affiliates (DOER Brief at 10-11, citing D.P.U. 21-80, Exh. ES-AMI-1, at 17; D.P.U. 21-81, Exh. NG-AMI-2, at 56). Additionally, DOER points to the Department's findings that full-scale deployment of AMI is likely to be more cost-effective than a limited AMI deployment (DOER Brief at 13, citing D.P.U. 20-69-A at 52).

Regarding the Attorney General's concerns that the proposed cost recovery framework could result in stranded costs, DOER points out that not all AMR meters require replacement immediately and that those that do should be replaced with an AMI meter (DOER Brief at 12, citing D.P.U. 21-80, Exh. AG-TN-1, at 6-7). In addition, DOER contends that the Companies' planned AMI investments reduce the risk of early retirement of a substantial number of AMR meters thereby preventing some stranded costs and that any remaining risk of early meter retirements is outweighed by the risk of high costs to meet clean energy goals if AMI is not deployed at this time (DOER Brief at 12-13, citing D.P.U. 21-80, Exh. AG 1-8). According to DOER, if the AMI cost recovery framework is rejected, additional time would be required for the Companies to develop a new plan, thereby increasing the risk of stranded costs because the Companies would need to replace meters that reach the end of their useful life with outdated AMR technology (DOER Brief at 13, citing D.P.U. 21-81, Exh. AG 5-9). Therefore, DOER submits that the Department should approve the Companies' cost recovery proposals to minimize costs for ratepayers and ensure the benefits of clean energy goals and grid modernization objectives continue to progress (DOER Brief at 13-14).

Finally, DOER recommends that the Department require the Companies to consult with DOER during the development of deployment strategies to ensure that the Companies are aligning AMI benefits with the Commonwealth's clean energy policies (DOER Brief at 14-15). DOER contends that achieving policy goals effectively through better grid planning and system operation will reduce the impact of the clean energy transition on customers (DOER Brief at 15).

c. Acadia Center

Acadia Center argues that the Department should provide preliminary approval to NSTAR Electric and National Grid's 2022-2025 Grid Modernization Plan and AMI Implementation Plan and deployment timelines, with certain modifications, and asserts that these plans comply with D.P.U. 20-69-A, the Grid Modernization Order, D.P.U. 12-76-C, and D.P.U. 12-76-B (D.P.U. 21-80, Acadia Center Brief at 3-4, 9; D.P.U. 21-81, Acadia Center Brief at 1-2, 9-10). In particular, Acadia Center contends that the plans must: (1) prioritize environmental justice; (2) propose specific AMI deployment performance metrics; (3) prioritize data access for customers and third-party vendors; and

(4) expedite TVR implementation timelines (D.P.U. 21-80, Acadia Center Brief at 10-17; D.P.U. 21-81, Acadia Center Brief at 8-14).

Acadia Center argues that efforts to modernize the electric grid should prioritize benefits for residents of environmental justice communities ("EJ communities"), but NSTAR Electric's and National Grid's plans make no mention of these communities (D.P.U. 21-80, Acadia Center Brief at 10; D.P.U. 21-81, Acadia Center Brief at 9). Acadia Center states that a resilient grid can benefit the most underserved communities in many ways, including by protection during extreme weather events and, thus, the development of a modern grid requires focused attention on environmental justice (D.P.U. 21-80, Acadia Center Brief at 12; D.P.U. 21-81, Acadia Center Brief at 10). Acadia Center observes that the Department is required to consider equity and GHG emissions reduction goals with respect to itself and the entities it regulates, and avers that the Department required each company to demonstrate how their proposed grid modernization investments would benefit low-income customers and EJ communities (D.P.U. 21-80, Acadia Center Brief at 9, 11, citing G.L. c. 25, § 1A; D.P.U. 20-69-A at 28; D.P.U. 21-81, Acadia Center Brief at 8, citing G.L. c. 25, § 1A; D.P.U. 20-69-A at 28). As a result, Acadia Center contends that the Department should require each company to revise its plan to more specifically target EJ communities (D.P.U. 21-80, Acadia Center Brief at 12; D.P.U. 21-81, Acadia Center Brief at 10).[45]

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45 The Department addresses Acadia Center's remaining arguments in Section V.

d. CLC

CLC generally supports AMI deployment to all NSTAR Electric customers in order for Massachusetts to meet its climate goals but recommends the Department condition approval on NSTAR Electric facilitating TVR for municipal aggregation and providing meaningful data access and billing (D.P.U. 21-80, CLC Brief at 2-3, 19). In particular, CLC asserts that NSTAR Electric should be required to demonstrate how its AMI Implementation Plan would achieve municipal aggregation TVR as part of its cost-benefit analysis (D.P.U. 21-80, CLC Brief at 10, citing Grid Modernization Order at 124, 133). CLC asserts, in its 2022-2025 Grid Modernization Plan and AMI Implementation Plan, NSTAR Electric did not engage with municipal aggregators or other stakeholders in terms of how AMI and new foundational investments would enable municipal aggregators and other stakeholders to receive the data access and billing needed for TVR (D.P.U. 21-80, CLC Brief at 2). CLC contends that, as a growing number of NSTAR Electric's customers are on municipal aggregation supply, municipal aggregators are uniquely positioned to maximize AMI customer benefits associated with TVR while also addressing local energy policies and objectives (D.P.U. 21-80, CLC Brief at 2-3, 12, citing Exhs. GECA-Surrebuttal-KS-1, at 14; DOER-GECA 1-2, at 2; Tr. 5, at 867; Grid Modernization Order at 124).

e. CLF

CLF urges the Department to conditionally approve the Companies' grid modernization proposals, because they make measurable progress toward achieving the Department's grid modernization objectives and are necessary for the Commonwealth to achieve its clean energy and climate goals and various related statutory mandates (D.P.U. 21-80, CLF Brief at 10-15; D.P.U. 21-81, CLF Brief at 10-16; D.P.U. 21-82, CLF Brief at 10-15). CLF also points to the Department's statements that the Commonwealth must adjust to changes in the electricity industry by facilitating the interconnection of DERs and enable electric distribution companies to maximize the use of technologies that make further progress in meeting service goals to best serve their customers and respond to climate change (D.P.U. 21-80, CLF Brief at 12-13, citing Grid Modernization Order at 8, 100; D.P.U. 12-76-B at 10; D.P.U. 21-81, CLF Brief at 12-13, citing Grid Modernization Order at 8, 100; D.P.U. 12-76-B at 10; D.P.U. 21-82, CLF Brief at 12, citing Grid Modernization Order at 8, 100; D.P.U. 12-76-B at 10). CLF maintains it otherwise supports approval of the Companies' filings and immediate deployment of AMI (D.P.U. 21-80, CLF Brief at 12; D.P.U. 21-81, CLF Brief at 12; D.P.U. 21-82, CLF Brief at 12).

CLF asserts that the Department should condition approval on: (1) a more expedited deployment timeline, specifically, to ensure customer benefits from AMI are realized by the third year of AMI deployment or sooner; (2) more education efforts towards customers and EJ communities; and (3) providing further explanation for proposed opt-out fees (D.P.U. 21-80, CLF Brief at 10, 21; D.P.U. 21-81, CLF Brief at 10-11, 22; D.P.U. 21-82, CLF Brief at 10, 19, 20).[46] CLF maintains that, if customers are educated about the benefits of AMI, they will be more likely to take advantage of the program (D.P.U. 21-80,

46 The Department addresses CLF's opt-out arguments in Section IV.

CLF Brief at 20; D.P.U. 21-81, CLF Brief at 20; D.P.U. 21-82, CLF Brief at 20). CLF urges the Department to require the Companies to identify underserved communities to ensure that environmental justice individuals benefit from AMI and to file annual reports that demonstrate how AMI is maximizing customer benefits (D.P.U. 21-80, CLF Brief at 19; D.P.U. 21-81, CLF Brief at 18, 19; D.P.U. 21-82, CLF Brief at 19). CLF also urges the Department to require the Companies to conduct consumer education on TVR before and after AMI deployment, deliver load disaggregation to all customers, and make AMI data available on a customer opt-out basis (D.P.U. 21-80, CLF Brief at 20; D.P.U. 21-81, CLF Brief at 20; D.P.U. 21-82, CLF Brief at 20).

Additionally, CLF contends that the vendor selection process is essential to assess the types of services provided by the utility and to measure AMI investment success (D.P.U. 21-80, CLF Brief at 25, citing Exh. CLF-CV at 16; D.P.U. 21-81, CLF Brief at 25-26, citing Exh. CLF-CV at 16). As a result, CLF urges the Department to review the results of NSTAR Electric's and National Grid's RFPs to ensure that they address the needs of the system and Massachusetts policies, and to assess whether the RFPs are constrained in terms of capabilities, whether any RFP responses provided alternatives, and the extent RFP responses leveraged other vendors and promoted interoperability (D.P.U. 21-80, CLF Brief at 25, citing Exh. CLF-CV at 16; D.P.U. 21-81, CLF Brief at 25-26, citing Exh. CLF-CV at 16).

Finally, CLF argues that Unitil should consider the benefits of utilizing a HAN to enable AMI information directly to other devices in real-time in order to fully realize the benefits of a modernized grid (D.P.U. 21-82, CLF Brief at 23-24).

f. GECA

GECA asserts that the lack of a modern electric grid in the Commonwealth presents serious obstacles to meeting the Commonwealth's objectives for a cleaner, more efficient electric grid, noting that ISO New England Inc. ("ISO-NE") recently informed FERC that the lack of AMI in New England hinders mass market residential and small commercial DERs from participating in wholesale markets (D.P.U. 21-80/D.P.U. 21-81, GECA Brief at 12-13, citing Exh. GECA-Surrebuttal-KS-1, at 13-14). GECA asserts that the lack of AMI meters and clear price signals showing the true costs of peak power usage are contributing to excessive electric bills and adverse environmental impacts that are particularly harmful to EJ communities (D.P.U. 21-80/D.P.U. 21-81, GECA Brief at 14). As such, GECA urges swift Department approval of NSTAR Electric's and National Grid's AMI proposals, stating that the Department should condition its approval of the proposals on an expeditious resolution of issues related to TVR, access to customer usage data, customer education, and municipal aggregation (D.P.U. 21-80/D.P.U. 21-81, GECA Brief at 1-2, 12-13, 26-27).[47] GECA states that the Department should address uncertainties in these proceedings related to

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[47] GECA adds that the Department should require the Companies to delivering "best available cost-effective" load disaggregation technology to all customers (including residential customers) immediately upon AMI rollout (GECA Brief at 2).

AMI costs and benefits as it has done previously with respect to grid modernization, recognizing that the consequences of inaction or delay is not consistent with the Department's statutory environmental mandate (D.P.U. 21-80/D.P.U. 21-81, GECA Brief at 10).

GECA asserts that the absence of TVR results in most of the Commonwealth's electricity consumers subsidizing on-peak usage, resulting in these ratepayers (notably including low- to middle-income consumers) incurring higher bills than they would with TVR (D.P.U. 21-80/D.P.U. 21-81, GECA Brief at 17, citing Exh. GECA-Surrebuttal-KS-4, at 6). As such, GECA asserts that the swift deployment of AMI and TVR are critical to protecting the Commonwealth's ratepayers against unjust and unreasonable rates (D.P.U. 21-80/D.P.U. 21-81, GECA Brief at 18). GECA adds that peak power usage is costly not only in economic terms, but also in terms of air pollution and GHG emissions, asserting that ongoing use of peaker plants directly thwarts the Commonwealth's environmental justice objectives (D.P.U. 21-80/D.P.U. 21-81, GECA Brief at 18).

g. NRG

NRG contends that the records in D.P.U. 21-80 and D.P.U. 21-81 fully support an Order requiring NSTAR Electric and National Grid to expeditiously deploy AMI technology so that Massachusetts basic service, competitive supplier, and municipal aggregation customers can access TVR and other customer data-driven products enabled by AMI (D.P.U. 21-80, NRG Brief at 2; D.P.U. 21-81, NRG Brief at 2). NRG concedes that NSTAR Electric and National Grid have each provided clear plans and timetables for building out essential back-office systems, deploying meters, and recovering expenses through rates (D.P.U. 21-80, NRG Brief at 10; D.P.U. 21-81, NRG Brief at 11). NRG recommends, however, that preauthorization and approval of cost recovery for NSTAR Electric's and National Grid's AMI Implementation Plans be contingent on each company collaborating with stakeholders to create a uniform data access protocol for submission and approval by the Department (D.P.U. 21-80, NRG Brief at 12; D.P.U. 21-81, NRG Brief at 15). For NSTAR Electric, NRG asserts that this collaboration should occur before the new CIS is in place to avoid the risk of developing a CIS that does not sufficiently facilitate or allow for data access by other market participants (D.P.U. 21-80, NRG Brief at 3, 9, citing Tr. 5, at 965-966). NRG states that the environmental, cost, and efficiency benefits of AMI flow directly from the ability of customers, including municipal aggregation customers and competitive supply customers, to access TVR and other value-added services, but that TVR and other programs will not be available to customers without access to the granular usage data available through AMI (D.P.U. 21-80, NRG Brief at 10; D.P.U. 21-81, NRG Brief at 10). NRG argues that approval of NSTAR Electric's and National Grid's AMI Implementation Plans without its recommended requirements will not provide meaningful benefits to ratepayers in a timely manner (D.P.U. 21-80, NRG Brief at 8; D.P.U. 21-81, NRG Brief at 8).

h. TEC

TEC urges that Department approval of the AMI Implementation Plans should enumerate principles regarding the use of AMI for integration with wholesale power markets (D.P.U. 21-80, TEC Brief at 3; D.P.U. 21-81, TEC Brief at 1). Further, TEC contends that approval of the AMI Implementation Plans should include a requirement to develop a roadmap for AMI integration with ISO-NE to enable more accurate pricing of wholesale energy by TVR and provide retail energy suppliers with greater flexibility to reflect the actual costs of serving customer load (D.P.U. 21-80, TEC Brief at 4; D.P.U. 21-81, TEC Brief at 2).[48]

i. Utilidata

Utilidata urges the Department to require NSTAR Electric to conduct a competitive solicitation for a DI platform, separate from and prior to solicitation for AMI meters (Utilidata Brief at 3, 11).[49] Utilidata also argues that a separate procurement will not produce an added administrative burden to the Department (Utilidata Brief at 10). Further, Utilidata recommends several DI-specific questions for use in the separate procurement process and maintains that a separate solicitation process will reduce costs and permit companies to still meet deployment deadlines (Utilidata Brief at 5, 6-9).

According to Utilidata, greater competition will result from separate procurements, because conducting a separate RFP for DI will permit companies not involved in metering, but known for their DI and software expertise, to participate (Utilidata Brief at 5, citing

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48 On brief, TEC also commented on NSTAR Electric's power quality monitoring investments and National Grid's advanced distribution automation and fault location, isolation, and service restoration investments (see D.P.U. 21-80, TEC Brief at 2-3; D.P.U. 21-81, TEC Brief at 3-4). The Department preauthorized these investments in Track 1 Order at 73, 77. 89-90.

49 Because Utilidata submitted a single brief for all three dockets, the Department does not cite to the individual dockets for Utilidata's brief.

Exh. U-MH/JM at 25-26). Utilidata maintains that under a bundled solicitation for meters and a DI platform, the costs and benefits of a DI platform are unclear (Utilidata Brief at 6). Utilidata contends that the benefits of a DI platform include integration of DERs into electric distribution companies' planning and operations processes, and grid visibility and control (Utilidata Brief at 6).

Finally, Utilidata asserts that separate procurements will increase the chance that Massachusetts will secure federal funding (Utilidata Brief at 9). Utilidata explains that DI meets the definition of advanced grid technology to enhance grid flexibility under the Infrastructure Investment and Jobs Act of 2021, Pub. L. 117-58 ("IIJA"), whereas AMI meters do not (Utilidata Brief at 9). Additionally, Utilidata contends that DOE will be reluctant to fund metering upgrades because it is perceived that previous investments fell short of delivering the projected benefits (Utilidata Brief at 10).

2. Companies

a. NSTAR Electric

NSTAR Electric states that it is proposing both "new" grid-facing and AMI investments for inclusion in its 2022-2025 Grid Modernization Plan, adjudicated as part of Track 2 of these proceedings, and for which it is seeking preauthorization to proceed with these investments (D.P.U. 21-80, NSTAR Electric Brief at 4, 17, 34, citing D.P.U. 20-69-A at 30; D.P.U. 15-122, at 110). The company contends that the record evidence demonstrates that NSTAR Electric has met its burden regarding the suitability of its grid-facing investments for preauthorization, and that the company's AMI Implementation Plan and proposed cost recovery mechanism for AMI investments are reasonable and should be approved (D.P.U. 21-80, NSTAR Electric Brief at 68, 88-119).

NSTAR Electric maintains that these new investments build upon its modernization efforts pursued to date and create pathways to grid optimization (D.P.U. 21-80, NSTAR Electric Brief at 17, citing Exh. ES-JAS-2, at 47). NSTAR Electric also maintains that, utilizing lessons learned from its first grid modernization plan, the company prioritizes in its 2022-2025 Grid Modernization Plan customer benefits and employs technologies that assist Massachusetts' aggressive clean energy initiatives and policy objectives (D.P.U. 21-80, NSTAR Electric Brief at 4, 34-35). According to NSTAR Electric, the company's dedication to designing its plan with these considerations in mind is apparent based on the support expressed in the briefs by DOER, TEC, CLC, and CLF (D.P.U. 21-80, NSTAR Electric Brief at 4).

With regard to costs, NSTAR Electric specifies that it has included cost estimates for the new investment categories for grid-facing and AMI investments, but that these estimates continue to undergo investigation and refinement as the company continues to gather information through RFIs and RFPs (D.P.U. 21-80, NSTAR Electric Brief at 57, 58-59, citing Exhs. AC 1-21; AC 1-27). The company explains that it does not intend to actively solicit bids for the 2022-2025 Grid Modernization Plan until a Department order has been issued and the company can ensure that bids are tailored to address any directives issued by the Department (D.P.U. 21-80, NSTAR Electric Brief at 57, citing Exhs. ES-AMI-1, at 31; DPU 5-7). The company states, however, that as a standard of doing business, it competitively procures materials, equipment, and external services for all projects and will present full documentation for Department and stakeholder review in a future GMF or AMIF cost recovery proceeding (D.P.U. 21-80, NSTAR Electric Brief at 57, citing Exhs. ES-AMI-1, at 31; DPU 5-7; DPU 12-3; DOER 2-2). NSTAR Electric reiterates that it is requesting approval by the Department to move ahead with the proposed investments subject to a prudence review and, were the Department to deny the company's proposed cost recovery mechanism, the deployment of AMI would decelerate and compete with other capital investments undertaken by the company (D.P.U. 21-80, NSTAR Electric Brief at 58, 100, citing Exh. DPU 15-4; Tr. 4, at 607-608, 623-630, 657-658; NSTAR Electric Reply Brief at 18).

NSTAR Electric asserts that the Attorney General's calculations used to recommend rejection of the company's AMI cost recovery proposal based on the level of projected annual AMI spending in relation to the company's total annual capital investments, are inaccurate and misleading (D.P.U. 21-80, NSTAR Electric Brief at 99, citing Attorney General Brief at 24). Specifically, NSTAR Electric contends that the Attorney General failed to include all AMI implementation costs in its calculations, including the estimated $172 million in CIS/MDMS costs and the $42 million for the customer portal, and erroneously included transmission-related capital additions, which average $292 million annually, in the $700 million annual capital investments identified (D.P.U. 21-80, NSTAR Electric Brief at 99, citing Attorney General Brief at 24; Exhs. ES-AMI-2, Appx. A; ES-Rebuttal at 22-23). According to the company, once the correct calculations are applied, it is clear that the average $103 million anticipated annual AMI costs are significant, thus supporting NSTAR Electric's cost recovery mechanism proposal (D.P.U. 21-80, NSTAR Electric Brief at 99).

NSTAR Electric argues that it provides quantification and detail regarding the magnitude of customer benefits expected from the new investments, including AMI (D.P.U. 21-80, NSTAR Electric Brief at 41). The company states that it applied the business case to the proposed investments based on a framework that reflects the need to assess a diverse mix of benefits utilizing a relative assessment of the degree to which each investment achieves the grid modernization objectives (D.P.U. 21-80, NSTAR Electric Brief at 41, citing Exh. DPU 14-11). NSTAR Electric explains that this assessment relies on a five-step process: (1) detailing the Department's grid modernization objectives in ten benefit categories; (2) generation of a list of grid modernization programs by a multi-disciplinary team; (3) assessment of each program or initiative on the degree to which each is expected to achieve each of the ten benefit categories; (4) use of an iterative process to adjust investment levels to ensure a balanced portfolio that provides a diversity of benefits that maximizes benefit to cost across all three of Department's grid modernization objectives; and (5) review of the suite of existing performance metrics and proposed additional metrics to ensure that the investment will ensure progress towards these objectives is measurable (D.P.U. 21-80, NSTAR Electric Brief at 41, citing Exh. DPU 14-11).

In response to the Attorney General's statement that the company's 2022-2025 Grid Modernization Plan investments likely have lower net benefits than reported and that the associated costs are understated, NSTAR Electric counters that the company developed its business case consistent with the Department's directives in D.P.U. 12-76-C at 13 and 18, to use (1) a single dollar value for the present value of each monetized cost and benefit included in the business case, and (2) the company-specific WACC (D.P.U. 21-80, NSTAR Electric Brief at 78, citing Attorney General Brief at 11 n.11). NSTAR Electric explains that its business case is based on an NPV comparison of costs and benefits using a discount rate commensurate with the company's cost of capital and, contrary to the Attorney General's contentions, it would have been inappropriate to both include carrying charges and apply a discount rate intended to reflect the time-value of money implied by the same carrying charges (D.P.U. 21-80, NSTAR Electric Brief at 78, citing Exhs. ES-Rebuttal at 48-51; AG 1-24). The company observes that the Attorney General participated in the working group to develop the business case and, at the time, supported the use of the WACC and the NPV of costs and benefits associated with grid modernization investments (D.P.U. 21-80, NSTAR Electric Brief at 78, citing D.P.U. 12-76, Attorney General Joint Comments at 13-16 (August 22, 2014)).

According to NSTAR Electric, the results of the business case provides justification for the proposed costs of the 2022-2025 Grid Modernization Plan portfolio by achieving the following ten benefits: (1) improvement of hosting capacity; (2) increased net benefits to DER; (3) reduction of demand and energy; (4) increased reliability; (5) improved power quality; (6) enabling dynamic grid objectives; (7) improved planning analysis; (8) increased operational efficiency; (9) advancing other objectives, such as enhanced safety management tools, retirement of aging infrastructure, and increased customer satisfaction; and (10) supporting new technology learning (D.P.U. 21-80, NSTAR Electric Brief at 41, citing Exh. DPU 14-11, at 3-5). NSTAR Electric contends that the new proposed technologies, including AMI, will achieve these benefits (D.P.U. 21-80, NSTAR Electric Brief at 42-54). Additionally, NSTAR Electric disputes the Attorney General's assertion that the company did not identify specific customer benefits in its business case for the proposed grid-facing investments, pointing to record evidence for these specific benefits (D.P.U. 21-80, NSTAR Electric Brief at 79, citing Attorney General Brief at 20; Exhs. DPU 1-1; DPU 5-1; DPU 5-2; DPU 14-6; DPU 14-11; AC 1-3; AG 4-11; RR-DPU-14). NSTAR Electric also contends that the Attorney General, through her recommendations, contorts the Department's preauthorization and prudence standards to require a guarantee that the estimated benefits in the business case accrue to customers in exactly the form and magnitude as initially estimated (D.P.U. 21-80, NSTAR Electric Brief at 74, 76).

NSTAR Electric argues that the practical effect of the Attorney General's recommendations to require a guarantee of benefits of the same type and magnitude as originally estimated in the business case without regard to intervening circumstances or factors outside of the company's control in order to recover the costs of those investments, would be a significant truncation of current and future grid modernization plans (D.P.U. 21-80, NSTAR Electric Brief at 76). NSTAR Electric contends that a variety of factors impact the company's ability to implement its grid modernization plan, including weather, customer behavior, the COVID-19 pandemic, changes to the distribution system and load forecasts, increases in labor and equipment costs, supply chain delays, and changes in available technology (D.P.U. 21-80, NSTAR Electric Brief at 76, citing NSTAR Electric Company, D.P.U. 22-40, Grid Modernization Term Report at 11-19; 2020 Grid Modernization Annual Reports, D.P.U. 21-30, NSTAR Electric Company's Martha's Vineyard Battery Storage Project Update (May 17, 2021); D.P.U. 21-80, NSTAR Electric Reply Brief at 9). NSTAR Electric states that, although it makes every effort to mitigate these impacts, complete mitigation or elimination of these risks to deployment is impossible and, under the Attorney General's proposed framework, the company would be penalized for failing to deliver the estimated benefits in the business case due to circumstances outside of its control (D.P.U. 21-80, NSTAR Electric Brief at 76-77, citing D.P.U. 22-40, Grid Modernization Term Report; D.P.U. 21-80, NSTAR Electric Reply Brief at 9). Further, NSTAR Electric characterizes as punitive and inappropriate the Attorney General's recommendation for the Department to reduce the company's AMI cost recovery revenue requirements by the amount of projected savings and revenue assurance benefits identified by year in the business case until the benefits are able to be fully captured in a future rate case (D.P.U. 21-80, NSTAR Electric Brief at 76, 104, 110-111, citing Attorney General Brief at 28-29; D.P.U. 21-80, NSTAR Electric Reply Brief at 10).

In response to the Attorney General's arguments regarding deficiencies with the company's business case and her recommendation for the Department to defer allowed recovery on the investments until the company achieves the targeted level of benefits, NSTAR Electric counters that the Department has not required that the company guarantee that the benefits estimated in the business case materialize exactly as estimated, instead recognizing that cost and benefit estimates may need to be revised and refined during the development and implementation of a company's grid modernization plan and, further, that there are often significant unquantified benefits associated with investments (D.P.U. 21-80, NSTAR Electric Brief at 67, 71, 74, citing D.P.U. 21-80, Attorney General Brief at 9-11; D.P.U. 15-122, at 107, 169; D.P.U. 12-76-C at 13). NSTAR Electric points out that the Department also directed the company to: (1) provide its best estimate of costs and benefits, including attempting to monetize all costs and benefits to the extent possible; and (2) to the extent that costs and benefits cannot be monetized, attempt to quantify them to the extent possible (D.P.U. 21-80, NSTAR Electric Brief at 67, citing D.P.U. 12-76-C at 13). NSTAR Electric states that the Department recognized that the deployment of individual grid-facing technologies may not result in a positive business case or make measurable progress towards the grid modernization objectives and, therefore, a coordinated deployment of the suite of grid-facing technologies is essential (D.P.U. 21-80, NSTAR Electric Brief at 67-68, citing D.P.U. 15-122, at 172; D.P.U. 12-76-C at 6-7). Moreover, the company states that a majority of the benefits in the business case do not produce outcomes that lend themselves to consistent quantification or monetization in a way that supports an accurate reflection of the magnitude of benefits for the associated costs (D.P.U. 21-80, NSTAR Electric Brief at 68, citing Exhs. DPU 1-1; AG 4-11). The company also specifies that the return on investment is an indispensable cost element associated with undertaking grid modernization and AMI investments, and the Department has long held that a utility is entitled to the opportunity to earn a reasonable rate of return on rate base, which represents the return that the utility's shareholders could earn in relation to other companies that are similarly situated and face similar levels of risk (D.P.U. 21-80, NSTAR Electric Reply Brief at 7-8, citing Incentive Regulation, D.P.U. 94-158, at 4 (1995)).

NSTAR Electric asserts that the Attorney General's recommendations effectively seek to discard the Department's prudency standard for capital additions and replace it with a variation of the total resource cost test employed for energy efficiency programs in Massachusetts (D.P.U. 21-80, NSTAR Electric Brief at 74). The company contends that this attempt to reframe cost recovery for grid modernization plan investments is inappropriate for several reasons (D.P.U. 21-80, NSTAR Electric Brief at 74). Specifically, the company asserts that the grid modernization stakeholder working group established by the Department in D.P.U. 12-76 rejected a strict application of the total resource cost test (D.P.U. 21-80, NSTAR Electric Brief at 74, citing D.P.U. 12-76, Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department from the Steering Committee at 88 (July 2, 2013) ("Working Group Report")). According to NSTAR Electric, the working group recommended a business case for grid modernization investments that was tailored to the unique aspects of these investments, including the high degree of expected interactions between utility investments and private investments, the complexity of quantifying some of the benefits that may be provided, and particular uncertainties associated with the investments, thus allowing more nuanced consideration of the uncertainties of the benefits and costs (D.P.U. 21-80, NSTAR Electric Brief at 74-75, citing D.P.U. 12-76, Working Group Report at 88). The company states that the Department accepted this recommendation, with modification (D.P.U. 21-80, NSTAR Electric Brief at 75, citing D.P.U. 12-76-C at 8; D.P.U. 12-76-B at 17-18). The company also states that the Attorney General's recommendations misapply the total resource cost test in terms of timing (D.P.U. 21-80, NSTAR Electric Brief at 75). The company explains that the Department utilizes the total resource cost test prospectively for total resource cost for energy efficiency determinations, whereas the Attorney General seeks to apply the test after NSTAR Electric has expended funds on the investments and, if the investments did not deliver benefits as identified exactly in the business case, to permit denial of accelerated cost recovery through the rate factor (D.P.U. 21-80, NSTAR Electric Brief at 75-76, citing Three-Year Energy Efficiency Plans, D.P.U. 21-120 through D.P.U. 21-129, at 165-166 (January 31, 2022)).

Similarly, NSTAR Electric disputes the Attorney General's arguments that AMI as reflected in the business case results in negative net benefits and emphasizes the need for the Department to hold the company accountable for the delivery of benefits related to this infrastructure (D.P.U. 21-80, NSTAR Electric Brief at 105, citing Attorney General Brief at 30). According to the company, the ongoing evolution of technology has made installation and use of AMI the only feasible operating alternative as compared to other technological solutions, with the potential to produce benefits for customers if implemented in an organized, comprehensive, and carefully sequenced process – which differs from the time of the Department's investigation in D.P.U. 12-76 and subsequent order in D.P.U. 15-122, when the transition to advanced metering functionality reflected a very significant departure from the company's normal course of business (D.P.U. 21-80, NSTAR Electric Brief at 106, citing Exh. ES-AMI-1, at 19-20; NSTAR Electric Reply Brief at 20). NSTAR Electric states that because there is no other option than AMI at this time, the company had no need to develop a business case to assist it in determining which metering alternative is the most prudent approach to take (D.P.U. 21-80, NSTAR Electric Brief at 106; NSTAR Electric Reply Brief at 20).

NSTAR Electric argues that, contrary to the Attorney General's position, its existing AMR meters are nearing the end of their useful life and that implementation and replacement of those meters with AMI as reflected in its end-of-life meter replacement plan creates a unique opportunity to mitigate the risk of stranded costs (D.P.U. 21-80, NSTAR Electric Brief at 34-35, 89, citing Attorney General Brief at 22; Exhs. ES-AMI-1, at 8, 16, 23; ES-AMI-2, at 3 & Appx. A; AG-TN-1, at 6). According to the company, the Attorney General's argument about the age of the AMR meters fails to recognize that replacing AMR meters with AMI meters in a piecemeal fashion, as opposed to following the AMI Implementation Plan, will not provide the same benefits for customers (D.P.U. 21-80, NSTAR Electric Brief at 89-90, 108-109, citing Exhs. ES-Rebuttal at 25; DPU 10-5).

The company states that for the AMI solution to operate efficiently, the network and a sufficient number of meters are required in geographic proximity to one another to enable the mesh communications network, and a business as usual approach to AMI deployment, i.e., replacing an AMR meter when it reaches the end of its useful life with an AMI meter as suggested by the Attorney General, is ill-suited to optimizing the efficacy of the mesh network (D.P.U. 21-80, NSTAR Electric Brief at 109-110, citing Exh. DPU 10-5). NSTAR Electric also states that AMI investments can only be considered to be routine or business as usual investments themselves once it has implemented the base AMI investments set out in the plan (D.P.U. 21-80, NSTAR Electric Reply Brief at 13). NSTAR Electric asserts that the Attorney General mistakenly concludes that the progression to AMI is comparable to the company's past transition to AMR meters, specifically because the implementation of AMR did not require any significant improvements to the CIS or other back-office systems to be fully functional, did not require a separate cost recovery mechanism outside of base distribution rates, and also resulted in significant O&M savings (D.P.U. 21-80, NSTAR Electric Brief at 91-92, citing Exhs. DPU 10-5; ES-Rebuttal at 19-20; AG-TN at 8-9; Tr. 4, at 627-630).

The company observes that the benefits associated with AMI are different than those identified as supporting the transition to AMR, in particular, that a transition to AMI technology is critical to meeting current and future customer needs and expectations and enabling the company to meet ever-growing demands for clean energy solutions that are driving changes in how power is generated, distributed, and consumed (D.P.U. 21-80, NSTAR Electric Brief at 93, citing Exhs. ES-AMI-1, at 11-18; DPU 17-2). NSTAR Electric states that if it were to follow the Attorney General's recommendations and continue to deploy AMR meters on its system, it would lock itself and its customers into a 20-year lifecycle of outdated technology that is inconsistent with customers' expectations of the modern and evolving grid and the company's plans for the grid's future state, and would be inconsistent with the Department's findings in D.P.U. 20-69-A at 25 (D.P.U. 21-80, NSTAR Electric Brief at 89-90, 94, citing Exh. ES-AMI-1, at 21). In particular, the company states that the Department has already found that a significant portion of the company's AMR meters will reach the end of their useful life within the next three to six years, thus providing the ideal opportunity to develop a comprehensive meter replacement plan with necessary upgrades to back-office supporting systems to enable advanced metering functionality (D.P.U. 21-80, NSTAR Electric Brief at 89, citing, D.P.U. 20-69-A at 6, 25-27, 29-34).

NSTAR Electric maintains that many of the benefits of AMI accrue to customers in the form of increased functionality and usability, or in terms of cost savings on components of a customer's electric bill that do not accrue directly to the company (e.g., the cost of energy) (D.P.U. 21-80, NSTAR Electric Brief at 94, citing Exh. ES-Rebuttal at 20). The company states that since its decision to move to AMI is not supported by cost savings or efficiencies that accrue to the utility, but to its customers in the form of cost savings on their distribution rates, the decision to deploy AMI and unlock the many benefits of such an investment, cannot be made without a regulatory support mechanism as proposed by the company (D.P.U. 21-80, NSTAR Electric Brief at 94, citing Exh. ES-Rebuttal at 20). Contrary to the Attorney General's contentions, NSTAR Electric asserts that AMI presents the only replacement option that can ensure that the company is able to manage its distribution system effectively and safely for customers and the only metering solution available to effectively manage and interact with the modern grid consistent with the Department's grid modernization objectives and customers' expectations (D.P.U. 21-80, NSTAR Electric Brief at 94, citing Exh. ES-AMI-1, at 20-21). Moreover, in response to DOER's recommendation for the Department to require NSTAR Electric to consult with DOER on AMI implementation, the company states that it does not oppose working collaboratively with stakeholders but that any stakeholder process must not delay implementation of the 2022-2025 Grid Modernization Plan, including the AMI deployment timeline (D.P.U. 21-80, NSTAR Electric Brief at 121, citing DOER Brief at 14).

Regarding the Attorney General's arguments and concerns involving the company's cost assumptions in the business case for the transition of bridge meters, NSTAR Electric responds that it is working with the meter manufacturer to conduct migration lab tests and evaluations and initial results show both a successful transition to AMI and a successful connection to the manufacturer's mesh network (D.P.U. 21-80, NSTAR Electric Brief at 107, citing Exhs. ES-Rebuttal at 52; AG 1-13; D.P.U. 21-80, NSTAR Electric Reply Brief at 24). NSTAR Electric states that, while additional upgrades are necessary to allow these bridge meters to move onto a new mesh network capable of supporting the advanced features of the next generation of AMI meters, there is no indication that these upgrades will not work or that the bridge meters will require replacement prior to the end of their useful life (D.P.U. 21-80, NSTAR Electric Brief at 107, citing Exhs. ES-Rebuttal at 52; AG 1-13; AG 5-8; AG 8-12). In the event it incurs additional costs to ensure a successful transition or because a successful transition cannot be accomplished, the company acknowledges that, consistent with the Department's prudence standard, it will need to demonstrate that those costs were prudently incurred and may risk disallowance of recovery through the AMIF if the Department finds that the treatment of bridge meters was imprudent (D.P.U. 21-80, NSTAR Electric Brief at 107, citing D.P.U. 20-69-A at 30-35). Additionally, NSTAR Electric explains that, while there was some confusion regarding the number of bridge meters due to a coding issuing resulting in a variance of 19,000 meters, the coding issue does not impact the company's AMI cost estimates because approximately 15,000 of those meters were excluded from the cost estimates, and the entirety of those 19,000 meters will not be transitioned to AMI due to geographical location or other limitations impacting the cost-effectiveness of a replacement (D.P.U. 21-80, NSTAR Electric Brief at 108, citing Exh. ES-Rebuttal at 51).

NSTAR Electric also urges the Department to reject the Attorney General's recommendation to condition approval of the proposed communications investments on the company demonstrating that constructing company-owned communications facilities is superior to obtaining public carrier services (D.P.U. 21-80, NSTAR Electric Brief at 80, citing Attorney General Brief at 21). NSTAR Electric counters that it provided a business case that demonstrates that the benefits of these proposed investments justify the proposed costs, and that it will bear the burden of demonstrating the prudency of the costs once it seeks cost recovery (D.P.U. 21-80, NSTAR Electric Brief at 81, 117, citing Exhs. DPU 1-1; DPU 5-1; DPU 5-2; DPU 14-3; DPU 14-6; DPU 14-11; AC 1-3; AG 4-11; RR-DPU-14). NSTAR Electric maintains that, while a "make vs. buy" analysis for the communications network may be appropriate during the prudency review, it would be inappropriate to condition approval of these investments on the provision of such an analysis, pointing to the deference that the Department generally grants to company management decisions involving capital investments (D.P.U. 21-80, NSTAR Electric Brief at 81, 118, citing Boston Gas Company, D.P.U. 17-170, at 29 (2018); D.P.U. 17-05, at 88-89 (2017); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 15-155, at 57 n.33 (2016); Boston Edison Company, D.P.U. 85-266-A/85-271-A at 11 (1986)). NSTAR Electric reiterates this position involving its anticipated deployment of a HAN strategy and DI functionality (D.P.U. 21-80, NSTAR Electric Brief at 116-118 (citations omitted)).

NSTAR Electric disagrees with Utilidata's recommendations for RFPs separate from any solicitation for meters or for additional Department oversight of the procurement process involving a DI platform (D.P.U. 21-80, NSTAR Electric Brief at 137-138, citing Utilidata Brief at 5-10). The company asserts that these recommendations are unnecessary and more likely to delay the implementation process, but will take them into account as part of future solicitations for DI and meters (D.P.U. 21-80, NSTAR Electric Brief at 138, citing Exh. ES-Rebuttal at 67). Because Utilidata is a software vendor, NSTAR Electric encourages Utilidata to participate in any future competitive solicitation process through opportunities for bidder questions and feedback, such as a bidder conference, thus allowing a level playing field for all vendors and to ensure a process that results in bids providing benefits to customers (D.P.U. 21-80, NSTAR Electric Brief at 138 & n.24, citing Exh. U-MH/JM at 3).

Regarding the Attorney General's HAN concerns, NSTAR Electric explains that it takes no issue with including a discussion of HAN in the data access proceeding but argues that the Department should reject recommendations requiring the company to include HAN-related hardware in its AMI meters (D.P.U. 21-80, NSTAR Electric Brief at 116). NSTAR Electric maintains that it will develop and deploy its HAN strategy once the threshold for the number of customers with connected devices that seek to optimize usage across those devices is reached (D.P.U. 21-80, NSTAR Electric Brief at 116, citing Exh. ES-Rebuttal at 63; Tr. 5, at 888). NSTAR Electric expects that the AMI meters it procures will have HAN functionality through the meter's built-in wireless fidelity ("Wi-Fi") radio, however, but it cannot fully develop a HAN strategy and undertake the necessary implementation of IT solutions and cybersecurity assessment until the meters are selected (D.P.U. 21-80, NSTAR Electric Brief at 116, citing Exhs. ES-Rebuttal at 62-63; CLC-ES 1-4). The company also expects to leverage National Grid's HAN experience, as it develops its own strategies for integrating AMI data with HAN (D.P.U. 21-80, NSTAR Electric Brief at 116, citing Exh. ES-Rebuttal at 62). The company does not object to including a discussion of HAN and DI in the future statewide data access proceeding as that discussion will inform its ultimate decisions on HAN and DI (D.P.U. 21-80, NSTAR Electric Reply Brief at 29).

NSTAR Electric maintains that the record demonstrates that a new CIS, which will be used to track customer information and render bills to customers, is critical for the full deployment of AMI, because the current CIS systems are not equipped to bill complex rates or handle AMI functionality (D.P.U. 21-80, NSTAR Electric Brief at 101, citing Exhs. ES-AMI-1, at 26; AG 5-18; AG 8-5; ES-Rebuttal at 9-10; Tr. 4, at 601-604, 612, 620-622). The company explains that it explored the feasibility of upgrading the existing CIS but determined that such upgrades were not prudent given the age and architecture of these legacy systems and the new AMI requirements, since an attempt to modify the current CIS would be costly, carry significant technical risk, and require a substantial architectural overhaul that may not even be possible (D.P.U. 21-80, NSTAR Electric Brief at 101-102, citing Exhs. ES-AMI-2, at 41; AG 5-18; ES-Rebuttal at 9-10; Tr. 4, at 602-605). The company further explains that absent full deployment of AMI, there would be no need at this time for the company to replace its CIS (D.P.U. 21-80, NSTAR Electric Brief at 102, citing Tr. 4, at 612-613). Additionally, the company states that National Grid's determination that it can fully implement AMI by upgrading rather than replacing its CIS is immaterial to NSTAR Electric's analysis and final determination on the matter (D.P.U. 21-80, NSTAR Electric Brief at 102).

NSTAR Electric contends that NRG's argument that the company must meet with stakeholders prior to CIS implementation is unfounded and ignores the reasons for deploying the AMI Implementation Plan on the currently proposed schedule, i.e., the need to deploy AMI meters consistent with the end of life for existing AMR meters and to implement CIS and MDMS prior to meter deployment to align customer benefits with AMI deployment as soon as AMI meters can be deployed (D.P.U. 21-80, NSTAR Electric Brief at 127, 128, 137, citing NRG Brief at 9; Exhs. ES-AMI-1, at 19-20, 25, 33-34; DPU 17-1; DPU 17-5; AC 1-23; CLC-ES 1-1, at 2; Tr. 5, at 965-966). NSTAR Electric explains that the selected CIS will allow for updates post-implementation to account for stakeholder feedback, and the selected software allows for adding modules to achieve specific objectives (D.P.U. 21-80, NSTAR Electric Brief at 123, 128, citing Tr. 4, at 612-613; Tr. 5, at 967). NSTAR Electric also explains that it must ensure that the new CIS is delivering accurate bills and exact results and facilitating the low-income customer programs that customers rely on (D.P.U. 21-80, NSTAR Electric Brief at 128, citing Tr. 4, at 604; Tr. 5, at 966). NSTAR Electric states that by making sure these investments are ready, it is ensuring readiness to move towards providing customer benefits through TVR rates as soon as the Department establishes its guidance for statewide data access and a TVR framework (D.P.U. 21-80, NSTAR Electric Brief at 128-129).

Furthermore, NSTAR Electric argues that cybersecurity is of paramount importance to the company, as evidenced by its cybersecurity plan included with its AMI Implementation Plan and by its information security department (D.P.U. 21-80, NSTAR Electric Brief at 119, citing Exh. ES-AMI-2, at 32-36 & Att. B; Tr. 5, at 917-921). NSTAR Electric contends that the Attorney General's cybersecurity recommendations are unnecessary given the protections undertaken daily by the company's information security department, as well as the cyber insurance coverage the company already maintains, and would likely add significant one-time and ongoing costs (D.P.U. 21-80, NSTAR Electric Brief at 118, 119, citing Attorney General Brief at 44; Tr. 5, at 917-921; RR-AG-ES-1).

For purposes of cost recovery, NSTAR Electric contends that the Attorney General's supposition that the company currently collects AMI meter costs through its PBR mechanism is fundamentally flawed, incorrect, and should be disregarded (D.P.U. 21-80, NSTAR

Electric Brief at 94-95, citing Attorney General Brief at 23-24; Tr. 4, 754-758, 763-767; D.P.U. 21-80, NSTAR Electric Reply Brief at 14-15). As an initial matter, NSTAR Electric states that the TFP study it relied upon in D.P.U. 17-05 measures the growth in inputs and outputs to utility operations, not the actual cost levels or cost recovery (D.P.U. 21-80, NSTAR Electric Brief at 95, citing Exh. ES-Rebuttal at 12; D.P.U. 21-80, NSTAR Electric Reply Brief at 14). If capital costs were incurred by the companies in the TFP study sample set that were not sustained over the study period, the company maintains that there is no cost trend that would influence the TFP study outcome (D.P.U. 21-80, NSTAR Electric Brief at 95, citing Exh. ES-Rebuttal at 12).

According to the company, the Attorney General fails to include in her X-factor PBR mechanism arguments that permanent reductions to operating costs during the TFP study would tend to improve productivity in the TFP study, thus causing the X-factor to be more positive rather than more negative (D.P.U. 21-80, NSTAR Electric Brief at 95-96, citing Exh. ES-Rebuttal at 12-13). NSTAR Electric states that this is important because AMI investment peaks over a couple of years and then declines, while efficiency gains associated with AMI implementation will persist after implementation (D.P.U. 21-80, NSTAR Electric Brief at 96, citing Exh. ES-Rebuttal at 13). Moreover, NSTAR Electric observes that of the 67 utilities included in the TFP study: (1) 40 did not implement AMI at any point during the study period; (2) six that did fully deploy AMI received federal funding through smart grid investment grants as part of the American Recovery and Reinvestment Act of 2009, Pub. L. 111-5 ("ARRA"), substantially reducing the total capital investment requirement for deployment; and (3) another five that fully deployed AMI but did not receive ARRA funds skipped the implementation of AMR technology or had only implemented AMR partially, thus were able to fully realize extraordinary productivity improvements that would reduce PBR revenues and that are improvements unavailable to the company because of its legacy AMR metering system (D.P.U. 21-80, NSTAR Electric Brief at 96-97, citing Exh. ES-Rebuttal at 13-14).

