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September 20, 2024

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Highway
P.O. Box 30221
Lansing, MI 48909

Re: **MPSC Case No. U-21534**

Dear Ms. Felice:

Attached for electronic filing in the above-referenced matter, please find the Official Exhibit List and Exhibits 9-33 of the Michigan Energy Innovation Business Council, the Institute for Energy Innovation and Advanced Energy United, together with the Proof of Service. Note that Exhibit 19 is confidential and is being served under separate cover. Thank you for your assistance in this matter.

Very truly yours,

Justin K. Ooms

Digitally signed by Justin K. Ooms
Date: 2024.09.20 12:45:07 -04'00'

Justin K. Ooms

JKO/srd
Enclosure
c. All parties of record.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority	)))))))	**Case No. U-21534**

Official Exhibit List of MEIU

Witness	Exhibit #	Exhibit Description
Dr. Laura S. Sherman	MEIU-1 (LSS-1)	Résumé of Dr. Laura S. Sherman
Dr. Laura S. Sherman	MEIU-2 (LSS-2)	California Public Utilities Commission, Docket No. A.14-04-014, "Decision Regarding Underlying Vehicle Grid Integration Application and Motion to Adopt Settlement Agreement," January 28, 2016
Dr. Laura S. Sherman	MEIU-3 (LSS-3)	California Public Utilities Commission, Decision 22-11-040, "Decision on Transportation Electrification Policy and Investment," November 21, 2022
Dr. Laura S. Sherman	MEIU-4 (LSS-4)	Connecticut Public Utilities Regulatory Authority Final Decision, Docket No. 21-08-06, "Annual Review of the Electric Vehicle Charging Program – Year 1," December 15, 2021
Dr. Laura S. Sherman	MEIU-5 (LSS-5)	Georgia Public Service Commission, Docket No. 44280, "Order Adopting Settlement Agreement as Modified," December 30, 2022
Dr. Laura S. Sherman	MEIU-6 (LSS-6)	Illinois Commerce Commission Order, 22-0432/22-0442 (Cons.), "Petition for Approval of Beneficial Electrification Plan under the Electric Vehicle Act, 20 ILCS 627/45 and New EV Charging Delivery Classes under the Public

		Utilities Act, Article IX and Investigation into Commonwealth Edison Company Beneficial Electrification Plan Filing pursuant to 20 ILCS 627/45," March 23, 2023
Dr. Laura S. Sherman	MEIU-7 (LSS-7)	Massachusetts Department of Public Utilities, Docket 17-05, "Order Establishing Eversource's Revenue Requirement," November 30, 2017
Dr. Laura S. Sherman	MEIU-8 (LSS-8)	Massachusetts Department of Public Utilities, Docket 21-90, "Order on Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative Proposal," December 30, 2022
Dr. Laura S. Sherman	MEIU-9 (LSS-9)	Massachusetts Department of Public Utilities, Docket 17-13, "Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for Approval of its Electric Vehicle Market Development Program, and of its Electric Vehicle Market Development Program Provision, pursuant to G.L. c. 164, §§ 76, 94, and Acts of 2016, c. 448," September 10, 2018
Dr. Laura S. Sherman	MEIU-10 (LSS-10)	Massachusetts Department of Public Utilities, Docket 21-91, "Order on Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III Electric Vehicle Market Development Program and Electric Vehicle Demand Charge Alternative Proposal," December 30, 2022
Dr. Laura S. Sherman	MEIU-11 (LSS-11)	Minnesota Public Utilities Commission, Docket 18-643, "Order Approving Pilots with Modifications, Authorizing Deferred Accounting, and Setting reporting Requirements," July 17, 2019
Dr. Laura S. Sherman	MEIU-12 (LSS-12)	Missouri Public Service Commission, Docket 2018-0132, "Order Approving Second Stipulation and Agreement," February 6, 2019