According to NSTAR Electric, the Attorney General advanced similar PBR mechanism arguments involving the claimed double recovery of costs associated with the gas system enhancement plan ("GSEP") for NSTAR Gas Company in that company's recent base distribution rate proceeding, which the Department rejected (D.P.U. 21-80, NSTAR Electric Brief at 97, citing NSTAR Gas Company, D.P.U. 19-120, at 41-42 (2020)). Additionally, the company states that the Department denied NSTAR Electric's proposal to incorporate grid modernization investments into the PBR, determining it was not in the public interest to include the grid modernization base commitment investments in the PBR and that it was necessary to utilize a separate process to establish a robust regulatory review for these investments (D.P.U. 21-80, NSTAR Electric Brief at 98, citing D.P.U. 17-05, at 395, 438-439). The company maintains that the same reasoning applies to the current proceeding and to the proposed AMI cost recovery mechanism in the model AMI tariff, which does not result in the double recovery of costs (D.P.U. 21-80, NSTAR Electric Brief at 98, 103, citing Exh. ES-Rebuttal at 19).

At the same time, NSTAR Electric argues that it has demonstrated that its O&M tracking proposal (i.e., track savings and offset costs within the context of the annual PBR mechanism) is appropriate and ensures customers realize AMI savings through the annual PBR mechanism adjustment, since the company anticipates AMI to reduce the company's O&M costs (D.P.U. 21-80, NSTAR Electric Brief at 104-105, 110, citing Attorney General Brief at 32; Exhs. AG 1-4; ES-Rebuttal at 56; D.P.U. 22-22, Exh. ES-REVREQ-1, at 200; NSTAR Electric Reply Brief at 22). As a result, NSTAR Electric contends that the Attorney General's claims, that savings garnered through the implementation of AMI will never be realized by customers without additional requirements and that the company has overstated avoided O&M costs, are unfounded (D.P.U. 21-80, NSTAR Electric Brief at 104-105, 110, citing Attorney General Brief at 32; Exhs. AG 1-4; ES-Rebuttal at 56; D.P.U. 22-22, Exh. ES-REVREQ-1, at 200; NSTAR Electric Reply Brief at 22). The company observes that the Attorney General unsuccessfully made similar recommendations to reduce cost recovery based on potential or projected savings anticipated to result from actions taken by a utility associated with mergers and IT implementations (D.P.U. 21-80, NSTAR Electric Brief at 104, citing D.P.U. 19-120, at 275-276; D.P.U. 17-05, at 170-171; D.P.U. 15-155, at 306-308). The company states that the Department rejected these recommendations, finding in each case cited that in order to make such an adjustment, the amount of the savings would need to be known and measurable and the potential savings were not yet calculable to the degree required by precedent (D.P.U. 21-80, NSTAR Electric Brief at 104-105, citing D.P.U. 19-120, at 275-276;

D.P.U. 17-05, at 170-171; D.P.U. 15-155, at 306-308). NSTAR Electric contends that this principal applies in the current proceeding since, while the company anticipates savings to result due to AMI roll-out, those savings are not sufficiently quantifiable at this time to be used as a cost offset (D.P.U. 21-80, NSTAR Electric Brief at 105, citing Exhs. ES-AMI-1, at 21-41; ES-AMI-4 (Rev.)).

b. National Grid

National Grid urges the Department to approve its proposed new grid-facing investments and demonstration projects, maintaining that these investments are designed to make progress on the Department's grid modernization objectives and go beyond the company's business as usual investments (D.P.U. 21-81, National Grid Brief at 8, 9, citing Exhs. NG-GMP-2 (Rev. 2) at 16-86, 124-125; DPU 1-1). National Grid also argues that its business case shows that the benefits justify the costs of the proposed grid-facing grid modernization projects (D.P.U. 21-81, National Grid Brief at 36, citing Exh. NG-GMP-2 (Rev. 2) at 127).

National Grid rejects the Attorney General's claim that the benefits, including reliability benefits, are likely lower than reported and argues that the Attorney General provides no calculations or numbers to support her claims or to otherwise support recommended reductions (D.P.U. 21-81, National Grid Brief at 44, 51-52, citing Exh. NG-AG 1-1; Tr. 6, at 1060-1061). National Grid states that its benefit cost ratio of 1.94 to deploy and maintain ten years of grid modernization plan investments indicates that the expected quantified benefits are nearly twice the expected costs on an NPV basis

(D.P.U. 21-81, National Grid Brief at 44-45, citing Exhs. NG-GMP-Rebuttal-1, at 16; NG-GMP-2 (Rev. 2) at 144). Further, National Grid maintains that it took a conservative approach in its benefit-cost ratio calculation and for most investments used costs as they are incurred by the company, rather than as they are passed on to customers on an NPV basis (i.e., the revenue requirement) to calculate its benefit-cost ratio (D.P.U. 21-81, National Grid Brief at 45, citing Exh. NG-GMP-Rebuttal-1, at 16-17). Consistent with its conservative approach, National Grid states it used the revenue requirement only to quantify the costs for investments in field devices with long average service lives, because it results in increased costs (D.P.U. 21-81, National Grid Brief at 45, citing Exh. NG-GMP-Rebuttal-1, at 16-17). National Grid contends that if it had used customers' costs and a typical customer discount rate for other investments, the estimated net benefits would be more beneficial for customers (D.P.U. 21-81, National Grid Brief at 45, citing Exh. NG-GMP-Rebuttal-1, at 16-17).

Regarding reliability benefits, National Grid maintains that system average interruption frequency index ("SAIFI") and system average interruption duration index ("SAIDI") benefit estimates are based on established engineering models, consistent with the company's 2015-2016 distribution automation demonstration in Worcester, Massachusetts, and aligned with other utility distribution automation experience (D.P.U. 21-81, National Grid Brief at 51, citing Exh. NG-GMP-Rebuttal-1, at 18). Further, National Grid maintains that DOE's ICE tool is the industry standard and the best available tool for estimating interruption costs. The company, however, believes ICE underestimates the average outage costs for residential customers as indicated by expenditures for backup power generation

(D.P.U. 21-81, National Grid Brief at 51). National Grid states that its distribution automation strategy will prioritize deployment to the worst performing feeders with the most customers (D.P.U. 21-81, National Grid Brief at 51, citing Exh. NG-GMP-Rebuttal-1, at 1).[50]

Additionally, National Grid requests that the Department approve its proposed AMI Implementation Plan, including preauthorization of $487 million in AMI investments and its AMI cost recovery mechanism proposal (D.P.U. 21-81, National Grid Brief at 1-2, 35, 54, 68-71). National Grid maintains that its AMI proposal complies with the directives in D.P.U. 20-69-A, will make measurable progress on the Departments grid modernization objectives, is supported by a business case, results in reasonable bill impacts, will benefit low-income customers and EJ communities, and will achieve advanced metering functionality through a full-scale deployment of AMI (D.P.U. 21-81, National Grid Brief at 2). National Grid argues that full-scale AMI deployment is the only suitable solution to meet grid modernization objectives and capabilities, customer expectations, and the company's need to replace its aging AMR meter assets (D.P.U. 21-81, National Grid Brief at 59, citing Exh. NG-AMI-1, at 16-17). National Grid argues that investing in AMI will provide enhanced information on the grid, avoids re-investing in AMR technology nearing

50 Additionally, because ADMS was addressed in Track 1 of these proceedings, National Grid urges the Department to disregard as untimely the Attorney General's concerns with ADMS spending and benefit-cost analysis (D.P.U. 21-81, National Grid Brief at 46). The Department agrees. The Department addressed all issues related to ADMS in its Track 1 Order at 80-83, and does not revisit this issue here.

obsolescence, and paves the way for enhanced functionality (D.P.U. 21-81, National Grid Brief at 58-59, citing Exh. NG-AMI-1, at 15). Further, National Grid states that it accelerated the proposed AMI schedule by leveraging the work of its affiliate in New York and will continue to look for similar opportunities to add efficiencies and to deliver additional functionality for customers in the Commonwealth (D.P.U. 21-81, National Grid Brief at 60-61, 90, citing Exhs. NG-AMI-Rebuttal-1, at 48-49; DPU 15-5).

National Grid asserts that it can implement AMI-related customer programs concurrently with AMI meter deployment, including customer access to energy usage information from the CEMP and other capabilities such as remote connect/disconnect and remote investigation (D.P.U. 21-81, National Grid Brief at 61, citing Exhs. NG-AMI-Rebuttal-1, at 24, 49; DPU 15-5). National Grid claims that customers will be able to access an approved TVR once it is programmed into the company's billing system, customer education materials are developed and disseminated, and the customer receives an AMI meter (D.P.U. 21-81, National Grid Brief at 60, citing Exh. DPU 15-5). Thus, National Grid insists that, contrary to CLF's claims, the company is not delaying customer-facing benefits until after year three investments begin but will start enabling customer benefits as soon as an AMI meter is installed, beginning approximately 18 months after launching the back-office system (D.P.U. 21-81, National Grid Brief at 90).

In response to the Attorney General, National Grid argues that her recommendation to deploy AMI in a business as usual manner would delay implementation and reduce the benefits of deploying a comprehensive modern metering platform and is also infeasible given the AMI communications network needs and proposed mesh AMI solution (D.P.U. 21-81, National Grid Brief at 75; National Grid Reply Brief at 4). To begin, National Grid argues that AMI deployment is not business as usual but a transformational investment in grid modernization that will enable customer benefits and cost saving opportunities (D.P.U. 21-81, National Grid Brief at 77-78; National Grid Reply Brief at 3-4). National Grid maintains that AMI is a change from the company's current AMR systems that is functionally different from AMR meters in numerous ways including remote meter reading, remote service connections/disconnections, remote meter investigations, automated outage/restoration notifications, enhanced voltage management, feeder monitoring capabilities, access to granular energy usage information from the company's customer portage or using Wi-Fi over the HAN, grid-edge computing, and TVR enablement (D.P.U. 21-81, National Grid Brief at 77, citing Exh. NG-AMI-Rebuttal-1, at 30; National Grid Reply Brief at 3-4). Further, National Grid argues that it is not otherwise part of the company's routine capital plan to replace approximately 900,000 meters over three years nor is it possible for the company to accommodate that level of capital investment within its routine capital plan in the three-year timeframe (D.P.U. 21-81, National Grid Reply Brief at 3-4, citing Exh. NG-AMI-Rebuttal-1, at 31).

National Grid argues that the benefits of AMI exceed the costs (D.P.U. 21-81, National Grid Brief at 62-63). National Grid states that its business case is based on work by its New York and former Rhode Island affiliates that included RFIs to qualify potential AMI vendors and a subsequent RFS (D.P.U. 21-81, National Grid Brief at 62-63, citing

Exhs. NG-AMI-1, at 26; NG-AMI-2, at 56; NG-AMI-5; DPU 2-6). The company states that its updated benefit cost model in this proceeding incorporates AMI program pricing quotes for RFS-related assumptions and refined the benefit cost analysis to capture Massachusetts-specific inputs (D.P.U. 21-81, National Grid Brief at 62, citing Exhs. NG-AMI-1, at 26; NG-AMI-Rebuttal-1; NG-AMI-Rebuttal-2; DPU 2-6, Att.; Tr. 4, at 770). The company argues that its benefit cost ratio will improve with realization of efficiencies from deployment of AMI by its affiliate, Niagara Mohawk Power Corporation ("NMPC") (D.P.U. 21-81, National Grid Brief at 63, citing Exh. NG-AMI-1, at 29).[51] Finally, National Grid argues that its AMI plan will result in reasonable bill impacts and that approximately 40 percent or more of the AMI bill impacts are unavoidable, because of the costs that would be incurred to replace the AMR metering assets, which are at or near the end of their estimated useful life (D.P.U. 21-81, National Grid Brief at 63, citing Exhs. NG-AMI-1, at 14; CLF-NG 1-3).

National Grid disagrees with the Attorney General's claim of deficiencies in the AMI Implementation Plan and that the costs outweigh the benefits (D.P.U. 21-81, National Grid Brief at 87-88). National Grid argues that its exclusion of stranded costs from the benefit cost analysis is appropriate and, as acknowledged by the Attorney General's witness, consistent with Department instructions (D.P.U. 21-81, National Grid Brief at 88, citing Exh. AG-WG-1, at 41 n.34). The company maintains that AMR was a prudent investment

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51 National Grid states that NMPC received regulatory approval to deploy AMI to approximately 1.7 million electric customers and 640,000 gas customers in November 2020 (D.P.U. 21-81, National Grid Brief at 55-56).

and recovery of the remaining value of embedded AMR costs from that investment should be allowed (D.P.U. 21-81, National Grid Brief at 88).[52] Further, National Grid states that its AMI Implementation Plan is aligned with the end of life of a large portion of existing AMR meters, which will minimize stranded costs (D.P.U. 21-81, National Grid Brief at 88, citing Exh. NG-AMI-Rebuttal-1, at 17-18).

National Grid also disputes the Attorney General's claim that its AMI reliability assumptions are overstated (D.P.U. 21-81, National Grid Brief at 88-89). National Grid maintains that, consistent with other jurisdictions, it incorporated an estimated $52.94 million (20-year NPV) outage management benefit in its refined AMI business case, used conservative outage information assumptions, and relied on a common utility industry tool, DOE's ICE calculator, to estimate outage costs and reliability improvement benefits (D.P.U. 21-81, National Grid Brief at 88, citing Exh. NG-AMI-Rebuttal-1, at 13-14). The company also notes that it is only after full meter deployment that the business case begins to reflect reliability improvement benefits (D.P.U. 21-81, National Grid Brief at 89).

In response to the Attorney General's recommendations regarding remote connect/disconnect capabilities of AMI meters, National Grid argues that this is a convenient customer feature that provides savings, enhances interactions, and reduces disruptions by avoiding the need for in-person appointments to turn on or off service (D.P.U. 21-81,

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52 For the same reason, National Grid opposes the Attorney General's recommendations to "net out" the recovery of meter costs that exist in base distribution rates in Section 2.7 of the proposed AMI tariff regarding AMI revenue requirement (D.P.U. 21-81, National Grid Brief at 83, citing Exh. NG-AMI-Rebuttal-1, at 42).

National Grid Brief at 105-106). Further, National Grid states that it has a comprehensive cybersecurity plan that will guard against intrusion risks (D.P.U. 21-81, National Grid Brief at 106). For collections-related disconnects, National Grid expects to continue the current process of an in-person visit by a company representative and to follow the Department's customer shut-off requirements (D.P.U. 21-81, National Grid Brief at 106, citing Exh. NG-AMI-2, at 30 n.31). National Grid further argues that the AMI will allow training of collection field personnel to shift from technical aspects to customer service and advocacy skills that, according to the company, will enrich the customer experience, particularly for vulnerable households (D.P.U. 21-81, National Grid Brief at 106, citing Exh. AC 1-6). National Grid states that individuals may also opt-out of an AMI meter and the remote connect/disconnect feature (D.P.U. 21-81, National Grid Brief at 106). National Grid states that, consistent with DOER's recommendations, remote shut-off procedures will be clearly communicated (D.P.U. 21-81, National Grid Brief at 106).

National Grid also opposes further review or consultation on AMI implementation or on the functionality or capabilities of AMI meters as recommended by the Attorney General, DOER, and CLF (D.P.U. 21-81, National Grid Brief at 94-95, 102-103, 104). National Grid states it has already completed a competitive RFP process throughout all jurisdictions in the NGSC footprint to leverage volume pricing, selected an AMI vendor and AMI meter, developed a robust AMI customer engagement plan, and is prepared to move forward with its AMI program, including HAN capabilities and grid-edge computing, as early as January 2023 (D.P.U. 21-81, National Grid Brief at 94-95, 102-103, 104, citing

Exhs. NG-AMI-1, at 26, 56; NG-AMI-Rebuttal-1, at 16, 56-57, 64; DOER 2-6; National Grid Reply Brief at 10-11). National Grid states it is amenable to informing stakeholders of its progress on AMI implementation and the lessons learned during deployment but argues that, to avoid implementation delay, any consultation should be for information only (D.P.U. 21-81, National Grid Brief at 94-95). National Grid maintains that, if necessary, the concerns expressed by the Attorney General, DOER, and Utilidata regarding grid-edge computing, DI, and tracking of DI benefits, could be explored in the data access proceeding (D.P.U. 21-81, National Grid Brief at 105; National Grid Reply Brief at 10-11).

National Grid opposes amending the GMF tariff and proposed AMI tariff to limit a return on grid modernization investments until the company demonstrates that the projected level of benefits have been achieved and delivered to customers (D.P.U. 21-81, National Grid Brief at 42-43, citing Exhs. NG-GMP-Rebuttal-1, at 27; NG-AMI-Rebuttal-1, at 27; National Grid Reply Brief at 2-3). National Grid argues that all investor-owned utilities require capital from investors to fund investments such as grid modernization and AMI projects and that return on equity is essential to attract capital, compensate investors for the cost of the capital they provide, and ensure financial integrity (D.P.U. 21-81, National Grid Brief at 42-43, citing Exhs. NG-GMP-Rebuttal-1, at 27; NG-AMI-Rebuttal-1, at 27; National Grid Reply Brief at 2-3). National Grid argues that the allowed return on equity, and the opportunity to earn that return, should be commensurate with that available to other assets (D.P.U. 21-81, National Grid Brief at 43). According to the company, it is unreasonable to subject these investments to disallowance of return on equity based on performance metric outcomes, which is not done for other investments, without a showing that the work and associated costs were not prudently incurred (D.P.U. 21-81, National Grid Brief at 43, citing Exhs. NG-GMP-Rebuttal-1, at 27; NG-AMI-Rebuttal-1, at 28; National Grid Reply Brief at 2-3). National Grid argues that doing so would effectively amount to a one-way penalty on grid modernization and AMI-related capital investments with no corresponding increase in allowed return to compensate for the increased risk and is unjustified for the proposed grid modernization and AMI projects that offer substantial net benefits and are foundational to achieving the transition to a clean energy future (D.P.U. 21-81, National Grid Brief at 43, citing Exhs. NG-GMP-Rebuttal-1, at 27; NG-AMI-Rebuttal-1, at 28).

National Grid argues that the absence of an approved short-term cost recovery mechanism for AMI is a barrier to implementing its AMI plan given the high initial capital costs, regulatory lag under traditional cost-of-service ratemaking, and the risk of cost disallowances (D.P.U. 21-81, National Grid Brief at 68-69, citing Exhs. DPU 2-1; DOER Track 2-1-1). Further, National Grid contends that operating under a PBR plan disincentivizes proceeding with its AMI plan because the PBR plan does not support broad-based technology upgrades like AMI over the PBR plan's five-year stay-out period (D.P.U. 21-81, National Grid Brief at 69). National Grid maintains that its proposed short-term AMI cost recovery mechanism reduces the barriers to proceed with accelerated investment in AMI and is consistent with the grid modernization cost recovery mechanism (D.P.U. 21-81, National Grid Brief at 70, 74-75).

Additionally, National Grid claims that its PBR does not include the cost of AMI meters and there is no basis for the Attorney General's claim that the PBR revenue provides for recovery of AMI investments (D.P.U. 21-81, National Grid Brief at 78-82; National Grid Reply Brief at 4-6). National Grid maintains that its PBR plan is not designed to cover the costs of AMI and the back-office systems to support AMI nor is AMI deployment a part of its routine capital plan (D.P.U. 21-81, National Grid Brief at 78-81; National Grid Reply Brief at 4-6). National Grid insists that the company would be unable to proceed with its AMI plan as part of its routine capital investments under its PBR plan in addition to meeting its core service obligations (D.P.U. 21-81, National Grid Brief at 78-82; National Grid Reply Brief at 4-6).

Regarding the X-factor in the PBR plan, National Grid argues that it represents historical trends in the utility industry and not unique capital spending pressures that National Grid faces (D.P.U. 21-81, National Grid Reply Brief at 5). Additionally, National Grid argues that because the base year does not include a significant amount of meter investment and its peers did not complete full scale AMI investment, National Grid's X-factor does not capture the cost of AMI (D.P.U. 21-81, National Grid Reply Brief at 5).

National Grid contends that in the D.P.U. 18-150 TFP study, out of the 68 utility companies studied between 2002 and 2016, 40 did not implement AMI and 13 had partial deployments (D.P.U. 21-81, National Grid Brief at 79; National Grid Reply Brief at 4, citing Exh. NG-AMI-Rebuttal-7). National Grid further contends that for companies with fully or partially implemented AMI, about 48 percent transitioned from manual meter reading to AMI without AMR and about 41 percent received federal grant assistance (D.P.U. 21-81, National Grid Brief at 79-80; National Grid Reply Brief at 4, citing Exh. NG-AMI-Rebuttal-7). Therefore, National Grid concludes, about 90 percent of studied companies did not have a full AMI deployment proposal like National Grid (D.P.U. 21-81, National Grid Brief at 80).

National Grid also argues that it is inappropriate to reduce the revenue requirement by the amount of projected O&M savings in the company's business case until the estimated benefits are captured in a rate case (D.P.U. 21-81, National Grid Brief at 53). National Grid argues that ratemaking is not based on forecasts of future costs, even if those costs are subject to true up, and that the same should apply to O&M savings realized from implementation of grid modernization (D.P.U. 21-81, National Grid Brief at 53). Further, National Grid states that it plays an active role in investment decisions and has committed to empowering customers to understand and achieve benefits from AMI, but states that many benefits from AMI are dependent on customers using AMI tools enabled by the AMI platform, which the company cannot control (D.P.U. 21-81, National Grid Reply Brief at 3, citing Exhs. NG-AMI-1, at 7, 29; NG-AMI-3, at 41-55).

Additionally, National Grid disputes the Attorney General's concerns with the model tariff. First, National Grid argues that recovery of the AMI revenue requirement in Section 2.7, parts (1) and (3), provide for the recovery of the revenue requirement in, respectively, the investment year and the recovery year and does not result in double recovery (D.P.U. 21-81, National Grid Brief at 83, citing Exh. NG-AMI-Rebuttal-1, at 42). In response to the Attorney General's recommendation for certain adjustments in the model tariff, National Grid argues that: (1) no adjustment to meter investment is needed for AMI opt-out customers because it will use AMI meters without AMI capabilities enabled for these customers; (2) reductions in O&M costs from new capital investments will be reflected at the time of a base distribution rate case; (3) pursuant to cost allocation rules, the presumption is that the company is only charged its allocated share of service company costs; (4) for recovery of property taxes, the company is mirroring the methodology approved in its most recent distribution rate case, D.P.U. 18-150; and (5) the company is not recovering any amount of AMI costs through base distribution rates that would require an AMI allowance in base distribution rates to be incorporated into the formula to calculate the annual AMI factor (D.P.U. 21-81, National Grid Brief at 84-85). Regarding the Attorney General's remaining assertions, National Grid responds that the model tariff provides for a fully reconciling charge, incremental as used in Sections 1.0 and 2.16 of the model tariff refers to capital investments the company is not currently making or O&M expenses not recovery through another recovery mechanism, and no provision for the termination of the tariff is necessary because the tariff would terminate when recovery of all amounts to be recovered through the tariff is complete (D.P.U. 21-81, National Grid Brief at 85).

Further, National Grid argues that it is committed to delivering the energy transition to all, including low-income customers and EJ communities (D.P.U. 21-81, National Grid Brief at 61, 97-98). In response to the Attorney General's claims that the company's proposals do not adequately address low-income customers and EJ communities, National Grid argues that all customers will benefit from all grid modernization investments, including

AMI (D.P.U. 21-81, National Grid Brief at 51, citing Exhs. NG-GMP-2 (Rev. 2) at 26, 29, 32, 45-46; DPU 4-3). Further, National Grid states that it will consider the location of EJ communities and low-income customers as a selection criterion in deployment of its grid-facing grid modernization investments and will consider whether it can apply more weight to these communities (D.P.U. 21-81, National Grid Brief at 51, citing Tr. 2, at 227-228). The company, however, states that the Attorney General's recommendations to track and target benefits to low-income customers and EJ communities is impractical (D.P.U. 21-81, National Grid Brief at 52). The company asserts that its AMI Implementation Plan aligns with the environmental justice principles of EEA and that its customer engagement plan incorporates key components of EEA's environmental justice policy, including using alternative media outlets, coordinating with community partnerships, scheduling public meetings at times and locations to accommodate differing customer schedules, and providing AMI engagement, marketing, and education materials in multiple languages (D.P.U. 21-81, National Grid Brief at 65, 101, citing Exhs. DPU 5-3; CLF-NG 1-5).

c. Unitil

Unitil requests that the Department provide preapproval to it proposed customer-facing investments (D.P.U. 21-82, Unitil Brief at 9, citing Exh. Unitil-GMP at 86-100). According to Unitil, the company transitioned to AMI metering in its service territory approximately 15 years ago, and, therefore, did not include a separate AMI implementation plan with its 2022-2025 Grid Modernization Plan (D.P.U. 21-82, Unitil Brief at 6, 9).

Unitil states that, to date, it is replacing its existing TS2 AMI meters, which are reaching the end of their useful life and are no longer produced by the manufacturer, with PLX AMI meters on a business as usual schedule (D.P.U. 21-82, Unitil Brief at 9, citing Exhs. Unitil-KES-2, at 11; AG 6-7). The company maintains that the new PLX meters contain improvements essential to ensuring that customers and the company can contribute to achieving the Department's grid modernization objectives (D.P.U. 21-82, Unitil Brief at 9-10). Unitil asserts that the new PLX meters can support complex TVR rate structures and can support 15-minute load profile information and other advanced attributes that are essential to realizing the benefits of optimizing system performance, system demand, and integrating DERs (D.P.U. 21-82, Unitil Brief at 10, citing Exhs. AG 1-3; AG 6-7).

Unitil argues that, in order to complete the meter replacements by the end of the short-term grid modernization plan investment cycle in 2025, it will need to accelerate the business as usual replacement of TS2 meters with new PLX meters, incurring incremental expenses for which it seeks preapproval (D.P.U. 21-82, Unitil Brief at 10-11, citing Exh. Unitil-KES-1, at 20). Unitil maintains that it already has all of the necessary communications, back-office, and billing system requirements in place to facilitate the deployment and integration of the new PLX meters and to potentially provide more complex TVR rates to customers (D.P.U. 21-82, Unitil Brief at 12). The Company contends that any delay in implementing the PLX meters would delay availability of TVR rates and could create inequities among customers with different meters in utilizing innovative rate offerings to lower bills and/or delay further optimization of the electric grid (D.P.U. 21-82, Unitil Brief at 11, citing Exh. AG 4-4). Unitil submits that a coordinated deployment of the PLX meters will avoid the possibility of a less controlled and more costly deployment and is the last significant capital investment hurdle to advancing grid modernization objectives in Unitil's service territory (D.P.U. 21-82, Unitil Brief at 12, citing Exh. Unitil-KES-2, at 15). In response to the Attorney General's assertion that Unitil already recovers the cost of its existing meter replacements through the capital tracker, Unitil reiterates that it only is seeking recovery for incremental costs incurred as a result of accelerating the meter deployments beyond business as usual replacements (D.P.U. 21-82, Unitil Reply Brief at 9).

Unitil argues that its proposals are based on the cost/benefit framework established by the Department (D.P.U. 21-82, Unitil Brief at 21-22). Regarding the Attorney General's contention that Unitil's business case is inadequate to support accelerated cost recovery for AMI investments, the company notes the inconsistency in the Attorney General's arguments (D.P.U. 21-82, Unitil Reply Brief at 3-4, citing Attorney General Reply Brief at 2, 5). Specifically, the company points to the Attorney General's recommendation, on the one hand, that the Department rely on the business case to establish metrics, but on the other hand, to reject the business case as unreliable for other purposes (D.P.U. 21-82, Unitil Reply Brief at 3-4, citing Attorney General Reply Brief at 2, 5). Additionally, Unitil asserts that targets based on customer choices rather than prudent investments are contrary to ratemaking policy and the Department's preauthorization framework (D.P.U. 21-82, Unitil Reply Brief at 8).

Unitil disputes the Attorney General's assertion that the company first cited reliance on the 2015 business case in its initial brief, pointing out instances in the record where the company's reliance on that business case was addressed (D.P.U. 21-82, Unitil Brief at 22-23, citing Exhs. Unitil-KES-2, at 3; AG-WG-Surrebuttal at 14; Unitil Reply Brief at 4). Further, Unitil asserts that it supplemented its 2015 business case during the course of the proceeding to show that the system-wide deployment would now be cost-effective and, accordingly, has provided sufficient information supporting the benefits and costs of its proposed meter deployment (D.P.U. 21-82, Unitil Reply Brief at 9). Regarding the Attorney General's argument that replacing TS2 meters before the end of their useful life is too speculative, Unitil asserts that equipment nearing the end of its useful life is more likely to fail to the detriment of the company and customers (D.P.U. 21-82, Unitil Reply Brief at 10). The company also maintains that the Attorney General's witness acknowledged that the Department instructed the utilities to exclude the stranded costs of the replaced meters from their business cases, and so cannot now argue that Unitil should not have done so (D.P.U. 21-82, Unitil Brief at 22, citing Exh. AG-WG-1, at 52). Lastly, Unitil argues that use of the ICE tool to analyze the costs to customers from service interruptions in order to calculate a cost/benefit analysis of its grid-facing investments is appropriate because although any estimating tool will have shortcomings, the tool is broadly used in the utility industry and the Attorney General has not provided or proposed an alternative (D.P.U. 21-82, Unitil Brief at 24-25).

Regarding the Attorney General and CLF's contentions that Unitil's proposals do not sufficiently target the needs of low-income and EJ communities, Unitil contends that a significant portion of its service territory consists of such populations, and they will receive greater benefits given that their energy bills are a higher percentage of their overall income and expenses (D.P.U. 21-82, Unitil Brief at 27, 31, citing Exhs. Unitil-GMP at 63; AG 2-13; CLF-U 1-2). Unitil agrees with the Attorney General that to the extent that the Department is interested in exploring the adoption of HAN and/or DI functions it should do so in a future proceeding, because Unitil did not propose such functionalities in the instant docket (D.P.U. 21-82, Unitil Brief at 28).[53] Likewise, Unitil rejects Utilidata's similar recommendation that the Department order the Companies to implement DI, noting that Utilidata admitted that DI is an emerging technology with unknown potential future capabilities and costs (D.P.U. 21-82, Unitil Brief at 29). Instead, Unitil supports its continuing dialogue with relevant entities including Utilidata about data gathering and system operations generally and notes that it is already in the process of implementing more advanced intelligence on its system, and included numerous entities, including Utilidata, in the development of its plans for those advancements (D.P.U. 21-82, Unitil Brief at 29, citing Exh. UDI 2-1).

The company disagrees with CLF's request to condition approval of Unitil's grid modernization plan upon Unitil implementing a clear education and marketing program to all

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[53] The company states the same rationale applies to CLF's arguments for HAN implementation (D.P.U. 21-82, Attorney General Brief at 31).

residents and especially to those with limited English proficiency, arguing that Unitil does not need to advocate for customers to adopt AMI because the company already has AMI in place (D.P.U. 21-82, Unitil Brief at 30-31). Unitil submits that when it implements its customer engagement and experience and platform investments, it will be in a strong position to collect the other information CLF requests the company be required to collect, such as how the company uses its AMI system including any data collected, without delaying implementation of its grid modernization plan (D.P.U. 21-82, Unitil Brief at 31, citing Exhs. DPU 9-1; CLF-U 1-2).

C. Analysis and Findings

1. New Grid-Facing Investments

a. Introduction

In Grid Modernization Order at 99-106, the Department established the following grid modernization objectives: (1) optimize system performance (by attaining optimal levels of grid visibility, command and control, and self-healing); (2) optimize system demand (by facilitating consumer price-responsiveness); and (3) interconnect and integrate distributed energy resources. To support achievement of these objectives, the Department implemented a construct whereby an electric distribution company's grid modernization plan investments could be eligible for preauthorization, subject to a budgetary cap, with the costs afforded special ratemaking treatment using a short-term targeted cost recovery mechanism, provided certain conditions are met.[54] D.P.U. 20-69-A at 30-31; Grid Modernization Order at 106, 113-116; 216-235. Additionally, the Department stated it would consider how proposed grid modernization investments will benefit low-income customers and EJ communities. See D.P.U. 20-69-A at 31.

The Department's findings on preauthorization are based on a review of the proposed investments. D.P.U. 20-69-A at 30-31; Grid Modernization Order at 115; D.P.U. 12-76-B at 19. To be eligible for preauthorization, a company must demonstrate that its proposed investments: (1) are designed to make measurable progress towards achievement of the Department's grid modernization objectives; (2) are incremental to existing or business as usual investments; (3) are supported by a business case that shows that the projected benefits justify the costs; and (4) will result in reasonable bill impacts. D.P.U. 20-69-A at 31; Grid Modernization Order at 115-116; D.P.U. 17-05, at 469-470; D.P.U. 12-76-C at 29-30; D.P.U. 12-76-B at 15-23.

As part of its business case, the company must demonstrate that the projected cost of the proposed investments is reasonable and that the projected benefits justify the costs. D.P.U. 20-69-A at 31; Grid Modernization Order at 116; D.P.U. 12-76-B at 15, 17.

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54 Preauthorization means that the Department will not revisit whether a company should have proceeded with the investments as proposed. Grid Modernization Order at 110. The Department will, however, review the prudence of a company's implementation of the preauthorized investments. Grid Modernization Order at 110; D.P.U. 12-76-B at 19. This latter prudence determination is required before the Department can approve final recovery of any eligible grid modernization costs. Grid Modernization Order at 110.

Further, the Department has determined that investments may be treated as incremental to current investment practices if their primary purpose is to accelerate progress in achieving the grid modernization objectives. D.P.U. 20-69-A at 32; Grid Modernization Order at 116, 145-146; D.P.U. 12-76-B at 19-20.

b. NSTAR Electric

i. Overview

As part of its 2022-2025 Grid Modernization Plan, NSTAR Electric requests that the Department preauthorize a budget of approximately $48.0 million for new grid-facing investments as follows: (1) three investments in the ALF category including $5.0 million for an analytics platform, $3.0 million for interconnection automation, and $2.0 million for probabilistic power flow modeling; (2) $14.0 million for communications system modernization in the communications category; (3) two investments in the DERMS category including $10.0 million for its DERMS and $6.0 million for its dynamic DER interface investment; and (4) two investments in the measurement, support, and verification category including $4.4 million for systems support and maintenance and $3.6 million for program management and third-party measurement and verification[55] (D.P.U. 21-80, Exhs. ES-JAS-1,

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[55] Because NSTAR Electric's cost estimates for the program management, verification, and support investment category includes components applicable to both Track 1 and Track 2 investments, the Department determined it would address preauthorization for this investment category in Track 2. Track 1 Order at 64-65. We note that in the Track 1 Order, the Department incorrectly identified that the total budget for the program management, verification, and support investment category as $2.7 million. Track 1 Order at 12. The correct budget proposal for this category is $3.6 million (D.P.U. 21-80, Exh. ES-JAS-2, at 134; RR-DPU-13).

at 14-16; ES-JAS-2, at 36, 46-52, 89-124, 134, 139-143; RR-DPU-13). NSTAR Electric describes its new investments as a continuation of its grid modernization efforts to date that creates additional pathways to grid optimization (D.P.U. 21-80, Exh. ES-JAS-2, at 47).

DOER generally supports approval of NSTAR Electric's proposed Track 2 investments (DOER Brief at 8-12). The Attorney General, however, contends that NSTAR failed to adequately analyze how to upgrade its communications infrastructure (D.P.U. 21-80, Attorney General Brief at 20-21). No other party addressed the proposed new grid-facing investments. Below, the Department addresses whether to preauthorize the company's proposed new grid-facing investments. With the exception of the analytics platform investment, we address all new proposed grid-facing investments together. The Department addresses the eligibility of the company's analytics platform investment separately.[56]

ii. Measurable Progress

In order to be eligible for preauthorization, a company must demonstrate that the proposed investments are designed to make measurable progress towards achieving the Department's grid modernization objectives. Track 1 Order at 59; D.P.U. 20-69-A at 30-31; Grid Modernization Order at 116, 139; D.P.U. 12-76-B at 20. In Grid Modernization Order at 144, the Department found that the interplay of foundational grid-facing investments in advanced sensing, SCADA, DMS, load flow analytics, advanced communications, VVO, and automated feeder reconfiguration or advanced distribution automation will bring direct

56 The Department addresses eligibility for targeted cost recovery of preauthorized investments in Section III.C.3.b, below.

benefits to customers and make measurable progress toward achievement of our grid modernization objectives. Here, the company's investments in interconnection automation, probabilistic power flow modeling, communications systems modernization, wireless communications network, DERMS, dynamic DER interface, and measurement, support, and verification are interrelated to or an expansion of the foundational investments preauthorized as part of the company's 2018-2021 Grid Modernization Plan or in Track 1 of these proceedings.

NSTAR Electric's proposed investment in interconnection automation builds upon planning tools deployed as part of the company's 2018-2021 Grid Modernization Plan and will integrate the company's various planning tools, including Power Clerk, PSCAD, and Synergi, into a single platform to increase the efficiency of the DG impact study process and enhance the company's ability to process interconnection applications (D.P.U. 21-80, Exh. ES-JAS-2, at 98-99; Tr. 3, at 428-431). The projected benefits associated with the proposed interconnection automation investment include reduction of the time and engineering resources needed to process DG applications and complete interconnection studies that will, in turn, provide direct benefits to interconnecting customers and support the Commonwealth in reaching its decarbonization objectives (D.P.U. 21-80, Exhs. ES-JAS-2, at 98-100; DPU 14-6). The Department also notes that other distribution utilities and jurisdictions have successfully deployed similar platform integration solutions (D.P.U. 21-80, Exh. DPU 14-7).

Turning to the proposed probabilistic power flow modeling investment within the ALF investment category, it will build upon previously preauthorized ALF investments and is enabled by prior grid modernization term investments in Synergi and advanced forecasting (D.P.U. 21-80, Exh. ES-JAS-2, at 110-113; Tr. 3, at 432). See NSTAR Electric Company, D.P.U. 20-74, at 30-32 (2021); Grid Modernization Order at 172. This investment proposes to study long-term scenarios related to regional changes in load and generation using a simulation environment to analyze thousands of randomized scenarios based on uncertain input variables that impact the distribution system, including customer behavior, energy market prices, and asset locations on the grid (D.P.U. 21-80, Exh. ES-JAS-2, at 111). The proposed investment will improve NSTAR Electric's distribution modeling capabilities, including long-term projections of DERs (D.P.U. 21-80, Exh. ES-JAS-2, at 110-113; Tr. 3, at 432). The proposed investment will also facilitate the consideration of various scenarios of bulk DER participation, and therefore supports the Commonwealth in reaching its decarbonization objectives (D.P.U. 21-80, Exh. DPU 13-4).[57]

Further, in Track 1 of the instant proceeding, NSTAR Electric demonstrated that its investments in communications infrastructure would support the connectivity required for control room technology (i.e., SCADA, DMS, OMS, DERMS). Track 1 Order at 64. Accordingly, the Department preauthorized the company's investments to improve its

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57 The Department disallowed the company's proposed congestion management study related to FERC Order 2222 on the basis that it was premature and outside the scope of the instant proceedings. D.P.U. 21-80/D.P.U. 21-81/D.P.U. 21-82, Interlocutory Order at 7-8 (2021). The Department notes, however, that the company's investment in probabilistic power flow modeling will enable consideration of various scenarios of bulk participation without any incremental investment to do so. Therefore, the ability to model potential FERC Order 2222 scenarios constitutes an additional benefit of the solution (D.P.U. 21-80, Exh. DPU 13-4).

wireless communications network, including installation of new base radios, infrastructure, and new devices equipped with IP communications, finding that these investments were the same or substantially similar to the technologies preauthorized by the Department in NSTAR Electric's 2018-2021 Grid Modernization Plan and that they would make measurable progress towards achievement of the Department's grid modernization objectives. Track 1 Order at 63-64.

Here, NSTAR Electric proposes additional communications system investments to modernize its existing communications infrastructure and transition to an IP communications network by installing IP communications to existing field devices to improve the connectivity of the company's FAN (D.P.U. 21-80, Exh. ES-JAS-2, at 89-93). The Department determines that the communications system modernization investment will increase operational efficiency and enable faster troubleshooting of communications disruptions to improve system availability, increasing the ability of assets in the field to support real-time system functions such as DMS, VVO, and DERMS (D.P.U. 21-80, Exh. DPU 14-6). In addition, the proposed investment will enable further remote access to field devices to improve maintenance and reduce disruptions and will also leverage the company's prior and ongoing investments in DMS, VVO, and DERMS (D.P.U. 21-80, Exh. DPU 14-6).

The Attorney General argues that NSTAR Electric is biased towards owning and constructing its own communications network and recommends that the Department condition approval of the communications system modernization investment on the company's demonstrating that construction of its own communications facilities is superior to obtaining services from public carriers (D.P.U. 21-80, Attorney General Brief at 21, citing D.P.U. 21-80, Exh. AG-WG-1, at 38). We disagree. For its planned investment in communications system modernization, NSTAR Electric proposes to expand the capacity of the company's existing private telecommunications network by supplementing existing infrastructure that the company built prior to implementing any preauthorized grid modernization investments and building new base stations to reduce data traffic congestion in areas with high concentrations of field devices (D.P.U. 21-80, Exh. DPU 14-3). In doing so, the proposed investment in communications system modernization further strengthens the company's wireless communications investment that the Department approved in D.P.U. 15-122 and the Track 1 Order. Grid Modernization Order at 41, 172-173; Track 1 Order at 63-67.

Similarly, the company's proposed investments in DERMS and dynamic DER interface are interrelated to previous foundational grid-facing investments. For example, the company's proposed DERMS will be directly integrated with the company's ECS/SCADA[58] and DMS (D.P.U. 21-80, Exhs. ES-JAS-2, at 118; DPU 7-3; DPU 12-1 & Att. 12-1(a); AG 5-13(b)). As part of its investments in DERMS, NSTAR Electric proposes to develop a standardized approach to integrating large DG facilities into its distribution system (D.P.U. 21-80, Exh. ES-JAS-2, at 118). In addition, NSTAR Electric will assess the feasibility of adopting a standardized interconnection interface for 24 front-of-the meter

58 ECS is the terminology NSTAR Electric uses to refer to its SCADA system (D.P.U. 21-80/D.P.U. 21-81/D.P.U. 21-82, Tr. 3, at 408).

DG facilities with planned integration of these facilities into its DERMS platform (D.P.U. 21-80, Exh. ES-JAS-2, at 122-123). Further, as described above, NSTAR Electric's communications system modernization investment will improve the system availability of field devices by reducing disruptions that could impact real-time systems including DERMS (D.P.U. 21-80, Exh. DPU 14-6). Importantly, NSTAR Electric plans to align the deployment of DERMS with the first of its control centers to have DMS capabilities (D.P.U. 21-80, Exh. DPU 12-4). Integration with the company's ECS/SCADA and DMS will enable the proposed DERMS platform to dispatch resources, including the 24 DG facilities proposed as part of the company's dynamic DER interface program, based on the as-operated power flow model, and facilitate the availability and control of these resources in advanced applications such as VVO (D.P.U. 21-80, Exhs. ES-JAS-2, at 117-118, 122-124; DPU 7-3).

For its systems support and maintenance investment, NSTAR Electric has shown that the additional engineering resources will provide the company with dedicated support for its deployments in advanced forecasting software, DMS applications, and other system optimization and planning investments, such as VVO and DERMS, that will enhance the value of investments in technology implemented under the 2018-2021 and 2022-2025 Grid Modernization Plans (D.P.U. 21-80, Exhs. ES-JAS-2, at 141-143; DPU 13-1). For example, the proposed additional engineers will develop weekly forecasts, including projecting the solar output of DG facilities based on weather conditions, that will optimize the company's distribution system in coordination with control room technologies such as DMS and DERMS

(D.P.U. 21-80, Exh. DPU 14-6). Further, the Department determines that incremental engineering support is appropriate as the company continues to deploy grid modernization investments with an increased emphasis on operational software systems (D.P.U. 21-80, Exhs. ES-JAS-2, at 141-143; DPU 13-1). The proposed systems support and maintenance investment and the incremental engineering resources to administer, maintain, and identify opportunities of the new applications and tools being deployed will maximize the value from the deployment of these investments.

The proposed program management and measurement and verification investment would provide a dedicated management team to oversee, track, and report on grid modernization plan implementation activities, as well as to engage a third party for measurement and verification activities (D.P.U. 21-80, Exh. ES-JAS-2, at 3, 44-45, 134-139). The proposed investment will also coordinate the deployment of all proposed investments and will therefore support implementation of the 2022-2025 Grid Modernization Plan in an efficient and effective manner (D.P.U. 21-80, Exh. ES-JAS-2, at 44-45, 134-139). Further, NSTAR Electric states that along with National Grid and Unitil, the Companies have engaged Guidehouse, Inc. ("Guidehouse") to provide third-party management and verification services to evaluate progress towards grid modernization objectives and the results of infrastructure and performance metrics (D.P.U. 21-80, Exh. ES-JAS-2, at 45, 135). This evaluation includes both continuing (i.e., Track 1) and new investments (i.e., Track 2) (D.P.U. 21-80, Exh. ES-JAS-2, at 135). The Department finds that the proposed investment is consistent with our establishment of a formal evaluation process for preauthorized grid modernization investments to provide a uniform statewide approach to study the deployment of the preauthorized grid modernization investments to ensure benefits are both maximized and achieved with greater certainty, that future investments are more effective, and to measure the progress made towards achievement of our grid modernization objectives. Grid Modernization Order at 204-205.

For the reasons discussed above, the Department determines that the proposed investments in interconnection automation, probabilistic power flow modeling, communications system modernization, DERMS, dynamic DER interface, systems support and maintenance, program management, and third-party measurement and verification will make measurable progress toward one or more the Department's grid modernization objectives to optimize system performance (by attaining optimal levels of grid visibility, command and control, and self-healing), to optimize system demand (by facilitating consumer price-responsiveness), and to interconnect and integrate DERs (D.P.U. 21-80, Exhs. ES-JAS-2, at 89, 94, 111; DPU 1-1; DPU 15-3). Grid Modernization Order at 103, 116, 137-145, 167, 172-173.

iii. Incremental

Next, only investments that are incremental to existing or business as usual investments are eligible for preauthorization. The Department has stated that investments may be treated as incremental to current investment practices if their primary purpose is to accelerate progress in achieving the grid modernization objectives. See D.P.U. 12-76-B at 19-20. Regarding the proposed interconnection automation investment, the Department determines that the greater efficiency it brings to the interconnection assessment process as DERs continue to grow is an important step to integrating DERs and achieving our grid modernization objective of integrating and interconnection DERs. Specifically, the proposed interconnection automation investment will result in a projected 75 percent reduction in internal company time required to process DG applications, with the ultimate goal to completely automate the processing of simplified track interconnection applications (D.P.U. 21-80, Exh. DPU 14-6).

Additionally, the Department finds that the probabilistic power flow modeling investment may be treated as incremental to the company's existing or business as usual investments because we find that a primary purpose of this investment is to accelerate progress in achieving the Department's grid modernization objective of interconnecting and integrating DERs (D.P.U. 21-80, Exhs. DPU 13-1; DPU 14-6; DPU 15-3). D.P.U. 12-76-B at 19-20. As noted above, the proposed investment will improve NSTAR Electric's distribution modeling capabilities, including long-term projections of DERs, and will also facilitate the consideration of various scenarios of bulk DER participation (D.P.U. 21-80, Exhs. ES-JAS-2, at 110-113; DPU 13-4; Tr. 3, at 432). Further, in addition to supporting integration of DERs, the proposed probabilistic power flow modeling investment will provide system planning engineers with analysis support tools that will improve reliability and increase system efficiency (D.P.U. 21-80, Exh. DPU 1-1).

Over the 2022-2025 Grid Modernization Plan term, as part of its proposed communications system modernization investment, NSTAR Electric proposes to convert

1,350 of its 4,000 existing field devices from serial to IP communications (D.P.U. 21-80, Exhs. ES-JAS-2, at 93; DPU 13-2; DPU 15-2). The conversion to IP communications for these existing devices builds directly upon the company's preauthorized Track 1 wireless communications improvements investment in which the company will deploy 1,200 new devices using IP communications (D.P.U. 21-80, Exh. DPU 15-2). NSTAR Electric's proposed deployment schedule to convert over one third of existing field devices to IP communications, coupled with the company's deployment of new field devices with IP communications for a total of 2,550 new and existing devices using IP communications, will accelerate the migration to an end-to-end IP communications network (D.P.U. 21-80, Exh. DPU 15-2).[59] The Department determines that the proposed investments will accelerate the transition of NSTAR Electric's communications infrastructure toward an end-to-end IP communications network that will support the full functionality of the modernized grid.

Additionally, the DERMS and dynamic DER interface investments are primarily driven by the value these investments provide to optimize the distribution system for increased hosting capacity and carbon reduction (D.P.U. 21-80, Exh. DPU 13-1). These DERMS investments also advance the continued growth and adoption of DERs on the distribution system (D.P.U. 21-80, Exh. ES-JAS-2, at 119). As part of the dynamic DER interface investment, NSTAR Electric will demonstrate the use of new technology (i.e.,

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59 The remaining population of approximately 2,650 devices will be migrated to IP communications as part of its business as usual capital plan beginning in 2026 (D.P.U. 21-80, Exh. DPU 13-2).

programmable controller, communications equipment including modem and router, and digital recloser) that is not currently deployed on the company's distribution system (D.P.U. 21-80, Exhs. ES-JAS-2, at 122-123; DPU 12-9; DPU 13-1). Furthermore, the company will deploy the dynamic DER interface investment across company- and customer-owned facilities to reflect a range of project factors including location, sizing, inverter equipment, and interconnection type (e.g., stand-alone solar, solar paired with energy storage, etc.) (D.P.U. 21-80, Exhs. ES-JAS-2, at 123; DPU 14-14). As a result of the investment, NSTAR Electric estimates (1) an 80 percent reduction in voltage violations at the point of interconnection, and (2) a 50 percent reduction in the number of hours that a DG facility is offline due to unplanned conditions (D.P.U. 21-80, Exh. DPU 14-6). The proposed approach is also expected to facilitate the company's ability to scale integration of additional DG facilities (D.P.U. 21-80, Exhs. ES-JAS-2, at 123; DPU 14-14).

For its systems support and maintenance investment, NSTAR Electric proposes to hire six full-time engineers and to dedicate two engineers to support each of the following three grid modernization systems: (1) DMS model maintenance; (2) optimization support, including implementation of optimization functions (e.g., VVO schemes); and (3) system forecasting, including development of detailed long-term forecasts of load, energy storage, demand response, and DG to support probabilistic modeling activities (D.P.U. 21-80, Exh. ES-JAS-2, at 141-142). The proposed engineering resources are beyond the company's existing workforce and will be dedicated to maintaining supporting real-time operations and system planning tools deployed as part of the company grid modernization plan (D.P.U. 21-80, Exhs. ES-JAS-2, at 141-143; DPU 13-1).

The proposed program management and third-party measurement and verification investment would also provide dedicated program management to oversee and coordinate the deployment of continuing and new preauthorized grid modernization investments, as well as to engage a third-party evaluator, to conduct measurement and verification activities. Moreover, the engagement by NSTAR Electric, National Grid and Unitil, jointly, of Guidehouse as the third-party evaluator will assist in ensuring a uniform statewide approach to study the deployment of the preauthorized grid modernization investments. In order to assess the equitable distribution of benefits of grid modernization benefits, the Companies should include a uniform statewide approach to evaluating equity of the preauthorized grid modernization investments. The Department is persuaded that coordination, oversight, and management of the implementation of grid modernization plan investments, coupled with the third-party evaluation, tracking of benefits, and identification of areas for improvement, will support the effective and efficient implementation of the 2022-2025 Grid Modernization Plan and thus has a primary purpose in accelerating progress towards our grid modernization objectives (D.P.U. 21-80, Exh. ES-JAS-2, at 44-45, 134-139).

In sum, based on the reasons discussed above, the Department determines that the proposed investments in interconnection automation, probabilistic power flow modeling, communications system modernization, DERMS, dynamic DER interface, systems support and maintenance, program management, and third-party measurement and verification are incremental to existing investments or can be treated as incremental because they have a primary purpose to accelerate achievement of one or more of our grid modernization objectives (D.P.U. 21-80, Exhs. ES-JAS-2, at 98-99, 141-143; DPU 13-1; DPU 14-6). Grid Modernization Order at 116, 146-149.

iv. Business Case

In order for the Department to determine eligibility for preauthorization, the company must demonstrate that the projected costs of the proposed investments are reasonable and that the projected benefits justify the costs. D.P.U. 20-69-A at 31; Grid Modernization Order at 116; D.P.U. 12-76-B at 15, 17. To develop a cost estimate for the interconnection automation investment, the company conducted an industry-wide survey of companies with interconnection automation software solutions (D.P.U. 21-80, Exh. DPU 1-4). NSTAR Electric held preliminary discussions with these companies and other vendors to determine estimated licensing and implementation costs (D.P.U. 21-80, Exh. DPU 1-4). Further, in addition to the benefits identified above, the proposed interconnection automation investment will allow for more accurate and timely information to interconnecting customers and lead to a 25 percent reduction in the nameplate capacity of DG applications that withdraw from the study process prior to completion of their project assessment (D.P.U. 21-80, Exh. DPU 14-6). The proposed interconnection automation investment is also projected to result in an estimated (1) 25 percent reduction in reliance upon internal engineering resources used to complete interconnection studies, and (2) 50 percent reduction in external engineering resources retained to support interconnection studies (D.P.U. 21-80, Exh. DPU 14-6).

For the proposed probabilistic modeling investment, the company based its cost estimates on subject matter experts' experience and historical costs from similar projects (D.P.U. 21-80, Exh. DPU 1-4). The company also relied upon preliminary discussions with current and prospective vendors and expects to use a competitive bid process to select vendors for cloud computing, software licensing, and systems integration services (D.P.U. 21-80, Exh. DPU 1-4). Additionally, as noted above, the proposed investment in probabilistic power flow modeling will provide system planning engineers with analysis support tools that will improve reliability, increase system efficiency, and integrate DERs (D.P.U. 21-80, Exh. DPU 1-1). The proposed probabilistic power flow modeling investment represents the final phase of the company's ALF investment category and is projected to result in an estimated (1) 50 percent reduction in engineering time used to build load flow models incorporating the results of advanced forecasting, and (2) ten-fold increase in the number of scenarios considered for long-term capital projects (D.P.U. 21-80, Exhs. DPU 13-1; DPU 14-6). In the company's grid-facing business case,[60] the probabilistic power flow modeling investment received the highest benefit score per million dollar in investments of all investments proposed for the 2022-2025 Grid Modernization Plan term

60 The company's business case compares the benefits of proposed investments against their estimated costs. The analysis consists of a multi-step process that assesses the degree to which each grid modernization investment contributes to categories of benefits designed to reflect the Department's grid modernization objectives. As part of the analysis, a multi-disciplinary team of subject matter experts generated a list of grid modernization investment benefit scores and these investments' estimated costs (D.P.U. 21-80, Exh. DPU 1-1).

(D.P.U. 21-80, Exh. DPU 1-1 & Att. (a)). NSTAR Electric's prior investments in ALF (i.e., the company's 2018-2021 Grid Modernization Plan investments in Synergi and advanced forecasting), allow it to enable further functionality such as probabilistic modeling at a relatively lower cost (D.P.U. 21-80, Exhs. DPU 1-1; DPU 15-3).

For its proposed communications system modernization investment, NSTAR Electric developed the costs estimates using subject matter experts' experience, and average historical costs from comparable projects with similar equipment (D.P.U. 21-80, Exh. DPU 1-4 & Att. (n)). The company categorized the costs on the basis of remote terminal unit upgrades, new devices, commissioning-only expenses, remotes, IT work, and labor hours (D.P.U. 21-80, Exh. DPU 1-4 & Att. (n)). As noted above, the benefits of the proposed communications system modernization investment include increased operational efficiency, faster troubleshooting of communications disruptions to improve system availability, increased ability of assets in the field to support real-time system functions, and further remote access to field devices to improve maintenance and reduce disruptions and will also leverage the company's prior and ongoing investments in DMS, VVO, and DERMS (D.P.U. 21-80, Exh. DPU 14-6).

NSTAR Electric developed its DERMS and dynamic DER interface investment cost estimates using subject matter expertise, preliminary discussions with vendors, vendor quotes, and historical costs from comparable projects (D.P.U. 21-80, Exh. DPU 1-4). Prior to selecting a specific DERMS solution, the company will conduct a competitive solicitation (D.P.U. 21-80, Exh. DPU 1-4). As noted above, the benefits associated with these investments include enabling the continued growth and adoption of DERs on the distribution system. Specifically, 456 circuits will be enabled with DERMS capability as a result of the proposed investments (D.P.U. 21-80, Exh. DPU 14-6).[61] Importantly, the proposed investments will facilitate the company's ability to accommodate additional DERs in the future. In doing so, the DERMS and dynamic DER interface investments will support the Commonwealth in reaching its decarbonization objectives.

To calculate the costs of the proposed additional engineers in the systems support and maintenance investment, the company used a blended labor rate for six employees within the engineer classification (D.P.U. 21-80, Exh. DPU 1-4). The company states that the specific compensation rate and employment start dates may fluctuate and shift the budget deployment timing (D.P.U. 21-80, Exh. DPU 1-4). As noted above, NSTAR Electric identifies several benefits associated with the systems support and maintenance investment.

In addition, NSTAR Electric developed its cost estimate for the program management and third-party measurement and verification investment using data acquired during the deployment of its 2018-2021 Grid Modernization Plan (D.P.U. 21-80, Exh. DPU 1-4, at 4). In further support of the cost estimate, the company provided a detailed budget including a blended monthly rate for project management activities and bi-annual payments for measurement and verification activities (D.P.U. 21-80, Exh. DPU 1-4 & Att. (j)). As noted above, the dedicated oversight, coordination, and management of the deployment of grid

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[61] Currently, no circuits on the company's system are enabled with DERMS (D.P.U. 21-80, Exh. DPU 14-6).

modernization investments, as well as third-party evaluation of progress will assist in an efficient and effective implementation of the 2022-2025 Grid Modernization Plan that ensures benefits are both maximized and achieved with greater certainty.

Accordingly, after review, the Department finds that the projected costs of the proposed investments in interconnection automation, probabilistic power flow modeling, communications system modernization, DERMS, dynamic DER interface, systems support and maintenance, program management, and third-party measurement and verification are reasonable and the projected benefits justify the costs (D.P.U. 21-80, Exhs. ES-JAS-2, at 94, 139; DPU 1-1 & Att. (a); DPU 1-4 & Atts.; DPU 13-5; DPU 15-1).

v. Bill Impacts

To be eligible for preauthorization, a company must demonstrate that its proposed investments will result in reasonable bill impacts. D.P.U. 20-69-A at 31; Grid Modernization Order at 116; D.P.U. 12-76-C at 29-30; see also G.L. c. 25, § 1A. NSTAR Electric has submitted a bill impact analysis allowing the Department to analyze the estimated increases that would result to each applicable rate class from proposed grid-facing investments, including continuing investments preauthorized in Track 1, over four years (D.P.U. 21-80, Exhs. DPU 4-3 & Atts.; DPU 5-3, Atts.; DPU 9-2 & Atts.;

DPU 9-3 & Atts.; DPU 9-4 & Atts.; DPU 10-3 & Atts; Tr. 2, at 234-237).[62] The Department finds that the bill impacts resulting from the proposed total estimated costs for the 2022-2025 Grid Modernization Plan are reasonable in light of the anticipated benefits that these investments will provide. G.L. c. 25, § 1A.

vi. Analytics Platform

NSTAR Electric's proposed analytics platform investment within its ALF investment category is intended to facilitate advanced analysis of large data sets by establishing a cloud infrastructure, including data storage and web services, to support software solutions and enhance processing capabilities (D.P.U. 21-80, Exhs. ES-JAS-1, at 15-16; ES-JAS-2, at 103-104). NSTAR Electric states that the proposed investment would integrate multiple data sources and reduce the resources required to prepare data for analysis (D.P.U. 21-80, Exh. ES-JAS-2, at 103-104). In addition, the company claims that the proposed analytics platform would enable other grid modernization investments, including power quality monitoring, VVO, and probabilistic power flow modeling (D.P.U. 21-80, Exhs. ES-JAS-2, at 101; DPU 12-1, Att. B).

To begin, the Department determines that the company has not adequately distinguished the functions of the proposed analytics platform from the ADMS and ALF

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62 The company estimates bill impacts to be in the range of 0.02 percent to 0.9 percent from its proposed new and continuing grid-facing investments over the four-year term, with the exact amount dependent on the final level of investments (D.P.U. 21-80, Exhs. DPU 4-3 & Atts.; DPU 5-3, Atts.; DPU 9-2 & Atts.; DPU 9-3 & Atts.; DPU 9-4 & Atts.; DPU 10-3 & Atts; Tr. 2, at 234-237).

investments for which the Department has to date preauthorized $46.5 million in investments. Specifically, the Department finds that ADMS serves as the central analytical platform for grid data (D.P.U. 21-80, Exhs. ES-JAS-2, at 55-56, 59-60; DPU 13-1). Further, the distribution management system, which is central to ADMS, will serve as the platform for optimization of the modern grid (D.P.U. 21-80, Exh. ES-JAS-2, at 59). While the proposed analytics platform may enhance prior term investments in ALF, the Department is not persuaded that the proposed analytics platform directly supports ADMS (D.P.U. 21-80, Exh. DPU 12-1 & Atts. (a), (b)). Accordingly, the Department is not convinced that a separate platform to facilitate data analysis is necessary as grid modernization investment given that ADMS serves as the central analytical platform for grid data.

Additionally, in Grid Modernization Order at 172, the Department preauthorized $17.0 million in investments in DMS technology and ALF. Subsequently, the Department preauthorized a supplement budget of $13.0 million for DMS investments and to automate the company's ALF tool, including enhancing its load and generation forecasting capabilities and updating its data historian environment to improve engineering analysis and ability to respond to system condition changes. D.P.U. 20-74, at 24-26. Further, in Track 1 of the present proceeding, the Department preauthorized $16.5 million in ADMS investments to continue implementation of DMS, including control room technology to model its entire distribution system based on real-time field device telemetry.[63] Track 1 Order at 77. Based on the above, the Department questions whether some redundancy exists between the proposed analytics platform and the preauthorized ADMS and ALF tool investments, as well as whether these preauthorized investments can be leveraged to perform the functions of the proposed analytics platform. Accordingly, the Department is unable to determine if the proposed analytics platform is indeed incremental to the company's existing investments or whether the investment should qualify for preauthorization as a grid modernization investment.

Additionally, the Department notes that as part of the 2018-2021 Grid Modernization Plan term, the company deployed VVO and power quality monitoring in the absence of a separate analytics platform. See D.P.U. 22-40, Grid Modernization Plan Term Report at 42, 69-75. Given that the company has deployed VVO and power quality monitoring in the absence of a separate analytics platform, the Department finds that the company has not adequately demonstrated that the proposed analytics platform is necessary to enable investments in power quality monitoring and VVO (D.P.U. 21-80, Exh. ES-JAS-2, at 101). Further, we are also not persuaded that the proposed analytics platform is a prerequisite to the probabilistic power flow modeling investment (D.P.U. 21-80, Exh. DPU 12-1, Att. B). Although the platform may enhance the probabilistic power flow modeling investment and

63 The Department also preauthorized for the 2022-2025 Grid Modernization Plan term \$5.4 million in unexpended calendar year 2021 budget amounts to complete ADMS investments preauthorized as part of the company's 2018-2021 Grid Modernization Plan, for a total ADMS budget of \$21.9 million. Track 1 Order at 11, 77.

may be an appropriate investment as part of the company's on-going business, the interaction of the proposed investments is unclear (D.P.U. 21-80, Exhs. ES-JAS-2, at 113; DPU 12-1, Att. B). In sum, the Department determines that the company failed to demonstrate that the proposed analytics platform qualifies as an eligible grid modernization investment. Therefore, we decline to preauthorize the proposed analytics platform investment.

The Department recognizes that an analytics platform may broadly support data storage and processing capabilities, including, for example, expansion of new models for real-time operations in the company's control rooms and on-demand analysis in engineering use cases (D.P.U. 21-80, Exhs. DPU 13-3; DPU 14-6). Notwithstanding our decision not to preauthorize the proposed analytics platform investment, nothing precludes the company from deploying the analytics platform as part of its normal course of business and seeking cost recovery through traditional ratemaking.

vii. Conclusion

Based on the foregoing, the Department preauthorizes a four-year $43 million budget for new grid-facing investments in ALF ($2.0 million for probabilistic power flow modeling and $3.0 million for interconnection automation), communications system modernization ($14.0 million), DERMS including dynamic DER interface ($16.0 million), and measurement, support, and verification ($8.0 million). Additionally, for the reasons discussed above, the Department declines to preauthorize $5.0 million in investments for the analytics platform.

Regarding the company's DERMS investments, while we preauthorize the company's proposed investments in DERMS, the Department expects the company to take all necessary steps to integrate its DERMS with control room technology (i.e., ADMS) and to maximize benefits to customers. As part of its DERMS project, NSTAR Electric will assess whether and how to consolidate the company's existing, stand-alone DERMS solution used for energy efficiency demand response programs into a single set of DER assets available for monitoring and control in its proposed DERMS (D.P.U. 21-80, Exhs. ES-JAS-2, at 118; DPU 7-3; DPU 12-6). Through this evaluation process, the company expects to determine if a module within the existing DERMS can be identified to monitor and control all DERs or whether a new solution is necessary (D.P.U. 21-80, Exhs. DPU 7-3; DPU 12-5). If a new solution is necessary, the Department directs the company to take all necessary steps to minimize stranded costs and to preserve existing functionality intended for energy efficiency demand response programs as the company transitions to a new solution.[64] The Department also recognizes that DERMS is a platform technology that may provide significant benefits to the company's electric power system and its customers (D.P.U. 21-80, Exhs. ES-JAS-2, at 117-118; DPU 7-3). As the company develops its DERMS and introduces new functionalities, the Department emphasizes that the company must act prudently and avoid

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64 The Department cautions NSTAR Electric that it shall take measures to ensure that it does not receive double recovery for this investment. For instance, a similar interface is utilized by the energy efficiency Program Administrator (see D.P.U. 21-80, Exhs. ES-JAS-2, at 118; DPU 7-3; DPU 12-6). As a result, NSTAR Electric shall demonstrate in its annual cost recovery filings that it is not receiving double recovery for this investment.

investments or decisions that lead to premature retirement of assets and/or do not allow for expanded DERMS capabilities in the future. Track 1 Order at 69-70.

Additionally, in Grid Modernization Order at 222, the Department limited recovery of incremental labor expense through the grid modernization factor to new positions created after May 10, 2018, unless the company can demonstrate that the associated costs are not already recovered through rates. Accordingly, the company shall comply with the Department's directives for identifying and tracking incremental grid modernization operations and maintenance expense, including application of the five-step incremental labor and overhead and burdens tests. Grid Modernization, D.P.U. 15-120-E/D.P.U. 15-121-E/ D.P.U. 15-122-E (September 7, 2022).

Consistent with Grid Modernization Order at 173, the four-year budget that we preauthorize today is a cap. Because these are new rather than continuing investments, the cap applies to the total proposed budgetary amount rather than to each investment category as the Department approved for the continuing grid-facing investments. Track 1 Order at 76-77. We determine that the level of flexibility previously afforded for new grid-facing investments in the first grid modernization term is warranted for the new grid-facing investments featured in the second grid modernization term. See Grid Modernization Order at 107-108. Accordingly, NSTAR Electric may shift spending among the new preauthorized grid-facing categories subject to the budget cap. Finally, any spending over the total budget cap is not eligible for targeted cost recovery through the GMF, and instead, may be recovered by the company in a base distribution rate proceeding subsequent to a prudency finding by the Department in a GMF filing or term review Order. Further, the Department's preauthorization only applies to expenditures during the approved four-year term. Track 1 Order at 77.

Finally, in discharging its responsibilities under chapters 25 and 164 of the general laws, the Department must prioritize, among other things, equity, with respect to itself and the entities it regulates. G.L. c. 25, § 1A. Consistent with D.P.U. 20-69-A at 31, the Department finds that the company's proposed grid-facing investments will deliver both direct and indirect benefits of a modernized grid to all customers within the company's service territory. However, the company should consider EJ communities as part of its deployment strategies for those preauthorized new and continuing investments that can provide location-specific benefits in order to ensure EJ communities receive benefits from these grid-facing investments.

c. National Grid

i. Overview

As part of its 2022-2025 Grid Modernization Plan, National Grid seeks Department preauthorization of $31.0 million in new grid-facing investments as follows: (1) 1.9 million for an investigative study in the DERMS category; (2) $15.7 million for DERMS implementation in the DERMS category; (3) $7.0 million for advanced short-term load forecasting capabilities in the DERMS category; (4) $6.2 million for an active resource integration investment in the demonstration category; (5) $0.2 million to evaluate local export power control in the demonstration category; and (6) $4.4 million for program management and third-party measurement and verification[65] (D.P.U. 21-81, Exhs. NG-GMP-1, at 11-13; NG-GMP-2 (Rev. 2) at 85-101, 112-128). National Grid maintains that its new investments, along with the investments in categories previously preauthorized by the Department, will provide enhanced and new functionality to enable increased DER integration capacity (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 10).

DOER generally supports approval of the proposed Track 2 investments (DOER Brief at 8-12). The Attorney General contends that National Grid's use of DOE's ICE tool overestimates the reliability benefits of proposed investments (D.P.U. 21-81, Attorney General Brief at 19-22). No other party addressed the proposed grid-facing investments.

For reasons stated below, the Department categorizes each of National Grid's proposed Track 2 grid-facing investments as falling within the DERMS investment category. The company's proposed investments in DERMS investigation, implementation, and advanced forecasting are interdependent, and the Department concludes it is appropriate to address these three investments together (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 85-101). Furthermore, the two proposed demonstration projects (i.e., active resource integration and local export power control) are closely interrelated to the deployment of DERMS (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 93, 112-126). In conjunction with the

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[65] National Grid's cost estimates for program management and third-party measurement and verification includes components applicable to both Track 1 and Track 2 investments (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 127-128). Because the record did not include a disaggregated budget for each track, the Department stated it would address this investment category as part of Track 2. Track 1 Order at 82.

proposed DERMS investments, the demonstration projects will provide the company with enhanced visibility and control of DERs. We find that these two proposed investments fall squarely within the DERMS investment category.

ii. Measurable Progress

In order to be eligible for preauthorization, a company must demonstrate that the proposed investments are designed to make measurable progress towards achieving the Department's grid modernization objectives. Track 1 Order at 59; D.P.U. 20-69-A at 30-31; Grid Modernization Order at 116, 139; D.P.U. 12-76-B at 20. In Grid Modernization Order at 144, the Department found that the interplay of foundational grid-facing investments in advanced sensing, SCADA, DMS, load flow analytics, advanced communications, VVO, and automated feeder reconfiguration or advanced distribution automation, will bring direct benefits to customers and make measurable progress toward achievement of our grid modernization objectives. The Department finds that the proposed DERMS investments are closely linked with previous foundational grid-facing investments. For example, the company's proposed DERMS will be directly integrated with the company's ADMS infrastructure, including distribution-level SCADA and DMS advanced applications (D.P.U. 21-81, Exh. DPU 11-7). The proposed DERMS will use the as-operated network model hosted in ADMS and real-time system conditions to enable grid management and optimization of the distribution system and DERs (D.P.U. 21-81, Exh. DPU 11-6). The company's investments in advanced short-term load forecasting capabilities will support ADMS deployment and will be subsequently integrated with the DERMS platform

(D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 99). National Grid's control center will also have access to DERMS to enable oversight over the operation and management of DERs (D.P.U. 21-81, Exh. AG 2-2). Further, the investments in DERMS will operate closely with existing grid modernization investments such as line sensors, IT, SCADA, VVO, and the data management platform to support all of the Department's grid modernization objectives (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 86, 95). The Department determines that the proposed DERMS investments will be integrated with the foundational grid-facing investments deployed as part of the 2018-2021 Grid Modernization Plan but also constitutes a next step towards achieving each of our grid modernization objectives.

Additionally, the proposed active resource integration demonstration project will inform the implementation of DERMS and enables the company to test active management of DG in a manner that minimizes the economic impacts from potential curtailment while maintaining safety and reliability of the distribution grid (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 114, 119). Under certain scenarios, active management of DG may provide an alternative to upgrading the system to accommodate increasing DG interconnections in areas where hosting capacity is saturated (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 113-114). Further, though the level of system integration has not been finalized, the company anticipates that the active resource integration investment will be integrated with other grid modernization investments such as SCADA, ADMS, and advanced short-term load forecasting (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 114).

Turing to the proposed local export power control project, this demonstration will allow the company to monitor and verify the net zero thermal impact on the distribution system of a planned solar and storage project in the town of Orange (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 124). While National Grid will work with a single customer to interconnect a planned DG project to the company's distribution system, validate power control system standards, monitor the functionality of the equipment under a variety of constraints, and ensure true net zero thermal impact is maintained, the company will also study the applicability of this technology to front-of-meter stand-alone interconnection projects and further expand the investment to other interconnection projects based on lessons learned (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 124). In particular, the learnings from the proposed local export power control demonstration project will advance interconnections in densely populated areas and for small commercial and industrial customers (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 125). Further, the proposed project will test a power control technology that could establish an export capacity when performing reviews and engineering analysis (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 123 n.41).[66]

The proposed program management and third-party measurement and verification investments would provide a dedicated management team to oversee, track, and report on grid modernization plan implementation activities, as well as to engage a third party for

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66 The concept of export capacity and export-limiting technologies was addressed jointly by stakeholders in Distributed Generation Interconnection, D.P.U. 19-55, and was retained in proposed consensus revisions to the tariff on standards for interconnection of DG (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 123 n.41).

measurement and verification activities (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 127-128). The proposed investments will also coordinate the deployment of all proposed investments and will therefore support implementation of the 2022-2025 Grid Modernization Plan in an efficient and effective manner (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 127-128). The Department finds that the proposed investment is consistent with our establishment of a formal evaluation process for preauthorized grid modernization investments to provide a uniform statewide approach to study the deployment of the preauthorized grid modernization investments to ensure benefits are both maximized and achieved with greater certainty, that future investments are more effective, and to measure the progress made towards achievement of our grid modernization objectives. Grid Modernization Order at 204-205.

Accordingly, based on the above and consistent with our findings in Grid Modernization Order at 137-145, the Department finds that the new investments in DERMS, including the active resource integration and local export power control demonstration projects, and program management and third-party measurement and verification will make measurable progress towards achievement of all three Department grid modernization objectives, and in particular, the Department's objective to interconnect and integrate DERs. Further, the proposed investments are consistent with and support the Commonwealth's energy and climate goals.

iii. Incremental

Next, only investments that are incremental to existing or business as usual investments are eligible for preauthorization. The Department has stated that investments may be treated as incremental to current investment practices if their primary purpose is to accelerate progress in achieving the grid modernization objectives. See D.P.U. 12-76-B at 19-20. National Grid does not currently have any active programs to implement DERMS to target areas with significant levels of DER penetration (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 92). Although the company has a DERMS for energy efficiency demand response management, the proposed DERMS platform will enable additional use cases, including DER registration and program enrollment, long-term and operational DER planning, and DER settlement (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 89; DPU 11-4). To support these new use cases, the company will demonstrate the use of new technologies (i.e., a centralized DER dispatch engine and grid edge control feature) that are not currently deployed on the company's distribution system (D.P.U. 21-81, Exhs. DPU 12-8; DPU 13-4). National Grid's proposed investment in advanced short-term load forecasting capabilities will also allow for advanced identification of system constraints that will enable the company to integrate and use DERs through the DERMS platform as a response to system constraints (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 99).

Turning to the two demonstration projects, the proposed location for the active resource integration demonstration has a history of withdrawn DG applications due to high interconnections costs and has low or no available hosting capacity (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 115, 119; DPU 12-4). Due to system constraints in the Risingdale area, the company's normal business practices would require DG developers to install a third supply cable to accommodate additional DG interconnections during system contingencies (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 115). The proposed active resource integration project could defer system upgrades and accelerate DG interconnection with existing infrastructure if the required level of curtailment is acceptable to developers and is anticipated to support the interconnection of up to 15 MW of DG at a lower overall interconnection cost and reduced timeline to interconnect (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 115, 119). Regarding the proposed local export power control project, the company states that, due to a high volume of DG in the town of Orange, its normal practices would dictate that the solar and storage facility planned in that town be subject to a distribution group and transmission study as well as the potential for large-scale system modifications that could take several years (D.P.U. 21-81, Exh. DPU 12-11). The proposed local export power control project, however, would reduce the study time and construction of minor upgrades to a matter of weeks (D.P.U. 21-81, Exh. DPU 12-11).

As noted above, the proposed program management and third-party measurement and verification investments would also provide dedicated program management to oversee and coordinate the deployment of continuing and new preauthorized grid modernization investments, as well as to engage a third-party evaluator, to conduct measurement and verification activities. Moreover, the engagement by National Grid, NSTAR Electric, and Unitil, jointly, of Guidehouse as the third-party evaluator will assist in ensuring uniform statewide approach to study the deployment of the preauthorized grid modernization investments (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 127). In order to assess the equitable distribution of benefits of grid modernization benefits, the Companies should include a uniform statewide approach to evaluating equity of the preauthorized grid modernization investments. The Department is persuaded that coordination, oversight, and management of the implementation of grid modernization plan investments, coupled with the third-party evaluation, tracking of benefits, and identification of areas for improvement, will support the effective and efficient implementation of the 2022-2025 Grid Modernization Plan and thus has a primary purpose in accelerating progress towards our grid modernization objectives (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 127).

For the reasons outlined above, the Department finds that the investments in DERMS, including the active resource integration and local export power control projects, and program management and third-party measurement and verification are incremental to the company's existing or business as usual investments and have a primary purpose to accelerate progress in achieving all three of the Department's grid modernization objectives, and in particular, in achieving the objective of interconnecting and integrating DERs. Further, these investments are consistent with and support the Commonwealth's energy and climate goals.

iv. Business Case

The company must demonstrate that the projected costs of proposed investments are reasonable and that the projected benefits justify the costs. D.P.U. 20-69-A at 31; Grid Modernization Order at 116; D.P.U. 12-76-B at 15, 17. For its DERMS investments, National Grid developed its cost estimates using subject matter expertise and prior experience with related services and/or equipment, including work in one of its other service territories (D.P.U. 21-81, Exh. DPU 1-2 (Supp. 3)). Additionally, National Grid leveraged existing contracts or initiated a competitive bidding process for new products or services as part of the procurement process that includes formal requests for proposals and requests for information (D.P.U. 21-81, Exh. DPU 1-2 (Supp. 3). The company's procurement department also undertakes an assessment of pricing data that includes evaluation of pricing comparison sheets for fee, equipment, labor rates, unit rates, core teams, and typical projects (D.P.U. 21-81, Exh. DPU 1-2 (Supp. 3)).

For its two demonstration projects, National Grid developed its cost estimates based on prior experience, subject matter expertise, analysis of best practices, and known equipment prices and research from other distribution utilities exploring similar solutions (D.P.U. 21-81, Exh. DPU 1-2 (Supp. 3)). For the active resource integration project, the company also issued an RFI regarding capabilities and deployment costs for DG management solutions that resulted in nine responses (D.P.U. 21-81, Exhs. DPU 1-2 (Supp. 3); DPU 1-2, Atts. 20(a) & (b)). Furthermore, the estimated costs of the local export power control project exclude costs associated with the system impact interconnection study at the planned solar and storage location, which will be paid for by the town of Orange (D.P.U. 21-81, Exhs. DPU 12-10; DPU 12-11).

In addition, National Grid developed its cost estimate for the program management and third-party measurement and verification investments using data acquired during the deployment of its 2018-2021 Grid Modernization Plan (D.P.U. 21 81, Exhs. DPU 1-2 (Supp. 3); DPU 1-2, Att.). In further support of the cost estimate, the company also used historical and forecasted vendor and labor costs (D.P.U. 21-81, Exh. DPU 1-2 (Supp. 3)). Based on the above, the Department finds that National Grid's cost estimates are sufficiently reliable for the purpose of determining eligibility for preauthorization.

National Grid has shown there are significant benefits, both quantified and unquantifiable, associated with the proposed DERMS investments (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 95-97; NG-GMP-3 (Rev.)). The DERMS investments will enable the Company to optimize load and avoid traditional distribution-system infrastructure investments, improve the customer DER experience through reduced interconnection costs and enhanced access to markets, and reduce curtailment, customer energy costs, and system losses (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 95-97; NG-GMP-3 (Rev.); DPU 13-3). As a result of the investment in advanced short-term load forecasting capabilities, National Grid will improve DER utilization and operational efficiency through advanced notification of granular forecasted system constraints and greater certainty of short-term distribution system needs (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 99). DERMS will also allow for better alignment of load and generation patterns that can optimize the use of system capacity (D.P.U. 21-81, Exh. AG 7-4). The projected benefits of the proposed active resource integration and local export power control demonstrations include reduced interconnection costs, expedited interconnection timelines, increased behind-the-meter interconnections in congested areas, system upgrade deferral, and accelerated DG interconnection with existing infrastructure (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 115, 119, 124-126; DPU 12-11). Importantly, the proposed DERMS investments, including the two demonstration projects, will also facilitate the company's ability to accommodate additional DERs in the future (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 85-101, 114, 123-125; DPU 12-8). In doing so, these investments will support the Commonwealth in reaching its decarbonization objectives.

In addition, National Grid Electric provided a cost estimate for the program management and third-party measurement and verification investment based on data acquired during the deployment of its 2018-2021 Grid Modernization Plan (D.P.U. 21-81, Exhs. DPU 1-2 (Supp. 3); DPU 1-2, Att.). In further support of the cost estimate, the company also used historical and forecasted vendor and labor costs (D.P.U. 21-81, Exh. DPU 1-2 (Supp. 3)). As noted above, the benefits of dedicated oversight, coordination, and management of the deployment of grid modernization investment, as well as third-party evaluation of progress, will assist in an efficient and effective implementation of the 2022-2025 Grid Modernization Plan that ensures benefits are both maximized and achieved with greater certainty.

While the Attorney General argues that DOE's ICE tool overstates the projected reliability benefits (D.P.U. 21-81, Attorney General Brief at 20, 30, citing Exh. AG-WG-5), the Attorney General proffers no alternative existing industry tool on which the company could rely for its business case, instead suggesting that the one of two possible studies be conducted by independent market researchers and economists (D.P.U. 21-81, Exh. NG-AG 1-3; Tr. 6, at 1060). The company counters that the ICE calculator is a tool commonly used throughout the utility industry to estimate outage costs and reliability improvement benefits, to determine an average cost per outage event per minute (D.P.U. 21-81, National Grid Brief at 88-89, citing Exh. NG-AMI-Rebuttal-1, at 13-14). Based upon our review, the Department finds that the tool is an industry standard and reasonable and appropriate for purposes of the business case.

Accordingly, after review and for the reasons outlined above, the Department finds that the projected costs of the proposed investments in DERMS, including the active resource integration and local export power control projects, and program management and measurement and verification are reasonable and the projected benefits justify the costs (D.P.U. 21-81, Exhs. NG-GMP-2 (Rev. 2) at 90, 95-97; 101, 122, 126-128, 143-144; DPU 1-2; DPU 11-2 (Supp. 2) & Att. 2; DPU 13-2 & Att.; DPU 13-3).

v. Bill Impacts

To be eligible for preauthorization, a company must demonstrate that its proposed investments will result in reasonable bill impacts. D.P.U. 20-69-A at 31; Grid Modernization Order at 116; D.P.U. 12-76-C at 29-30; see also G.L. c. 25, § 1A. National Grid has a submitted bill impact analysis allowing the Department to analyze the estimated increases that would result to each applicable rate class from proposed grid-facing investments, including continuing investments preauthorized in Track 1, over four years (D.P.U. 21-81, Exhs. DPU 7-2 & Atts.; DPU 7-3, Atts.; AG 2-16 & Atts.; Tr. 2, at 234-237).[67] The Department finds that the bill impacts resulting from the total estimated costs for the 2022-2025 Grid Modernization Plan are reasonable in light of the anticipated benefits that these investments will provide. G.L. c. 25, § 1A.

vi. Conclusion

Based on the foregoing, the Department preauthorizes a four-year $35.4 million budget for National Grid's new grid-facing investments in DERMS ($24.6 million), demonstration projects ($6.4 million), program management and third-party measurement and verification ($4.4 million). Consistent with Grid Modernization Order at 113, 155-156, the four-year budget that we preauthorize today is a cap. Because these are new rather than continuing investments, the cap applies to the total proposed budgetary amount rather than to each investment category or project. Track 1 Order at 97. We determine that the level of flexibility previously afforded for new grid-facing investments in the first grid modernization term is warranted for the new grid-facing investments featured in the 2022-2025 Grid Modernization Plan. See Grid Modernization Order at 107-108, 155-156. Accordingly, National Grid may shift spending among the new preauthorized grid-facing categories subject to the budget cap. Finally, any spending over the total budget cap is not eligible for targeted cost recovery through the GMF, and instead, may be recovered by the company in a base

67 The company estimates bill impacts to be in the range of 0.3 percent to 2.1 percent from its proposed new and continuing grid-facing investments over the four-year term, with the exact amount dependent on the final level of investments (D.P.U. 21-81, Exhs. NG-GMP-2, at 12; AG 2-16 & Att.; DPU 7-2 & Atts.; DPU 7-3 & Atts.; Tr. 2, at 234-237).

distribution rate proceeding subsequent to a prudency finding by the Department in a GMF filing or term review Order. The Department's preauthorization only applies to expenditures made during the approved four-year term. Track 1 Order at 77.

While we preauthorize the company's DERMS investments, the Department expects that the company will take all necessary steps to integrate its DERMS with control room technology (i.e., ADMS) and maximize benefits to customers. As part of its DERMS investigation, National Grid will assess whether and how to consolidate the company's existing, stand-alone DERMS solution used for energy efficiency demand response programs with its proposed DERMS platform (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 90; Tr. 3, at 435-436). Through this investigative process, the company expects to determine whether it will transition its existing DERMS into a single DERMS as part of the proposed DERMS platform or if it will maintain its existing DERMS separate from the proposed DERMS platform (D.P.U. 21-81, Tr. 3, at 435-436). Regardless of the approach that the company selects as its preferred option, the Department directs the company to take all necessary steps to minimize stranded costs and ensure the company preserves existing functionality intended for energy efficiency demand response programs as it transitions to a new solution.[68] The Department also recognizes that DERMS is a platform technology with significant potential benefits to the company's electric power system and its customers (D.P.U. 21-81,

68 The Department cautions National Grid, like NSTAR Electric, that it shall take measures to ensure that it does not receive double recovery for this investment and demonstrate such in its annual cost recovery filings (D.P.U. 21-81, Exh. NG-GMP-2 (Rev. 2) at 90; Tr. 3, at 435-437).

Exh. NG-GMP-2 (Rev. 2) at 86-90). As the company develops its DERMS and introduces new functionalities, the Department emphasizes that the company must act prudently and avoid investments or decisions that lead to premature retirement of assets and/or do not allow for expanded DERMS capabilities in the future. Track 1 Order at 69-70.

Finally, in discharging its responsibilities under chapters 25 and 164 of the general laws, the Department must prioritize, among other things, equity, with respect to itself and the entities it regulates. G.L. c. 25, § 1A. Consistent with D.P.U. 20-69-A at 31, the Department finds that the company's proposed grid-facing investments will deliver both direct and indirect benefits of a modernized grid to all customers within the company's service territory. However, the company should consider EJ communities as part of its deployment strategies for those preauthorized new and continuing investments that can provide location-specific benefits in order to ensure EJ communities receive benefits from these grid-facing investments.

d. Unitil

i. Overview

As part of its 2022-2025 Grid Modernization Plan, Unitil requests that the Department preauthorize a budget of $1.2 million in two new grid-facing investments: (1) DER mitigation ($1.04 million), including substation overvoltage protection; and (2) DERMS ($162,000), to be integrated in ADMS (D.P.U. 21-82, Exhs. Unitil-GMP at 83, 74; DPU 6-1). Additionally, Unitil proposes a budget of $300,000 for third-party evaluation in the measurement, verification, and support category (D.P.U. 21-82, Exh. Unitil-GMP at 13, 82).

DOER urges the Department to approve Unitil's grid-facing DERMS investments, arguing that these investments contribute to achieving all of the Department's grid modernization objectives that are essential to the Commonwealth's clean energy and climate goals (DOER Brief at 8-9). The Attorney General questions the accuracy of DOE's ICE tool's calculation of projected economic benefits (D.P.U. 21-82, Attorney General Brief at 21). No other parties commented on Unitil's proposed new grid-facing investments.

ii. Measurable Progress

In order to be eligible for preauthorization, a company must demonstrate that the proposed investments are designed to make measurable progress towards achieving the Department's grid modernization objectives. Track 1 Order at 59; D.P.U. 20-69-A at 30-31; Grid Modernization Order at 116, 139; D.P.U. 12-76-B at 20. In Grid Modernization Order at 144, the Department found that the interplay of foundational grid-facing investments in advanced sensing, SCADA, DMS, load flow analytics, advanced communications, VVO, and automated feeder reconfiguration or advanced distribution automation, will bring direct benefits to customers and make measurable progress toward achievement of our grid modernization objectives. Here, the company's investment in DERMS is interrelated to or build on the foundational investments preauthorized as part of the company's 2018-2021 Grid Modernization Plan or in Track 1 of these proceedings. For example, the company's proposed DERMS will be integrated with and enabled as a module within the company's

ADMS system, which is also being used for VVO, OMS, SCADA, switch order module, DERMS, unbalanced load flow, and in the future, fault location, isolation, and service restoration ("FLISR") (D.P.U. 21-82, Exhs. Unitil-GMP at 74; DPU 2-8; DPU 6-1; AG 2-6, Att.; Tr. 3, at 483).[69] Not only will the proposed DERMS investment be integrated with ADMS and the foundational grid-facing investments deployed as part of the 2018-2021 Grid Modernization Plan, but also it constitutes a next step towards achieving each of our grid modernization objectives. Integrating DERMS into ADMS will provide a single system using the same SCADA information in its network model to operate and optimize the system (D.P.U. 21-82, Exhs. Unitil-GMP at 28, 49-50; DPU 2-8; Tr. 3, at 483).

Similarly, the Department determines that the proposed DER mitigations investment will make measurable progress towards achievement of the Department's grid modernization objective to interconnect and integrate DERs. Under its proposed DER mitigation project, Unitil will install ground-fault overvoltage protection and upgrade voltage regulators or load tap changers to address issues with reverse power flow caused by DER saturation at three substations experiencing reverse power flow (D.P.U. 21-82, Exhs. DPU 7-5; AG-3-12, Att.). The amount of DG interconnected to Unitil's distribution system is primarily rooftop solar with generation accounting for over 50 percent of peak load and over 160 percent of light

69 We note that in its 2022-2025 Grid Modernization Plan, Unitil proposed the DERMS investment within the ADMS investment category because DERMS is so closely tied to ADMS, however, the Department determined that the DERMS investment was a new grid-facing investment for the company for review in Track 2. Track 1 Order at 93.

load (D.P.U. 21-82, Exhs. Unitil-GMP at 24; Unitil-KES-1, at 5; DPU 7-1). During periods of light load, the electric system can experience reverse power flow that creates adverse impacts on voltage regulation, short-circuit protection, and overvoltage protection (D.P.U. 21-82, Exh. Unitil-GMP at 41, 82).[70] At three of Unitil's substations, concerns with reverse power flows are due to aggregated DERs, especially residential-scale DER or next in queue residential-scale DER projects, rather than from larger projects that would require impact studies (D.P.U. 21-82, Exh. Unitil-GMP at 83-84; Tr. 3, at 479-480).[71] Residential-scale DERs are not typically able to support the costs for mitigations at substation and sub-transmission levels (D.P.U. 21-82, Exhs. Unitil-GMP at 83-84; DPU 7-3). No additional DER of any size can be served safely on most distribution circuits without system modifications given the saturation of Unitil's distribution system (D.P.U. 21-82, Exhs. 7-1; DPU 7-3).