Dr. Laura S. Sherman	MEIU-13 (LSS-13)	New Mexico Public Regulation Commission Final Order Adopting Recommended Decision, Case No. 20-00237- UT, "I/M/O Public Service Company of New Mexico's Application for Approval of its 2022-2023 Transportation Electrification Program," November 12, 2021
Dr. Laura S. Sherman	MEIU-14 (LSS-14)	New York Public Service Commission, Case 18-E- 0138, "Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs," July 16, 2020
Dr. Laura S. Sherman	MEIU-15 (LSS-15)	Pennsylvania Public Utilities Commission, Docket No. R-2018-3000124, "Opinion and Order," December 20, 2018
Dr. Laura S. Sherman	MEIU-16 (LSS-16)	Rhode Island Public Utilities Commission, Docket No. 4780, "Re: the Narragansett Electric Company d/b/a National Grid Proposed Power Sector Transformation Vision and Implementation Plan," August 16, 2018
Dr. Laura S. Sherman	MEIU-17 (LSS-17)	Virginia Division of Public Utility Regulation, Case No. PUR-2019-00154, "Final Order. Petition of Virginia Electric and Power Company for approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia, and for approval of an addition to the terms and conditions applicable to electric service," March 26, 2020
Dr. Laura S. Sherman	MEIU-18 (LSS-18)	Public Attachment "U-21534 MEIUDE-1.4 EV Sales Forecast"
Dr. Laura S. Sherman	*Confidential* MEIU-19 (LSS-19)	Confidential Attachment "NDA U-21534_MEIUDE-1.4_DTE EV Charging market model v.40"
Dr. Laura S. Sherman	MEIU-20 (LSS-20)	Discovery Response MEIUDE-2.1a
Dr. Laura S. Sherman	MEIU-21 (LSS-21)	Discovery Response MEIUDE-2.4a
Justin R. Barnes	MEIU-22 (JRB-1)	Curriculum Vitae of Justin R. Barnes
Justin R. Barnes	MEIU-23 (JRB-2)	Discovery Response MEIUDE-1.20(a)

Justin R. Barnes	MEIU-24 (JRB-3)	Discovery Response MEIUDE-1.19(a)
Justin R. Barnes	MEIU-25 (JRB-4)	Discovery Responses MEIUDE-1.18 (a), (e) & (f)
Justin R. Barnes	MEIU-26 (JRB-5)	Discovery Response MEIUDE-1.18(b)
Justin R. Barnes	MEIU-27 (JRB-6)	Discovery Response MEIUDE-1.18 (d)
Justin R. Barnes	MEIU-28 (JRB-7)	Discovery Response MEIUDE-1.27(a)
Justin R. Barnes	MEIU-29 (JRB-8)	Discovery Response MEIUDE-3.3(b)
Justin R. Barnes	MEIU-30 (JRB-9)	Discovery Response MEIUDE-3.3(a)
Justin R. Barnes	MEIU-31 (JRB-10)	Illustrative Rate Comparison Report Format
Dr. Laura S. Sherman	MEIU-32 (LSS-22)	Discovery Response EVgo-AG-1
Hearing Room	MEIU-33	Discovery Responses to MEIUDE-4

STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	)	**Case No. U-21534**

EXHIBITS

OF

THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL,

INSTITUTE FOR ENERGY INNOVATION,

AND

ADVANCED ENERGY UNITED

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 17-13 September 10, 2018

Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for Approval of its Electric Vehicle Market Development Program, and of its Electric Vehicle Market Development Program Provision, pursuant to G.L. c. 164, §§ 76, 94, and Acts of 2016, c. 448.

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I. INTRODUCTION

On January 20, 2017, Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid" or "Companies"), filed a petition with the Department of Public Utilities ("Department") pursuant to G.L. c. 164, §§ 76 and 94, for approval of the Electric Vehicle Market Development Program ("EV Program") and a tariff to recover the EV Program's costs, M.D.P.U. No. 1334 ("EV Program Provision"). On February 13, 2017, the Companies filed revisions to the Companies' petition and pre-filed testimony that addressed the proposals' compliance with the Zero Emission Vehicle Act[1] and removed the Companies' request for pre-approval of the total estimated costs. The Companies set a target of assisting the deployment of charging stations at 140 sites through the EV Program and estimated that the program would cost about $25 million, including a performance incentive the Companies would collect if the program results in the development of at least 75 percent of the target number of sites (Exhs. KAB/BJC-1 (Rev.) at 58-62; KAB/BJC-2; KAB/BJC-11). The Department docketed this matter as D.P.U. 17-13.