While the Department approves Unitil's DER mitigation proposal, the Department has concerns about the potential impact of using these strategies as a long-term solution for reverse power flow. The solar facilities interconnected to Unitil's distribution system are

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70 During times of low or minimum load, a high density of DER on a circuit reduces the capacity of the circuit by causing as much or more power to flow in the reverse direction that can cause challenges in controlling the voltage of the circuit (D.P.U. 21-82, Exh. AG 4-7). For this reason, when analyzing the impact of DER on a circuit and the needed capacity of a circuit, the worst case of peak load and DER output during minimum load is used (D.P.U. 21-82, Exh. AG 4-7).

71 Unitil provides electric service to approximately 30,000 customers of which approximately 90 percent are residential (D.P.U. 21-82, Exh. Unitil-KES-1, at 2).

producing energy far in excess of energy demand at certain times (D.P.U. 21-82, Exhs. Unitil-GMP at 82-84; DPU 7-3; DPU 7-9). Unitil's solution for protecting the system from reverse power flow is essential to maintaining safe and reliable service, but also has the potential to enable (and encourage) more distributed energy generation to produce unusable electricity, potentially exacerbating the issues in the future. This is particularly the case for smaller residential solar facilities (i.e., cap exempt Class I net metering facilities) that receive full net metering credits and are not subject to interconnection studies and costs. G.L. c. 164, § 139(i); 220 CMR 18.00, et. seq.; Distributed Energy Resource Planning and Assignment and Recovery of Costs for the Interconnection of Distributed Generation, D.P.U. 20-75-B, at 3 n.6 (2021); NSTAR Electric, M.D.P.U. No. 55A; National Grid, M.D.P.U. No. 1468; Unitil, M.D.P.U. No. 375. These facilities may interconnect and receive credits based on energy supply, transmission, and distribution costs, and are generally sized to meet a customer's annual consumption (i.e., the facilities produce far in excess of a customer's energy needs during certain times of day/year, so the facility exports excess electricity to the distribution system, but during other times, the facilities do not produce energy and the customer uses energy produced by other forms of generation). 220 CMR 18.04(1). Because the customers receive net metering credits for all excess output, the customer has a financial incentive to fully net meter excess generation rather than store excess generation using an energy storage system (e.g., battery) and dispatch at a peak demand period. If the net metering credits exceed a customer's annual usage, the customer may fully offset their electric bill even though the customer uses energy generated by another facility which is delivered to the customer premise via the transmission and distribution system. This prospect is more attractive as distribution costs increase because the potential net metering credit increases as well.

Currently, grid modernization costs are included in net metering calculations. 220 CMR 18.04 (all distribution charges are included in net metering calculations unless expressly excluded pursuant to 220 CMR 18.04(7)). Therefore, unless the net metering formulas are revised, solar customers in Unitil's service territory will experience an increase in net metering credits because the upgrades required to allow solar facilities to safely operate on the system. Said another way, customers without solar will need to support the cost of addressing reverse power flow caused by solar facilities and pay a higher net metering recovery surcharge to fund a higher credit level for solar facilities that will flow back to owners of the equipment causing the power flow issues. This scenario does not advance the Commonwealth's clean energy policy because renewable energy may potentially be grounded out of the system rather than used to meet our energy needs, as well as creates inequities between customer groups, particularly moderate-income customers[72] that may not have the resources to take advantage of the Commonwealth's solar policies.

Accordingly, the Department urges Unitil to explore alternative methods or proposals that are designed to align energy demand with energy production, such as distribution or

[72] Pursuant to G.L. c. 164, § 141, low-income customers receive a fully compensating adjustment to their rates for the costs associated with DG, and accordingly are not impacted by this scenario.

third-party battery storage or other innovative energy production controls. The Department may investigate whether certain grid modernization costs should be excluded from net metering credit calculations to avoid inequitable and perverse incentives. Finally, the Department notes that as saturation of DG continues, the Commonwealth may need to review its statutory and regulatory policies to ensure that the policies are encouraging maximizing the use of clean energy generation, rather than simply encouraging expansion of generation. Below the Department addresses the deployment of AMI meters to enable TVR, which may be one solution to aligning energy consumption and generation.

Turning to the proposed third-party evaluations for the 2022-2025 Grid Modernization Plan, third-party evaluation is consistent with our establishment of a formal evaluation process for preauthorized grid modernization investments to provide a uniform statewide approach to study the deployment of the preauthorized grid modernization investments to ensure benefits are both maximized and achieved with greater certainty, that future investments are more effective, and to measure the progress made towards achievement of our grid modernization objectives. Grid Modernization Order at 204-205. Accordingly, for the reasons outlined above and consistent with our findings in Grid Modernization Order at 137-145, the Department finds that the DERMS, DER mitigation, and third-party evaluation investments are designed to measurable progress towards achievement of the Department's grid modernization objectives of integrating and interconnecting DERs and optimizing system performance by attaining optimal levels of grid visibility, command and control, and self-healing.

iii. Incremental

Next, only investments that are incremental to existing or business as usual investments are eligible for preauthorization. The Department must assess whether the DERMS, DER mitigation, and third-party evaluation investments are incremental to existing or business as usual investments. In Grid Modernization Order at 145-146, the Department stated that investments may be treated as incremental if a primary purpose of the proposed investment is to accelerate progress in achieving our grid modernization objectives. The proposed DER mitigation investment is specific to three substations experiencing reverse power flows and will enable the integration of additional DERs up to the rating of the substation or a total of approximately 60 MVA at the substation levels (D.P.U. 21-82, Exhs. DPU 7-9, Att. 1; AG 3-12, Att. 1; AG 6-4). As originally planned for future deployment, the DER mitigation project would be deployed in the normal course of business (D.P.U. 21-82, Exh. DPU 7-2). The Department finds that inclusion of the proposed DER mitigation project in the company's 2022-2025 Grid Modernization Plan and the accelerated deployment schedule of the proposed DER mitigation investment to safely interconnect additional facilities is reasonable and consistent with the Department's grid modernization objective to integrate and interconnect DERs (D.P.U. 21-82, Exh. DPU 7-2).

Additionally, DERMS technology will improve grid visibility and enable grid operators to manage and control distribution assets across the electric system in a safe and reliable manner (D.P.U. 21-82, Exh. Unitil-GMP at 28, 74). DERMS will enable integration of additional renewable energy resources and other DERs and support state energy policy goals (D.P.U. 21-82, Exhs. Unitil-GMP at 102; DPU 1-2). Further, DERMS is designed to react to localized constraints and to respond precisely to achieve an optimized state (D.P.U. 21-82, Exh. Unitil-GMP at 33).

Finally, the third-party evaluations will assist in ensuring uniform statewide approach to study the performance of the preauthorized grid modernization investments in an efficient and effective manner and assist in progress to achieve the Department's grid modernization objectives in a manner that ensures benefits are both maximized and achieved with greater certainty. In order to assess the equitable distribution of benefits of grid modernization benefits, the Companies should include a uniform statewide approach to evaluating equity of the preauthorized grid modernization investments. Accordingly, consistent with our findings in Grid Modernization Order at 145,148, the Department determines that because the primary purpose of the proposed DERMS investment, DER mitigation, and third-party evaluation investments is to accelerate achievement of the Department's grid modernization objectives, these investments may be treated as incremental to the company's existing or business as usual investments.

iv. Business Case

In order for the Department to determine eligibility for preauthorization, the company must demonstrate that the projected costs of the proposed investments are reasonable and that the projected benefits justify the costs. D.P.U. 20-69-A at 31; Grid Modernization Order at 116; D.P.U. 12-76-B at 15, 17. Unitil developed the cost estimates for the DER mitigation investment based on similar completed projects (D.P.U. 21-82, Exh. DPU 1-3).

Seven of Unitil's ten substations have been equipped with overvoltage protection that was financed by medium to large customers with larger DER projects that allowed them to bear the associated cost or by the company's capital budget (D.P.U. 21-82, Exh. Unitil-GMP at 83; Tr. 3, at 482). Further, the company proposes to deploy the investment using company employees and contract labor that will be based upon price and availability of resources when the investment is deployed (D.P.U. 21-82, Exh. DPU 1-3 & Att. 7). For the DERMS investment, Unitil developed the project's budget through discussions with its vendor for ADMS, VVO, and DERMS and with the integrator the company uses to integrate company systems (D.P.U. 21-82, Exh. DPU 1-3). Additionally, the budget estimate for the DERMS investment was based on a competitive bidding process (D.P.U. 21-82, Exh. DPU 3-8). The company's estimates involve a company-specific allocation of $162,000 of the total $500,000 in costs for the DERMS investment, with the remainder allocated to Unitil Energy Systems (D.P.U. 21-82, Exh. DPU 1-3 & Att. 4).

Unitil developed the proposed budget of $300,000 for the third-party evaluation on estimates (D.P.U. 21-82, Exh. Unitil-GMP at 82). The company, in conjunction with NSTAR Electric and National Grid, previously engaged the services of a third party for evaluation studies of the respective 2018-2021 Grid Modernization Plan (D.P.U. 21-82, Exh. Unitil-GMP at 82). Based on the reasons above, the Department determines that the DERMS, DER mitigation, and third-party evaluation cost estimates are sufficiently reviewable and reliable for purposes of determining eligibility for preauthorization.

We now turn to the projected benefits of the proposed investments. As noted above, the projected benefits of the DER mitigation investment include enabling the interconnection of additional DERs up to the rating of 60 MVA at the substation levels and therefore will facilitate further deployment of renewable energy generation (D.P.U. 21-82, Exhs. Unitil-GMP at 102; AG 6-4). Additionally, DERMS will provide grid operators with the visibility necessary to optimize system performance, improve asset utilization, improve safety and reliability, and integrate DERs. Specifically, DERMS will be used to manage and control multiple DER facilities and other infrastructure (e.g., EV charging stations, load curtailment) and to manage real and reactive power needs (D.P.U. 21-82, Exhs. Unitil-GMP at 74; DPU 6-1). The DERMS system will also be integrated into the VVO algorithm and have the capability to perform voltage management (D.P.U. 21-82, Exh. Unitil-GMP at 74). Further, the proposed DERMS and the resulting ADMS/DERMS system will be capable of integrating approximately 3,500 field end devices or sites, such as substations, distribution line devices, DERs, and/or edge control/customers/inverters and will also have an integration with GIS to obtain the most up-to-date system model, as well as with the company's CIS system (D.P.U. 21-82, Exhs. AG 2-2; AG 3-9). The DERMS will use real-time information to monitor, control, and manage grid connected assets, including the ability to adjust power flow settings and voltage on individual devices (D.P.U. 21-82, Exh. Unitil-GMP at 28).[73] DERMS can also be used to control and optimize localized segments of the electric system or

[73] Further, the ADMS/DERMS system can also be expanded to accommodate additional field end devices or sites (D.P.U. 21-82, Exh. AG 2-2).

entire feeders and to monitor segments of the electric system to determine if the system has too many DERs or could accommodate more DERs based on time of year and system loads (D.P.U. 21-82, Exh. Unitil-GMP at 28). DERMS will provide the company with accurate real-time data to assist the company in addressing the challenges caused by two-way power flow and increasing loads from interconnected DERs, such as net-metered facilities (D.P.U. 21-82, Exh. Unitil-GMP at 28, 49-50).

Finally, the third-party evaluation will help to ensure an efficient and effective deployment of the grid modernization investments in the 2022-2025 Grid Modernization Plan and provide valuable feedback to the company on its implementation progress as well as track progress towards meeting the Department's grid modernization objectives. The third-party evaluation will also ensure a uniform statewide approach and facilitate coordination and comparability of evaluation results (D.P.U. 21-82, Exh. Unitil-GMP at 82).

While the Attorney General argues that DOE's ICE tool overstates the projected reliability benefits (D.P.U. 21-82, Attorney General Brief at 20-22, citing Exhs. AG-WG-1; AG-WG-5; AG-WG-Surrebuttal), the Attorney General proffers no alternative existing industry tool on which the company could rely for its business case (D.P.U. 21-80/ D.P.U. 21-81/D.P.U. 21-82, Tr. 6, at 1060). The company counters that the ICE calculator is a tool commonly used in the utility industry, and it is unaware of any other widely adopted tool for estimating costs to customers (D.P.U. 21-82, Unitil Brief at 24). Based upon our review, the Department finds that the tool is an industry standard and best available tool.

The Department therefore determines that the projected benefits are sufficiently reviewable and reliable for purposes of determining eligibility.

Accordingly, for the reasons stated above, the Department concludes that the projected cost of the proposed DERMS, DER mitigation investment, and third-party evaluation are reasonable and that the projected benefits justify the cost.

v. Bill Impacts

To be eligible for preauthorization, a company must demonstrate that its proposed investments will result in reasonable bill impacts. D.P.U. 20-69-A at 31; Grid Modernization Order at 116; D.P.U. 12-76-C at 29-30; see also G.L. c. 25, § 1A. Unitil has a submitted bill impact analysis allowing the Department to analyze the estimated increases that would result to each applicable rate class from proposed grid-facing investments, including continuing investments preauthorized in Track 1, over four years (D.P.U. 21-82, Exhs. DPU 3-2 & Atts.; DPU 3-3 & Atts.; DPU 3-4 & Atts.; AG 2-7, Att.; Tr. 2, at 234-237).[74] Notwithstanding the concerns noted above regarding the company's DER mitigation proposals, the Department finds that the bill impacts resulting from the total estimated costs for the 2022-2025 Grid Modernization Plan are reasonable in light of the anticipated benefits that these investments will provide. G.L. c. 25, § 1A.

[74] The company estimates bill impacts to be in the range of 0.4 percent to 3.1 percent from its proposed new and continuing grid-facing investments over the four-year term, with the exact amount dependent on the final level of investments (D.P.U. 21-82, Exhs. DPU 3-2 & Atts.; DPU 3-3 & Atts.; DPU 3-4 & Atts.; AG 2-7, Att.; Tr. 2, at 234-237).

vi. Conclusion

Based on the foregoing, the Department preauthorizes a four-year $1.5 million budget for Unitil's grid-facing investments in DERMS ($162,000), DER mitigation ($1.04 million), and third-party evaluation ($300,000). Consistent with Grid Modernization Order at 164, the four-year budget that we preauthorize today is a cap. Because these are new rather than continuing investments, the cap applies to the total proposed budgetary amount rather than to each investment category as the Department approved for the continuing grid-facing investments. Track 1 Order at 97. We determine that the level of flexibility previously afforded for new grid-facing investments in the first grid modernization term is warranted for the new grid-facing investments in the 2022-2025 Grid Modernization Plan term. See Grid Modernization Order at 164. Accordingly, Unitil may shift spending among the new preauthorized grid-facing categories subject to the budget cap. Finally, any spending over the total budget cap is not eligible for targeted cost recovery through the GMF, and instead, may be recovered by the company in a base distribution rate proceeding subsequent to a prudency finding by the Department in a GMF filing or term review Order. The Department's preauthorization only applies to expenditures made during the approved four-year term. Track 1 Order at 77.

Finally, in discharging its responsibilities under chapters 25 and 164 of the general laws, the Department must prioritize, among other things, equity, with respect to itself and the entities it regulates. G.L. c. 25, § 1A. Consistent with D.P.U. 20-69-A at 31, the Department finds that the company's proposed grid-facing investments will deliver both direct and indirect benefits of a modernized grid to all customers within the company's service territory. However, the company should consider EJ communities as part of its deployment strategies for those preauthorized new and continuing investments that can provide location-specific benefits in order to ensure EJ communities receive benefits from these grid-facing investments.

2. Customer-Facing Investments

a. Introduction

For customer-facing investments, the Department required each company to submit a 2022-2025 Grid Modernization Plan that included: (1) a five-year strategic plan to achieve advanced metering functionality[75] through the full-scale deployment of AMI;[76] (2) a separate four-year, short-term investment plan for these customer-facing technologies; and (3) a composite business case in support of the short-term investment plan. D.P.U. 20-69-A at 28, 38-39, 52. Additionally, the Department directed that each company propose a detailed

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[75] The Department has defined "advanced metering functionality" as: (1) the collection of customers' interval usage data, in near real time, usable for settlement in the ISO-NE energy and ancillary services markets; (2) automated outage and restoration notification; (3) two-way communication between customers and the electric distribution company; and (4) with a customer's permission, communication with and control of appliances. Grid Modernization Order at 118, citing D.P.U. 12-76-B at 3 n.1.

[76] The Department did not expect the Companies to reach full-scale deployment of AMI within the five-year term of their strategic plans. D.P.U. 20-69-A at 29 & 34 n.12. Instead, the Department expected the short-term investment plan to address the investments needed in the initial years of a company's meter deployment plan. D.P.U. 20-69-A at 29 & 34 n.12.

end-of-life meter replacement plan and address all proposed investments needed to support the company's longer-term strategic plan for full AMI deployment. D.P.U. 20-69-A at 29, 34. The Department required each company to demonstrate that its proposed timeline for full AMI deployment is reasonable. D.P.U. 20-69-A at 29. The Department stated that it would review the short-term investment plans to determine which proposed investments and technologies were appropriate for preauthorization, the requirements for which are explained in further detail above in Section III.C.1.a. D.P.U. 20-69-A at 30, 38.

Below, the Department addresses the Companies' end-of-life meter replacement plans and finds that the Companies' proposed timelines for full AMI deployment are reasonable. The Department also determines which investments are preauthorized and which investments are not preauthorized but may be eligible for cost-recovery. Finally, the Department reviews the Companies' cost recovery proposals and establishes parameters for customer-facing investments.

In considering the proposed customer-facing grid modernization investments, the Department determines that it must also take into account the Commonwealth's long-term energy policy and climate goals. See D.P.U. 20-69-A at 25, 27. The Department has recognized that there is a fundamental evolution taking place in the way electricity is produced and consumed in Massachusetts. D.P.U. 17-05, at 373-374. This evolution has been driven, in large part, by a number of legislative and administration policy initiatives designed to address climate change and foster a clean energy economy through the promotion of energy efficiency, demand response, and DERs, reductions to GHG emissions, and the procurement of long-term contracts for renewable energy. See, e.g., An Act Driving Clean Energy and Offshore Wind, St. 2022, c. 179 ("2022 Clean Energy Act"); An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, St. 2021, c. 8; 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; An Act Establishing the Global Warming Solutions Act, St. 2008, c. 298; EEA, 2050 Decarbonization Roadmap; EEA, Massachusetts Clean Energy and Climate Plan for 2025 and 2030 (June 30, 2022). To varying degrees, this evolution is 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. Track 1 Order at 113; D.P.U. 17-05, at 373-374. The Commonwealth's long-term energy policies weigh heavily in favor of full-scale deployment of AMI, if implemented in an organized and cost-effective manner, as AMI deployment in the Companies' service territories will enable and support this ongoing evolution, as well as support the underlying, long-term benefits of cleaner energies and technologies, and customer expectations. With these considerations in mind, the Department next reviews the customer-facing grid modernization investments proposed by the Companies.

b. Framework for Review

In D.P.U. 12-76, the Department outlined a policy framework intended to move Massachusetts towards a modern electric grid, which included a process for preauthorizing grid modernization investments. Preauthorization means that the Department will not revisit whether the company should have proceeded with the investments as proposed but will review the prudence of a company's implementation of the preauthorized investments. D.P.U. 20-69-A at 30 n.9; Grid Modernization Order at 110; D.P.U. 12-76-B at 3-4, 19. When the Department first established the preauthorization construct, the Department intended for advanced metering functionality[77] to be a prerequisite for grid modernization investments to be eligible for preauthorization and targeted cost recovery. Grid Modernization Order at 206, 216-217; D.P.U. 12-76-B at 3-5, 17, 20.

In Grid Modernization Order at 133-134, the Department determined that the benefits of a full-scale deployment of advanced metering functionality did not outweigh the substantial costs as presented in the Companies' grid modernization plan filings at the time. The Department also eliminated the requirement for investments in advanced metering functionality as a prerequisite for preauthorization, instead, finding at the time that the proposed grid-facing technologies would enhance reliability, reduce outage durations, and lay the foundational framework to improve the Companies' ability to integrate DERs onto the electric grid, including improved visibility of where DERs can be interconnected, and management of intermittent power flow associated with these DERs. Grid Modernization Order at 3, 152, 159, 168-169, 216-217, 219. At the same time, the Department stated that we remained committed to the pursuit of advanced metering functionality as a means to

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77 The Department views advanced metering functionality as the basic technology platform of grid modernization. D.P.U. 12-76-B at 13-14.

achieve our grid modernization objectives, with our ultimate goal being to ensure that all customers have the opportunity to realize the benefits of dynamic pricing in a more cost-effective manner. Grid Modernization Order at 135.

In D.P.U. 20-69-A at 26, the Department found that, because a significant portion of the Companies' meters would reach the end of their useful life in the next few years, it offered an ideal opportunity to craft comprehensive meter replacement plans. In consideration of the status of the Companies' metering infrastructure, as well as the Commonwealth's long-term energy policy and climate goals and the Department's grid modernization objectives, the Department found it appropriate to consider a path to achieve advanced metering functionality through a full-scale deployment of AMI. D.P.U. 20-69-A at 25, 27. The Department instructed the Companies to submit plans for all proposed customer-facing grid modernization investments, regardless of whether the investments would be eligible for short-term targeted cost recovery. D.P.U. 20-69-A at 29, 34. The Department indicated that we would review the Companies' investment plans to determine which investments are appropriate for preauthorization. D.P.U. 20-69-A at 30.

The plans submitted by the Companies in the instant proceedings identify the full suite of investments that the Companies anticipate are necessary to support full AMI deployment within their service territories, and their business cases include cost estimates for the entirety of those investments. As a result, the Department must determine which customer-facing grid modernization investments are appropriate for preauthorization if they meet the four prongs for establishing eligibility for preauthorization. Based on the scale of investments involved and the uncertainties inherent in the Companies' business cases (see Grid Modernization Order at 235-236; D.P.U. 12-76-C at 38), the Department determines that not all customer-facing investments are appropriate for preauthorization.

In reviewing the Companies' customer-facing investment proposals, the Department identifies two, broad categories of AMI investments: (1) core AMI investments, which are infrastructure investments necessary to install and enable AMI functionality to produce much more granular customer usage data, as well as voltage and other grid-facing data; and (2) supporting AMI investments, which are investments that utilize the AMI data to provide broader customer and system benefits. The core AMI investment category includes: (1) the AMI meters;[78] (2) the communications networks that transmit data from the meters to the Companies' back-offices; (3) the HES and MDMS that process and store the data for use in other applications; and (4) the CIS that allow the Companies to bill customers based on the AMI data. See D.P.U. 20-69-A at 34-35; D.P.U. 12-76-B at 34. In addition, the Department includes project management and cybersecurity as core AMI investments because these investments are required to ensure that: (1) the Companies deploy AMI efficiently and effectively; and (2) the AMI data is produced in a way that does not compromise customer privacy or system security.

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78 For NSTAR Electric and National Grid, the core AMI investments include replacement of AMR meters with AMI meters and, for NSTAR Electric, any necessary upgrades to the company's existing bridge meters to enable necessary AMI functionalities. For Unitil, this category includes replacement of existing TS2 AMI meters with more advanced PLX AMI meters.

The supporting AMI investment category includes the systems that will analyze the AMI data and integrate the data into the Companies' systems for billing purposes and to provide broader customer benefits, such as enhanced outage management and VVO. In addition, the Department includes customer engagement and education and customer enablement products and services as supporting AMI investments because these investments, while not necessary for the functionality of AMI, may provide robust customer benefits through TVR offerings and other demand-side programs. Supporting AMI investments also include HAN and DI functionality, which as discussed below, may be impacted by the stakeholder process established in Section VI, below. Implementation of core AMI investments represent the initial investments necessary to achieve advanced metering functionality, and generally commence prior to the supporting AMI investments, although some deployment overlap between core and supporting AMI investments may occur (D.P.U. 21-80, Exhs. ES-AMI-1, at 24-28, 32-34; ES-AMI-4 (Rev.) at 10, 12-15, 19; DPU 10-5; DPU 17-5; DPU 17-6; AC 1-9; D.P.U. 21-81, Exhs. NG-AMI-2, at 5, 43-45; DPU 8-1; D.P.U. 21-82, Exhs. Unitil-KES-1, at 7; Unitil-GMP at 87-88; Tr. 4, at 587-588, 592-593, 599; D.P.U. 22-22, Exh. DPU 46-4, Att.). D.P.U. 20-69-A at 25, 27. Based on these reasons, the Department finds that core AMI investments are appropriate for preauthorization but supporting AMI investments are not.

At the same time, the Department determines that supporting AMI investments, even though not appropriate for preauthorization, should not be precluded from accelerated cost recovery through an annual reconciling mechanism established for customer-facing grid modernization investments. Thus, the Department will allow certain supporting AMI investments to be eligible for cost recovery through the approved reconciling mechanisms discussed below. Unlike preauthorized investments, the Department will provide preliminary approval for the Companies to pursue non-preauthorized customer-facing investments but will review whether the company should have proceeded with the supporting AMI investments once the company submits costs associated with those investments for recovery.[79] To be eligible for recovery, the supporting AMI investments must be attributable to AMI implementation and provide customer benefits. The company must demonstrate that the expenses were reasonable and prudently incurred.

Regardless of whether an investment is preauthorized, the Department emphasizes the importance of the Companies' developing and maintaining systematic, ample, and contemporaneous documentation of all grid modernization projects for which they seek targeted cost recovery. Grid Modernization Order at 221. A failure to provide clear, cohesive, and reviewable evidence demonstrating eligibility will result in disallowance of targeted cost recovery of the expenditures in question. See Massachusetts Electric Company, D.P.U. 95-40, at 7 (1995); Boston Gas Company, D.P.U. 93-60, at 26-27 (1993); The Berkshire Gas Company, D.P.U. 92-210, at 24 (1993).

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[79] As such, a company would not be required to submit a new business case in support of those investments.

c. Format of Customer-Facing Investment Plans

The Department required each company to submit a 2022-2025 Grid Modernization Plan that included a five-year strategic plan that was inclusive of a plan for the full deployment of advanced metering functionality, and a separate four-year, "short-term" investment plan for these customer-facing technologies. D.P.U. 20-69-A at 28, 38-39. Each strategic plan must address the full universe of grid modernization planning for the company, not only investments that are incremental (capital or expense), and regardless of whether the investments are eligible for short-term targeted cost recovery (i.e., accelerated cost recovery outside of base distribution rates). D.P.U. 20-69-A at 29. The Department also required that each short-term investment plan address all proposed customer-facing grid modernization investments needed to support the company's longer-term strategic plan for full AMI deployment. D.P.U. 20-69-A at 34.

As an initial matter, the Department finds that Unitil complied with these directives. Unitil's grid modernization plan applies to the 2022-2025 term, incorporates the company's AMI implementation proposals during this four-year term, and includes the company's longer-term strategic plan (D.P.U. 21-82, Exh. Unitil-GMP at 23, 26, 35-39, 59-63, 86-100, 103-109). Unitil's plan also identifies and addresses the investments necessary for its AMI proposals (D.P.U. 21-82, Exh. Unitil-GMP at 86-100).

Additionally, the Department finds that NSTAR Electric and National Grid have also complied with the Department's directives. Each company submitted a multi-year AMI Implementation Plan addressing customer-facing grid modernization investments and a detailed five-year strategic plan that references this AMI Implementation Plan as part of its overall Grid Modernization Plan (D.P.U. 21-80, Exhs. ES-AMI-2; ES-JAS-2, at 30-32; D.P.U. 21-81, Exhs. NG-AMI-2; NG-GMP-2 (Rev. 2) at 9-15). While their AMI Implementation Plans reflect a seven-year (NSTAR Electric) and five-year (National Grid) timeline, respectively, for full AMI deployment within the company's service territory, the plans include details for the initial four years of anticipated investments and, thus, also satisfy the Department's directives (D.P.U. 21-80, Exh. ES-AMI-2; D.P.U. 22-22, Exh. DPU 46-4, Att.; D.P.U. 21-81, Exh. NG-AMI-2).

d. AMI Deployment Timelines and End-of-Life Meter Replacement Plans

In D.P.U. 20-69-A at 29, the Department required each company to demonstrate that its proposed timeline for full deployment of AMI is reasonable. The Department also directed each company to propose a detailed end-of-life meter replacement plan that is designed to minimize stranded costs as the Companies transition to full deployment of AMI meters. D.P.U. 20-69-A at 29, citing Grid Modernization Order at 121-122, 133-134. In addressing the Companies' proposed deployment timelines, the Department reviews the timelines of the primary capital infrastructure investment categories necessary for enabling advanced metering functionality and for which finite end dates for deployment exist: meters, communications, HES, MDMS, and CIS.[80] The Attorney General raises issues associated with the benefits identified by NSTAR Electric and National Grid, stating that the companies overstate the benefits based on the false assumption that there is an imminent need to replace the existing meters (D.P.U 21-80, Attorney General Brief at 31-32, D.P.U. 21-81, Attorney General Brief at 30). Each company counters that the need for accelerated replacements and transition to AMI meters exists (see D.P.U. 21-80, NSTAR Electric Brief at 90-110; D.P.U. 21-81, National Grid Brief at 54-55, 59, 76-82, 88; D.P.U. 21-82, Unitil Brief at 9-12, 22-24). As discussed further below, the Department agrees with the Companies.

NSTAR Electric intends to replace approximately 1.1 million AMR meters for its residential and small commercial customers with AMI meters and convert approximately 260,000 "bridge" meters to AMI mode, from 2025 through mid-year 2027 (D.P.U. 21-80, Exhs. ES-AMI-1, at 23; ES-AMI-2, at 11, 24; Tr. 3, at 538; D.P.U. 22-22, Exh. DPU 46-4, Att.). To achieve this, NSTAR Electric anticipates a six-year period, out of its seven-year implementation timeline, for AMI meter deployment and other primary capital infrastructure investments (D.P.U. 22-22, Exh. DPU 46-4, Att.). The Department finds that NSTAR Electric's deployment period is aligned to reflect the optimal timing for replacement of its existing meter infrastructure, a significant portion of which is reaching the end of its

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80 While the Companies identify other customer-facing grid modernization investment categories, these other categories, while all related to AMI implementation, are dependent on the deployment of the primary infrastructure. For example, the need for additional cybersecurity protections, program management, customer enablement and education, and data analytics and system integrations would not exist but for the deployment and implementation of AMI metering infrastructure.

useful life (D.P.U. 21-80, Exhs. ES-AMI-1, at 23, 32-33; ES-AMI-2, at 2; DPU 17-2; AG 1-8; AG 1-12 & Att. (a); AG 5-4; AG 8-12; Tr. 3, at 541-542). Consistent with this, NSTAR Electric plans to initially focus deployment of AMI meters in its western Massachusetts service territory, where the existing AMR meters are closest to the end of their useful lives (D.P.U 21-80, Exhs. ES-AMI-4 (Rev.) at 12; ES-AMI-2, at 11; Tr. 5, at 865-866). The company will replace meters based on a geographic deployment schedule that re-traces the 2000 to 2006 AMR deployments starting in western Massachusetts, followed by Metro West, Boston, and South regions (D.P.U. 21-80, Exh. ES-AMI-2, at 11). NSTAR Electric plans to transition to deployment of AMI meters in its eastern Massachusetts service territory by the first quarter of 2026 (D.P.U. 21-80, Exh. ES-AMI-4 (Rev.) at 12). Further, NSTAR Electric's schedule reflects the dependencies and coordination of infrastructure investments in communications, and the HES, CIS, and MDMS necessary to enable AMI functionalities (D.P.U 21-80, Exhs. ES-AMI-1, at 32-33; DPU 17-5; DPU 17-6; AC 1-9). Based on its current proposed timeline, the advanced metering functionality for customers in NSTAR Electric's service territory will begin to be enabled in 2025 (D.P.U. 22-22, Exh. DPU 46-4, Att.).

National Grid intends to replace approximately 1.4 million AMR meters for its residential and small commercial customers with AMI meters commencing in 2024 through mid-year 2027 (D.P.U. 21-81, Exh. NG-AMI-2, at 5, 43; Tr. 5, at 795-796). National Grid anticipates a four-and-one-half year deployment for its primary customer-facing grid modernization capital infrastructure investments (D.P.U. 21-81, Exh. NG-AMI-2, at 5, 43).

The Department finds that National Grid has aligned AMI implementation with the end-of-life of a large portion of existing AMR meters, thus minimizing stranded costs (D.P.U. 21-81, Exhs. NG-AMI-1, at 19-20; NG-AMI-2, at 8-10; NG-AMI-Rebuttal-1, at 11-12; DPU 8-2; AG 5-9). National Grid also plans to reduce/eliminate non-required meter replacements and use refurbished meters to reduce stranded asset costs in anticipation of AMI deployment (D.P.U. 21-81, Exhs. NG-AMI-Rebuttal-1, at 11-12; DPU 15-2; AG 1-8). During the three-year AMR meter replacement period, National Grid plans to install approximately 30 percent of the electric AMI meters in the first year, 40 percent in the second year, and the final 30 percent of the territory in the last year of meter deployment (D.P.U. 21-81, Exh. NG-AMI-1, at 20). Based on National Grid's proposed timeline, the advanced metering functionality for customers in its service territories will begin to be enabled in 2024 (D.P.U. 21-81, Exh. NG-AMI-2, at 5; Tr. 5, at 795-796).

Unitil intends to replace all of its 29,107 existing TS2 meters with more advanced PLX meters during its 2022-2025 Grid Modernization Plan term (D.P.U. 21-82, Exh. Unitil-GMP at 87-88). Unitil identifies two compelling needs for accelerating its transition to modern AMI functionalities: (1) an operational need created by the company's existing TS2 meters, approximately half of which are nearing the end of their estimated useful lives, with the likelihood that its meter vendor will no longer support those meters; and (2) a technology need, stating that, while its existing meter technology was considered state of the art at the time of deployment over a decade ago, the meters have been outpaced by new technology that can provide more information in a timelier fashion, thus supporting the company's plan for implementing TVR rates (D.P.U. 21-82, Exhs. Unitil-KES-2, at 11; Unitil-GMP at 86-87; AG 1-3; AG 1-6; AG 6-6, at 2; AG 6-7; DPU 10-1; Tr. 3, at 516-520). Based on Unitil's proposed timeline, the advanced metering functionality for customers in its service territories will begin to be enabled in 2022 (D.P.U. 21-82, Exh. Unitil-GMP at 87-88).

In response to the Attorney General's argument that the need for meter replacements for NSTAR Electric and National Grid is overstated (D.P.U 21-80, Attorney General Brief at 31-32; D.P.U. 21-81, Attorney General Brief at 30), the Department finds that the need exists. In particular, in D.P.U. 20-69-A at 25-26, the Department stated that, because a significant portion of AMR meters deployed in the Commonwealth will reach the end of their useful life within the next few years, this offers an ideal opportunity to craft comprehensive meter replacement plans. A full deployment of AMI meters requires striking an appropriate balance between maximizing customer benefits and minimizing stranded cost. D.P.U. 20-69-A at 29. While deferring full deployment may minimize the potential for stranded costs, such a deferral would delay implementation of tools such as TVR and more granular system modelling that will assist in achieving the Commonwealth's clean energy goals, as well as delay the resiliency and reliability benefits that AMI will provide, such as improved load-flow planning models and outage detection analytics.

Based on the above considerations and a review of the Companies' timeline proposals, the Department finds that NSTAR Electric, National Grid, and Unitil have demonstrated that their proposed timelines to achieve the full deployment of AMI are reasonable and their meter replacement plans strike an appropriate balance between maximizing customer benefits and minimizing stranded costs. However, because the potential for stranded costs exists, the Department requires each company to identify and explain stranded costs in its annual cost recovery filings. The Companies must still demonstrate the prudency of those costs. See, e.g., Milford Water Company, D.P.U. 12-86, at 55-61, 94-95 (2013) (new and retired water treatment plant and equipment); Bay State Gas Company, D.T.E. 05-27, at 197-200 (2005) (obsolete meter reading system). To the extent that the AMI implementation activities result in unexpected, extraordinary stranded costs based on the early retirement of AMR meters, the Department will determine the appropriate ratemaking and accounting treatment based on our significant body of precedent for such costs. See D.P.U. 12-76-C at 28 (citations omitted).[81]

Additionally, several intervenors suggest certain actions to precede the Companies' planned deployments. DOER supports the Companies' deployment timelines but recommends that the Department require the Companies to consult with it on AMI implementation to ensure that the Companies' investments support the Commonwealth's clean energy goals (DOER Brief at 8, 14-15). With respect to NSTAR Electric, NRG argues that the Department should require the company to engage and collaborate with stakeholders on

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81 Because the Department directs the inclusion of legacy meter costs in NSTAR Electric and National Grid's proposed AMIF tariff, and Unitil collects business as usual meter replacement costs through its capital tracker, the Department will address the appropriate accounting treatment and recovery of these potential unexpected and extraordinary stranded costs if and when any of the Companies incur and seek recovery of those costs.

data access issues prior to the deployment of its new CIS and AMI meters (D.P.U. 21-80, NRG Brief at 9, citing Tr. 5, at 965-966). NSTAR Electric states that it does not oppose working collaboratively with stakeholders, provided that such collaboration does not delay its AMI deployment timeline, which aligns with the end of its AMR meters' useful lives, or its CIS deployment (D.P.U. 21-80, NSTAR Electric Brief at 121, 128). National Grid states that it is amenable to informing DOER on the progress of its AMI implementation, provided that this consultation is informational only (i.e., not require approval from DOER for its implementation), so as to avoid delay in AMI implementation (D.P.U. 21-81, National Grid Brief at 94-95).

The Department declines to adopt NRG's and DOER's recommendations, as they will unnecessarily delay AMI implementation in Massachusetts. Additionally, in Section VI, the Department sets forth a process by which the Companies will work with stakeholders. The process is intended to ensure that stakeholders have reasonable opportunity to provide input to the Companies on these matters without unduly delaying the implementation of the Companies' proposed plans. The Department concludes that this process will reasonably and appropriately address the concerns raised by DOER and NRG, as well as other intervenors.[82]

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[82] The Department notes that the Companies and several intervenors expressed their support of a stakeholder process to develop statewide policies involving issues such as data access, TVR design, and customer education and engagement. The Department addresses these issues in Section VI, below.

e. AMI Meter Functionalities

i. Introduction

Several intervenors request that the Department require the inclusion of certain functionalities within the Companies' proposed AMI investments or condition preauthorization or approval of their AMI implementation proposals on adoption of the functionality considerations. In particular, intervenors recommend that the Department consider and address requirements involving HAN[83] and DI[84] functionality and disallow remote shut-off and turn-on capabilities. The Companies urge the Department to deny these recommendations (D.P.U. 21-80, NSTAR Electric Reply Brief at 29-30; D.P.U. 21-81, National Grid Brief at 102-106; National Grid Reply Brief at 10-12; D.P.U. 21-82, Unitil Brief at 29-30).

ii. HAN Functionality

The Attorney General asserts that HAN functionality raises significant concerns regarding fair market competition and access to data, cybersecurity and privacy,

83 HAN functionality refers to the ability of AMI meters to communicate with HANs, which can provide customers and third parties with near real-time access to meter data and be used to communicate with other customer devices such as smart inverters or EV charging equipment (see D.P.U. 21-80, Exh. CLF-CV at 9; D.P.U. 21-81, Exh. CLF-CV at 9; D.P.U. 21-82, Exh. CLF-CV at 9).

84 DI functionality, also referred to as grid-edge computing, refers to the capability of grid-edge devices such as AMI meters to perform computing, analytics, and decision making at a localized level, instead of at a central location (see D.P.U. 21-80/ D.P.U. 21-81/D.P.U. 21-82, Exh. U-MH/JM at 4-5). Enabling DI in AMI meters can result in reduced network strain, faster and more efficient computation, and increased capabilities and potential use cases (see D.P.U. 21-80/D.P.U. 21-81/ D.P.U. 21-82, Exh. U-MH/JM, at 5).

cost-effectiveness (based on how many customers and appliances with sufficient capabilities are available to use this functionality), and equity[85] (D.P.U. 21-80, Attorney General Brief at 39-41, citing Exh. AG-WG-Surrebuttal at 25–27; Tr. 5, at 885-888; D.P.U. 21-81, Attorney General Brief at 38-40; D.P.U. 21-82, Attorney General Brief at 37-39). The Attorney General recommends that the Department address these concerns by carefully weighing the costs and benefits of these technologies to decide whether the Companies should include them in the AMI meters before the meters are procured, as well as address data access through a separate stakeholder process (D.P.U. 21-80, Attorney General Brief at 41-42; D.P.U. 21-81, Attorney General Brief at 38-40; D.P.U. 21-82, Attorney General Brief at 37-39).

NSTAR Electric does not object to discussing HAN-related issues in a data access stakeholder proceeding but opposes the recommendation that the Department determine prior to meter procurement whether the company should be required to include HAN functionality in its AMI meters (D.P.U. 21-80, NSTAR Electric Brief at 115-117). National Grid states that it has conducted a competitive solicitation process to procure AMI meters with HAN functionality throughout all jurisdictions within the National Grid footprint, and that additional AMI meter procurement processes will only serve to delay AMI implementation

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85 The Attorney General identifies HAN-related equity issues related to affordability, access to Wi-Fi, and access by apartment-dwellers and other customers whose meters are outside of the reach of their HAN (D.P.U. 21-80, Attorney General Brief at 41-42, citing Exh. AG-WG-Surrebuttal at 26; D.P.U. 21-81, Attorney General Brief at 38; D.P.U. 21-82, Attorney General Brief at 37-39).

(D.P.U. 21-81, National Grid Brief at 102-103, citing Exhs. NG-AMI-1, at 26; NG-AMI-3, at 50-51). Unitil states that it is not proposing HAN functionality within its grid modernization plan but supports further discussion and evaluation of such functionality if the Department deems it appropriate (D.P.U. 21-82, Unitil Brief at 28).

The Department determines that issues related to HAN functionality are data access issues. As discussed below in Section VI, the Department directs the Companies to convene a stakeholder group to discuss data access issues. The stakeholder group should discuss efficient and cost-effective way(s) for customers and third-parties to gain access to usage data for the purpose of enhancing customer benefits. Any proposal arising out of the stakeholder process must demonstrate how the data access benefits customers, balances equity, and addresses security and privacy (see, e.g., D.P.U. 21-80, Attorney General Brief at 37-38; D.P.U. 21-81, Attorney General Brief at 37-38).

While the Department acknowledges the benefits that might result from deferring the Companies' procurement of AMI meters until issues related to HAN functionality are fully resolved, we conclude that such benefits are outweighed by the costs associated with delaying the deployment of AMI that will serve as an important to tool to achieve the Department's grid modernization objectives, as well as delaying the direct benefits that customers will realize from full AMI deployment. As a result, the Department declines to require that the Companies defer procurement of AMI meters until issues related to HAN functionality are resolved or to condition cost recovery for the proposed investments on such functionality. Nonetheless, the Department expects that, given the scale of the proposed investments, the

Companies should ensure that their decisions regarding functionalities of AMI meters balance costs and meeting future needs.[86] With this consideration in mind, each company will bear the burden of demonstrating the prudence of their decisions regarding meter-related functionalities when they seek recovery of their implementation costs.

iii. DI Functionality

The Attorney General states that, while she recognizes that DI functionalities can potentially layer benefits onto an AMI deployment, the record in these proceedings is not sufficient regarding the incremental costs, benefits, risks (cybersecurity and market), and future potential of DI to make informed recommendations (D.P.U. 21-80, Attorney General Brief at 41-42, citing Exhs. AG-WG-Surrebuttal at 34-35; CLF-CV at 10; D.P.U. 21-81, Attorney General Brief at 39-40; D.P.U. 21-82, Attorney General Brief at 38-39).[87] The Attorney General recommends that the Department consider these issues, as well as issues related to access to data and data privacy, in a data access stakeholder proceeding (D.P.U. 21-80, Attorney General Brief at 42-43; D.P.U. 21-81, Attorney General Brief at 39-40; D.P.U. 21-82, Attorney General Brief at 38-39). CLF similarly recommends that

86 The Department anticipates that many customers will access their metering data through a mobile phone application. Accordingly, and to ensure that all customers can readily access data, the Department encourages the Companies to consider user accessibility and technological compatibility when making their investments.

87 The Attorney General states that, while Unitil does not appear to be pursuing DI capabilities currently, the Department may consider directing all electric distribution companies to implement DI as part of this or a subsequent proceeding (D.P.U. 21-82, Attorney General Brief at 42-43, citing Exh. Unitil-KES-2, at 17).

the Department utilize a stakeholder process to determine how to best design the DI platform to ensure cost-effectiveness (D.P.U. 21-80, CLF Brief at 13-14, citing Exh. U-MH/JM at 21; D.P.U. 21-81, CLF Brief at 13-14, citing Exh. U-MH/JM at 21; D.P.U. 21-82, CLF Brief at 13-14, citing Exh. U-MH/JM at 21). Utilidata recommends that the Department require the Companies to conduct competitive solicitations for a DI platform separate from and prior to a solicitation for AMI meters, asserting that greater competition will result from separate procurements, because separate RFPs will allow the participation of companies that are known for their DI expertise, but are not involved in metering (Utilidata Brief at 4-5). Utilidata additionally asserts that unbundling the solicitations for AMI meters and DI will provide greater transparency by separating values attributed to the DI platform from values attributed to the AMI meters (Utilidata Brief at 6).

NSTAR Electric states that Utilidata's recommendation for a solicitation for a DI platform separate from and prior to a solicitation for AMI meters, is unnecessary and would likely delay its AMI implementation process (D.P.U. 21-80, NSTAR Electric Brief at 137-138). NSTAR Electric also states that it will take DI functionality into account as part of its AMI meter procurement (D.P.U. 21-80, NSTAR Electric Brief at 138, citing Exh. ES-Rebuttal at 67). National Grid states that the AMI solution selected through its competitive solicitation process already includes grid-edge computing capabilities, so further process on DI functionality will only serve to further delay the implementation of AMI in the Commonwealth and the corresponding delivery of benefits to customers (D.P.U. 21-81, National Grid Brief at 104-105, citing Exh. NG-AMI-Rebuttal-1, at 56-57). National Grid agrees that the concerns expressed by intervenors regarding DI functionality may be appropriate for discussion in the data access stakeholder process (D.P.U. 21-81, National Grid Brief at 104-105). Unitil states that it is in the process of implementing more advanced intelligence on its system and that, while advanced system operation is generally desirable, mandating that it be developed and procured in a particular way risks locking the company into processes and technologies that may not present the best solutions (D.P.U. 21-82, Unitil Brief at 29-30). Unitil is also supportive of continuing discussions regarding issues related to DI (D.P.U. 21-82, Unitil Brief at 29).

For the same reasons that we decline to delay meter procurement to ensure HAN functionality, the Department declines to require the Companies to conduct solicitations for a DI platform separate from the solicitations for AMI meters. Instead, the Department will require the Companies to demonstrate the prudence of their decisions when they seek recovery of their AMI meter-related costs. Additionally, the Department recognizes that the Companies and stakeholders can benefit from more discussion regarding a DI platform , particularly balancing customer benefits with cybersecurity risks and data access (see, e.g., D.P.U. 21-80, Attorney General Brief at 42-43; D.P.U. 21-81, Attorney General Brief at 39-40; D.P.U. 21-82, Attorney General Brief at 38-39; CLF Brief at 13-14). Therefore, the Companies should address these issues through the stakeholder process established in Section VI, below. Such discussions, however, should not delay the Companies' AMI implementation timelines.

iv. Remote Shut-off/Turn-on Capabilities

The Attorney General states that providing AMI meters with remote shut-off capabilities introduces a new cybersecurity risk that customers could lose service as a result of an intrusion by a "hacker" who could remotely turn off service at the meters and potentially reprogram the meters to permanently shut off (D.P.U. 21-80, Attorney General Brief at 43-44; D.P.U. 21-81, Attorney General Brief at 40-41). Given this cybersecurity risk, the Attorney General recommends that the Department order each company to either (1) install AMI meters without remote shut-off capabilities, or (2) demonstrate that the remote shut-off function cannot be hacked from an outside entity or company employee or vendor, and provide financial insurance to back up all liabilities associated with any meter intrusion (D.P.U. 21-80, Attorney General Brief at 43-44; D.P.U. 21-81, Attorney General Brief at 40-41). If the Department allows for remote shut-off capabilities, the Attorney General recommends that the Department order each company to allow customers to opt-out of AMI meters that have such capabilities (D.P.U. 21-80, Attorney General Brief at 43-44; D.P.U. 21-81, Attorney General Brief at 40-41).

NSTAR Electric and National Grid both support the inclusion of remote shut-off (and turn-on) capabilities in the AMI meters (D.P.U. 21-80, NSTAR Electric Brief at 118-119, D.P.U. 21-81, National Grid Brief at 105-106). NSTAR Electric states that such capabilities provide two of the most significant benefits associated with AMI, reductions in bad debt and energy savings from reductions in energy theft and remote disconnects (D.P.U. 21-80, NSTAR Electric Brief at 118-119, citing Exh. ES-AMI-4 (Rev.) at 27-28). NSTAR Electric also states that cybersecurity and protecting customers from the impacts of cyber threats is of paramount importance to the company, as evidenced by the comprehensive cybersecurity plan included as part of its AMI Implementation Plan (D.P.U. 21-80, NSTAR Electric Brief at 119, citing Exh. ES-AMI-2, at 34-36 & Att. (B); Tr. 5, at 917-921). The company asserts that the Attorney General's cybersecurity recommendations are unnecessary given the protections undertaken by the company's information security department (D.P.U. 21-80, NSTAR Electric Brief at 119, citing RR-AG-ES-1; Tr. 5, at 917-921).

National Grid states that remote shut-off and turn-on capabilities will deliver both convenience and savings to customers by avoiding the need to schedule an in-person appointment to have electric service turned on or off (e.g., move-in/move-out) (D.P.U. 21-81, National Grid Brief at 105-106, citing Exh. AC-1-6). National Grid also states that its comprehensive AMI cybersecurity plan will guard against the risks of intrusions, noting that customers will have the ability to opt out of receiving an AMI meter and the associated remote connect/reconnect/disconnect features (D.P.U. 21-81, National Grid Brief at 106, citing Exhs. NG-AMI-1, at 28, 40; NG-AMI-2, at 19, 25-26, 45, 50-51; NG-AMI-4). Unitil identifies remote turn-on and turn-off capabilities as a benefit of AMI meters (D.P.U. 21-82, Exh. Unitil-GMP at 23, 35-36).

The Department recognizes that customers will need to have a high level of confidence in the security of the distribution system, AMI meters, and their individual data before they will engage in, and thereby benefit from, the opportunities presented by a modernized grid. Grid Modernization Order at 175-176; D.P.U. 12-76-B at 34.

Cybersecurity is a critical component of grid modernization, and the Companies must continuously assess and upgrade their distribution system defenses against potential cyberattacks. Grid Modernization Order at 175; D.P.U. 12-76-B at 34. Allowing for remote shut-off/turn-on capabilities creates a cybersecurity risk and places two significant burdens on the Companies: (1) protecting customers from unwarranted service disconnections; and (2) protecting customers' service and privacy from being compromised by outside entities, company employees, or vendors. Protecting customers from unwarranted service disconnections is of paramount importance to the Department, as evidenced by the Department's disconnection requirements. 220 CMR 25.00. While the Department supports the benefits that AMI meter remote shut-off and turn-on capabilities can provide in terms of financial savings and customer convenience, such capabilities cannot result in a degradation of the protections that customers currently are provided from unwarranted disconnections. The introduction of remote disconnect capabilities heightens the importance of ensuring that the Companies clearly communicate remote shut-off procedures to customers (see D.P.U. 21-80, Exh. AC 1-14; D.P.U. 21-81, Exhs. NG-AMI-2, at 30 n.31; AC 1-6). The Department will hold each company fully responsible for any deficiencies in its cybersecurity activities that jeopardize customer protections against unwarranted service disconnections. Accordingly, based on the Companies' obligations to protect customers from unwarranted service disconnections and ensure that their cybersecurity activities are robust and protect customers, the Department declines to adopt the Attorney General's recommendations at this time.

f. Review of Company-Specific Customer-Facing Investment Plans

i. NSTAR Electric

(A) Introduction

NSTAR Electric estimates approximately $668.2 million[88] in capital and O&M costs through 2028 for the following customer-facing investment categories identified in its AMI Implementation Plan: (1) AMI electric meters; (2) communications network; (3) HES and MDMS; (4) CIS; (5) customer enablement products and services; (6) analytics; (7) operational system integrations and enhancements; (8) cybersecurity; (9) customer engagement and education; (10) project management; and (11) contact center and theft investigation costs (D.P.U. 21-80, Exhs. ES-AMI-1, at 24-30; ES-AMI-4 (Rev.) at 10, 12-22; ES-Rebuttal at 51-52; DPU 1-2, Att.; DPU 17-1, Att.; DPU 17-8; AG 5-4, Att. (Rev.); D.P.U. 22-22, Exh. DPU 46-4). The company requests approval of its AMI Implementation Plan and preauthorization of its CIS and MDMS investments with an associated budget of $273 million (D.P.U. 21-80, Exhs. ES-AMI-1, at 39-40; DPU 2-5; DPU 15-4; Tr. 4, at 657-658, 663, 669-671, 743; D.P.U. 22-22, Exhs. ES-AMI-1, at 15-16; DPU 40-3). The company proposes to request preauthorization of additional categories of investments identified in its AMI Implementation Plan through multiple filings at later dates

88 For this figure and the budget established in Section III.C.2.f.i.(F), the Department relies on the nominal value, rather than the NPV, of NSTAR Electric's projected costs incurred through 2028 as reflected in the supporting documentation for the company's AMI business case (see D.P.U. 21-80, Exh. DPU 1-2, Att., Detailed Summary Tab).

(D.P.U. 21-80, Exhs. ES-AMI-1, at 31-32, 40; DPU 2-5; DPU 15-4; Tr. 4, at 662-672; D.P.U. 22-22, Exhs. ES-AMI-1, at 15-16; ES-CAS/DPH-1, at 110; DPU 40-3).[89]

Because, to date, preauthorization has been a pre-condition for approval of accelerated cost recovery for grid modernization investments and, consequently, the establishment of a new reconciling mechanism for cost recovery of those investments outside of base distribution rates as proposed by the company, the Department first addresses the extent to which NSTAR Electric's customer-facing investments and record evidence submitted by the company satisfies the requirements for preauthorization. D.P.U. 20-69-A at 30-31, 34; Grid Modernization Order at 115-116, 220; D.P.U. 12-76-B at 19-20, 22. The Department addresses the company's cost recovery proposals in Section III.C.3.c, below.

(B) Measurable Progress and Incremental

In order to be eligible for preauthorization, a company must demonstrate that the proposed investments are designed to make measurable progress towards achieving the Department's grid modernization objectives. Track 1 Order at 59; D.P.U. 20-69-A at 30-31; Grid Modernization Order at 116, 139; D.P.U. 12-76-B at 20. Additionally, a company must also demonstrate that the proposed investments are incremental to existing or business as usual investments, where the primary purpose of the proposed investment is to accelerate progress in achieving the Department's grid modernization objectives. Track 1 Order at 59;

89 Since the Department provides preliminary approval below, the Department will not revisit whether these additional categories warrant preauthorization in a separate proceeding.

D.P.U. 20-69-A at 31; Grid Modernization Order at 116, 145-146.[90] As discussed above, the Department also finds that only customer-facing core AMI investments may be preauthorized.

The Attorney General argues that NSTAR Electric's proposed investments are business as usual for utility operations and the de facto electric industry standard in the United States, and the company's proposed investment in AMI would simply bring the company's AMR system up to these standards (D.P.U. 21-80, Attorney General Brief at 22-23, citing Exh. AG-TN-1, at 7). The Attorney General also argues that NSTAR Electric's proposed CIS and AMI meter costs can be recovered through the company's PBR mechanism and planned annual capital investment expenditures (D.P.U. 21-80, Attorney General Brief at 23-24). NSTAR Electric counters that the pace of AMI implementation it proposes would not occur and is not possible as a business as usual investment without short-term cost recovery, and disputes that its existing PBR mechanism and planned annual capital investment expenditures are not sufficient to allow it to recover customer-facing grid modernization costs under the accelerated timelines proposed for deployment (D.P.U. 21-80, NSTAR Electric Brief at 58, 94-95, 99, 100, citing Tr. 4, at 607-608, 623-625, 628-630).

As a preliminary matter, based on our review of the record, the Department finds that NSTAR Electric's proposed investments will make measurable progress towards achieving the grid modernization objectives. First, the deployment of customer-facing grid

[90] A finding of incremental for preauthorization purposes is not the same as a finding of incremental for cost recovery purposes. Grid Modernization Order at 145 n.77.

modernization infrastructure will optimize system demand by providing the granular usage data that enable customers to access TVR product and service offerings, thus enabling customer price-responsiveness (D.P.U. 21-80, Exhs. ES-AMI-1, at 22; ES-AMI-4 (Rev.) at 24). Second, the deployment of customer-facing grid modernization infrastructure will optimize system performance by: (1) enhancing the effectiveness of VVO schemes and leveraging investments in distribution equipment and control systems to deliver increased energy and demand savings; (2) enabling system operators to identify outages at individual meters, a capability that is particularly important in reducing the duration and complexity of major events; and (3) supporting pro-active identification of equipment overload conditions (D.P.U. 21-80, Exhs. ES-AMI-1, at 21-22; ES-AMI-2, at 47-48). Finally, the data available from the deployment of AMI will provide system operators with access to improved load flows based on more detailed and accurate customer load data, thus improving the ability of the planners to forecast the impact of DERs and satisfying the objective of interconnecting and integrating DERs (D.P.U. 21-80, Exh. ES-AMI-1, at 22).

The Department also finds that NSTAR Electric’s proposed customer-facing grid modernization investments are incremental to business as usual investments in that the primary purpose of the investments is to accelerate progress in achieving the Department’s grid modernization objectives. D.P.U. 20-69-A at 32; Grid Modernization Order at 145-146. First, the investments are forward-looking in that they are not designed to solely support today’s grid functionality but will also support the full functionality of the end-state modern grid, as exemplified by the Department’s grid modernization objectives (see D.P.U. 21-80, Exhs. ES-AMI-1, at 8-11, 20-21; ES-AMI-2, at 1-7). See Grid Modernization Order at 105-106. In particular, the Department finds that these investments will optimize system demand by facilitating consumer price-responsiveness by providing customers with access to the granular usage data that is necessary for them to participate in TVR and other dynamic pricing products (D.P.U. 21-80, Exhs. ES-AMI-1, at 21-23, 29-30; ES-AMI-2, at 4-5, 36; ES-AMI-4 (Rev.) at 12-24; ES-Rebuttal at 67; DPU 17-5; DPU 17-6; AC 1-23; CLC-ES 2-9; Tr. 4, at 620-622). See Investigation into Time Varying Rates, D.P.U. 14-04, at 1 (2014); D.P.U. 12-76-B at 11; D.P.U. 12-76, at 9. Consumer price-responsiveness has the potential to fundamentally transform the electric grid by reducing peak demand and encouraging effective use of DG, thus avoiding investment in new generation, transmission, and distribution resources that may be utilized during only a few peak hours of the year. D.P.U. 12-76-B at 10-11; D.P.U. 12-76, at 9. Second, although meter replacement and related back-office system upgrades have traditionally been included as part of a utility company's normal business investments and the transition to AMI technology is the industry standard nationwide, the company's replacement of approximately 1.1 million existing meters during the term of its AMI Implementation Plan significantly exceeds the scale of any prior meter deployment initiative in the company's service territory (D.P.U. 21-80, Exhs. ES-AMI-1, at 19-20; DPU 10-5; Tr. 4, at 604-613). See D.P.U. 20-69-A at 25-26.

Third, regarding the Attorney General's argument that AMI costs are already accounted for in NSTAR Electric's existing PBR mechanism, PBR plans are forms of incentive regulation that adjust rates annually. D.P.U. 18-150, at 7; D.P.U. 17-05, at 334.

In D.P.U 18-150 and D.P.U. 17-05, the Department approved a PBR formula with an X-factor that estimates productivity based on industry-wide past performance and is then used to determine an incremental base revenue requirement through application of the PBR formula in each year of the PBR plan. D.P.U. 18-150, at 8; D.P.U. 17-05, at 334-335. It is not intended for recovery of any specific costs. D.P.U. 19-120, at 95-96. Therefore, we are not persuaded by the Attorney General's argument that NSTAR Electric's PBR mechanism X-factor already captured customer-facing grid modernization costs because compared companies in the industry already implemented AMI.

Grid modernization expenditures have a dedicated reconciling mechanism for cost recovery through the GMFs. As discussed in Section III.C.3.c, the Department establishes a new AMIF to recover NSTAR Electric's customer-facing grid modernization costs. Further, similar to the GSEP capital expenditures recovered through a dedicated reconciling mechanism, double recovery of costs is not a concern here. D.P.U. 19-120, at 95. Accordingly, the Department finds that NSTAR Electric's proposed customer-facing grid modernization investments are incremental to the company's existing or business as usual investments, and they have a primary purpose to accelerate progress in achieving our grid modernization objectives. D.P.U. 20-69-A at 32; <u>Grid Modernization Order</u> at 145-146 & n.77.

Finally, while the Department finds that the customer-facing investments as proposed will make measurable progress towards achieving the Department's grid modernization objectives and are incremental to the company's business as usual investments, we note that the company is still required to demonstrate the incremental nature of any investments, from both a base distribution rate and business as usual perspective, in its annual cost recovery filings. See Section III.C.3.c; see also NSTAR Electric, M.D.P.U. No. 73F, §§ 1.0, 4.0, 6.2. As a result, the Department, the Attorney General, and other interested stakeholders, will have the opportunity to review the costs incurred during the annual prudency reviews for these investments.[91]

(C) Business Case

The Department's findings on eligible grid modernization investments, as well as preauthorization, are also based upon a review of the proposed investments, as supported by a company's business case. See Section III.C.1.a; D.P.U. 20-69-A at 30-31; Grid Modernization Order at 115; D.P.U 12-76-B at 19. The business case must include: (1) a detailed description of the proposed grid modernization investments; (2) the rationale and business drivers for the investments; and (3) a reviewable and reliable identification of all projected costs and benefits. Grid Modernization Order at 115-116; D.P.U. 12-76-B at 17. Cost estimates should, to the extent possible, be based on vendor quotes, estimates from in-state pilot projects, and data from relevant case studies in other jurisdictions. Grid Modernization Order at 116 n.52; D.P.U. 12-76-C at 13. Projected benefits include benefits that: (1) can be both quantified and monetized; (2) can be quantified but not monetized; and

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91 In Section III.C.3.c.vi, the Department establishes an annual prudency review, rather than at the end of the approved term, for NSTAR Electric's customer-facing grid modernization investments.

(3) cannot be quantified. Grid Modernization Order at 116 n.53; D.P.U. 12-76-C at 13, 24-25. The Department expects a company to present costs and benefits at a level of granularity that strikes the appropriate balance between enabling review of the proposed investments while reflecting the relatively high-level nature of the plan and the uncertainty inherent in planning estimates. See D.P.U. 12-76-C at 38. A company must demonstrate that the projected cost of the investments is reasonable, and that the projected benefits justify the costs. Grid Modernization Order at 116; D.P.U. 12-76-B at 17.

In Grid Modernization Order at 107, the Department explained that the usefulness of a company's short-term investment plan depends largely on the certainty of the projections included therein and that these projections are critical to the Department's evaluation of a company's proposals. The Department has also acknowledged the uncertainty inherent in planning estimates for short-term grid modernization investment plans, inclusive of advanced metering functionality considerations, and instructed that a company must provide its best estimates of the costs and benefits at the time the short-term investment plan is submitted to the Department. See D.P.U. 12-76-C at 13, 38. The Department has recognized that cost and benefit estimates may need to be revised and refined during the development and implementation of a company's grid modernization plan. See D.P.U. 12-76-C at 13.

The Attorney General contends that the Department is being asked to preauthorize spending without knowing either the total costs or benefits, which should be provided before any preauthorization occurs, and criticizes NSTAR Electric's "razor-thin" cost-benefit ratio, asserting that the company's business case likely results in negative net benefits

(D.P.U. 21-80, Attorney General Brief at 21, 29-30, 33). In particular, the Attorney General claims that NSTAR Electric underestimates its costs because it fails to address how stranded costs impact its business case even though these costs are likely to be significant (D.P.U. 21-80, Attorney General Brief at 31). NSTAR Electric explains that it did not directly account for stranded costs in its business case due to the fact that the company proposed to implement AMI as part of an end-of-life meter replacement strategy for AMR infrastructure (D.P.U. 21-80, NSTAR Electric Brief at 108). Additionally, NSTAR Electric asserts that the Department can and should rely on the company's business case when reviewing the company's AMI proposals, and that the conclusion that the benefits will exceed the costs over a 20-year time horizon is the result of a robust effort to determine the most accurate possible assumptions despite uncertainties (D.P.U. 21-80, Exh. AG 5-9). The Department agrees with the company.

As a preliminary matter, NSTAR Electric provided a composite business case modeled on a 20-year timeframe and provided both an NPV comparison of costs and benefits using a discount rate commensurate with the company's cost of capital, as well as a comparison of the nominal costs and benefits (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.) at 7-9; ES-Rebuttal at 48; DPU 1-2, Att.; AG 1-24(b); AG 4-8; AG 8-9). Additionally, the company's AMI Implementation Plan describes all investment categories that the company anticipates are necessary to enable and/or support the full deployment of AMI within its Massachusetts service territories and identifies the rationale and business drivers for those investments (see generally D.P.U. 21-80, Exhs. ES-AMI-1; ES-AMI-2; ES-AMI-4 (Rev.)).

The company acknowledges that it provided high-level indicative AMI cost estimates (D.P.U. 21-80, Exhs. ES-AMI-1, at 31-32; DPU 2-5(a); Tr. 4, at 668; D.P.U. 22-22, Exhs. ES-AM-1, at 15-16; DPU 40-3). The company states it would further refine its budget estimates and present those pre-construction quality estimates to the Department for review and approval prior to commencing cost recovery under its proposed cost recovery mechanism, if approved by the Department (D.P.U. 21-80, Exh. ES-AMI-1, at 31-32, 40; Tr. 4, at 668; D.P.U. 22-22, Exhs. ES-AMI-1, at 15-16; DPU 40-3).

The Department has stated that, to the extent possible, a company should base its cost estimates on vendor quotes, estimates from relevant projects, and data from relevant case studies in other jurisdictions. Grid Modernization Order at 116 n.52; D.P.U. 12-76-C at 13. NSTAR Electric has complied with these directives. In particular, for the AMI meter and communications investment cost estimates, the company utilized an RFI process and adjusted certain labor costs with internal labor data from previous labor union negotiations to calculate the labor rate for meter and network deployments in Massachusetts (D.P.U. 21-80, Exhs. DPU 2-6; AG 1-10; AG 5-3 & Atts.). Because the communications network vendor is the typical provider of the HES software, the above RFI process also included quotes for the HES (D.P.U. 21-80, Exhs. DPU 2-6; AC 1-2). NSTAR Electric explained that it could not provide more refined cost estimates and would not issue RFPs for AMI implementation, including the new proposed MDMS, without more specific guidance on whether the Department approved its AMI plan and allowed for a cost recovery mechanism for the potential recovery of those investments, as the company did not intend to otherwise pursue these investments at this time (D.P.U. 21-80, Tr. 4, at 604-608, 611-613; D.P.U. 22-22, Exhs. DPU 40-3; DPU 46-6; DPU 46-10).

For its CIS and MDMS cost estimates, NSTAR Electric relied on a consultant in partnership with the company's subject matter experts and historical costs from previous CIS and MDMS deployments (D.P.U. 21-80, Exh. DPU 2-6). For cost estimates relating to customer enablement products, NSTAR Electric relied on its subject matter experts' historical AMI deployment experience (D.P.U. 21-80, Exh. DPU 2-6). Similarly, the company based its cost estimates for project management on its current labor rates for project management and FTE estimates provided by a consultant with experience in AMI project management (D.P.U. 21-80, Exh. DPU 2-6). For the remaining categories of investments, the company relied on its subject matter experts' previous experience and data from historical projects applicable to those category types (D.P.U. 21-80, Exh. DPU 2-6). Based on the above considerations, the Department finds that the company's approach for developing its cost estimates, in this instance, is reasonable, and that these cost estimates are sufficiently reviewable and reliable and based on the company's best estimates (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.) at 7-9; ES-Rebuttal at 48-49; DPU 1-2, Att.; DPU 2-6; AG 1-24; AG 4-8; AG 8-9). See Grid Modernization Order at 115-116; D.P.U. 12-76-C at 13.

Moreover, the Department is not persuaded by the Attorney General's argument involving the company's exclusion of stranded costs from its business case. In D.P.U. 12-76-C, the Department specifically excluded stranded costs from inclusion in the benefit and cost analysis portion of a company's business case, finding that this segment of the business case will be forward-looking and, therefore, only the costs of new investments and the benefits that flow from those investments are appropriate for inclusion consistent with economic principles. D.P.U. 12-76-C at 27 & n.13. A separate accounting of stranded costs from investment costs enhances the transparency of a company's cost estimates. Further, stranded costs were intended as a component within the overall justification of the business case. D.P.U. 12-76-C at 27. In D.P.U. 20-69-A, the Department directed the companies to develop end-of-life meter replacement plans designed to minimize stranded costs as the Companies transition to full AMI deployment. D.P.U. 20-69-A at 9. As discussed in Section III.C.2.d, the Department finds that the company's proposed meter replacement plans are reasonable. As a result, the Department finds that the company's approach of excluding stranded assets from its business case cost estimates to be reasonable.

The Department also finds that NSTAR Electric's estimated benefits for purposes of the business case, in this instance, are sufficiently reviewable and reliable and based on the company's best estimates (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.) at 23-37; DPU 1-2, Att.; AG 1-14; AG 5-9). See Grid Modernization Order at 115-116; D.P.U. 12-76-C at 13. Consistent with the Department's directives, the company identifies both the quantitative and qualitative benefits utilized in its analysis, as well as the assumptions relied upon (D.P.U. 21-80, Exhs. ES-AMI-1, at 21-22, 33; ES-AMI-4 (Rev.) at 23-37; DPU 1-2, Att.; AG 1-14; AG 5-9; AG 5-10; AG 5-19; AC 1-3). See Grid Modernization Order at 116 n.53; D.P.U. 12-76-C at 13, 24-25. Given the degree of uncertainty in assumptions associated with predicting benefits over a 20-year period, NSTAR Electric also performed a sensitivity analysis of the most impactful assumptions used to assess its estimated benefits in order to calculate the impact on the NPV of the AMI proposals (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.) at 36; DPU 1-2, Att.; AG 5-9; AG 5-10).

The company calculates quantitative benefits associated with: (1) customer adoption of TVRs and the expected reduction and shifting of load across those customers based on previous pilots and industry benchmarks; (2) avoided labor and capital costs for AMR meter replacements, offset by the periodic replacement of AMI meters reflected in the cost section of the business case; (3) reduced metering and billing system costs currently associated with the legacy systems; (4) bad debt reductions due to increased efficiencies in the collections, disconnection, and reconnection processes; (5) reduced theft and remoted disconnect energy savings based on industry benchmarks and the anticipated ability to perform remote shut-offs and turn-ons almost immediately after a customer request; (6) reductions to no trouble found calls due to the ability to perform remote diagnostics and mitigating the need for connectivity surveys as a result of AMI meters' anticipated functionalities; (7) additional avoided costs for meter reading and field operations; (8) reduced outage restoration costs arising from the anticipated availability of real-time data and earlier identification of nested outages; (9) asset analytics, associated with improvements in the company's ability to better predict system conditions such as blown fuses and transformer overloads through its analysis of AMI data; (10) additional CVR/VVO energy and demand reductions and voltage sensor savings resulting from AMI integration into the existing CVR/VVO system; and (11) reduced carbon emissions resulting from additional CVR/VVO and remote disconnect energy savings (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.) at 9, 23-34; DPU 1-2, Att.; AG 1-14; AG 8-14; AC 1-3). NSTAR Electric also identifies two sets of qualitative benefits: (1) customer benefits; and (2) operational benefits (D.P.U. 21-80, Exhs. ES-AMI-1, at 21-23; ES-AMI-2, at 4-5; ES-AMI-4 (Rev.) at 37; AG 8-5, at 3). These non-quantified benefits include the potential to increase safety, improve customer satisfaction, increase participation in energy efficiency and demand response programs, and facilitate DER integration (D.P.U. 21-80, Exhs. ES-AMI-2, at 4-5; ES-AMI-4 (Rev.) at 37; AG 1-23; AG 8-14; AC 1-3).

Many of the benefits of AMI will accrue to customers in the form of increased functionality and usability (D.P.U. 21-80, Exh. ES-Rebuttal at 20-21). For instance, access to usage information, insights, alerts, and availability of optional TVR enabled by AMI functionalities will provide customers with new opportunities to manage energy consumption and lower bills (D.P.U. 21-80, Exhs. ES-AMI-1, at 21-23, 29-30; ES-AMI-2, at 4-5, 36; ES-AMI-4 (Rev.) at 24; Tr. 4, at 620-622). In addition, reductions in costs associated with energy theft and bad debt that are socialized to all customers can be reduced through initiatives made possible with AMI deployment (D.P.U. 21-80, Exhs. ES-AMI-1, at 22; ES-AMI-4 (Rev.) at 27-28; ES-Rebuttal at 34-35; AG 8-14, at 2). AMI may also improve the efficacy of customer information tools such as load disaggregation applications (D.P.U. 21-80, Exhs. ES-AMI-2, at 5, 24; ES-AMI-2, Appx. C at 11; ES-Rebuttal at 68; AG 4-17(g)). Customers will benefit from more timely updates such as mid-cycle high bill alerts (D.P.U. 21-80, Exhs. ES-AMI-2, at 5; ES-AMI-2, Appx. C at 11-12; NRG 1-12; Tr. 4, at 735-736). AMI technology can also improve the frequency and precision of communications during outages and storm restoration, as well as reduced time for meter transactions, including service turn-on (D.P.U. 21-80, Exhs. ES-AMI-2, at 4-5; ES-AMI-4 (Rev.) at 31, 37).

For grid operators, AMI will provide tools to remotely examine power flow, voltage and power quality, and thus reduce outage response time, improve the accuracy of estimated restoration times, and reduce the frequency of visits to customer locations (D.P.U. 21-80, Exhs. ES-AMI-2, at 5; ES-AMI-4 (Rev.) at 29; AG 5-10, at 2). In combination with real-time load flow tools such as a distribution management system, grid operators will also benefit from improved model accuracy and precision, which will improve situational awareness for both day-ahead planning and forecasting and real-time operations. (D.P.U. 21-80, Exhs. ES-AMI-2, at 5; ES-AMI-4 (Rev.) at 37). For distribution planning engineers, AMI data will provide access to granular information to be utilized in load-flow planning models (D.P.U. 21-80, Exhs. ES-AMI-1, at 22; ES-AMI-2, at 5-6, 49; ES-AMI-4 (Rev.) at 32, 37). Future applications may also use advanced analytics to identify areas prone to outages before the outage occurs (D.P.U. 21-80, Exh. ES-AMI-2, at 6). Planning and communications engineers can leverage the AMI communications network to collect data from other field devices, such as line sensors, providing a reliable method to further improve visibility of the grid (D.P.U. 21-80, Exh. ES-AMI-2, at 6).

Moreover, because implementation of AMI in the company’s service territory is complex and comprised of various interdependent systems necessary to provide the anticipated functionalities and benefits to customers, this results in a level of uncertainty for the projected benefits (D.P.U. 21-80, Exh. ES-AMI-1, at 33). See Grid Modernization Order at 235-236; D.P.U. 12-76-C at 38. Factors that may impact the actual realization of the benefits of AMI implementation include: labor and materials availability, customer interest in TVR and new metering technologies, customer behavior and ability to shift load, adoption of EVs and other increases in flexible load, economic factors affecting customers' ability to pay for service, outage activity affecting avoided "no trouble found" calls, changes in load and generation impacting system voltages that drive calls to assess voltage complaints, and weather and the number and severity of major storm events causing significant disruptions to normal company operations (D.P.U. 21-80, Exhs. AG 1-14; AG 5-9(d); DOER 1-1 (Track 2)).

In considering whether NSTAR Electric has demonstrated that the benefits justify the costs, the Department determines that it must also take into account the Commonwealth's long-term energy policy and climate goals, as well as the current status of the company's metering infrastructure. See D.P.U. 20-69-A at 25, 27. The company argues that continuing AMR meter installations would detract from its ability to make substantial progress in modernizing the distribution system and enabling tools that facilitate a cleaner energy future (D.P.U. 21-80, Exh. ES-AMI-2, at 2). The Department agrees. With a significant portion of the company's AMR meters nearing the end of their useful life and the need to upgrade back-office supporting systems to enable advanced metering functionality, the Department finds that it is an optimal time to deploy AMI if the company follows a thoughtful implementation process to minimize stranded costs for ratepayers and, thus, achieve the benefits identified herein. See D.P.U. 20-69-A at 25-27, 29; Grid Modernization Order at 121-122. As the company implements AMI meter replacements, however, the Department emphasizes that the company must act prudently and take all necessary steps to minimize stranded costs. Track 1 Order at 69-70.

Accordingly, based on our review and considerations herein, the Department finds the projected costs of the proposed AMI Implementation Plan investments are reasonable and that the anticipated benefits justify the estimated costs.

(D) Bill Impacts

A company must demonstrate that its proposed investments will result in reasonable bill impacts. D.P.U. 20-69-A at 31; Grid Modernization Order at 116; D.P.U. 12-76-C at 29-30; see also G.L. c. 25, § 1A. NSTAR Electric has submitted bill impact analyses identifying estimated increases that would result to each applicable rate class from the proposed AMI Implementation Plan investments over the seven-year timeline (D.P.U. 21-80, Exh. AG 1-5 & Att.).[92] The Department finds that the bill impacts resulting from the total estimated costs for the proposed customer-facing investments are within the range of reasonableness in light of the anticipated benefits these investments will provide.

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92 NSTAR Electric estimates that the average monthly non-heating residential bill impact upon full deployment of AMI based on the 2028 revenue requirement is estimated to be $4.22, or 3.3 percent, for eastern Massachusetts, and $4.22, or 3.5 percent, for western Massachusetts (D.P.U. 21-80, Exh. AG 1-5).

(E) Preauthorization and Preliminary Approval of Customer-Facing Investments

In D.P.U. 20-69-A at 29, 34, the Department instructed the Companies to submit plans for all proposed customer-facing grid modernization investments, regardless of whether the investments would be eligible for short-term targeted cost recovery. The Department indicated that we would review the Companies' investment plans to determine which investments are appropriate for preauthorization. D.P.U. 20-69-A at 30. Based upon our above findings, the customer-facing investments identified by NSTAR Electric in its AMI Implementation Plan are eligible for accelerated cost recovery. However, for the reasons outlined below, the Department finds that only a certain segment of these investment categories is appropriate for preauthorization.

As discussed in Section III.C.2.b, the Department identifies two, overarching categories of AMI implementation investments – core AMI investments and supporting AMI investments. In reviewing the company's proposals, the Department determines that the core AMI investment categories within NSTAR Electric's AMI Implementation Plan are AMI electric meter installations,[93] the communications network installation and HES, replacement of the legacy CIS/C2 systems and MDMS, cybersecurity, and project management (see D.P.U. 21-80, Exh. ES-AMI-4 (Rev.) at 12-15, 19, 21). Having met the requirements for preauthorization, the Department preauthorizes these investment categories

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93 This category includes AMR meter replacements and any necessary upgrades to the company's existing bridge meters to enable necessary AMI functionalities.

and, consequently, generally approves the company's implementation proposals for these investments.

While preauthorization means that the Department will not revisit whether the company should have proceeded with the investments as proposed, the Department will, however, review the prudence of a company's implementation of the preauthorized investments. D.P.U. 20-69-A at 30 n.9; Grid Modernization Order at 110. For instance, the Department cautions the company against deploying temporary solutions that increase financial burdens for ratepayers (see D.P.U. 21-80, Exh. ES-AMI-2, at 29 ("to accelerate meter deployments in the field, the [c]ompany will assess opportunities to implement an interim MDMS solution"). The grid modernization framework is not intended to promote constant replacements and early retirements of technologies. Track 1 Order at 69. Further, given the scale of investments proposed, the Department expects the company to deploy AMI meters and associated systems capable of advanced functionalities that balance costs and the needs of the future and provide long-term solutions for customers. Track 1 Order at 70. For example, given the legislative requirement for the Companies to implement EV time of use ("TOUs") in the near term, AMI meters should be capable of load disaggregation, among other functions, which will eliminate the need for the company to install more than one AMI meter at a customer's location (D.P.U. 21-80, Exhs. ES-AMI-1, at 22; ES-AMI-2, at 5, 24). See 2022 Clean Energy Act, § 90 (directing electric distribution companies to submit proposals to the Department for approval to offer a TOU rate designed to reflect the cost of providing electricity to a consumer charging an EV at an EV charging station at different times of the day).

Additionally, the Department identifies four categories of supporting AMI investments for NSTAR Electric: data analytics and system integrations, customer engagement and education, customer enablement products and services, and the contact center and theft investigation (D.P.U. 21-80, Exh. ES-AMI-4 (Rev.) at 16-18, 20, 22). While the Department recognizes that NSTAR Electric's proposed investments for these categories are integral components of the company's AMI Implementation Plan and will likely provide important benefits in terms of optimizing system performance and demand (D.P.U. 21-80, Exhs. ES-AMI-1, at 21-23, 29-30; ES-AMI-2, at 4-6, 36; ES-AMI-4 (Rev.) at 16-18, 20, 22; DPU 17-5; DPU 17-6; AC 1-23; Tr. 4, at 620-622), as supporting AMI investments, the Department does not preauthorize these investment categories. Many key aspects of these supporting AMI investments, including detailed budgets, implementation plans, and data access issues are not fully developed, but remain elements of the overall business case. The Department finds, however, that these categories may be eligible for accelerated cost recovery through the mechanism established in Section III.C.3.c. Further, as set forth in Section VI, below, the Department requires the Companies to work with stakeholders to address issues related to customer engagement and education, as well as data access. The Department concludes that a determination on accelerated recovery of costs associated with the supporting AMI investments may be informed by this stakeholder process. Therefore, unlike preauthorized investments, the Department will review whether the company should have proceeded with its specific investments once the company submits costs for recovery. In particular, to be eligible for recovery, the supporting AMI investments must be attributable to AMI implementation, and the company must demonstrate that the expenses were incremental to business as usual investments, incremental to costs included in base distribution rates or recovered through other reconciling mechanisms, and prudently incurred. Thus, the Department provides preliminary approval for the company's implementation proposals for the supporting AMI investments, consistent with the company's initial filing request for approval, and expects additional details for these investments to be submitted in future AMIF cost recovery filings to determine whether accelerated cost recovery for these investments is appropriate.

(F) Budget Caps

In Grid Modernization Order at 173, the Department established a budget cap for preauthorized investments, permitting NSTAR Electric the flexibility to shift spending among the preauthorized categories in order to respond to evolving conditions. The Department found that in the early stages of grid modernization, it was reasonable to expect that significant changes would take place associated with, among other things, the introduction of new technologies and the costs of new and existing technologies. Grid Modernization Order at 107, citing D.P.U. 17-05, at 442. In Section III.C.1.b.vii, the Department establishes a flexible budget cap for NSTAR Electric's preauthorized new grid-facing investments. The Department finds that a measure of flexibility is similarly warranted here. Accordingly, the

Department establishes a $534.8 million budget cap for expenses incurred through 2028[94] for the following preauthorized categories of core AMI investments, inclusive of capital and O&M costs: (1) AMI electric meters; (2) communications network and HES; (3) MDMS; (4) CIS; (6) cybersecurity; and (7) project management (D.P.U. 21-80, Exhs. ES-AMI-1, at 24-30; ES-AMI-4 (Rev.) at 10, 12-22; ES-Rebuttal at 51-52; DPU 1-2, Att.; DPU 17-1, Att.; AG 5-4, Att. (Rev.); D.P.U. 22-22, Exh. DPU 46-4, Att.). Additionally, because the Department's bill impact analysis relied on the estimated costs for all the company's proposed customer-facing grid modernization investment categories, and to ensure future affordability of these investments for the company's customers, the Department establishes a $133.1 million budget cap for expenses incurred through 2028 for the following categories of supporting AMI investments, inclusive of capital and O&M costs: (1) analytics and system integrations; (2) customer engagement and education and customer enablement products and services; and (3) the contact center and theft investigation (D.P.U. 21-80, Exh. ES-AMI-4 (Rev.) at 16-18, 20, 22). Any spending over the overall budget cap for each bucket of investments is not eligible for accelerated cost recovery through the AMIF mechanism established in Section III.C.3.c and, instead, may be recovered by the company in a base distribution rate proceeding subsequent to a prudency finding by the Department in a future AMIF filing docket. Further, the Department's preauthorization and preliminary approval of

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94 As discussed in further detail below, the Department establishes a finite, seven-year term for accelerated cost recovery through the AMIF for eligible AMI implementation costs incurred through CY 2028.

the investments identified herein only applies to expenditures during the approved seven-year term between 2022 and 2028.

(G) Conclusion

Based on the foregoing, the Department preauthorizes the following categories of core AMI implementation investments through 2028, with a combined seven-year budget of $534.8 million: (1) AMI electric meters ($232.1 million); (2) communications network ($43.5 million); (3) HES and MDMS ($48.2 million); (4) CIS ($154.4 million); (5) cybersecurity ($13.8 million); and (6) project management ($43.1 million) (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.) at 12-22; DPU-2-1, Att.). Additionally, the Department provides preliminary approval for the following supporting AMI investment categories for implementation through 2028, with a combined seven-year budget of $133.1 million: (1) customer enablement products and services ($17.0 million); (2) analytics ($37.6 million); (3) system integrations and enhancements ($40.0 million); (4) customer engagement and education ($7.3 million); and (5) contact center and theft investigation costs ($31.2 million) (D.P.U. 21-80, Exhs. ES-AMI-4 (Rev.) at 12-22; DPU 2-1, Att.). NSTAR Electric may seek initial cost recovery for these supporting AMI investments, including for costs that may begin to be incurred for these investment categories as of the effective date of this Order, as part of its May 15, 2024 AMIF filing, subject to the requirements outlined in Section III.C.3.c, below.[95] The Department finds that these investments will improve safety,

[95] During the course of the proceedings, NSTAR Electric accelerated its AMI implementation timeline to commence investments in 2022 rather than 2023 (see

security, reliability of service, affordability, and equity, and will enable clean energy technologies to lower emissions. G.L. c. 25, § 1A.[96]

In discharging its responsibilities under chapters 25 and 164 of the general laws, the Department must prioritize, among other things, equity, with respect to itself and the entities it regulates. G.L. c. 25, § 1A. Consistent with D.P.U. 20-69-A at 31, the Department finds that the company's proposed customer-facing investments will deliver both direct and indirect benefits of a modernized grid to all customers within the company's service territory.

ii. National Grid

(A) Introduction

National Grid requests preauthorization of $487.1 million[97] in capital and O&M costs through 2027 for the following customer-facing investment categories identified in its AMI Implementation Plan: (1) AMI electric meters; (2) communications network; (3) HES/MDMS; (4) CIS enhancements; (5) customer enablement products and services;

D.P.U. 21-80, Exhs. ES-AMI-2, Appx. A at 3; DPU 17-1 & Att.; D.P.U. 22-22, Exh. DPU 46-4 & Att.). Because only costs incurred after the Department issues its Order are allowed for accelerated cost recovery through the AMIF, the costs that would potentially be incurred during December 2022 may be deferred until the company's filing due in 2024.

96 Affordability considerations are inherent in multiple aspects of our review, including of estimated bill impacts and for purposes of establishing budget caps, as well as limiting preauthorization to only certain categories of investments.

97 For this figure and the budget established in Section III.C.2.f.ii.(F), the Department relies on the nominal values, rather than the NPV of National Grid's projected costs incurred through 2027 as reflected in the supporting documentation for the company's AMI business case (see D.P.U. 21-81, Exhs. NG-AMI-Rebuttal-1, at 61; NG-AMI-Rebuttal-2).

(6) analytical tools and systems integration; (7) cybersecurity; (8) customer engagement and education; and (9) project management (D.P.U. 21-81, Exhs. NG-AMI-1, at 9; DPU 2-3; NG-AMI-Rebuttal-1, at 31, 61; NG-AMI-Rebuttal-2; Tr. 4, at 650-654).

Because, to date, preauthorization has been a pre-condition for approval of accelerated cost recovery for grid modernization investments and, consequently, the establishment of a new reconciling mechanism for cost recovery of those investments outside of base distribution rates as proposed by the company, the Department first addresses the extent to which National Grid's customer-facing investments and record evidence submitted by the company satisfies the requirements for preauthorization. D.P.U. 20-69-A at 30-31, 34; Grid Modernization Order at 115-116, 220; D.P.U. 12-76-B at 19-20, 22. The Department addresses the company's cost recovery proposals in Section III.C.3.c, below.

(B) Measurable Progress and Incremental

In order to be eligible for preauthorization, a company must demonstrate that the proposed investments are designed to make measurable progress towards achieving the Department's grid modernization objectives. Track 1 Order at 59; D.P.U. 20-69-A at 30-31; Grid Modernization Order at 116, 139; D.P.U. 12-76-B at 20. Additionally, a company must also demonstrate that the proposed investments are incremental to existing or business as usual investments, where the primary purpose of the proposed investment is to accelerate progress in achieving the Department's grid modernization objectives. Track 1 Order at 59;

D.P.U. 20-69-A at 31; Grid Modernization Order at 116, 145-146.[98] As discussed above, the Department also finds that only customer-facing core AMI investments may be preauthorized.

The Attorney General argues that National Grid's proposed investments are business as usual for utility operations and the de facto electric industry standard in the United States, and the company's proposed investment in AMI would simply bring the company's AMR system up to these standards (D.P.U. 21-81, Attorney General Brief at 22-23, citing Exh. AG-TN-1, at 7). The Attorney General also argues that National Grid's proposed AMI meter costs can be recovered through the company's PBR mechanism and planned annual capital investment expenditures (D.P.U. 21-81, Attorney General Brief at 23-25). National Grid counters that, without an accelerated cost recovery mechanism, AMI implementation in the Commonwealth would not occur at the pace or level outlined in its AMI Implementation Plans, and disputes that its existing PBR mechanism and planned annual capital investment expenditures are sufficient to allow it to recover customer-facing grid modernization costs under the accelerated timelines proposed for deployment (D.P.U. 21-81, National Grid Brief at 68-69, 78-82; National Grid Reply Brief at 4-6)

As a preliminary matter, based on our review of the record, the Department finds that National Grid's proposed investments will make measurable progress towards achieving the grid modernization objectives. First, National Grid's deployment of customer-facing grid

[98] A finding of incremental for preauthorization purposes is not the same as a finding of incremental for cost recovery purposes. Grid Modernization Order at 145 n.77.

modernization investments will optimize system demand by providing the granular usage data that enable customers to access TVR product and service offerings, thus enabling customer price-responsiveness (D.P.U. 21-81, Exhs. NG-AMI-1, at 7-8; NG-AMI-4, at 11, 16). Second, by providing granular and timely usage information and remote capabilities at the customer level, the company's proposed AMI investments will optimize system performance by improving grid visibility at all points along a feeder, providing enhancements to grid modernization functionalities such as power quality management, distribution grid control, and reliability management (D.P.U. 21-81, Exhs. NG-AMI-1, at 6-8; NG-AMI-4, at 14-15). Finally, the granular and timely load provided by AMI at the customer level can be aligned with other system data to create loading and voltage profiles at all points along a feeder, leading to more detailed load and DER forecasts for planning and operational needs (D.P.U. 21-81, Exhs. NG-AMI-1, at 7-8; NG-AMI-4, at 15).

The Department also finds that National Grid's proposed customer-facing grid modernization investments are incremental to business as usual investments in that the primary purpose of the investments is to accelerate progress in achieving the Department's grid modernization objectives. D.P.U. 20-69-A at 32; Grid Modernization Order at 145-146. First, the investments are forward-looking in that they are not designed to solely support today's grid functionality but, will also support the full functionality of the end-state modern grid, as exemplified by the Department's grid modernization objectives (D.P.U. 21-81, Exhs. NG-AMI-1, at 7-8; NG-AMI-4, at 14-15; AC 1-4; DOER (Track 2) 1-2, at 2). See Grid Modernization Order at 105-106. In particular, the Department finds that these investments will optimize system demand by facilitating consumer price-responsiveness by providing customers with access to the granular usage data that is necessary for them to participate in TVR and other dynamic pricing products (D.P.U. 21-81, Exhs. NG-AMI-1, at 7-8; NG-AMI-4, at 14; DOER (Track 2) 2-3). See D.P.U. 14-04, at 1; D.P.U. 12-76-B at 11; D.P.U. 12-76, at 9. Consumer price-responsiveness has the potential to fundamentally transform the electric grid by reducing peak demand and encouraging effective use of DG, thus avoiding investment in new generation, transmission, and distribution resources that may be utilized during only a few peak hours of the year. D.P.U. 12-76-B at 10-11; D.P.U. 12-76, at 9.

Second, although meter replacement and related back-office system upgrades have traditionally been included as part of a utility company's normal business investments and the transition to AMI technology is the industry standard nationwide, the company's replacement of greater than 900,000 existing meters during the term of its AMI Implementation Plan significantly exceeds the scale of any prior meter deployment initiative undertaken by the company in its service territories (D.P.U. 21-81, Tr. 4, at 683-694). See D.P.U. 20-69-A at 25-26. Third, the Department addresses the Attorney General's PBR arguments in Section III.C.2.f.i.(B) and, for the same reasons, finds that the proposed recovery of AMI costs does not constitute double recovery. Accordingly, the Department finds that National Grid's proposed customer-facing grid modernization investments are incremental to the company's existing or business as usual investments, and they have a primary purpose to accelerate progress in achieving our grid modernization objectives. D.P.U. 20-69-A at 32; Grid Modernization Order at 145-146 & n.77.

Finally, while the Department finds that the customer-facing grid modernization investments as proposed will make measurable progress towards achieving the Department's grid modernization objectives and are incremental to the company's business as usual investments, we note that the company is still required to demonstrate the incremental nature of any investments, from both a base distribution rate and business as usual perspective, in its annual cost recovery filings. See Section III.C.3.c; see also National Grid, M.D.P.U. No. 1497, §§ 1.0, 4.0, 6.2. As a result, the Department, the Attorney General, and other interested stakeholders, will have the opportunity to review the costs incurred during the annual prudency review for these investments.[99]

(C) Business Case

The Department's findings on eligible grid modernization investments, as well as preauthorization, are also based upon a review of the proposed investments, as supported by a company's business case. See Section III.C.1.a and Section III.C.2.f.i.(C). D.P.U. 20-69-A at 30-31; Grid Modernization Order at 115; D.P.U 12-76-B at 19. In Grid Modernization Order at 107, the Department explained that the usefulness of a company's short-term investment plan depends largely on the certainty of the projections included therein

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99 In Section III.C.3.c.vi, the Department establishes an annual prudency review, rather than at the end of the approved term, for National Grid's customer-facing grid modernization investments.

and that these projections are critical to the Department's evaluation of a company's proposals. The Department has also acknowledged the uncertainty inherent in planning estimates for short-term grid modernization investment plans, inclusive of advanced metering functionality considerations, and instructed that a company must provide its best estimates of the costs and benefits at the time the short-term investment plan is submitted to the Department. See D.P.U. 12-76-C at 13, 38. The Department has recognized that cost and benefit estimates may need to be revised and refined during the development and implementation of a company's grid modernization plan. See D.P.U. 12-76-C at 13.

The Attorney General contends that the Department is being asked to preauthorize spending without knowing either the total costs or benefits, which should be provided before any preauthorization occurs, and, noting National Grid's cost-benefit ratio reduction resulting from the company's updated cost estimates, contends that the projected costs and benefits are subject to ongoing variability and uncertain cost-effectiveness (D.P.U. 21-81, Attorney General Brief at 29-31). The Attorney General also contends that National Grid underestimates its costs because it fails to address how stranded costs impact its business case even though these costs are likely to be significant (D.P.U. 21-81, Attorney General Brief at 30).

National Grid disagrees with the Attorney General's data deficiency claims and assertions that the costs outweigh the benefits, arguing that the opposite is true and implementation of AMI is cost-effective (D.P.U. 21-81, National Grid Brief at 62-63, 87-88). National Grid contends that the Attorney General's witnesses acknowledged that the company's approach of excluding stranded assets from the cost estimates is not unique, but rather consistent with the Department's instructions (D.P.U. 21-81, National Grid Brief at 88, citing Exh. AG-WG-1, at 41 n.34). Further, National Grid argues that full-scale AMI deployment is the only suitable solution to meet grid modernization objectives and capabilities, customer expectations, and the company's need to replace its aging AMR meter assets (D.P.U. 21-81, National Grid Brief at 59, citing Exh. NG-AMI-1, at 16-17). The Department agrees with the company.

As a preliminary matter, National Grid provided a composite business case modeled on a 20-year timeframe and provided an NPV comparison of costs and benefits using a discount rate equal to its after-tax WACC, as well as calculations related to nominal costs and benefits (D.P.U. 21-81, Exhs. NG-AMI-1, at 26-32; NG-AMI-2, at 23-43; NG-AMI-Rebuttal-1, at 59-64; NG-AMI-Rebuttal-2; AG 1-19, Att.). Additionally, the company's AMI Implementation Plan describes all investment categories that the company anticipates are necessary to enable and/or support the full deployment of AMI and identifies the rationale and business drivers for those investments (D.P.U. 21-81, Exhs. NG-AMI-1, at 11-19; NG-AMI-2, at 6-11, 26-29). The company asserts that a review of its business case demonstrates that the benefits will exceed the costs over a 20-year time horizon, and thus supports the finding that it is appropriate for the Department to approve the company's AMI implementation proposals (D.P.U. 21-81, Exh. NG-AMI-Rebuttal-1, at 59-62).

The Department has stated that, to the extent possible, a company should base its cost estimates on vendor quotes, estimates from relevant projects, and data from relevant case studies in other jurisdictions. Grid Modernization Order at 116 n.52; D.P.U. 12-76-C at 13. National Grid has complied with these directives. In particular, National Grid developed its AMI cost estimates using vendor quotes and internal stakeholder input based on the work previously completed by its affiliates in New York and Rhode Island, which included an RFI to qualify potential AMI vendors, followed by an RFS (D.P.U. 21-81, Exhs. NG-AMI-1, at 26; NG-AMI-2, at 56; NG-AMI-Rebuttal-1, at 59-62 & Att.; DPU 2-6; DPU 8-1, at 2; AG 5-7; AG 6-5). The final vendor contract awarded under the RFI and RFS includes Massachusetts-specific pricing components, which the company utilized to update its cost estimates (D.P.U. 21-81, Exhs. NG-AMI-Rebuttal-1, at 59-62 & Att.; DPU 2-6; AG 5-7; AG 6-5; Tr. 4, at 770). The company's affiliates also worked extensively with internal stakeholders to develop assumptions and estimates for non-RFS cost components (D.P.U. 21-81, Exhs. NG-AMI-1, at 26; NG-AMI-2, at 56; DPU 2-6; AC 1-13). Based on the above considerations, the Department finds that the company's approach for developing its cost estimates, in this instance, is reasonable, and that these cost estimates are sufficiently reviewable and reliable and based on the company's best estimates (D.P.U. 21-81, Exhs. NG-AMI-1, at 26; NG-AMI-2, at 56; NG-AMI-Rebuttal-1, at 59-62 & Att.; DPU 2-6; DPU 8-1, at 2; AG 5-7; AG 6-5). See Grid Modernization Order at 115-116; D.P.U. 12-76-C at 13. Moreover, for the same reasons outlined above in Section III.C.2.f.i.(C), the Department is not persuaded by the Attorney General's argument involving the company's exclusion of stranded costs from its business case and, thus, finds that the company's approach of excluding stranded assets from its business case cost estimates to be reasonable. See D.P.U. 12-76-C at 27 & n.13.

The Department also finds that National Grid's estimated benefits for purposes of the business case, in this instance, are sufficiently reviewable and reliable and based on the company's best estimates (D.P.U. 21-81, Exhs. NG-AMI-1, at 30; NG-AMI-2, at 29-30; NG-AMI-Rebuttal-1, at 61-63; NG-AMI-Rebuttal-2; AG 1-14; AG 1-19; AG 7-8). See Grid Modernization Order at 115-116; D.P.U. 12-76-C at 13. Consistent with the Department's directives, the company identifies both the quantitative and qualitative benefits utilized in its analysis, as well as the assumptions relied upon (D.P.U. 21-81, Exhs. NG-AMI-1, at 30; NG-AMI-2, at 29-30; NG-AMI-Rebuttal-1, at 61-63; NG-AMI-Rebuttal-2; AG 7-8; CLF-NG 1-3; CLF-NG 1-9). See Grid Modernization Order at 116 n.53; D.P.U. 12-76-C at 13, 24-25.[100] Given the degree of uncertainty in assumptions associated with predicting benefits over a 20-year period, National Grid also performed a sensitivity analysis used to assess its estimated benefits in order to calculate the impact on the NPV benefits of the AMI proposals, including the economics of an opt-out TVR rate and the impact of removing all benefits that depend on customer response to rates and usage information (D.P.U. 21-81, Exhs. NG-AMI-2, at 41-43; AC 1-2).

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[100] The Department does not rely on societal benefits for the purpose of these findings. Massachusetts Electric Company v. Department of Public Utilities, 419 Mass. 239 (1994).

The Attorney General asserts that National Grid overstates benefits to customers because of its reliance on the ICE tool for the company's AMI-specific business case (D.P.U. 21-81, Attorney General Brief at 30, citing Exh. AG-WG-5). The Attorney General raised the same argument in relation to National Grid's grid-facing business case, which the Department addressed in Section III.C.1.c.iv. For the same reasons discussed in Section III.C.1.c.iv, the Department finds that the tool is an industry standard and reasonable and appropriate for purposes of the business case.

The company calculates quantitative benefits associated with: (1) avoided O&M costs associated with, among other things, meter reading vehicles and personnel; (2) avoided AMR costs associated with the elimination of the need to replace aging AMR meters that are approaching the end of their estimated useful life; (3) customer benefits associated with reduced energy loads from VVO and customer price-responsiveness, and shorter outage durations; and (4) revenue benefits associated with meter-reading accuracy improvements and reductions in theft and bad-debt write-offs (D.P.U. 21-81, Exhs. NG-AMI-1, at 30; NG-AMI-2, at 29-30; NG-AMI-Rebuttal-2).

Additionally, National Grid identifies two, primary qualitative benefits associated with its customer-facing investment proposals, and states that there are many other benefits enabled by AMI that are difficult to quantify due to high uncertainty around developing markets and technology (D.P.U. 21-81, Exhs. NG-AMI-1, at 30; NG-AMI-2, at 37). The first qualitative benefit identified by the company relates to the ability of DERs to participate fully in the wholesale market in compliance with FERC Order 2222, which requires revenue quality metering solutions capable of meeting the settlement requirements of ISO-NE (D.P.U. 21-81, Exh. NG-AMI-2, at 37). Specifically, deployment of AMI to customers at the retail delivery point will enable meeting ISO-NE's anticipated requirements and revenue quality metering for DER energy settlement (D.P.U. 21-81, Exh. NG-AMI-2, at 37).[101]

The second qualitative benefit involves leveraging the AMI communications network and back-office systems over time to integrate other end-point devices, including AMI for streetlights and ancillary devices to provide additional customer value (D.P.U. 21-81, Exhs. NG-AMI-1, at 30; NG-AMI-2, at 37-41; AC 1-9). The company also identified potential future benefits that rely on grid-edge computing capabilities but did not quantify the benefits for these functionalities because they are in various stages of development and testing by AMI vendors (D.P.U. 21-81, Exh. NG-AMI-1, at 21).

Many of the benefits of AMI will accrue to customers in the form of increased functionality and usability (D.P.U. 21-81, Exh. NG-AMI-2, at 32-35). For instance, access to usage information, insights, alerts, and availability of optional TVR enabled by AMI functionalities will provide customers with new opportunities to manage energy consumption and lower bills (D.P.U. 21-81, Exh. NG-AMI-2, at 32-35). [102] In addition, reductions in

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[101] GECA contends that ISO-NE recently informed FERC that the lack of AMI in New England hinders mass market residential and small commercial DERs from participating in wholesale markets (D.P.U. 21-80/D.P.U. 21-81, GECA Brief at 12-13, citing Exh. GECA-Surrebuttal-KS-1, at 13-14.)

[102] Customers will also benefit from reduced energy loads due to enhanced VVO (D.P.U. 21-81, Exh. NG-AMI-2, at 32-35).

costs associated with energy theft and bad debt that are socialized to all customers can be reduced through initiatives made possible with AMI deployment (D.P.U. 21-81, Exh. NG-AMI-2, at 36). Customers will also benefit from reduced outage durations due to AMI deployment, as well as improvements in the frequency and precision of communications during outages and storm restoration, as well as reduced time for meter transactions, including service turn-on (D.P.U. 21-81, Exhs. NG-AMI-1, at 7-8; NG-AMI-2, at 32-35). For distribution planning engineers, AMI data will provide access to granular and timely information at the customer level that can be utilized in improved load-flow planning models (D.P.U. 21-81, Exhs. NG-AMI-1, at 7-8; NG-AMI-4, at 14). Planning and communications engineers can leverage the AMI communications network to collect data from other field devices, such as line sensors, providing a reliable method to further improve visibility of the grid (D.P.U. 21-81, Exhs. NG-AMI-1, at 7-8; NG-AMI-4, at 14).

Moreover, because implementation of AMI in the company's service territory is complex and comprised of various systems that depend on each other to provide the anticipated functionalities and benefits to customers, this results in a level of uncertainty for the projected benefits (D.P.U. 21-81, Exh. NG-AMI-1, at 14, 29). See Grid Modernization Order at 235-236; D.P.U. 12-76-C at 38. Factors that may impact the actual realization of the benefits of AMI implementation include: labor and materials availability, customer interest in TVR and new metering technologies, customer behavior and ability to shift load, adoption of electric vehicles and other increases in flexible load, economic factors affecting customers' ability to pay for service, outage activity affecting avoided "no trouble found" calls, changes in load and generation impacting system voltages that drive calls to assess voltage complaints, and weather and the number and severity of major storm events causing significant disruptions to normal company operations (see D.P.U. 21-81, Exh. NG-AMI-2, at 32-35).

In considering whether National Grid has demonstrated that the benefits justify the costs, the Department determines that it must also take into account the Commonwealth's long-term energy policy and climate goals, as well as the current status of the company's metering infrastructure. See D.P.U. 20-69-A at 25, 27. National Grid identifies three compelling needs that drive the transition to AMI: (1) an operational need created by the current fleet of AMR metering assets reaching the end of their estimated useful lives; (2) evolving customer expectations; and (3) a shared commitment to achieving ambitious clean energy goals (D.P.U. 21-81, Exhs. NG-AMI-1, at 13-15; NG-AMI-2, at 6-7). The Department agrees. With a significant portion of the company's AMR meters nearing the end of their useful life and the need to upgrade back-office supporting systems to enable advanced metering functionality, the Department finds that it is an optimal time to deploy AMI if the company follows a thoughtful implementation process to minimize stranded costs for ratepayers and, thus, achieve the benefits identified herein. See D.P.U. 20-69-A at 25-27, 29; Grid Modernization Order at 121-122. As the company implements AMI meter replacements, however, the Department emphasizes that the company must act prudently and take all necessary steps to minimize stranded costs. Track 1 Order at 69-70.

Accordingly, based on our review and considerations herein, the Department finds the projected costs of the proposed AMI Implementation Plan investments are reasonable and that the anticipated benefits justify the estimated costs.

(D) Bill Impacts

A company must demonstrate that its proposed investments will result in reasonable bill impacts. D.P.U. 20-69-A at 31; Grid Modernization Order at 116; D.P.U. 12-76-C at 29-30; see also G.L. c. 25, § 1A. National Grid has submitted bill impact analyses identifying estimated increases that would result to each applicable rate class from the proposed AMI Implementation Plan investments over the five-year timeline (D.P.U. 21-81, Exhs. NG-AMI-Rebuttal-5; AG 1-5 & Att.; CLF-NG 1-3).[103] The Department finds that the bill impacts resulting from the total estimated costs for the proposed customer-facings investments are in the range of reasonableness in light of the anticipated benefits these investments will provide.

(E) Preauthorization and Preliminary Approval of Customer-Facing Investments

In D.P.U. 20-69-A at 29, 34, the Department instructed the Companies to submit plans for all proposed customer-facing grid modernization investments, regardless of whether

[103] The company estimates that for an average non-heating residential customer using 600 kWh per month, the total monthly bill would increase by approximately $1.10 or 0.6 percent in the first AMIF year (D.P.U. 21-81, Exh. NG-AMI-Rebuttal-5, at 2). National Grid estimates that the average monthly non-heating residential bill impact upon full deployment of AMI based on the 2027 revenue requirement is estimated to be $2.47 or 1.38 percent (D.P.U. 21-81, Exh. AG 1-5).

the investments would be eligible for short-term targeted cost recovery. The Department indicated that we would review the Companies' investment plans to determine which investments are appropriate for preauthorization. D.P.U. 20-69-A at 30. Based upon our above findings, the customer-facing investments identified by National Grid in its AMI Implementation Plan are eligible for accelerated cost recovery. However, for the reasons outlined below, the Department finds that only a certain segment of these investment categories is appropriate for preauthorization.

As discussed in Section III.C.2.b, the Department identifies two, overarching categories of AMI implementation investments – core AMI investments and supporting AMI investments. In reviewing the company's proposals, the Department determines that the core investment categories within National Grid's AMI Implementation Plan are AMI electric meter installations, the communications network installation, HES and MDMS, CIS enhancements, cybersecurity, and project management (see D.P.U. 21-81, Exhs. NG-AMI–1, at 51; NG-AMI-2). Having met the requirements for preauthorization, the Department preauthorizes these investment categories and, consequently, generally approves the company's implementation proposals for these investments.

While preauthorization means that the Department will not revisit whether the company should have proceeded with the investments as proposed, the Department will, however, review the prudence of a company's implementation of the preauthorized investments. D.P.U. 20-69-A at 30 n.9; Grid Modernization Order at 110. For instance, the Department cautions the company against deploying temporary solutions that increase financial burdens for ratepayers. The grid modernization framework is not intended to promote constant replacements and early retirements of technologies. Track 1 Order at 69. Further, given the scale of investments proposed, the Department expects the company to deploy AMI meters and associated systems to be capable of advanced functionalities that balance costs and the needs of the future and provide long-term solutions for customers. Track 1 Order at 70. For example, given the legislative requirement for the Companies to implement EV TOUs in the near term, AMI meters should be capable of load disaggregation, among other functions, which will eliminate the need for the company to install more than one AMI meter at a customer's location (D.P.U. 21-81, Exh. NG-AMI-2, at 47-48). See 2022 Clean Energy Act, § 90.

Additionally, the Department identifies three categories of supporting AMI investments for National Grid: customer engagement and education, customer enablement products and services, and analytical tools and system integrations (D.P.U. 21-81, Exhs. NG-AMI-2, at 55-56, NG-AMI-3). While the Department recognizes that National Grid's proposed investments for these categories are integral components of the company's AMI Implementation Plan and will likely provide important benefits in terms of optimizing system performance and demand (see D.P.U. 21-81, Exhs. NG-AMI-1, at 28, 32-34, 36-41; NG-AMI-2, at 46-56; DPU 8-1), as supporting AMI investments, the Department does not preauthorize these investment categories. Many key aspects of these supporting AMI investments, including detailed budgets, implementation plans, and data access issues are not fully developed, but remain elements of the overall business case. The Department finds, however, that these categories may be eligible for accelerated cost recovery through the mechanism established in Section III.C.3.c. Further, as set forth in Section VI, below, the Department requires the Companies to work with stakeholders to address issues related to customer engagement and education, as well as data access. The Department concludes that a determination on accelerated recovery of costs associated with the supporting AMI investments may be informed by this stakeholder process.

Therefore, unlike preauthorized investments, the Department will review whether the company should have proceeded with its specific investments once the company submits costs for recovery. In particular, to be eligible for recovery, the supporting AMI investments must be attributable to AMI implementation and the company must demonstrate that the expenses were incremental to business as usual investments, incremental to costs included in base distribution rates or recovered through other reconciling mechanisms, and prudently incurred. Thus, the Department provides preliminary approval for the company's implementation proposals for supporting AMI investments and expects additional details for these investments to be submitted in future AMIF cost recovery filings to determine whether accelerated cost recovery for these investments is appropriate.

(F) Budget Caps

In Grid Modernization Order at 154-155, the Department established a budget cap for preauthorized investments, permitting National Grid the flexibility to shift spending among the preauthorized categories in order to respond to evolving conditions. The Department found that in the early stages of grid modernization, it was reasonable to expect that significant changes would take place associated with, among other things, the introduction of new technologies and the costs of new and existing technologies. Grid Modernization Order at 107, citing D.P.U. 17-05, at 442. In Section III.C.1.c.vi, the Department establishes a flexible budget cap for National Grid's preauthorized new grid-facing investments. The Department finds that a measure of flexibility is similarly warranted here. Accordingly, the Department establishes a $391.1 million budget cap for expenses incurred through 2027[104] for the following preauthorized categories of core AMI investments: (1) AMI electric meters; (2) communications network; (3) HES/MDMS; (4) CIS enhancements; (5) cybersecurity and (6) project management (D.P.U. 21-81, Exhs. NG-AMI-Rebuttal-1, at 61; NG-AMI-Rebuttal-2). Additionally, because the Department's bill impact analysis relies on the estimated costs for all of the company's proposed customer-facing grid modernization investment categories, and to ensure future affordability of these investments for the company's customers, the Department establishes a $96.1 million budget cap for expenses incurred through 2027 for the following categories of supporting AMI investments: (1) analytical tools and system integrations; (2) customer engagement and education; and (3) customer enablement products and services; (D.P.U. 21-81, Exhs. NG-AMI-Rebuttal-1, at 59-62; NG-AMI-Rebuttal-2). Any spending over the overall budget cap for each bucket of investments is not eligible for accelerated recovery through the AMIF mechanism established

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[104] As discussed in further detail below, the Department establishes a finite, five-year term for accelerated cost recovery through the AMIF for eligible AMI implementation costs incurred through CY 2027.

in Section III.C.3.c and, instead, may be recovered by the company in a base distribution rate proceeding subsequent to a prudency finding by the Department in a future AMIF filing docket. Further, the Department's preauthorization and preliminary approval of the investments identified herein only applies to expenditures during the approved five-year term between 2023 and 2027.

(G) Conclusion

Based on the foregoing, the Department preauthorizes the following categories of core AMI implementation investments through 2027, with a combined five-year budget of $391.1 million: (1) AMI electric meters ($273.4 million); (2) communications network ($12.4 million); (3) HES/MDMS ($25.0 million); (4) CIS enhancements ($7.1 million); (5) cybersecurity ($0.9 million); and (6) project management ($72.3 million) (D.P.U. 21-81, Exhs. NG-AMI-Rebuttal-1, at 61; NG-AMI-Rebuttal-2). Additionally, the Department provides preliminary approval for the following supporting AMI investment categories for implementation through 2027, with a combined five-year budget of $96.1 million: (1) analytical tools and system integrations ($46.5million); (2) customer engagement and education ($41.5 million); and (3) customer enablement products and services ($8.1 million) (D.P.U. 21-81, Exhs. NG-AMI-Rebuttal-1, at 61; NG-AMI-Rebuttal-2). National Grid may seek initial cost recovery for these supporting AMI investments, including for costs that may begin to be incurred for these investment categories as of the effective date of this Order,[105]

105 As identified above, National Grid's timeline for proposed AMI Implementation Plan investments does not commence until calendar year 2023 (D.P.U. 21-81,

as part of its March 15, 2024 AMIF filing, subject to the requirements outlined in Section III.C.3.c, below. The Department finds that these investments will improve safety, security, reliability of service, affordability, and equity, and will enable clean energy technologies to lower emissions. G.L. c. 25, § 1A. [106]

In discharging its responsibilities under chapters 25 and 164 of the general laws, the Department must prioritize, among other things, equity, with respect to itself and the entities it regulates. G.L. c. 25, § 1A. Consistent with D.P.U. 20-69-A at 31, the Department finds that the company's proposed customer-facing investments will deliver both direct and indirect benefits of a modernized grid to all customers within the company's service territory.

iii. Unitil

(A) Introduction

Unitil requests Department preauthorization and approval of its proposed customer-facing grid modernization investments. For these investments, Unitil estimates approximately $13.6 million in costs[107] through 2025 for the following investment categories: (1) AMI meter replacements; (2) customer engagement and experience; and (3) a data sharing

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Exh. NG-AMI-2, at 5). As a result, National Grid's first annual filing for these investments is anticipated to be in 2024.

[107] These estimated costs include capitalized labor (D.P.U. 21-82, Exhs. Unitil-GMP at 88; AG 3-7(b)).

platform (D.P.U. 21-82, Exhs. Unitil-KES-1, at 18-22; Unitil-GMP at 13, 88, 91, 99; DPU 9-1; DPU 9-2).[108]

Because, to date, preauthorization has been a pre-condition for approval of accelerated cost recovery for grid modernization investments and, consequently, cost recovery of those investments outside of base distribution rates as proposed by the company, the Department first addresses the extent to which Unitil's customer-facing investments and the record evidence submitted by the company satisfies the requirements for preauthorization. D.P.U. 20-69-A at 30-31, 34; Grid Modernization Order at 115-116, 220; D.P.U. 12-76-B at 19-20, 22. The Department addresses the company's cost recovery proposals in Section III.C.3.c, below.

(B) Measurable Progress and Incremental

In order to be eligible for preauthorization, a company must demonstrate that the proposed investments are designed to make measurable progress towards achieving the Department's grid modernization objectives. Track 1 Order at 59; D.P.U. 20-69-A at 30-31; Grid Modernization Order at 116, 139; D.P.U. 12-76-B at 20. Additionally, a company must also demonstrate that the proposed investments are incremental to existing or business as usual investments, where the primary purpose of the proposed investment is to accelerate progress in achieving the Department's grid modernization objectives. Track 1 Order at 59;

108 The Department addresses Unitil's cost recovery proposal in Section III.C.3.c, below.

D.P.U. 20-69-A at 31; Grid Modernization Order at 116, 145-146.[109] As discussed above, the Department also finds that only customer-facing core AMI investments may be preauthorized.

The Attorney General argues that Unitil's proposed data sharing platform and certain components of its proposed customer engagement and experience project spending (i.e., a mobile app, customer self-service, online chat with customer care, and customer alerts) are business as usual investments that are unrelated to PLX meter interval data capabilities (D.P.U. 21-82, Attorney General Brief at 23, 28-29, citing Exhs. Unitil-GMP at 89-91; Unitil-KES-2, at 13; AG-WG-1, at 54; AG-WG-Surrebuttal at 20; AG 6-7). Unitil counters that these investments are not required for the company to continue to meet its core mission of providing safe and reliable service to customers and that the investments are incremental to the company's existing or business as usual investments (D.P.U. 21-82, Unitil Brief at 17).

Additionally, the Attorney General maintains that Unitil recovers the costs of its existing meter replacements, including the costs of the PLX meters installed on a business as usual pace, through the company's existing capital tracker and, thus, there is no basis or need to allow those costs to flow through Unitil's existing GMF (D.P.U. 21-82, Attorney General Reply Brief at 6-7). Unitil contends that it is only seeking recovery for incremental costs incurred as a result of accelerating the meter deployments beyond those business as usual deployments accounted for in its capital tracker (D.P.U. 21-82, Unitil Reply Brief at 9).

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109 A finding of incremental for preauthorization purposes is not the same as a finding of incremental for cost recovery purposes. Grid Modernization Order at 145 n.77.

As a preliminary matter, based on our review of the record, the Department finds that Unitil's proposed investments will make measurable progress towards achieving the grid modernization objectives. First, the deployment of more advanced AMI meters, coupled with the company's proposed customer engagement and experience and data sharing platform investments, will help to ensure that customers have access to more granular and timely information about their energy use, allowing them to adjust the ways they use energy, to their ultimate benefit and to the benefit of the grid, and thus directly contributing to achieving the Department's grid modernization objective of optimizing system demand by facilitating customer price-responsiveness (D.P.U. 21-82, Exhs. Unitil-GMP at 36-38, 88-89; AG 1-3; AG 6-7). Second, refined usage information at the grid edge provided by the deployment of AMI meters will provide the company with more complete and timely information about the status of grid components, thus contributing to achieving the Department's grid modernization objectives of optimizing system performance and integrating DERs (D.P.U. 21-82, Unitil Brief at 10; Exh. Unitil-GMP at 33). For example, AMI data can (1) be used to support the implementation of VVO that provides the opportunity to actively monitor and control load and power factor to reduce peak capacity during peak demand periods, and (2) provide for improved outage management by providing improved outage detection, faster response time, and reduced overall outage restoration (D.P.U. 21-82, Exhs. Unitil-GMP at 37-38; AG 1-3; AG 6-7). Finally, AMI data will provide the information necessary to match actual load usage curves with the potential DERs supporting the load, thus allowing it to better integrate DERs and other renewable resources into the distribution system (D.P.U. 21-82, Exh. Unitil-GMP at 36-39).

The Department also finds that Unitil's proposed customer-facing grid modernization investments are incremental to business as usual investments in that the primary purpose of the investments is to accelerate progress in achieving the Department's grid modernization objectives. D.P.U. 20-69-A at 32; Grid Modernization Order at 145-146. First, the Department finds that these investments will optimize system demand by facilitating consumer price-responsiveness by providing customers with access to the granular usage data that is necessary for them to participate in TVR and other dynamic price products (D.P.U. 21-82, Exhs. Unitil-GMP at 36-38, 88-89; AG 1-3; AG 6-7; DPU 9-1; DPU 9-2). D.P.U. 14-04 at 1; D.P.U. 12-76-B at 11; D.P.U. 12-76, at 9. Consumer price-responsiveness has the potential to fundamentally transform the electric grid by reducing peak demand and encouraging effective use of DG, thus avoiding investment in new generation, transmission, and distribution resources that may be utilized during only a few peak hours of the year. D.P.U. 12-76-B at 10-11; D.P.U. 12-76, at 9. Second, while Unitil currently replaces its existing TS2 meters with new PLX AMI on a business as usual schedule, the company's proposals in its 2022-2025 Grid Modernization Plan accelerate this replacement schedule by approximately 15 years (D.P.U. 21-82, Exhs. Unitil-KES-2, at 11; Unitil-GMP at 86-87; DPU 5-1; DPU 10-1; AG 1-3; AG 6-7; Tr. 3, at 516-520).

In addition, the Department finds that Unitil's existing capital tracker does not sufficiently support the company's proposed accelerated deployment of customer-facing grid modernization investments; rather, the capital tracker recovers the company's existing business as usual pace of meter replacements (D.P.U. 21-82, Exhs. DPU 1-3; DPU 5-1; DPU 9-2; RR-DPU-FGE-1). See D.P.U. 19-130, at 11-12, 15-16; Unitil, M.D.P.U. No. 359. _Moreover, recovery of these investments through a dedicated, reconciling short-term recovery mechanism, rather than through an existing capital tracker, will facilitate the necessary Department oversight and stakeholder input regarding the investments. D.P.U. 17-05, at 439, 441-442. Accordingly, the Department finds that Unitil's proposed customer-facing grid modernization investments are incremental to the company's existing or business as usual investments, and they have a primary purpose to accelerate progress in achieving our grid modernization objectives. D.P.U. 20-69-A at 32; Grid Modernization Order at 145-146 & n.77.

Finally, while the Department finds that the customer-facing grid modernization investments as proposed will make measurable progress towards achieving the Department's grid modernization objectives and are incremental to the company's business as usual investments, we note that the company is still required to demonstrate the incremental nature of any investments, from both a base distribution rate and business as usual perspective, in its annual cost recovery filings. See Section III.C.3.c; see also Unitil, M.D.P.U. No. 379, §§ 1.0, 4.0, 6.2. As a result, the Department, the Attorney General, and other interested stakeholders will have the opportunity to review the costs incurred during the annual prudency reviews for these investments.

(C) Business Case

The Department's findings on eligible grid modernization investments, as well as preauthorization, are also based upon a review of the proposed investments, as supported by a company's business case. See Section III.C.1.a and Section III.C.2.f.i.(C); D.P.U. 20-69-A at 30-31; Grid Modernization Order at 115; D.P.U 12-76-B at 19. The Attorney General critiques Unitil's reliance on its 2015 business case for the company's proposed customer-facing investments and, thus, should reject the company's request for preauthorization (D.P.U. 21-82, Attorney General Brief at 2, 22-23, citing Exh. AG-WG-1, at 43-44; D.P.U. 20-69-A at 30-31; Attorney General Reply Brief at 5, citing Exh. Unitil-KES-2, at 9-10). Unitil counters that it appropriately relied on its 2015 business case, which it supplemented during the course of the proceeding to show that the system-wide deployment would now be cost-effective and, accordingly, has provided sufficient information supporting the benefits and costs of its proposed meter deployment consistent with the framework established by the Department (D.P.U. 21-82, Unitil Brief at 21-22; Unitil Reply Brief at 9).

In Grid Modernization Order at 107, the Department explained that the usefulness of a company's short-term investment plan depends largely on the certainty of the projections included therein and that these projections are critical to the Department's evaluation of a company's proposals. The Department has also acknowledged the uncertainty inherent in planning estimates for short-term grid modernization investment plans, inclusive of advanced metering functionality considerations, and instructed that a company must provide its best estimates of the costs and benefits at the time the short-term investment plan is submitted to the Department. See D.P.U. 12-76-C at 13, 38. The Department has recognized that cost and benefit estimates may need to be revised and refined during the development and implementation of a company's grid modernization plan. See D.P.U. 12-76-C at 13.

Unitil provided a summary, high-level composite business case that included both its grid-facing and customer-facings investments identified in its 2022-2025 Grid Modernization Plan (D.P.U. 21-82, Exh. Unitil-GMP at 89, 91, 100-103). The company supplemented the information provided in its business case during discovery (see, e.g., D.P.U. 21-82, Exhs. DPU 1-1 & Atts; DPU 1-3 & Atts. 8-9; AG 1-1 & Att. 1; AG 4-2). Additionally, the company's plan describes all investment categories that the company anticipates are necessary to enable and/or support the full deployment of enhanced AMI within its service territory and identifies the rationale and business drivers for those investments (D.P.U. 21-82, Exhs. Unitil-GMP at 86-99; DPU 10-1; AG 6-7). The record reflects that, in developing its business case and supplemental information for its proposed customer-facing grid modernization investments, Unitil relied on multiple sources, including its business case submitted by the company in D.P.U. 15-121, a TVR pilot study conducted by the company in 2012, experience and data deriving from its business as usual PLX meter deployments and existing customer web portal, and information deriving from affiliate activities in relation to the proposed investments (D.P.U. 21-82, Exhs. Unitil-KES-2, at 3-4, 9-10; Unitil-GMP at 86, 89, 91-92, 99; DPU 1-3, at 2; DPU 5-1; DPU 9-1; DPU 10-1; AG 1-1;

AG 4-2; CLF-U 1-6; CLF-U 1-8; AG-WG-Surrebuttal at 16; Tr. 3, at 517-520; Tr. 4, at 587-588, 702-704).

While the basis of Unitil's business case is based on its 2015 filing, the Department finds the business case provided in D.P.U. 21-82 is sufficiently reviewable and reliable for purposes of assessing eligibility for preauthorization. Importantly, the business case was adjusted for more current data (D.P.U. 21-82, Exhs. Unitil-KES-2, at 3; DPU 1-1 & Atts.; DPU 1-3 & Atts. 8, 9; AG-WG-Surrebuttal at 14). Additionally, the Department did not mandate that the business case be created within a specific timeframe in its D.P.U. 20-69-A directives for the instant filings. Moreover, the projected costs of the company's proposed customer-facing grid modernization investments, approximately 83 percent,[110] are attributed exclusively to accelerated AMI meter replacements, and the company already has in place the other enabling, core technologies and back-office systems necessary to facilitate AMI functionalities and more advanced TVR capabilities (i.e., HES, MDMS, CIS, communications) (D.P.U. 21-82, Exhs. Unitil-GMP at 13, 86-87; DPU 5-1; DPU 9-1; DPU 10-1; AG 1-1, at 2; AG 1-3; AG 4-3; AG 6-7; Tr. 4, at 587-588, 592-593, 599, 659; Tr. 5, at 800-801, 807-809, 818, 827-878). As a result, while a level of uncertainty in the data may still exist, this uncertainty is minimized by the company's existing in-service infrastructure and limited investment focus under its 2022-2025 Grid Modernization Plan

[110] $11.23 million/$13.56 million = 83 percent (see D.P.U. 21-82, Exh. Unitil-GMP at 13).

proposals and plan term. Accordingly, the Department finds that the company submitted a business case consistent with the Department's directives.

The Attorney General also argues that the company failed to demonstrate that customer benefits from accelerating its business as usual meter replacements would justify the costs, and critiques the company's exclusion of stranded costs from its business case (D.P.U. 21-82, Attorney General Brief at 23-28). According to the Attorney General, the company's accelerated AMI meter replacements, as proposed, would be more costly to ratepayers than if the company continued its business as usual meter replacements over a ten-year period, and the company's existing meters are already capable of "rudimentary" TVR and peak time rebate offerings, such as universal PTRs ("uPTRs") (D.P.U. 21-82, Attorney General Brief at 23, citing Exhs. AG-WG-1, at 45-47; AG 1-3; AG 3-4). The company contends that its proposals meet the Department's requirements for preauthorization, including that the anticipated benefits exceed the costs, and that uPTR capabilities are beyond the scope of the proceeding (D.P.U. 21-82, Unitil Brief at 22-23). The Department agrees with the company.

In particular, the Department has stated that, to the extent possible, a company should base its cost estimates on vendor quotes, estimates from relevant projects, and data from relevant case studies in other jurisdictions. Grid Modernization Order at 116 n.52; D.P.U. 12-76-C at 13. Unitil developed its cost estimates using its 2015 business case experience and data deriving from its business as usual PLX meter deployments and existing customer web portal, and information deriving from affiliate activities in relation to the proposed investments (D.P.U. 21-82, Exhs. Unitil-KES-2, at 3-4, 10; Unitil-GMP at 86-89, 91-92, 99; DPU 1-3, at 2 & Atts. 8, 9; DPU 5-1; DPU 9-1; DPU 10-1; CLF-U 1-6, at 1, 3; DOER-FGE 2-1 (Track 2), Att.; AG-WG-Surrebuttal at 16; Tr. 3, at 517-520; Tr. 4, at 587-588). Based on the above considerations, the Department finds that the company's approach for developing its cost estimates, in this instance, is reasonable, and that these cost estimates are sufficiently reviewable and reliable and based on the company's best estimates (D.P.U. 21-82, Exhs. Unitil-KES-2, at 3-4, 10; Unitil-GMP at 86-89, 91-92, 99; DPU 1-3, at 2 & Atts. 8, 9; DPU 5-1; DPU 9-1; DPU 10-1; CLF-U 1-6, at 1, 3; DOER-FGE 2-1 (Track 2), Att.; AG-WG-Surrebuttal at 16; Tr. 3, at 517-520; Tr. 4, at 587-588). See Grid Modernization Order at 115-116; D.P.U. 12-76-C at 13. Moreover, for the same reasons outlined above in Section III.C.2.f.i.(C), the Department is not persuaded by the Attorney General's argument involving the company's exclusion of stranded costs from its business case and, thus, finds that the company's approach of excluding stranded assets from its business case cost estimates to be reasonable (see D.P.U. 21-82, Attorney General Brief at 27, citing Exhs. AG 1-2; AG-WG-1, at 52). See D.P.U. 12-76-C at 27 & n.13.

The Department also finds that Unitil's estimated benefits for purposes of the business case, in this instance, are sufficiently reviewable and reliable and based on the company's best estimates. See Grid Modernization Order at 115-116; D.P.U. 12-76-C at 13. Consistent with the Department's directives, the company identifies the benefits and related assumptions relied upon in support of its proposed investments (D.P.U. 21-82, Exhs. Unitil-KES-1, at 20-22; Unitil-KES-2, at 10, 12; Unitil-GMP at 89, 91-92, 100, 102-103; DPU 9-1; AG 1-1 & Att.; AG 1-3; AG 4-2). See Grid Modernization Order at 116 n.53; D.P.U. 12-76-C at 13, 24-25. The benefits identified by the company are largely qualitative and not monetized (D.P.U. 21-82, Exhs. Unitil-KES-1, at 20-22; Unitil-GMP at 89, 91-92, 100, 102-103; DPU 9-1; AG 1-3; AG 4-2; AG 6-7; Tr. 5, at 951-952). The replacement of the company's existing meters with more advanced AMI meters will provide grid-edge (i.e., customer-level) granular usage data that will: (1) allow customers to participate in TVR (thus facilitating price responsive usage); (2) provide the company with more complete and timely information about the status of grid components (thus reducing operating and maintenance costs); (3) support the implementation of VVO; (4) provide for improved outage management; and (5) allow the company to better integrate DERs and other renewable resources into the distribution system (D.P.U. 21-82, Unitil Brief at 10; Exhs. Unitil-KES-1, at 20-21; Unitil-GMP at 33, 36-39, 89, 102; DPU 9-1; AG 1-1; AG 1-3; AG 6-7). The company's customer engagement and experience and data sharing platform will provide: (1) proactive alerts to customers regarding, among other things, increases in usage and outage notifications; (2) a single location to educate customers on, among other things, rate plans, products and services, and home energy management systems; (3) information that will allow the company to better understand how consumers use energy in their homes, facilitating the development of future products and service offerings; (4) more dynamic bill presentations; and (5) customers with access to usage information that can be shared with customers' selected third-parties in a responsible manner (D.P.U. 21-82, Exhs. Unitil-KES-1, at 21-22; Unitil-GMP at 90-103; DPU 9-1; Tr. 5, at 596-597).

In considering whether Unitil has demonstrated that the benefits justify the costs, the Department determines that it must also take into account the Commonwealth's long-term energy policy and climate goals, as well as the current status of the company's metering infrastructure. See D.P.U. 20-69-A at 25, 27. Unitil identifies two compelling needs for accelerating its transition to modern AMI functionalities: (1) an operational need created by the company's existing TS2 meters, approximately half of which are nearing the end of their estimated useful lives, with the likelihood that its meter vendor will no longer support those meters; and (2) a technology need, stating that, while its existing meter technology was considered state of the art at the time of deployment over a decade ago, the meters have been outpaced by new technology that can provide more information in a timelier fashion, thus supporting the company's plan for implementing TVR rates (D.P.U. 21-82, Exhs. Unitil-KES-2, at 11; Unitil-GMP at 86-87; AG 1-3; AG 1-6; AG 6-6, at 2; AG 6-7; DPU 10-1; Tr. 3, at 516-520). The proposed investments in customer enablement and education and a data sharing platform will supplement the deployment of AMI meters by providing customers with (1) access to their AMI usage data (also available to selected third-parties), (2) proactive alerts regarding usage increases and outages, and (3) information and education on TVR plans and other products and services (D.P.U. 21-82, Exhs. Unitil-KES-1, at 21-22; Unitil-GMP at 90-91, 92-100, 102-103; DPU 9-1; Tr. 5, at 596-597). With approximately half of the company's existing TS2 meters nearing the end of their useful lives and an increasing risk of failures necessitating replacement, the obsolesce of existing meters, and the need to enable more advanced metering functionality other than the "rudimentary" TVR capability of these meters identified by the Attorney General (see D.P.U. 21-82, Attorney General Brief at 24-25 & n.15), the Department finds that it is an optimal time for Unitil to accelerate replacement of its AMI meters in the next few years if the company follows a thoughtful implementation process to minimize stranded costs for ratepayers and, thus, achieve the benefits identified herein, including the capability for more complex advanced metering functionality than otherwise provided by the company's existing meters and other customer-facing infrastructure (D.P.U. 21-82, Exhs. Unitil-KES-2, at 11; Unitil-GMP at 86-87; AG 1-3; AG 6-7; DPU 10-1; Tr. 3, at 516-520). See D.P.U. 20-69-A at 25-27, 29; Grid Modernization Order at 121-122. As the company implements AMI meter replacements, however, the Department emphasizes that the company must act prudently and take all necessary steps to minimize stranded costs. Track 1 Order at 69-70.

Accordingly, based on our review and considerations herein, the Department finds the projected costs of the proposed customer-facing grid modernization investments are reasonable and that the anticipated benefits justify the estimated costs.

(D) Bill Impacts

A company must demonstrate that its proposed investments will result in reasonable bill impacts. D.P.U. 20-69-A at 31; Grid Modernization Order at 116; D.P.U. 12-76-C at 29-30; see also G.L. c. 25, § 1A. Unitil has submitted bill impact analyses identifying estimated increases that would result to each applicable rate class from the proposed customer-facing grid modernization investments over the four-year timeline (D.P.U. 21-82, Exh. Unitil-KES-1, at 24).[111] The Department finds that the bill impacts resulting from the total estimated costs for the proposed customer-facing investments are in the range of reasonableness in light of the anticipated benefits these investments will provide.

(E) Preauthorization and Preliminary Approval of Customer-Facing Investments

In D.P.U. 20-69-A at 29, 34, the Department instructed the Companies to submit plans for all proposed customer-facing grid modernization investments, regardless of whether the investments would be eligible for short-term targeted cost recovery. The Department indicated that we would review the Companies' investment plans to determine which investments are appropriate for preauthorization. D.P.U. 20-69-A at 30. Based upon our above findings, the AMI investments categories identified by Unitil in its 2022-2025 Grid Modernization Plan are eligible for accelerated cost recovery. However, for the reasons outlined below, the Department finds that only a certain segment of these investment categories are appropriate for preauthorization.

As discussed in Section III.C.2.b, the Department identifies two, overarching categories of AMI implementation investments– core AMI investments and supporting AMI investments. In reviewing the company's proposals, the Department determines that the only core AMI investment proposed for preauthorization and accelerated recovery involves the company's accelerated transition and replacement of its existing older-generation

111 The company estimates that upon full deployment of AMI, an average residential non-heating customer using 587 kWh per month could expect the total monthly bill to increase by approximately of $4.62 (D.P.U. 21-82, Exh. Unitil-KES-1, at 24).

TS2 meters with PLX AMI meters (D.P.U. 21-81, Exhs. Unitil-KES-1, at 20-21; Unitil-GMP at 13, 87-88; DPU 5-1; DPU 9-1; DPU 10-1; AG 4-2, at 3). Having met the requirements for preauthorization, the Department preauthorizes this investment category and, consequently, generally approves the company's implementation proposals for its meter replacement investments.

While preauthorization means that the Department will not revisit whether the company should have proceeded with the investments as proposed, the Department will, however, review the prudence of a company's implementation of the preauthorized investments. D.P.U. 20-69-A at 30 n.9; Grid Modernization Order at 110. For instance, the Department cautions the company against deploying temporary solutions that increase financial burdens for ratepayers. The grid modernization framework is not intended to promote constant replacements and early retirements of technologies. Track 1 Order at 69. Further, given the scale of investments proposed, the Department expects the company to deploy AMI meters and associated systems to be capable of advanced functionalities that balance costs and the needs of the future and provide long-term solutions for customers. Track 1 Order at 70. For example, given the legislative requirement for the Companies to implement EV TOUs in the near term, AMI meters should be capable of load disaggregation, among other functions, which will eliminate the need for the company to install more than one AMI meter at a customer's location. See 2022 Clean Energy Act, § 90.

Additionally, the Department identifies two categories of supporting AMI investments for Unitil: customer engagement and experience and a data sharing platform (D.P.U. 21-82, Exhs. Unitil-KES-1, at 21-22; Unitil-GMP at 89-100; DPU 9-2AG 4-1, at 1-2). While the Department recognizes that Unitil's proposed investments for these categories are integral components of the company's customer-facing grid modernization investment proposals and will likely provide benefits in terms of optimizing system performance and demand (D.P.U. 21-82, Exhs. Unitil-KES-1, at 21-22; Unitil-GMP at 89-100; DPU 9-2; AG 4-1, at 1-2), as supporting AMI investments, the Department does not preauthorize these investment categories. Many key aspects of these supporting AMI investments, including detailed budgets, implementation plans, and data access issues are not fully developed, but remain elements of the overall business case. The Department finds, however, that these categories may be eligible for accelerated cost recovery through the company's GMF, as discussed in Section III.C.3.c. Further, as set forth in Section VI, below, the Department requires the Companies to work with stakeholders to address issues related to customer engagement and education, as well as data access. The Department concludes that a determination on accelerated recovery of costs associated with the supporting AMI investments may be informed by this stakeholder process.

Therefore, unlike preauthorized investments, the Department will review whether the company should have proceeded with its specific investments once the company submits costs for recovery. In particular, to be eligible for recovery, the supporting AMI investments must be attributable to AMI implementation, and the company must demonstrate that the expenses were incremental to business as usual investments, incremental to costs included in base distribution rates or recovered through other reconciling mechanisms, and prudently incurred.

Thus, the Department provides preliminary approval to the company's implementation proposals for supporting AMI investments and expects additional details for these investments to be submitted in future AMIF cost recovery filings to determine whether accelerated cost recovery for these investments is appropriate.

(F) Budget Caps

In Grid Modernization Order at 164, the Department established a budget cap for preauthorized investments, permitting Unitil the flexibility to shift spending among the preauthorized categories in order to respond to evolving conditions. The Department found that in the early stages of grid modernization, it was reasonable to expect that significant changes would take place associated with, among other things, the introduction of new technologies and the costs of new and existing technologies. Grid Modernization Order at 107, citing D.P.U. 17-05, at 442. In Section III.C.1.d.vi, the Department establishes a flexible budget cap for Unitil's preauthorized new grid-facing investments. The Department finds that a measure of flexibility is similarly warranted here. Accordingly, the Department establishes a $11.2 million budget cap for expenses incurred through 2025[112] for Unitil's implementation of its core AMI project, AMI meter replacements (D.P.U. 21-82, Exh. Unitil-KES-1, at 18). Additionally, because the Department's bill impact analysis relied on the estimated costs for all the company's proposed customer-facing investment categories

112 As discussed in further detail below, the Department establishes a finite, four-year term for accelerated cost recovery through the company's GMF for eligible AMI implementation costs incurred through CY 2025.

and to ensure future affordability of these investments for the company's customers, the Department establishes a $2.3 million budget cap for expenses incurred through 2025 for its supporting AMI investments, customer engagement and experience, and data sharing platform (D.P.U. 21-82, Exh. Unitil-KES-1, at 18). Any spending over the overall budget cap for each bucket of investments is not eligible for accelerated recovery through the GMF and, instead, may be recovered by the company in a base distribution rate proceeding subsequent to a prudency finding by the Department in a future GMF filing docket. Further, the Department's preauthorization and preliminary approval of the investments identified herein only applies to expenditures during the approved four-year term between 2022 and 2025.

(G) Conclusion

Based on the foregoing, the Department preauthorizes Unitil's AMI meter replacement investments, with a budget of $11.2 million through 2025 (D.P.U. 21-82, Exh. Unitil-KES-1, at 18). Additionally, the Department provides preliminary approval for Unitil's customer engagement and experience and data sharing platform investments, with a combined budget of $2.3 million through 2025 (D.P.U. 21-82, Exh. Unitil-KES-1, at 18). Unitil may request initial cost recovery for these supporting AMI investments, including for costs that may begin to be incurred for these investment categories as of the effective date of this Order, as part of its April 15, 2023 GMF filing, subject to the requirements outlined in Section III.C.3.c, below. The Department finds that the implementation of this project will improve safety, security, reliability of service, affordability, and equity, and will enable clean energy technologies to lower emissions. G.L. c. 25, § 1A.[113]

In discharging its responsibilities under chapters 25 and 164 of the general laws, the Department must prioritize, among other things, equity, with respect to itself and the entities it regulates. G.L. c. 25, § 1A. Consistent with D.P.U. 20-69-A at 31, the Department finds that the company's proposed customer-facing investments will deliver both direct and indirect benefits of a modernized grid to all customers within the company's service territory.

3. Cost Recovery

a. Introduction

In addressing cost recovery of grid modernization investments, the Department seeks to align an electric distribution company's investment priorities with the interests and needs of its customers. Grid Modernization Order at 8, 216; D.P.U. 17-05, at 435; D.P.U. 12-76-A at 27 (2013); see also Aquarion Water Company of Massachusetts, D.P.U. 17-90, at 45 (2018), citing D.P.U. 15-155, at 51; Fitchburg Gas and Electric Light Company, D.P.U. 13-90, at 36 (2014); Fitchburg Gas and Electric Light Company, D.P.U. 11-01/D.P.U. 11-02, at 111 (2011); Western Massachusetts Electric Company, D.P.U. 10-70, at 51-52 (2011); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 09-39, at 80-84 (2009) (explaining that, in evaluating capital cost recovery

113 Affordability considerations are inherent in multiple aspects of our review, including of estimated bill impacts and for purposes of establishing budget caps, as well as limiting preauthorization to only certain categories of investments.

mechanisms for electric distribution companies, the Department's standard of review examines whether the mechanism is warranted and in the best interest of ratepayers). If correctly designed, an accelerated cost recovery mechanism will facilitate the achievement of our grid modernization objectives by reducing the financial risk associated with grid modernization investments, while preserving important ratepayer protections. Grid Modernization Order at 8, 216, citing D.P.U. 12-76-B. To achieve these results, the Department identified and established a reconciling cost recovery mechanism, the GMF, as the appropriate mechanism through which the Companies would recover eligible grid modernization costs associated with their first grid modernization plans. See Grid Modernization Order at 205-206, 216-234; see also D.P.U. 17-05, at 435; D.P.U. 12-76-B at 22-23.[114] The Department concluded that a cost recovery mechanism outside of base distribution rates would reduce a company's risk associated with grid modernization investments, while avoiding the significant disadvantages of a future-test-year ratemaking approach. See Grid Modernization Order at 216-217; see also D.P.U. 17-05, at 435; D.P.U. 12-76-B at 22-23.

In D.P.U. 20-69-A at 30-35, the Department stated that the Companies may seek accelerated cost recovery of eligible grid modernization investments, inclusive of both grid-facing and customer-facing investments, as part of their second grid modernization plan

[114] At the time, the Department only preauthorized the Companies' proposed grid-facing investments for the first grid modernization plan term. Grid Modernization Order at 113, 134, 154-155, 163-164, 172-173.

filings. In this proceeding, for their new grid-facing investments, the Companies each requested cost recovery through their existing GMF tariffs, subject to Department review and approval (D.P.U. 21-80, Exhs. ES-JAS-1, at 14-16; ES-JAS-2, at 35-36; D.P.U. 21-81, Exhs. NG-GMP-1, at 11; NG-GMP-2 (Rev. 2) at 16; D.P.U. 21-82, Exhs. Unitil-KES-1, at 16-22; Unitil-GMP at 12-14). See also NSTAR Electric, M.D.P.U. No. 73F, §§ 1.0, 2.6; National Grid, M.D.P.U. No. 1497, §§ 1.0, 2.6; Unitil, M.D.P.U. No. 379, §§ 1.0, 2.6.

For their proposed AMI-related investments, NSTAR Electric and National Grid each requested that the Department approve a new proposed cost recovery mechanism, the AMIF (D.P.U. 21-80, Exhs. ES-AMI-1, at 37-40; ES-AMI-5; DPU 2-2; DPU 2-5; DPU 15-4; Tr. 4, at 657, 663, 666-671, 746; D.P.U. 21-81, Exhs. NG-AMI-1, at 4, 8-11; NG-AMI-6; NG-AMI-Rebuttal at 59-65; DPU 2-2; DPU 2-5; Tr. 4, at 650-651, 672-676; D.P.U. 22-22, Exhs. ES-AMI-1, at 16-17; DPU 7-1; DPU 40-3). NSTAR Electric and National Grid jointly proposed a model AMIF tariff and requested Department approval of a company-specific tariff based on the model tariff (D.P.U. 21-80, Exh. ES-AMI-1, at 37-38; D.P.U. 21-81, Exh. NG-AMI-1, at 8-9).[115] For its proposed customer-facing investments, Unitil requested cost recovery through its existing GMF tariff, subject to Department review and approval (D.P.U. 21-82, Exhs. Unitil-KES-1, at 20-22; AG 1-9; Tr. 4, at 658-659).

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115 As noted above in Section III.A.1, NSTAR Electric requested approval of the model tariff in D.P.U. 21-80 and a company-specific tariff in D.P.U. 22-22, and National Grid requested approval of a company-specific tariff during the course of the instant proceedings.

The Attorney General urges the Department, to the extent the Department approves the Companies' cost recovery proposals, to predicate cost recovery for grid modernization investments on the realization of specific customer benefits as projected by the Companies in their business cases (D.P.U. 21-80, Attorney General Brief at 8-11, 23-24; D.P.U. 21-81, Attorney General Brief at 8-10, 23-25; D.P.U. 21-82, Attorney General Reply Brief at 6-7, 10-11). The Attorney General also suggests several revisions to the model AMIF tariff proposed by NSTAR Electric and National Grid (D.P.U. 21-80, Attorney General Brief at 25-26; D.P.U. 21-81, Attorney General Brief at 25-26). DOER urges the Department to approve the Companies' cost recovery proposals (DOER Initial Brief at 12). No other intervenor specifically addressed the cost recovery proposals.

In Sections III.C.1 and III.C.2, above, the Department approved certain grid-facing and customer-facing grid modernization investments. Further, in Section III.C.2.b, for supporting AMI investments, the Department determines that a change to the design of the accelerated cost recovery mechanism outlined in the Grid Modernization Order at 110, 220, is warranted for supporting AMI investments that are not preauthorized but approved for inclusion in an accelerated cost recovery mechanism. Below, the Department addresses the design of the accelerated cost recovery mechanism proposals for preauthorized grid-facing investments, preauthorized customer-facing investments, and those supporting customer-facing investments for which the Department provides preliminary approval.

b. Accelerated Cost Recovery of Grid-Facing Investments

As an initial matter, no party objects to targeted cost recovery through the existing GMF for preauthorized grid-facing investments that the Companies proposed for the 2022-2025 Grid Modernization Plan term.[116] The existing GMF mechanism and tariffs provide for the Companies' recovery of preauthorized grid-facing investments consistent with Department precedent. See Grid Modernization Order at 216; D.P.U. 12-76-B. Accordingly, the Department approves each company's request to recover through the GMFs, subject to Department review and approval and consistent with the directives outlined below, the eligible costs incurred for preauthorized grid-facing investments that will be made during the 2022-2025 Grid Modernization Plan term.

c. Accelerated Cost Recovery of Customer-Facing Investments

i. Unitil

Unitil proposes to recover eligible customer-facing grid modernization investments through its existing GMF. The term for implementing Unitil's customer-facing investments mirrors those for its grid-facing investments. Further, the Department determines that recovery of customer-facing grid modernization investments through the GMF will allow for the necessary Department oversight and stakeholder input regarding Unitil's preauthorized

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[116] In the Track 1 Order at 60-98, the Department preauthorized certain continuing investments proposed by the Companies. In Section III.C.1, the Department also preauthorizes new grid-facing investments proposed by NSTAR Electric, National Grid, and Unitil, as well as investments involving program management, and third-party measurement and verification for both Track 1 and Track 2 investments.

and preliminarily approved customer-facing grid modernization investments. D.P.U. 17-05, at 439, 441-442. Accordingly, the Department approves Unitil's request to recover through its existing GMF mechanism the eligible costs incurred for customer-facing investments that will be made during its 2022-2025 Grid Modernization Plan term. The Department determines, however, that limited modifications to Unitil's GMF tariff in relation to these investments are necessary.

Because the Department approves cost recovery through Unitil's GMF both for eligible preauthorized and certain preliminarily approved customer-facing investments, and consistent with the parameters established below for accelerated recovery for customer-facing investments by NSTAR Electric and National Grid, the Department determines that revisions to the company's existing GMF tariff are necessary. First, the company's GMF tariff requires revisions to account for the distinction between customer-facing and grid-facing investments and, also, to clarify that customer-facing investments eligible for recovery under the GMFs are those that are preauthorized or preliminarily approved by the Department. Second, Unitil shall revise the annual cost recovery filing requirements provision in the GMF to account for the following requirements specific to its preauthorized and preliminarily approved customer-facing investments: (1) full project documentation of all eligible AMI investments, inclusive of capital investments recorded as in-service during the prior investment year and allowed O&M expenses, with narrative providing justification that the costs meet the cost recovery eligibility requirements outlined in the tariff; (2) supporting documentation demonstrating that costs sought for recovery for categories of eligible AMI investments preauthorized by the Department are incremental, prudently incurred, and, where applicable, in-service, and used and useful; (3) supporting documentation demonstrating that the costs sought for recovery for categories of eligible AMI investments preliminarily approved but not preauthorized by the Department are incremental, prudently incurred, and, where applicable, used and useful; (4) any cost variances in relation to the budget estimates for that investment year and as defined in the company's capital authorization policies; (5) a demonstration that eligible AMI investments preliminarily approved but not preauthorized are attributable to AMI implementation and incremental to business as usual investments; (6) a demonstration that the aggregate totals of expenditures for (i) preauthorized, and (ii) preliminarily approved, eligible AMI investments is under the relevant budget cap set by the Department; and (7) consistent with Section III.C.3.v, below, a provision to offset and reconcile any alternative government or outside funding received for the investments. See Grid Modernization Order at 225-226, 231.

Further, consistent with Grid Modernization Order at 110-113, the Department determines that a final prudence review of the company's grid-facing and customer-facing grid modernization investments at the conclusion of the four-year term is appropriate. However, a final prudence review is required for cost recovery for any supporting AMI investments granted preliminary approval herein.[117] Unitil shall also comply with all other applicable directives, as noted below.

ii. NSTAR Electric and National Grid

(A) AMIF

Turning to NSTAR Electric's and National Grid's cost recovery proposals, the Department finds merit to a separate accelerated cost recovery mechanism, the AMIF, for the companies' AMI Implementation Plans and establishes a new AMIF to recover eligible costs associated with each company's customer-facing investments. While part of each company's overall grid modernization proposal, the Department finds that the accelerated deployment of AMI and corresponding customer-facing investments is sufficiently distinct from grid-facing investments to justify a separate cost recovery mechanism. In particular, the Department notes that the timelines for deployment of the grid-facing investments and customer-facing investments are different, and a separate cost recovery mechanism will facilitate the efficient of review of these costs. As with cost recovery for preauthorized grid-facing investments, recovery of customer-facing grid modernization investments through a dedicated, reconciling short-term recovery mechanism, rather than through an existing capital tracker, will facilitate the necessary Department oversight and stakeholder input regarding the grid modernization investments. D.P.U. 17-05, at 439, 441-442. Accordingly, the Department determines that

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117 In Section III.C.3.c.vi, below, the Department establishes annual prudency reviews for NSTAR Electric and National Grid's customer-facing investments submitted for targeted cost recovery.

a separate accelerated cost recovery mechanism, the AMIF, modeled after the GMF mechanism and tariffs is reasonable and appropriate. After review and consideration of the proposed model AMIF tariff, the Department approves, in part, and denies, in part, the model AMIF tariff, and directs each company to submit a company-specific AMIF tariff consistent with the modifications and revisions outlined below.[118]

As discussed further below, the Department will perform annual prudence reviews of the customer-facing investments. Accordingly, the Department directs NSTAR Electric and National Grid to revise the annual cost recovery filing requirements provision in the model AMIF tariff to require that the filings include, but not be limited to: (1) full project documentation of all eligible AMI investments, inclusive of capital investments recorded as in-service during the prior investment year and allowed O&M expenses, with narrative providing justification that the costs meet the cost recovery eligibility requirements outlined in the tariff; (2) supporting documentation demonstrating that costs sought for recovery for categories of eligible AMI investments preauthorized by the Department are incremental, prudently incurred, and, where applicable, used and useful; (3) supporting documentation demonstrating that the costs sought for recovery for categories of eligible AMI investments preliminarily approved but not preauthorized by the Department are incremental, prudently incurred, and, where applicable, in service, and used and useful; (4) any cost variances in

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118 Due to additional AMIF tariff-related directives in D.P.U. 22-22, at 353, NSTAR Electric shall submit its company-specific AMIF mechanism tariff with the modifications described herein as a compliance filing for approval in D.P.U. 22-22.

relation to the budget estimates for that investment year and as defined in the company's capital authorization policies; (5) a demonstration that the proposed factors are calculated appropriately; (6) AMIF-specific bill impacts; (7) consolidated bill impacts for the company's GMFs and AMIFs effective on the same date; (8) a demonstration that eligible AMI investments preliminarily approved but not preauthorized are attributable to AMI implementation and incremental to business as usual investments; (9) a demonstration that the aggregate totals of expenditures for (i) preauthorized, and (ii) preliminarily approved, eligible AMI investments is under the relevant budget cap set by the Department; and (9) details on alternative government funding obtained for the investments and the associated offset for such funding. See Grid Modernization Order at 225-226, 231.

We emphasize the importance of NSTAR Electric and National Grid developing and maintaining systematic, ample, and contemporaneous documentation of all grid modernization projects for which they seek targeted cost recovery. The Department, therefore, expects each company to provide full supporting documentation of costs as part of their annual AMIF cost recovery filings. Each company shall also provide a clear demonstration that they relied on a competitive procurement process to obtain third-party contractors to complete work identified in the AMI Implementation Plans, and shall provide copies of all RFPs and responses received, as well as the basis for selecting particular vendors. A failure to provide clear, cohesive, and reviewable evidence demonstrating eligibility and the prudency of costs incurred will result in disallowance of targeted cost recovery of the expenditures in question. See Grid Modernization Order at 221 (citations omitted).

Finally, the Department directs that the annual AMIF cost recovery filings be submitted on the same dates as each company submits its annual GMF cost recovery filings: March 15 with a May 1 effective date for National Grid, and May 15 with a July 1 effective date for NSTAR Electric.

(B) Recovery Period

The Attorney General suggests that the Department include a tariff termination provision in the model AMIF tariff (D.P.U. 21-80, Attorney General Brief at 26; D.P.U. 21-81, Attorney General Brief at 26). NSTAR Electric and National Grid counter that a termination provision is unnecessary because, upon conclusion of AMI deployment, they expect to transfer recovery of AMI-related costs to their base distribution rates (D.P.U. 21-80, Exhs. AG 1-6; ES-Rebuttal at 34; NSTAR Electric Brief at 103; D.P.U. 21-81, Exhs. AG 1-6; NG-AMI-Rebuttal-1, at 45; National Grid Brief at 85-86). For the following reasons, the Department agrees that a tariff termination provision is appropriate.

The AMIF approved herein, like the GMF, is a special ratemaking mechanism designed to remove financial barriers to a reasonable level of investment in grid modernization technologies, and the Department precludes business as usual investments from accelerated cost recovery through this mechanism. See Track 1 Order at 110; D.P.U. 20-69-A at 32, 34-35; Grid Modernization Order at 145-146, 224; D.P.U. 12-76-B at 4, 19-20. A primary purpose of grid modernization investments for which accelerated cost recovery is allowed must be to accelerate progress in achieving our grid modernization objectives. D.P.U. 20-69-A at 32; Grid Modernization Order at 145-146; D.P.U. 12-76-B at 19-20. To that end, as designed, the GMF tariffs limit accelerated cost recovery for preauthorized grid modernization investments made during the two, specific grid modernization plan terms approved by the Department (i.e., 2018 through 2021, and 2022 through 2025). See Track 1 Order at 111; Grid Modernization Order at 235; D.P.U. 15-120-D/D.P.U. 15-121-D/D.P.U. 15-122-D at 4-7 & n.7; NSTAR Electric, M.D.P.U. No. 73F, § 6.1; National Grid, M.D.P.U. No. 1497, § 6.1; Unitil, M.D.P.U. No. 379, § 6.1.[119] As a result, any grid modernization investment placed in-service after the terms approved by the Department are not eligible for accelerated cost recovery through the GMFs and, instead, may be recovered by the company in a base distribution rate proceeding subsequent to a prudency finding by the Department on those investments. Track 1 Order at 77, 89, 98, 111. Because the Department approves Unitil's recovery of its proposed customer-facing grid modernization investments through the GMF, these cost recovery limitations already apply to Unitil's customer-facing investments made during its 2022-2025 Grid Modernization Plan term.[120] Further, in D.P.U. 20-69-A at 35,

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119 The Department notes that going forward many of investments included in the grid modernization plans will be subsumed in the electric sector modernization plans pursuant to G.L. c. 164, § 92B and cost recovery of future investments will be governed by G.L. c. 164, § 92B.

120 The Companies' existing GMF tariffs do not distinguish between grid-facing and customer-facing grid modernization investments for purposes of cost recovery through the GMFs. See NSTAR Electric, M.D.P.U. No. 73F; National Grid, M.D.P.U. No. 1497; Unitil, M.D.P.U. No. 379.

the Department stated that we expected any proposals for short-term targeted or alternative ratemaking treatment for customer-facing investments to be designed for a finite period, because the Department also expected that grid modernization, including AMI-related investments, would become a part of the Companies' normal course of business over time. The Department affirms this precedent for NSTAR Electric's and National Grid's customer-facing investments.

Further, as discussed in Section III.C.2.c, rather than a four-year short-term investment plan consistent with their 2022-2025 Grid Modernization Plan terms for grid-facing investments, NSTAR Electric and National Grid provided a seven-year (2022 through 2028) and five-year (2023 through 2027), respectively, AMI Implementation Plan for the Department's consideration that outlined each company's estimated timeline and necessary investments to enable full AMI deployment (D.P.U. 21-80, Exhs. ES-AMI-2; ES-AMI-4 (Rev.) at 10; D.P.U. 22-22, Exhs. DPU 46-4 & Att.; D.P.U. 21-81, Exhs. NG-AMI-2, at 5). According to NSTAR Electric and National Grid, they proposed a model AMIF tariff separate from their GMF tariffs, in part, because they envisioned AMI deployment to be a transitory and shorter-term program than grid modernization, generally, which continues to evolve (D.P.U. 21-80, Exh. DPU 2-2, at 2; D.P.U. 21-81, Exh. DPU 2-2, at 2).

In determining an appropriate term for the customer-facing grid modernization investments eligible for accelerated cost recovery, the Department seeks to strike the appropriate balance between a high degree of certainty in planning outcomes and administrative efficiency. <u>See</u> <u>Grid Modernization Order</u> at 108. The Department concludes that seven- and five-year terms, coupled with changes to the regulatory review construct for AMIF filings, will provide NSTAR Electric and National Grid with greater certainty to more effectively plan accelerated AMI deployment and allow the Department to fulfill its regulatory oversight responsibilities in an efficient and effective manner. The Department acknowledges that the AMI Implementation Plan terms approved here differ from the short-term investment plan term lengths previously envisioned for accelerated cost recovery for grid modernization investments. See Grid Modernization Order at 108-110; D.P.U. 12-76-B at 17. At the same time, the Department's understanding for achieving full advanced metering functionality has evolved since we began to explore these issues more than a decade ago, which is informed by our ongoing consideration of technological requirements and capabilities on each company's system, continued advances in available technology, and the Commonwealth's evolving energy policies. Moreover, the Department also explained that it neither required nor expected that each company would achieve full AMI deployment within the grid modernization plan term. D.P.U. 20-69-A at 29.

Accordingly, based on these considerations, the Department approves a seven-year term, 2022 through 2028, for accelerated cost recovery through the AMIF for NSTAR Electric's AMI implementation investments, and a five-year term, 2023 through 2027, for accelerated cost recovery through the AMIF for National Grid's AMI implementation investments. NSTAR Electric and National Grid shall revise their proposed AMIF tariffs to reflect that accelerated cost recovery through the AMIF is limited to eligible investments made during these terms.[121] To ensure timely AMI deployment and related benefits to customers, the Department conditions accelerated cost recovery on each company meeting its anticipated investment implementation timelines. Failure to meet these implementation timelines may jeopardize accelerated recovery of certain investment year costs.[122]

(C) Definitions, Applicability, and Incremental Expenses

The model AMIF tariff defines "eligible investments" as the cumulative capitalized costs directly attributable to implementation of AMI recorded as in-service, including net salvage, and are used and useful at the end of the AMI investment year that is prior to the recovery year (D.P.U. 21-80, Exh. ES-AMI-5, at 2; D.P.U. 21-81, Exh. NG-AMI-6, at 2). In comparison, the GMF tariffs provide a substantially similar definition for "eligible GMP investments" as the cumulative capitalized costs of eligible GMP projects recorded as in-service, including net salvage, and are used and useful at the end of the GMP investment

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121 At the end of the terms, no new AMI implementation investments will be eligible to be collected through the AMIF tariffs, but NSTAR Electric and National Grid may continue to recover costs for existing investments through the AMIF until each company's AMI investments are moved into a different cost recovery mechanism. Like the term-specific requirements for cost recovery through the GMFs, any customer-specific grid modernization investment placed in service after the terms approved by the Department are not eligible for accelerated cost recovery through the AMIFs and, instead, may be recovered by the company in a base distribution rate or other traditional ratemaking proceeding subsequent to a prudency finding by the Department on those investments. See Track 1 Order at 77, 89, 98, 111.

122 The purpose of allowing accelerated cost recovery for AMI-related investments is to accelerate the deployment of full AMI functionality, and the corresponding benefits, within the Companies' service territories.

year that is prior to the GMP recovery year. NSTAR Electric, M.D.P.U. No. 73F, § 2.5; National Grid, M.D.P.U. No. 1497, § 2.5; Unitil, M.D.P.U. No. 379, § 2.5. The GMF tariffs define an "eligible GMP project" as a project contained in the company's grid modernization plan and preauthorized by the Department to be eligible for cost recovery as a project which contributes towards achieving the Department's three grid modernization objectives. NSTAR Electric, M.D.P.U. No. 73F, § 2.6; National Grid, M.D.P.U. No. 1497, § 2.6; Unitil, M.D.P.U. No. 379, § 2.6. Further, in the sections titled "Applicability" and "Eligibility for Recovery as Allowed O&M Expenses," the GMF tariffs identify additional requirements to be eligible for recovery, including provisions for the incremental nature of the investments. NSTAR Electric, M.D.P.U. No. 73F, §§ 1.0, 4.0; National Grid, M.D.P.U. No. 1497, §§ 1.0, 4.0; Unitil, M.D.P.U. No. 379, §§ 1.0, 4.0. The model AMIF tariff does not contain a similar definition for an "eligible AMI project" and, as observed by the Attorney General, does not define the term "incremental" as used in the proposed tariff (D.P.U. 21-80, Attorney General Brief at 26; D.P.U. 21-81, Attorney General Brief at 26).

As discussed in Section III.C.2.f, the Department preauthorizes core AMI investment categories in NSTAR Electric and National Grid's AMI Implementation Plans, and otherwise provides preliminary approval to the remaining supporting AMI investment categories. Only those AMI Implementation Plan cost categories preauthorized or provided preliminary approval are eligible for cost recovery through the AMIF, subject to Department review and approval. Moreover, the annual filing requirements section language shall be modified in the proposed AMIF tariffs to include references to "eligible AMI investments," reflective of the more expansive provisions related to eligibility for accelerated cost recovery in the existing GMF tariffs. To account for these considerations, the Department directs NSTAR Electric and National Grid to revise "eligible investments" to "eligible AMI investments" and to define these investments as the cumulative capitalized costs of AMI implementation investments recorded as in-service, including net salvage, and are used and useful at the end of AMI investment year that is prior to the recovery year and: (1) are preauthorized or approved by the Department as eligible for accelerated cost recovery, subject to Department review and approval; (2) contribute towards achieving the Department's grid modernization objectives; (3) are incremental relative to the company's current investment practices or new types of technology for capital investments; (4) are incremental to those costs that the company currently recovers through its base distribution rates for O&M expenses and solely attributable to preauthorized or approved AMI-related grid modernization investments; (5) are prudently incurred; (6) have aggregate total expenditures for preauthorized or approved AMI investments less than the relevant budget caps determined by the Department; and (7) are recorded as in-service by December 31 of each AMI investment year. Each company shall also revise any additional "eligible investments" references in the tariff to "eligible AMI investments" and "implementing AMI" to "implementing eligible AMI investments" accordingly.

The Attorney General urges that the "eligible investments" definition in the model AMIF tariff should adjust for meter investments, whether in-service or in the warehouse inventory, of new AMR or bridge meters that can be repurposed for those customers who opt-out of AMI (D.P.U. 21-80, Attorney General Brief at 25-26; D.P.U. 21-81, Attorney General Brief at 26). NSTAR Electric counters that AMI meters will be treated as pre-capped units of property by the company and, therefore, all AMI meters would be considered in-service at the time of purchase, similar to how all other meter capital is accounted for (D.P.U. 21-80, Exh. ES-Rebuttal at 30). National Grid states that it will not repurpose AMR meters for those who opt out of AMI but will, instead, use a version of the AMI meter that does not have the AMI capabilities enabled (i.e., no radio frequency) for opt-out customers (D.P.U. 21-81, Exh. NG-AMI-Rebuttal-1, at 42-43). The Department declines to adopt the Attorney General's proposal, because the Department's directive to move all meter-related costs to the AMIF renders the Attorney General's recommendation moot.

In addition, the Department recently required the Companies to submit revised GMF tariffs in the instant proceedings as a result of Department approvals relating to a protocol for tracking and identifying incremental grid modernization O&M expense. D.P.U. 15-120-E/ D.P.U. 15-121-E/D.P.U. 15-122-E, at 25-41; see also Grid Modernization Order at 222. On September 30, 2022, the Department approved revised GMF tariffs submitted by the Companies in accordance with this directive. Accordingly, the Department directs NSTAR Electric and National Grid to incorporate a substantially similar provision into the proposed AMIF tariff for application to the AMIFs, and to update other AMIF tariff provisions to account for this addition, as necessary. See NSTAR Electric, M.D.P.U. No. 73F, §§ 1.0, 4.0; National Grid, M.D.P.U. No. 1497, §§ 1.0, 4.0; Unitil, M.D.P.U. No. 379, §§ 1.0, 4.0. However, rather than relying on the May 10, 2018 effective date of the Grid Modernization Order for application to the five-step test, each company shall rely on the effective date of the instant Order in this test for purposes of AMI implementation investments.[123]

iii. Benefits and Cost Recovery

The Attorney General urges the Department to: (1) create performance metrics or targets to measure the delivery of ratepayer benefits as projected by the Companies in their business cases; and (2) amend the Companies' tariffs such that each company can only earn a return on its grid modernization investments after it shows that it has actually achieved and delivered the projected level of benefits (D.P.U. 21-80, Attorney General Brief at 8-11; Attorney General Reply Brief at 2, 5-6; D.P.U. 21-81, Attorney General Brief at 8-10; Attorney General Reply Brief at 2, 4-5; D.P.U. 21-82, Attorney General Brief at 7, 10-11; Attorney General Reply Brief at 2-5). Further, the Attorney General recommends that the Department reduce each company's revenue requirements by the amount of projected O&M savings and revenue assurance benefits by year, as identified in each company's business case, until the benefits are able to be fully captured in a base distribution rate case (D.P.U. 21-80, Attorney General Brief at 27-28; Attorney General Reply Brief at 10-11; D.P.U. 21-81, Attorney General Brief at 28-29; Attorney General Reply Brief at 8).

123 This same requirement applies to Unitil for its customer-facing investments and the company shall revise its GMF tariff accordingly.

The Companies oppose these proposals, countering that they are punitive, contort the Department's preauthorization and prudence standards to require a guarantee of benefits, and are inconsistent with ratemaking principles (D.P.U. 21-80, NSTAR Electric Brief at 76-77, 104, 110-111; NSTAR Electric Reply Brief at 9-10; D.P.U. 21-81, National Grid Brief at 87; National Grid Reply Brief at 3, 6-7; D.P.U. 21-82, Unitil Reply Brief at 6). Additionally, NSTAR Electric counters that the Department has not required that the company guarantee that the benefits estimated in the business case materialize exactly as estimated, instead recognizing that cost and benefit estimates may need to be revised and refined during the development and implementation of a company's grid modernization plan and, further, that there are often significant unquantified benefits associated with investments (D.P.U. 21-80, NSTAR Electric Brief at 67, 71, 74, citing Attorney General Brief at 9-11; D.P.U. 15-122, at 107, 169; D.P.U. 12-76-C at 13).[124]

At this time, the Department declines to adopt the Attorney General's recommendations. Grid modernization is a complex endeavor, and there is a level of uncertainty inherent in planning estimates. See Grid Modernization Order at 107, 235-236; D.P.U. 12-76-C at 38. With preauthorization of investments in a multi-year grid modernization investment plan, the Department has found that it is important to provide the Companies with a certain level of flexibility to deviate from their projections to respond to

124 Unitil also maintains that targets based on customer choices rather than prudent investments are contrary to ratemaking policy (D.P.U. 21-82, Unitil Reply Brief at 8). Our directives herein therefore apply to Unitil's recovery of eligible customer-facing investments through the GMF.

changes that inevitably will take place over the term of the plan. Grid Modernization Order at 107. The Department has also found that it is reasonable to expect that the Companies' understanding of how best to deploy grid modernization technologies to optimize their performance will evolve considerably over a multi-year period. Grid Modernization Order at 108. Thus, the business case is a composite analysis of interrelated categories of investments for purposes of a preauthorization and is not intended as a basis upon which to condition accelerated cost recovery.

The Department, however, recognizes that grid modernization investments should result in avoided or deferred O&M costs. Grid Modernization Order at 218. Until each company files a base distribution rate case, the benefit of any such cost reductions will accrue to shareholders, rather than ratepayers. Grid Modernization Order at 218. In D.P.U. 22-22, NSTAR Electric proposed to establish an incremental O&M expenses savings baseline derived from the test-year levels of FERC Accounts 586, 597, 902, and 905, to determine incremental cost recovery for AMI meter-related O&M (D.P.U. 22-22, Exhs. ES-REVREQ-1, at 206-207; ES-AMI-1, at 24-25; ES-AMI-3, at 1). The Department approved this proposal in that proceeding and directed NSTAR Electric to account for actual AMI-related O&M savings as part of its annual reconciling mechanism filing. D.P.U. 22-22, at 352. NSTAR Electric shall also incorporate this proposal in its company-specific AMIF tariff terms to be submitted in D.P.U. 22-22 as a compliance filing. The Department directs National Grid to submit a similar proposal for the Department's consideration in its next base distribution rate case filing, anticipated in late-2023 or early 2024.[125,126] See D.P.U. 18-150, at 75 (the company's final PBR term expires on September 30, 2024).

iv. Legacy Assets

The Attorney General notes the possibility of double recovery by NSTAR Electric and National Grid between legacy and AMI-related investments (D.P.U. 21-80, Attorney General Brief at 25-26, D.P.U. 21-81, Attorney General Brief at 25-26). During the transition from AMR to AMI, the potential for overcollection of costs associated with legacy metering infrastructure exists (D.P.U. 21-80, Exhs. ES-AMI-2, at 10; AG-TN-1, at 13-14; AG-TN-Surrebuttal at 11, lines 9-10; RR-DPU-ES-3; Tr. 3, at 511; D.P.U. 21-81, Exhs. NG-AMI-2, at 8-9; AG 1-10; AG-TN-1, at 13; AG-TN-Surrebuttal at 6, lines 6-7). D.P.U. 22-22, at 351. NSTAR Electric and National Grid each collect a representative level of legacy meter costs in base distribution rates. See D.P.U. 18-150, at 574, 577; D.P.U. 17-05, at 767, 769, 776, 778. To minimize this potential for over-recovery of costs, in D.P.U. 22-22, at 351, 353, the Department removes legacy meter, CIS, and MDMS costs

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125 National Grid does not anticipate commencing AMI meter deployments in its service territories until 2024 (D.P.U. 21-81, Exh. NG-AMI-2, at 5). As a result, avoided O&M costs will not exist until after the baseline is established for National Grid, and therefore, ratepayers will receive the full benefit of O&M savings through the operation of the AMIF.

126 With regard to Unitil, the company already utilizes AMI metering technology in its service territory that allows for remote meter reads (D.P.U. 21-82, Tr. 4, at 713-714). As a result, the potential for avoided O&M costs by Unitil, as otherwise applicable to NSTAR Electric and National Grid, is limited. Accordingly, the Department does not require Unitil to establish an incremental O&M expense savings proposal at this time.

from NSTAR Electric's base distribution rates for recovery through the AMIF mechanism for effect January 1, 2023, and directs the company to submit an updated AMIF tariff consistent with the Department's findings in that docket.[127] Accordingly, the Department similarly directs National Grid to remove legacy meter costs from its base distribution rate recovery proposals for recovery through its AMIF tariff in its next base distribution rate case filing, and to submit corresponding tariff revisions to its company-specific AMIF tariff in that proceeding.

v. Alternative Funding Sources

National Grid stated that it is actively developing a proposal to seek federal funding for AMI deployment under the IIJA (D.P.U. 21-81, Exh. NG-AMI-Rebuttal-1, at 65). Although not guaranteed, the company anticipates that any approved IIJA funding would offset a portion of the proposed customer-facing investment (D.P.U. 21-81, Exh. NG-AMI-Rebuttal-1, at 65). In D.P.U. 22-22, NSTAR Electric stated that if it received Department approval for its AMI Implementation Plan, it also anticipated seeking IIJA funding for its AMI-related investments and would explore other funding opportunities for these investments if they become available (D.P.U. 22-22, Exhs. DPU 40-1; DPU 59-1; DPU 59-2). NSTAR Electric specified that such funding would offset the necessary capital

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[127] The Department notes that NSTAR Electric's legacy CIS and MDMS are enterprise IT expenses (D.P.U. 22-22, Exh. DPU 46-7). With the exception of the company's long-term investment plan, the Department expects the company's annual AMIF filing to appropriately reflect the documentation necessary for a prudency review of such expenses. See D.P.U. 22-22, at 227-228; D.P.U. 18-150, at 273-275; D.P.U. 19-120, at 251-252.

investments and, thus, benefit customers because the offsets would be reflected in its AMIF cost recovery requests and annual filings to the Department (D.P.U. 22-22, Exhs. DPU 59-2(b); DPU 59-3).[128] Unitil did not address the possibility of federal or other alternative funding sources. Currently, neither the GMF nor proposed AMIF tariffs include an offset for alternate funding sources.

The Department commends company efforts that seek to explore alternative government funding sources. Such efforts, if successful, may offset costs that would otherwise be collected from ratepayers, thus helping to minimize potential bill impacts. See, e.g., NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 16-105, at 4, 10-11 (2016) (approving proposed offsets to the annual revenue requirement for the company's solar program deriving from ISO-NE market credits and solar renewable energy certificates); NSTAR Electric Company, D.P.U. 09-33, at 58 (2010) (discussing a Department of Energy grant funding award to the company under the American Recovery and Reinvestment Act of 2009 that offset 50 percent of the company's smart grid pilot budget). The Department has previously instructed or approved inclusion of alternate funding source offsets in annual reconciling mechanisms. See D.P.U. 17-90, at 74; D.P.U. 16-105, at 10-11. Accordingly, to account for potential alternative government and outside funding sources, the Department directs the Companies to include an offset or

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128 In D.P.U. 22-22, the Attorney General argued that NSTAR Electric's proposed company-specific tariff should be amended to reflect credits to ratepayers if the company receives government funding, including from the IIJA and other funding sources (D.P.U. 22-22, Attorney General Brief at 54-55)

reconciliation adjustment in both their GMF and AMIF mechanism revenue requirement calculations contained within their current GMF and proposed AMIF tariffs. Such adjustments shall be based on actual rather than estimated credits and funding sources. See NSTAR Electric, M.D.P.U. No. 67C, §§ 3.1, 4.1; National Grid, M.D.P.U. No. 1477, at 1; Unitil, M.D.P.U. No. 368, §§ 3.0, 4.0.

vi. Annual Filings, Plan Performance Reports, and Timing of Prudence Reviews

Pursuant to the Companies' existing GMF tariffs, Section 6.0 addresses the filings that each company must submit to the Department on an annual and four-year term basis; specifically, an annual cost recovery filing, a grid modernization annual report filing, and a grid modernization term report filing. NSTAR Electric, M.D.P.U. No. 73F, §§ 6.0-6.4; National Grid, M.D.P.U. No. 1497, §§ 6.0-6.4; Unitil, M.D.P.U. No. 379, §§ 6.0-6.4. The annual GMF cost recovery filings must include: (1) full project documentation of all eligible grid modernization plan projects, inclusive of capital investment recorded as in-service during the prior grid modernization plan investment year and allowed O&M expense, with narrative providing justification that the costs meet the cost recovery eligibility requirements outlined in the tariff; (2) supporting documentation demonstrating that the costs sought for recovery are preauthorized, incremental, prudently incurred, and, where applicable, in-service, and used and useful; (3) any cost variances as defined in the company's capital authorization policies; (4) a demonstration that the proposed factors are calculated appropriately; (5) bill impacts; and (6) a demonstration that the aggregate total of expenditures for preauthorized eligible grid modernization plan projects is under the four-year expenditure cap set by the Department. NSTAR Electric, M.D.P.U. No. 73F, § 6.2; National Grid, M.D.P.U. No. 1497, § 6.2; Unitil, M.D.P.U. No. 379, § 6.2. The annual and term reports are due April 1.[129] M.D.P.U. No. 73F, §§ 6.3, 6.4; National Grid, M.D.P.U. No. 1497, §§ 6.3, 6.4; Unitil, M.D.P.U. No. 379, §§ 6.3, 6.4. Under the regulatory construct established for grid modernization investments, the Department deemed it appropriate to investigate the implementation of each company's grid modernization plan, including the final prudence reviews for the investments, at the conclusion of the investment term. Grid Modernization Order at 112. The Department determined that the annual reports would be docketed for informational purposes only and, during the term, would allow the Department and stakeholders to monitor the status of a company's performance and, if warranted, the Department could open a formal investigation into the company's performance. Track 1 Order at 105; Grid Modernization Order at 112. This regulatory review construct will continue to apply to each company's preauthorized grid-facing investments, as well as to Unitil's preauthorized and preliminarily approved customer-facing investments.

Under the model AMIF tariff, NSTAR Electric and National Grid do not identify annual or term report filings but propose annual cost recovery filings with the Department that include: (1) project documentation of all eligible investments recorded as in-service by the company or its affiliate during the prior AMI investment year; (2) documentation

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[129] The grid modernization term report filing is due on April 1, 2026.

supporting non-recurring O&M expenses as part of recoverable O&M expense; (3) an AMI reconciliation; and (4) bill impacts (D.P.U. 21-80, Exhs. ES-AMI-1, at 39; ES-AMI-5, at 4; D.P.U. 21-81, Exhs. NG-AMI-1, at 9-10; NG-AMI-6, at 4). The annual AMIF filing and effective dates would align with the filing and effective dates associated with each company's annual GMF filings (D.P.U. 21-81, Tr. 4, at 649-650; D.P.U. 22-22, Exh. ES-AMI-2, at 5-6). NSTAR Electric's considerations for a reconciling mechanism separate from the GMF included a four-year prudency review process and timeline for grid modernization plan investments that did not align with the proposed project milestones for AMI deployment (D.P.U. 21-80, RR-DPU-ES-2, at 1-2; Tr. 3, at 524-525, 530). Similarly, National Grid anticipates that the separate AMIF mechanism positions the program well for annual prudence reviews (D.P.U. 21-81, Exh. DPU 2-4). The Department agrees.

Unlike the more limited four-year term established by the Department and applicable to investments under the GMF tariffs, the Department establishes longer terms for the AMIF mechanism and implementation of the AMI-related investments proposed by NSTAR Electric and National Grid and does not preauthorize all categories of the proposed investments. See Sections III.C.2.f, III.C.3.c.ii.(B). Moreover, NSTAR Electric and National Grid provided higher-level benefit and cost estimates for their AMI Implementation Plan investments that reflect a greater level of uncertainty as implementation progresses, which is reasonable (D.P.U. 21-80, Exhs. ES-AMI-1, at 31-32; DPU 2-5; AG 1-14; AG 5-9; Tr. 4, at 668-669; D.P.U. 22-22, Exhs. ES-AM-1, at 15-16; DPU 40-3; D.P.U. 21-81, Exhs. NG-AMI-1, at 26; NG-AMI-Rebuttal-1, at 59-60, 64; DPU 2-6; DPU 8-1, at 2; AG 5-7; Tr. 4, at 650-651, 675-676). See Sections III.C.2.f.i.(C) and III.C.2.f.ii.(C); Grid Modernization Order at 235-236; D.P.U. 12-76-C at 38. Further, the cost-effective deployment of AMI remains an important tool in meeting our grid modernization objectives. Grid Modernization Order at 236. The Department has also explained that annual prudency reviews are appropriate when investments are not preauthorized. Grid Modernization Order at 110, citing D.P.U. 09-39, at 12, 78-85; Bay State Gas Company, D.P.U. 09-30, at 129-135 (2009).[130]

Based on these considerations, the Department finds that annual prudency reviews of customer-facing investments are warranted. Accordingly, the Department will conduct annual prudency reviews on NSTAR Electric and National Grid's AMIF cost recovery filings. The Department finds that such a process will ensure that the investments will be implemented in a manner that will support achievement of measurable progress towards the Department's grid modernization objectives and will provide confidence that the investments will be implemented in a cost-effective manner. Since the Department will conduct annual reviews of the customer-facing investments, the Department will not require an annual report for these investments. As part of the AMIF cost recovery filings, however, NSTAR Electric

130 As discussed in Section III.C.2.f, the Department only preauthorizes certain categories of NSTAR Electric and National Grid's proposed customer-facing investments. The Department, instead, approves the remaining categories of investments, indicating that costs submitted for recovery from these investment categories would be under a more stringent review.

and National Grid should include an update on their AMI implementation, including, but not limited to, progress towards meeting the timelines set forth in the AMI Implementation Plans.

d. Conclusion

Above, the Department establishes the parameters for accelerated cost recovery for the Companies' eligible grid-facing and customer-facing grid modernization investments and directs each company to revise their respective GMF tariffs and, for NSTAR Electric and National Grid, proposed AMIF tariffs. NSTAR Electric shall submit its compliance AMIF tariff, inclusive of the directives herein, in D.P.U. 22-22. National Grid and Unitil shall submit compliance tariff revisions for the Department's review no later than January 15, 2023.

Finally, as is the case with any costs to be recovered from ratepayers, all grid modernization expenditures, both grid-facing and customer-facing, must be prudently incurred to be eligible for accelerated cost recovery. The Department's standard of review on prudence involves a determination of whether a company's actions, based on all that it knew or should have known at that time, were reasonable and prudent in light of the existing circumstances. Attorney General v. Department of Public Utilities, 390 Mass. 208, 229 (1983). Additionally, as part of its prudence review, the Companies must demonstrate that all costs proposed for recovery through either the GMF or AMIF are eligible grid modernization costs that are incremental to costs recovered through base distribution rates or other cost recovery mechanisms and incremental to business as usual investments.

IV. OPT-OUT TARIFFS

A. Introduction

In D.P.U. 20-69, in response to a number of commenters concerned about alleged health consequences of radio frequency emissions from AMI meters, the Department directed each company to include as part of their customer-facing investment plan an illustrative meter opt-out tariff for review by the Department. D.P.U. 20-69-A at 35-36 & n.15. The Department directed the Companies to propose opt-out charges that adhere to traditional ratemaking principles of cost causation and provide full support for all proposed opt-out charges in their illustrative meter opt-out tariffs. D.P.U. 20-69-A at 35-36 & n.15; see also D.P.U. 12-76-B at 47-49.

B. Proposals

NSTAR Electric submitted an AMI opt-out tariff modeled after National Grid's existing AMR opt-out tariff (D.P.U. 21-80, Exhs. ES-AMI-1, at 41; ES-AMI-6). NSTAR Electric proposed the following fees: (1) $42 for the removal of an advanced meter or installation of an analog meter; (2) $34 for monthly meter reading; and (3) $42 for the re-installation of an advanced meter (D.P.U. 21-80, Exh. ES-AMI-6, at 1).

National Grid submitted a modified version of its existing AMR opt-out tariff, M.D.P.U. No. 1215 (D.P.U. 21-81, Exhs. NG-AMI-1, at 23-24; NG-AMI-7; NG-AMI-8). National Grid proposed the following fees: (1) $26 for the removal of an advanced meter or installation of an analog meter; (2) $11 for monthly meter reading; and (3) $26 for the re-installation of an advanced meter (D.P.U. 21-81, Exh. NG-AMI-7, at 2). The fees in the proposed tariff are unchanged from the existing tariff (D.P.U. 21-81, Exh. NG-AMI-8, at 2).

Unitil did not submit an opt-out tariff and requested a waiver from the opt-out tariff requirement (D.P.U. 21-82, Exh. Unitil-KES-1, at 22). Unitil cited its unique situation, where AMI metering has been in place for more than ten years without an opt-out tariff and meter data is not transmitted through radio frequencies (D.P.U. 21-82, Exh. Unitil-KES-1, at 22).

C. Positions of the Parties

1. Intervenors

a. Attorney General

The Attorney General recommends establishing a new rate class rather than implementing AMI opt-out charges established in the proposed tariff (D.P.U. 21-80, Attorney General Brief at 27, citing Exh. AG-TN-1, at 16-18; D.P.U. 21-81, Attorney General Brief at 27, citing Exh. AG-TN-1, at 16-17). The Attorney General contends that NSTAR Electric and National Grid's rates already include the cost of the AMR and proposed AMI system (D.P.U. 21-80, Attorney General Brief at 26-27, citing Exh. ES-AMI-6; D.P.U. 21-81, Attorney General Brief at 26-27, citing Exh. ES-AMI-6). Applying the rate design principle of fairness, the Attorney General argues that non-AMI customers would be paying the costs to serve AMI customers (D.P.U. 21-80, Attorney General Brief at 27; D.P.U. 21-81, Attorney General Brief at 27). Therefore, the Attorney General concludes, customers who elect to opt-out of having an AMI meter should have a separate rate class to adhere to the fairness principle (D.P.U. 21-80, Attorney General Brief at 27; D.P.U. 21-81, Attorney General Brief at 27).

b. CLF

CLF maintains that an opt-out customer should be responsible for the costs of removing an AMI meter and installing an analog meter; and in the event the opt-out customer moves, reinstalling an AMI meter (D.P.U. 21-80, CLF Brief at 22; D.P.U. 21-81, CLF Brief at 23). CLF, however, alleges that NSTAR Electric and National Grid each failed to provide a detailed justification of the costs associated with the opt-out fees (D.P.U. 21-80, CLF Brief at 22, citing Exh. CLF-CV at 5; D.P.U. 21-81, CLF Brief at 23, citing Exh. CLF-CV at 18).

For Unitil, CLF argues that the Department should reject the company's request for a waiver from proposing an AMI opt-out tariff (D.P.U. 21-82, CLF Brief at 21, citing Exh. CLF-CV at 22). CLF contends that the Department required Unitil to submit an AMI opt-out tariff with cost-based fees (D.P.U. 21-82, CLF Brief at 21-22). In support of its argument, CLF cites the ability to opt-out alleviates customer concerns around a variety of reasons other than exposure to radio frequency, such as data privacy (D.P.U. 21-82, CLF Brief at 21-22, citing Exh. CLF-CV at 6, 7).

c. DOER

DOER argues that the Department should reject Unitil's request for a waiver from proposing an AMI opt-out tariff to maintain consistency with the opt-out tariffs for National Grid and NSTAR Electric (D.P.U. 21-82, DOER Brief at 26). In addition, DOER contends that customers may object to AMI for a variety of reasons and uniformly offering opt-out ensures customer satisfaction and avoids potential delays to continued AMI advancement for all other customers (D.P.U. 21-82, DOER Brief at 26).

2. Companies

a. NSTAR Electric

NSTAR Electric argues that creating an AMI opt-out rate class will deprive other customers from the full benefits of AMI (D.P.U. 21-80, NSTAR Electric Brief at 103, citing Exh. ES-Rebuttal at 34). Specifically, due to the mesh design of the system, NSTAR Electric contends that outage restoration will be weakened due to missing data points along with other impacts like an increase in bad debt socialization[131] (D.P.U. 21-80, NSTAR Electric Brief at 103, citing Exh. ES-Rebuttal at 34). For these reasons, NSTAR Electric urges the Department to reject the Attorney General's recommendation (D.P.U. 21-80, NSTAR Electric Brief at 103).

b. National Grid

National Grid argues that based on ratemaking principles, customers do not pick and choose which specific investments to pay for (D.P.U. 21-81, National Grid Brief at 86). All customers, National Grid contends, pay for the distribution system and do not opt-out of specific system investments (D.P.U. 21-81, National Grid Brief at 86). National Grid also

131 This is described as a failure to settle financial obligations with the customer at the moment of service termination. Service termination for customers with analog meters is a manual process, and the delay between determining service termination and actual termination at the meter could result in increased bad debt expense shared by all customers (see D.P.U. 21-80, Exh. ES-Rebuttal at 34-35).

notes that rate classes should be established in a base distribution rate proceeding, not in a separate proceeding (D.P.U. 21-81, National Grid Brief at 86 n.33).

c. Unitil

Unitil argues that because its AMI system was installed more than 15 years ago, complying with the AMI opt-out tariff requirement would bring significant economic, administrative, and operational challenges (D.P.U. 21-82, Unitil Brief at 13). The main alleged health concerns that caused the AMI opt-out requirement, Unitil asserts, are inapplicable, because Unitil implemented a powerline carrier system that does not emit radio frequencies (D.P.U. 21-82, Unitil Brief at 12-14). Unitil further contends that it is not aware of any customers seeking to opt-out from AMI meters based on alleged health or data privacy concerns (D.P.U. 21-82, Unitil Brief at 14, 15). Lastly, Unitil submits that its plan to accelerate the replacement of its TS2 meters with PLX meters expands upon its existing AMI capabilities rather than a transition to achieving the type and level of functionality as contemplated by the Department in requiring an opt-out tariff (D.P.U. 21-82, Unitil Brief at 14).

In response to intervenor arguments, Unitil disagrees with DOER's position of maintaining policy alignment, contending that it is unjustified due to Unitil's powerline system and absence of implementation issues (D.P.U. 21-82, Unitil Brief at 15). Furthermore, in response to CLF's position, Unitil argues that data privacy concerns have been insufficient to cause any customer to opt-out of AMI (D.P.U. 21-82, Unitil Brief at 15).

Based on the foregoing reasons, Unitil argues that its request for a waiver from the AMI opt-out tariff requirement should be approved (D.P.U. 21-82, Unitil Brief at 16).

D. Analysis and Findings

1. NSTAR Electric

One of the Department's principles of rate design is fairness, where, generally, a rate structure should not require any class of customers to pay more than the costs of serving that class. The Department also considers relevant statutory requirements in determining appropriate rate design and allocation. See G.L. c. 164, § 94*I* (cost-allocation method based on equalized rates of return for each customer class with specific parameters).

Broadly, there are significant AMI investments, such as outage management and VVO, at the distribution system level that benefits all customers regardless of whether they opt-out of using an AMI meter. Customers who elect to opt-out of AMI meter installation may do so and pay the opt-out fees, but they have no ability to opt-out of realizing or experiencing the distribution level benefits. Therefore, free-riding will occur if a new AMI opt-out rate class is introduced, since AMI customers will pay more than their share for the distribution level benefits by paying on behalf of a hypothetical AMI opt-out rate class of customers. Installation of an analog meter and manual meter reading are costs unique to opt-out customers.

Moreover, consideration for a new rate class must be introduced in a base distribution rate case, where a cost of service study is performed to determine the cost to serve each individual rate class. Colonial Gas Company, D.P.U. 86-27-A at 9 (1988); Massachusetts

Electric Company, D.P.U. 85-146, at 7 (1986). The cost to serve a hypothetical AMI opt-out rate class is currently unknown. Additionally, based on known data from National Grid's customers, the AMI opt-out rate is approximately 0.0 to 0.1 percent of their residential customers (D.P.U. 21-81, Exh. DPU 5-8). Uptake of AMI opt-out appears to be minimal. Based on the foregoing reasons, the Department will not require the establishment of a separate rate class for AMI opt-out customers at this time.

To comply with the Department's directives in D.P.U. 20-69-A, NSTAR Electric submitted an AMI opt-out tariff with opt-out charges (D.P.U. 21-80, Exh. ES-AMI-6). NSTAR Electric provided supporting calculations in sufficient detail in determining and justifying its proposed opt-out fees (D.P.U. 21-80, Exh. DPU 7-4 & Att.). The Department finds the fees to be cost-based and approves NSTAR Electric's proposed AMI opt-out tariff, subject to one revision. In particular, the Department determines that new customers shall not be penalized for decisions made by prior customers at the same address. As a result, the company shall revise the proposed tariff to clarify that a new customer will not be charged a re-installation fee. NSTAR Electric shall submit a compliance opt-out tariff for the Department's review by no later than January 15, 2023.

2. National Grid

For the same reasons as outlined above, the Department declines to establish a separate AMI opt-out rate class for National Grid. The Department has reviewed National Grid's revised version of its AMR opt-out tariff, proposed M.D.P.U. No. 1215 (D.P.U. 21-81, Exhs. NG-AMI-1, at 23-24; NG-AMI-7; NG-AMI-8). National Grid provided adequate detail and reasoning in supporting its proposed opt-out fees derived from its existing AMI opt-out tariff (D.P.U. 21-81, Exh. CLF-NG 1-8). The Department finds National Grid's fees in its AMI opt-out tariff to be cost-based and approves its proposed AMI opt-out tariff, subject to one revision. In particular, the Department determines that new customers shall not be penalized for decisions made by prior customers at the same address. As a result, the company shall revise its tariff to also clarify that a new customer will not be charged a re-installation fee. National Grid shall submit a revised opt-out tariff for the Department's review by no later than January 15, 2023.

3. Unitil

The Department required electric distribution companies installing new advanced meters to submit an opt-out tariff with opt-out charges that are consistent with the principles of cost causation. D.P.U. 20-69-A at 35-36; D.P.U. 12-76-B at 48-49. The Department also determined that an opt-out approach advances grid modernization objectives while extending customers the opportunity to decline advanced meter installation for health or other concerns. D.P.U. 12-76-B at 48.

The Department concurs with DOER that consistent application of the Department's previously set policy among all distribution companies is appropriate and that customers may want to opt-out for unspecified reasons. Additionally, Unitil intends to replace its existing meters over time with new advanced meters (D.P.U. 21-82, Exh. Unitil-KES-1, at 20). The Department finds Unitil's argument that to date no customer has requested to opt out of an AMI meter unpersuasive. Future customers that have sincere concerns with AMI meters, such as health-related concerns, deserve equitable consumer protections. For these reasons, Unitil's request for a waiver from proposing an AMI opt-out tariff is denied. Therefore, based on the Department's directives in D.P.U. 20-69-A, Unitil must comply and submit an AMI opt-out tariff. The Department directs Unitil to submit a proposed AMI opt-out tariff with full support for any proposed opt-out fees as a compliance filing to this Order by April 1, 2023. The proposed tariff shall also include a provision to clarify that new customer will not be charged a re-installation fee.

V. METRICS

A. Description of the Proposals

1. Grid-Facing Investments[132]

a. State-Wide Metric

The Companies jointly proposed one statewide metric for new grid-facing DERMS investments (D.P.U. 21-80, Exh. ES-JAS-2, at 146-147 & Att. B at 1, 2; D.P.U. 21-81, Exh. NG-GMP-5, at 2; D.P.U. 21-82, Exh. Unitil-GMP, Att. B at 2). The Companies proposed that this statewide performance metric would monitor the number and percentage of DER sites enrolled in each company's DERMS system and the associated dispatched kWs and would be provided on an annual basis with the Grid Modernization Annual report for the year prior (D.P.U. 21-80, Exh. ES-JAS-2, Att. B at 1, 2; D.P.U. 21-81, Exh. NG-GMP-5, at 2; D.P.U. 21-82, Exh. Unitil-GMP, Att. B at 2).

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[132] No intervenors commented on the Companies' proposed new grid-facing metrics.

b. Company-Specific Metrics

i. NSTAR Electric

NSTAR Electric submitted a load forecasting milestone completion performance metric[133] (D.P.U. 21-80, NSTAR Electric Brief at 57, citing Exh. ES-JAS-2, at 146). This metric is designed to demonstrate progress towards the final completion of the advance forecasting workflow from adoption propensity model to probabilistic scenario modelling (D.P.U. 21-80, Exh. ES-JAS-2, Att. B at 4). The percent completion reported for this metric is based on demonstrated progress with respect to the following milestone targets: bulk station adoption propensity models, bulk feeder adoption propensity models, scenario generation, automated scenario model creation, and result analysis (D.P.U. 21-80, Exh. ES-JAS-2, Att. B at 4, 5). The results of this metric would be organized by percent of feeders meeting each milestone target and will provide reporting on an annual basis at the end of each calendar year (D.P.U. 21-80, Exh. ES-JAS-2, Att. B at 5).

ii. National Grid

National Grid proposed two company-specific performance metrics. The company's first proposed performance metric would track progress and milestones in the implementation of its DERMS investment (D.P.U. 21-81, Exh. NG-GMP-5, at 5). National Grid also proposes a performance metric that measures the increase in feeders with advanced short-term load forecasting capabilities (D.P.U. 21-81, Exh. NG-GMP-5, at 4). The metric would

133 The Department approved NSTAR Electric's second company-specific metric, power quality monitoring metric, in the Track 1 Order at 104.

track and report a forecast model from the feeder or substation as it is available to generate a short-term hourly load forecast and would support the objective of optimizing system performance and more specifically improving grid visibility, improving reliability, and integrating distributed energy resource (D.P.U. 21-81, Exh. NG-GMP-5, at 4). The company proposed to provide reporting for both metrics on an annual basis at the end of each calendar year (D.P.U. 21-81, Exh. NG-GMP-5, at 4-5).

iii. Unitil

Unitil submitted a company-specific performance metric for its DER mitigation investment. The proposed performance metric would measure the amount of DER capacity enabled as a direct result of the DER mitigation project completed (D.P.U. 21-82, Exh. Unitil-GMP, Att. C at 2). Unitil proposed to provide the performance result at each of the relevant substations on an annual basis (D.P.U. 21-82, Exh. Unitil-GMP, Att. C at 2).

2. Customer-Facing Investments

a. NSTAR Electric

NSTAR Electric did not include any AMI performance metrics in its AMI Implementation Plan, stating that a comprehensive stakeholder process and discussion on such metrics is necessary to determine what data is useful and feasible/practicable to track and measure (D.P.U. 21-80, NSTAR Electric Brief at 57, citing Exhs. AG 4-18, at 2; AG 5-9, at 2). NSTAR Electric stated that such discussion is particularly necessary with respect to setting a meaningful baseline and targets for AMI metrics, which must include baseline and target performances that are within the company's control (D.P.U. 21-80, Exh. AG 5-9, at 2). NSTAR Electric noted that this is consistent with the process used to establish the existing grid-facing grid modernization metrics (D.P.U. 21-80, Exh. CLF-ES 1-3).

b. National Grid

National Grid did not propose any AMI performance metrics but identifies the following types of metrics that would allow the Department and stakeholders to track the status of its AMI Implementation Plan: (1) operational and program metrics related to (i) deployment, (ii) billing accuracy, (iii) outage management, and (iv) system operation and environmental benefits; and (2) customer metrics related to (i) awareness, (ii) enablement and empowerment, and (iii) Green Button Connect My Data (D.P.U. 21-81, National Grid Brief at 66-68, citing Exh. AC 1-23). National Grid stated that it is committed to working with the Department, either as part of this docket or in another suitable proceeding, to identify metrics that track the status of the company's AMI Implementation Plan (D.P.U. 21-81, Exhs. NG-AMI-1, at 19; NG-AMI-2, at 63; AC 1-23).

c. Unitil

Unitil proposed three performance metrics associated with its AMI Implementation Plan: (1) AMI meter replacement metric, which would quantify the number of meters deployed with the ability to provide interval metering; (2) customer engagement metric, which would measure the number of customers that have enrolled in the customer engagement system; and (3) data sharing platform metric, which would measure the number of customers that have enrolled in the data sharing program (D.P.U. 21-82, Exh. Unitil-GMP, Att. C at 3-5).

B. Positions of the Parties

1. Intervenors

The Attorney General recommends establishing performance metrics based on operating performance targets that align with the level of benefits that the Companies project in their business cost analyses, particularly for investments that could achieve an investment metric but that wouldn't necessarily produce corresponding benefits due to diminishing returns (D.P.U. 21-80, Attorney General Brief at 11-12; D.P.U. 21-81, Attorney General Brief at 11-12; D.P.U. 21-82, Attorney General Brief at 11-12).

The Attorney General also urges the Department to consider measures such as an increase in DER hosting capacity (in MW); system-wide reduction in SAIDI and SAIFI (with and without major event days); count of residential customers registered to receive high bill alerts; count of residential customers who viewed or downloaded detailed energy data; count of residential customers authorizing a third party to access energy data; and count of residential customers billed on a time-varying rate (D.P.U. 21-80, Attorney General Brief at 14-15; D.P.U. 21-81, Attorney General Brief at 13-14; D.P.U. 21-82, Attorney General Brief at 14-15). Further, the Attorney General recommends that the Department direct the Companies to develop with the full participation of stakeholders appropriate performance targets that the Companies should report on as part of the evaluation and final review of investments done at the end of each grid modernization plan term (D.P.U. 21-80, Attorney General Brief at 15; D.P.U. 21-81, Attorney General Brief at 14-15; D.P.U. 21-82, Attorney General Brief at 14-15). Lastly, because the Companies have not made any real benefit projections for low- and moderate-income and environmental justice customers in their respective grid modernization plan, the Attorney General argues that these metrics could be developed through a stakeholder process after the Companies identify specific benefits for these types of customers (D.P.U. 21-80, Attorney General Brief at 17-18; D.P.U. 21-81, Attorney General Brief at 16-17; D.P.U. 21-82, Attorney General Brief at 17-18).[134]

Acadia Center argues that the Department should establish performance metrics that specifically track success in meeting AMI deployment timelines, as well as outcome-based metrics such as: (1) system performance improvements as a result of AMI; (2) customer usage of online portals; (3) customer AMI opt-out rates; (4) the number of third parties who successfully access customer data; and (5) ensuring that customer savings from AMI actually

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[134] The Attorney General also recommends that the Department create metrics to measure whether the benefits projected in NSTAR Electric's and National Grid's business cases were delivered to ratepayers, and to amend their existing GMF tariffs (and proposed AMI tariffs if approved) so that they must show that they have achieved and delivered the projected level of benefits before they can earn a return on their grid modernization investments (D.P.U. 21-80, Attorney General Brief at 10, citing Exh. AG-WG-1, at 32-33, 66-67; D.P.U. 21-81, Attorney General Brief at 9-10, citing Exh. AG-WG-1, at 32-33, 48-49). For Unitil, the Attorney General recommends that the Department direct Unitil to present a detailed business case compliant with D.P.U. 20-69-A, then establish metrics to measure whether the projected benefits projected in that analysis were delivered to ratepayers, and amend Unitil's existing GMF tariff so that Unitil must show that it has achieved and delivered the projected level of benefits before it can earn a return on its grid modernization investments (D.P.U. 21-82, Attorney General Brief at 10-11, citing Exh. AG-WG-1, at 39). The Companies oppose the Attorney General's recommendations (D.P.U. 21-80, NSTAR Electric Brief at 63; D.P.U. 21-81, National Grid Brief at 93-94, citing Exh. NG-AMI-Rebuttal-1, at 25-26; D.P.U. 21-82, Unitil Brief at 26, citing Exh. Unitil-KES-1, at 23-24). The Department addresses this matter in Section III.C.3.c.iii.

materialize (D.P.U. 21-80, Acadia Center Brief at 13; D.P.U. 21-81, Acadia Center Brief at 13-14).

CLC agrees with the Attorney General and CLF's proposals to require NSTAR Electric to develop performance metrics for TVR that encourage data access and billing for TVR (D.P.U. 21-80, CLC Brief at 17, citing Exhs. AG-WG-1, at 50, 65-66; CLF-CV-1, at 11, 21-22). CLF also urges the Department to require the Companies to file an annual report that demonstrates how they utilize their AMI system to maximize customer benefits (D.P.U. 21-80, CLF Brief at 19; D.P.U. 21-81, CLF Brief at 19; D.P.U. 21-82, CLF Brief at 19).

DOER recommends that the Department require the Companies to provide regular updates in their reporting on implementation timing and identify any potential barriers or delays, and should detail stakeholder collaboration in annual reporting (DOER Brief at 16). Further, DOER argues that the Companies should be required to demonstrate in their annual filings through narrative language and quantitative metrics how the GMP and AMI investments will advance clean energy goals while minimizing costs and bill impacts (DOER Brief at 17-18). DOER requests that the Companies be required to consult with DOER before the first GMF compliance filing to develop appropriate performance targets and metrics that are consistent between the Companies (DOER Brief at 18-19).

GECA urges the Department to adopt the metrics identified by the Attorney General, which would require the Companies to track the number of residential customers who (1) registered to receive high bill alerts, (2) viewed or downloaded detailed energy data,

(3) authorized a third party to access energy data, and (4) were billed on a TVR, as well as tracking the average system-wide demand response per event (in MW) by residential customers (D.P.U. 21-80/D.P.U. 21-81, GECA Brief at 21, citing D.P.U. 21-80, Exh. AG-WG-1, at 69; D.P.U. 21-81, Exh. AG-WG-1, at 51-52). GECA recommends that the Department also adopt metrics that would require the Companies to track the number of residential customers who received disaggregated load data and shave-the-peak-type alerts, as well as tracking the average system-wide demand response per event (in MW) attributable to these alerts (D.P.U. 21-80/D.P.U. 21-81, GECA Brief at 21, citing Exh. GECA-KS-1, at 2-3, 6-7). GECA states that the Department should apply these metrics to residential and commercial and industrial customers, both basic service and municipal aggregation customers (D.P.U. 21-80/D.P.U. 21-81, GECA Brief at 21, citing Exh. GECA-KS-1, at 2-3).

2. Companies

a. NSTAR Electric

In response to the Attorney General, NSTAR Electric asserts that it is willing to utilize metrics and has stated throughout this proceeding that metrics that track the progress and benefits of grid modernization and AMI investments are a necessary component of its overall GMP and AMI Investment Plan (D.P.U. 21-80, NSTAR Electric Reply Brief at 4). NSTAR Electric points out that it has proposed a new statewide and two Company-specific grid-facing metrics and has committed to implementing metrics for its AMI Implementation Plan (D.P.U. 21-80, NSTAR Electric Reply Brief at 4, citing, Exhs. ES-JAS-2, at 145-146 & Att. B; AG 4-18; AG 5-9).

b. National Grid

National Grid affirms that it is committed to reporting on its AMI implementation and working with the Department and other stakeholders to identify metrics that track the status of the company's AMI implementation and is amenable to reporting on potential barriers or delays, and stakeholder collaboration (D.P.U. 21-81, National Grid Brief at 93-94, citing Exhs. NG-AMI-1, at 19; NG-AMI-2, at 63; AC 1-23; NG-AMI-Rebuttal-1, at 25-26, 50).

c. Unitil

Unitil is open to include specific targets and additional meaningful metrics to track progress toward the Department's grid modernization objectives (D.P.U. 21-82, Unitil Brief at 26, citing Exh. Unitil-KES-1, at 23-24). Unitil asserts that through collaboration with stakeholders and the EDCs, Unitil already reports on a number of metrics in its annual reports (D.P.U. 21-82, Unitil Brief at 26).

C. Analysis and Findings

Performance metrics and reporting are key components of ensuring the transparency of the Companies' grid modernization investment implementation and performance. The Department finds that it is critical for the Companies to develop grid modernization performance metrics with input from stakeholders. Performance metrics are particularly important when the Companies demonstrate difficulty in identifying quantitative benefits of AMI investments (D.P.U. 21-80, Exh. ES-AMI-4 (Rev.); D.P.U. 21-81, Exh. NG-AMI-5; D.P.U. 21-82, Exh. Unitil-GMP at 100-103).

The intervenors suggest the Department develop additional performance metrics for the Companies' grid modernization investments involving benefits to customers, including low-income customers and EJ communities. Track 1 Order at 104-105. As an initial matter, the Department declines to approve the proposed new grid-facing and AMI performance metrics at this time. The Department finds additional work is needed in collaboration with the parties to develop performance metrics that appropriately track the quantitative benefits associated with grid-facing and customer-facing investments, and progress toward grid modernization objectives. Further, certain existing grid-facing performance metrics applicable to the continuing investments preauthorized in the Track 1 Order may need to be refreshed or revised. Track 1 Order at 104 & n.51. Therefore, the Department will work with the parties through public comments and, as needed, technical conferences and further process in the instant proceedings, similar to the process utilized in Grid Modernization for metrics and the grid modernization annual reports, to address the following: (1) the adequacy of existing grid-facing performance metrics for the continuing investments; (2) potential additional performance metrics to evaluate customer benefits, especially related to low-income customers and EJ communities; and (3) exploration of performance metrics for new grid-facing and customer-facing investments. See Grid Modernization, D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, Procedural Notice (February 20, 2019); Grid Modernization, D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, Procedural Notice (August 16, 2018)). The Department will also review performance metrics from Track 1 as part of this process after the instant Order issues. See Track 1 Order at 104.

VI. ISSUES FOR STAKEHOLDER PROCESS

Several parties generally support convening a stakeholder working group to discuss certain issues related to implementation of the Companies' respective AMI implementation plans, including data access, TVR design, and customer education and engagement (e.g., D.P.U. 21-80, NRG Brief at 2; DOER Brief at 20; D.P.U. 21-80, Attorney General Brief at 38; D.P.U. 21-81, Attorney General Brief at 36, 37; D.P.U. 21-82, Attorney General Brief at 37-38; D.P.U. 21-80/D.P.U. 21-81, GECA Brief at 11; D.P.U. 21-80, CLC Brief at 3). However, the Companies caution that any stakeholder process must not delay implementation of the 2022-2025 Grid Modernization Plans including the AMI deployment timeline in order to ensure that the investments provide customer benefits in a timely manner (D.P.U. 21-80, NSTAR Electric Brief at 121; D.P.U. 21-81, National Grid Reply Brief at 8, 9; D.P.U. 21-82, Unitil Brief at 31). As discussed in Section III.C.2.e, above, the Department agrees that a stakeholder process must not delay the implementation of Companies' proposed investments. Nevertheless, the Department finds that a stakeholder process may elicit valuable input to inform the Companies' implementation of AMI.

There are a number of complex issues that must be addressed in order for customers and the Commonwealth to realize the benefits afforded by a full deployment of AMI. Further, providing a forum to discuss issues related to customer-facing AMI functions will help inform prudent development of AMI functionality, as well as minimize potential conflicts. The Department therefore directs the Companies to convene a statewide AMI stakeholder working group and to facilitate the statewide stakeholder process consistent with the directives outlined herein. Further, as the state energy policy office, we anticipate that DOER will play a leading role, particularly in the development of a statewide data access strategy (see DOER Brief at 20).

The Department directs the Companies to convene the stakeholder group no later than February 1, 2023. Starting on May 15, 2023, the Companies shall submit a quarterly status report to the Department in the instant proceedings 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. The Companies shall submit the final status report, along with final consensus proposals and a summary of areas of disagreement on August 1, 2024. Thereafter, the Department will review the final report and the Department will determine next steps.

The objective of the AMI stakeholder working group process is to provide a forum for the Companies and interested stakeholders to collaborate in a non-adjudicatory setting to discuss AMI-related issues and to develop a joint proposal for Department review that sets forth all issues on which a consensus has been reached and identifying outstanding issues, if any, that remain to be resolved.

To ensure an effective and efficient process, the Companies shall (1) designate the company personnel responsible for oversight and management of the stakeholder process, (2) recognize all entities on the service list for these proceedings as stakeholder participants in the AMI stakeholder working group[135] and ensure each stakeholder participant receives all correspondence related to the AMI stakeholder working group and process, and (3) identify, solicit, and allow other interested stakeholders, such as municipal aggregators and competitive suppliers and others who did not participate in these dockets, to participate in the process. Additionally, to ensure an orderly and efficient process, the Companies shall be responsible for maintaining a stakeholder participant distribution list and ensuring that all company communications are circulated to that list.

As discussed more below, the stakeholder working group should focus on: (1) customer and third-party access to customer usage data; (2) customer education and engagement; (3) billing of TVR offered by competitive suppliers; and (4) AMI deployment strategies that may expedite the ability for competitive suppliers to offer TVR products.[136]

The Department has recognized that access to customer usage data is crucial for customers, third-parties, and competitive suppliers to provide the benefits of TVR. Grid Modernization Order at 128, 136-137; D.P.U.12-76-B at 34. With the deployment of AMI meters, the Companies will have customer usage data available for each hour of the billing cycle (see D.P.U. 21-80/D.P.U. 21-81/D.P.U. 21-82, Tr. 5, at 1010-1013; D.P.U. 21-80, Exh. TEC-ES-1-2). The Department directs the Companies to work with stakeholders to

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135 Any entity on the service list for these proceedings may opt-out of participating in the AMI stakeholder process.

136 The Department will address TVR for basic service, as well as potential TVR for transmission and distribution, in a separate investigation.

identify the most effective and efficient way(s) for customers to access their hourly usage data, as well as voluntarily share the data with competitive suppliers. The Department further directs the Companies to work with stakeholders to assess the need for and value of providing aggregated hourly usage data to stakeholders, and how to efficiently provide such data in a manner that protects customer privacy (D.P.U. 21-80/D.P.U. 21-81/D.P.U. 21-82, Tr. 5, at 883-884, 971-980, 1010-1013).

For a competitive supply customer that receives a single bill from their distribution company, the Companies currently calculate the supply portion of the monthly bill based on the supply rate provided by the customer's competitive supplier for that billing cycle. With the availability of AMI usage data, a customer's supply portion of the bill could be based on numerous supply rates (D.P.U. 21-80/D.P.U. 21-81/D.P.U. 21-82, Tr. 5, at 822-826, 959-969). The Department directs the Companies to work with stakeholders to identify the most effective and efficient way(s) in which the Companies can incorporate competitive supply TVR products on the Companies' bill (D.P.U. 21-80/D.P.U. 21-81/D.P.U. 21-82, Tr. 5, at 831-838). The Companies must assess the potential costs and limitations of incorporating competitive supplier's rates on a single bill.

While the Department's approval of customer-facing investments will ensure that AMI is deployed ubiquitously throughout each company's service territory, in order to maximize the benefits of AMI, customer education must be a priority. D.P.U. 20-69, at 2, 3, citing Grid Modernization Order at 133, 136. To that end, if low- to moderate-income customers and those in EJ communities or other underserved communities are not adequately informed and engaged with new technology and offerings available as a result of AMI implementation, or if customers are unable to obtain information due, for example, to language barriers, customer acceptance of AMI and potential dynamic pricing products could be diminished. Therefore, as part of the stakeholder process the Companies shall receive input on developing specific strategies and tactics to provide customer education and engage low- and moderate-income customers, EJ communities, and other underserved populations. In recognition of the important role that competitive suppliers, including municipal aggregations, can play in promoting price-responsive usage, the Department directs the Companies to work with stakeholders to identify effective and efficient ways in which the Companies can coordinate their customer education efforts with these entities.

Finally, the Department seeks to ensure that TVR products are available to customers in a timely manner.[137] Accordingly, the Department directs the Companies to work with stakeholders to identify AMI meter deployment strategies that may expedite and maximize the availability of TVR products to customers during the AMI deployment period (D.P.U. 21-80/ D.P.U. 21-81/D.P.U. 21-82, Tr. 5, at 852-874).

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137 The Department anticipates that some competitive suppliers, including municipal aggregations, may seek to offer TVR. The Department notes that municipal aggregations will need approval of a revised municipal aggregation plan that sets forth how the aggregation intends to set its rates and demonstrate how the revised plan will provide universal access, equitable treatment of customers, and reliability. G.L. c. 164, § 134.

VII. ELECTRIC SECTOR GRID MODERNIZATION PLANS

In 2014, the Department adopted a vision of a cleaner, more efficient and reliable electric grid, which would empower customers to manage and reduce their energy costs. Grid Modernization Order at 1, citing D.P.U. 12-76-B. The Department again affirms and embraces this broad vision first articulated in D.P.U. 12-76-B as a guidepost for the evolution of the electric distribution industry in Massachusetts. See Grid Modernization Order at 1. Through D.P.U. 12-76-B, the Department established a regulatory construct governing electric distribution companies' grid modernization planning and investments, and required the Companies to file grid modernization plans designed to achieve the Department's grid modernization objectives. Additionally, the Department identified advanced metering functionality as the basic technology platform for grid modernization. D.P.U. 12-76-B at 13. In D.P.U. 14-04-C, the Department's established a policy framework for the implementation of TVRs for basic service customers once advanced metering functionality was deployed.

In 2015, the Companies each filed their first grid modernization plans, but the Department determined after review of the evidence in those proceedings that the benefits of a full deployment of advanced metering functionality did not justify the costs at that time. Grid Modernization Order at 117-135. At the same time, the Department stated that it remained committed to the pursuit of advanced metering functionality as a means to achieve our grid modernization objectives, with our ultimate goal being to ensure that all customers have the opportunity to realize the benefits of dynamic pricing in a more cost-effective manner. Grid Modernization Order at 135. The Department subsequently preauthorized the

Companies' proposed grid-facing investments for a four-year term, establishing the Companies' first grid modernization plans, finding that they would make measurable progress toward meeting the Department's grid modernization objectives by reducing outages and optimizing distribution system performance, optimizing system demand, and integrating DERs. Grid Modernization, D.P.U. 15-120-D/D.P.U. 15-121-D/D.P.U. 15-122-D at 7 (2020); Grid Modernization Order at 107-108, 113-114, 154, 163, 172.

In D.P.U. 20-69-A at 26, the Department found that, because a significant portion of the Companies' meters would reach the end of their useful life in the next few years, it offered an ideal opportunity to craft comprehensive meter replacement plans. In consideration of the Department found it appropriate to consider a path to achieve advanced metering functionality through a full-scale deployment of AMI. D.P.U. 20-69-A at 25, 27. In consideration of the status of the Companies' aging metering infrastructure, as well as the Commonwealth's long-term energy policy and climate goals as well, the Department found it appropriate to consider achieving advanced metering functionality through a full-scale deployment of AMI. D.P.U. 20-69-A at 25, 27. Consequently, the Department established the form and content for the Companies' second grid modernization plan filings, inclusive of both grid-facing and customer-facing investments. D.P.U. 20-69-A at 28.

In the instant proceedings, on July 1, 2021, the Companies filed their second grid modernization plans and proposals to facilitate accelerated deployment of AMI-related investment in their service territories (D.P.U. 21-80, Exhs. ES-JAS-1; ES-JAS-2; ES-AMI-1; ES-AMI-2; D.P.U. 21-81, Exhs. NG-GMP-1; NG-GMP-2; NG-AMI-1; NG-AMI-2;

D.P.U. 21-82, Exhs. Unitil-KES-1; Unitil-GMP). During the pendency of our review, the 2022 Clean Energy Act was enacted on August 11, 2022. The 2022 Clean Energy Act establishes a new regulatory construct regarding electric sector grid modernization. As a result, each electric company must develop an electric-sector modernization plan to proactively upgrade its distribution system and where applicable the transmission system to: (i) improve grid reliability, communications and resiliency; (ii) enable increased, timely adoption of renewable energy and DERs; (iii) promote energy storage and electrification technologies necessary to decarbonize the environment and economy; (iv) prepare for future climate-driven impacts on the transmission and distribution systems; (v) accommodate increased transportation electrification, increased building electrification and other potential future demands on distribution and, where applicable, transmission systems; and (vi) minimize or mitigate impacts on the ratepayers of the Commonwealth, thereby helping the commonwealth realize its statewide GHG emissions limits and sub-limits under G.L. c. 21N. G.L. c. 164, § 92B(a); see also G.L. c. 164, § 1 (defining "electric company").

The electric-sector modernization plans must describe multiple elements, including: (i) improvements to the electric distribution system to increase reliability and strengthen system resiliency to address potential weather- and disaster-related risks; (ii) 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; (iii) patterns and forecasts of DER adoption in the company's territory and upgrades that might facilitate or inhibit increased adoption of such technologies; (iv) improvements to the distribution system that will enable customers to express preferences for access to renewable energy resources; (v) improvements to the distribution system that will facilitate transportation or building electrification; (vi) improvements to the transmission or distribution system to facilitate achievement of the statewide GHG emissions limits under G.L. c. 21N; (vii) opportunities to deploy energy storage technologies to improve renewable energy utilization and avoid curtailment; (viii) 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 (ix) 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). For all proposed investments and alternative approaches, each electric company must identify customer benefits associated with the investments and alternative approaches 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).

An electric company must also prepare five- and ten-year forecasts and a demand assessment through 2050 to account for future trends such as in the adoption of renewable energy, DERs, and energy storage and electrification technologies. G.L. c. 164, § 92B(c). Further, the electric company must include a summary of investments and solicit input such as planning scenarios and modeling from the newly established Grid Modernization Advisory Council ("Council"), respond to discovery requests from the Council, and conduct technical conferences and at least two stakeholder meetings. G.L. c. 164, § 92B (c)(ii) & (iii).

An electric company must submit its first plan for review to the Council by September 1, 2023, and thereafter every five years on a schedule to be determined by the Department, and not later than 150 days before filing the plan with the Department. G.L. c. 164, § 92B(d). The Council must return the plan to the electric company with recommendations no later than 70 days before the company files it plan with the Department. G.L. c. 164, § 92B(d). An electric company must submit its final electric-sector modernization plan along with the Council's review to the Department in accordance with the Department's established schedule. G.L. c. 164, § 92B(d). The Department must consider the plan and hold a public hearing for interested parties to be heard, and rule on the plan within seven months of submittal. G.L. c. 164, § 92B(d). In order to be approved, a plan must provide net benefits for customers as well as meet the criteria enumerated in G.L. c. 164, § 92B(a)(i)-(vi). G.L. c. 164, § 92B(d). An electric company must submit two reports per year to the Department and the Massachusetts Joint Committee on Telecommunications, Utilities and Energy on the deployment of approved investments in accordance with any performance metrics included in the approved plans. G.L. c. 164, § 92B(e).

The new legislation required the Department to direct each electric company to develop an electric-sector modernization plan within 30 days of the Act's effective date. 2022 Clean Energy Act, § 75. In compliance with this requirement, the Department issued a Letter Order on September 12, 2022 ("Letter Order"). In particular, the Department directed each electric company to develop and file with the Council by September 1, 2023, an electric-sector modernization plan consistent with the 2022 Clean Energy Act for the Council's review, input, and recommendations. Letter Order at 1. Each company must file its final electric-sector modernization plan with the Department no later than January 29, 2024, with a list of each recommendation proposed by the Council and an explanation of whether and why each recommendation was: (1) adopted; (2) adopted as modified; or (3) rejected. Letter Order at 1. In addition, each company must include with its filing a proposal of how it intends to proactively upgrade its distribution system to enable increased, timely adoption of renewable energy and DERs. Letter Order at 2. The Department will review the company's proposal through an adjudicatory proceeding. Letter Order at 2.

The new legislation permits an electric company to include in base electric distribution rates all prudently incurred plant additions that are used and useful but requires each company to identify alternative approaches to financing the proposed investments, including but not limited to cost allocation arrangements between developers and ratepayers. G.L. c. 164, § 92B(d). In consideration of the passage of the 2022 Clean Energy Act, the

Department immediately closed its investigation and stakeholder process assessing electric distribution companies' optimal solutions for long-term planning for the interconnection of DG facilities. D.P.U. 20-75-C (September 12, 2022). In doing so, the Department determined that the 2022 Clean Energy Act effectively establishes a statutory, 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. The Department noted that it would review other ongoing investigations and stakeholder processes to determine whether any should be discontinued in light of this new process for electric system planning established in the 2022 Clean Energy Act. Letter Order at 2.

As a result, upon resolution of the instant proceedings, inclusive of the process to establish final metrics for the grid-facing and customer-facing investments, as well as the anticipated stakeholder process discussed in Section VI, the Department's ongoing process of modernizing the electric grid that would have been achieved pursuant to our existing regulatory construct will instead be filed pursuant to the requirements established in the 2022 Clean Energy Act. In particular, upon expiration of the Companies' 2022-2025 Grid Modernization Plan terms, NSTAR Electric's 2028 AMI implementation term, and National Grid's 2027 AMI implementation term, any further proposed grid-facing or customer-facing grid modernization investments must be proposed in each company's electric sector modernization plan consistent with the requirements of G.L. c. 164, § 92B.

VIII. ORDER

After due notice, hearing, and consideration, it is

ORDERED: That the 2022 through 2025 grid modernization plan filed by NSTAR Electric Company d/b/a Eversource Energy as described herein is APPROVED in part and DENIED in part, consistent with and subject to the directives contained herein; and it is

FURTHER ORDERED: That the advanced metering infrastructure implementation plan filed by NSTAR Electric Company d/b/a Eversource Energy is APPROVED, consistent with and subject to the directives contained herein; and it is

FURTHER ORDERED: That the 2022 through 2025 grid modernization plan filed by Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid as described herein is APPROVED, consistent with and subject to the directives contained herein; and it is

FURTHER ORDERED: That the advanced metering infrastructure implementation plan filed by Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid is APPROVED, consistent with and subject to the directives contained herein; and it is

FURTHER ORDERED: That the 2022 through 2025 grid modernization plan filed by Fitchburg Gas and Electric Light Company d/b/a Unitil as described herein is APPROVED, consistent with and subject to the directives contained herein; and it is

FURTHER ORDERED: That the language proposed in the model advanced metering infrastructure factor tariff filed by NSTAR Electric Company d/b/a Eversource Energy and Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid is APPROVED in part and DENIED in part, consistent with the directives contained herein;

and it is

FURTHER ORDERED: That NSTAR Electric Company d/b/a Eversource Energy shall file a proposed company-specific advanced metering infrastructure factor tariff in D.P.U. 22-22, consistent with the directives contained herein and in D.P.U. 22-22; and it is

FURTHER ORDERED: That Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid shall file a proposed company-specific advanced metering infrastructure factor tariff by January 15, 2023, consistent with the directives contained herein; and it is

FURTHER ORDERED: That Fitchburg Gas and Electric Light Company d/b/a Unitil shall file a proposed revised grid modernization factor tariff by January 15, 2023, consistent with the directives contained herein; and it is

FURTHER ORDERED: That the language proposed in the model opt-out tariffs filed by NSTAR Electric Company d/b/a Eversource Energy and Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid are APPROVED, consistent with and subject to the directives contained herein; and it is

FURTHER ORDERED: That NSTAR Electric Company d/b/a Eversource Energy shall file a compliance opt-out tariff by January 15, 2023, consistent with the directives contained herein; and it is

FURTHER ORDERED: That Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid shall file a revised opt-out tariff by January 15, 2023, consistent with the directives contained herein; and it is

FURTHER ORDERED: That Fitchburg Gas and Electric Light Company d/b/a Unitil shall file a compliance opt-out tariff by April 1, 2023, consistent with 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,

Matthew H. Nelson, Chair

Robert E. Hayden, Commissioner

Cecile M. Fraser, 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.