II. BACKGROUND

The Commonwealth of Massachusetts has supported electric vehicle ("EV") implementation in several ways to reduce greenhouse gas ("GHG") emissions in the transportation sector. For instance, on September 30, 2013, the Executive Office of Energy and Environmental Affairs ("EOEEA") convened the Massachusetts Electric Vehicle Initiative task force, which included numerous public and private stakeholders. Electric Vehicles,

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[1] An Act Promoting Zero Emission Vehicle Adoption. St. 2016, c. 448, codified at G.L. c. 25A, § 16; G.L. c. 40, § 22A.

D.P.U. 13-182, at 2 (2012). Soon thereafter, Massachusetts joined seven states as a signatory to the State Zero-Emission Vehicle ("ZEV") Programs Memorandum of Understanding setting a collective target of having at least 3.3 million ZEV on their roads by 2025.[2] Recently, Governor Charlie Baker directed the Secretary of Energy and Environmental Affairs to work in consultation with state and regional agencies that handle transportation, environment, and energy issues to develop regional policies to reduce GHG from the transportation sector consistent with meeting the 2050 interim emissions limits of the Global Warming Solutions Act ("GWSA").[3] Executive Order No. 569: Establishing an Integrated Climate Change Strategy for the Commonwealth (September 16, 2016).[4]

In line with those efforts, on December 23, 2013, the Department issued a Notice of Investigation ("NOI") into EVs and EV charging. D.P.U. 13-182. The Department recognized that the widespread adoption of EVs in the Commonwealth will improve air quality, reduce GHG emissions from the transportation sector, and require adding new technologies to the electric grid, including an increase of EV-related infrastructure. D.P.U. 13-182, at 3. Among other Department policies, the Department investigated how electric distribution company ("EDC") involvement in EV charging could help facilitate and accommodate widespread

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2 State Zero-Emission Vehicle ("ZEV") Programs Memorandum of Understanding, October 24, 2013, available at http://www.nescaum.org/topics/zero-emission-vehicles (click on "October 24, 2013 Governor's MOU").

3 The GWSA, codified as G.L. c. 21N, establishes limits on GHG emissions in the Commonwealth and directs state agencies to promulgate regulations that reduce energy use, increase efficiency, and encourage renewable sources of energy in the sectors of energy generation, buildings, and transportation. G.L. c. 21N, § 6.

4 Acts of 2016, c. 448, codified at G.L. c. 25A, § 16; G.L. c. 40, § 22A.

adoption of EVs, and the Department established a standard of review for the recovery of costs related to EV charging infrastructure. D.P.U. 13-182, at 4; D.P.U. 13-182-A at 13.

III. PROCEDURAL HISTORY

On February 2, 2017, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a notice of intervention pursuant to G.L. c. 12, § 11E. On April 12, 2017, the Department conducted a public hearing to receive comments on the Companies' petition pursuant to notice duly issued. The Department granted full party status to the following: the Department of Energy Resources ("DOER"); Conservation Law Foundation ("CLF"); Energy Consumers Alliance of New England, Inc. d/b/a Massachusetts Energy Consumers Alliance ("Mass Energy"); Sierra Club; Acadia Center; ChargePoint, Inc. ("ChargePoint"); and Natural Resources Defense Council ("NRDC"). The Department granted limited participant status to: NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy ("Eversource"); Global Partners, LP ("Global Partners"); Tesla, Inc. ("Tesla"); and Cumberland Farms, Inc. ("CFI"). The Department also received written comments from Low-Income Weatherization and Fuel Assistance Program Network; Plug In America; Clark University; EVSE, LLC; General Motors, LLC; The Alliance of Automobile Manufacturers and the Association of Global Automakers; and John MacDougall.

The Department held an evidentiary hearing on September 18, 2017. In support of the Companies' filing, the following witnesses, all of whom are employed by the Companies, provided testimony: Karsten A. Barde, principal program manager, New Energy Solutions Group; Brian J. Cronin, director of communications and marketing, New Energy Solutions Group; and Jeanne A. Lloyd, principal program manager, Electric Pricing, New England. The

Attorney General sponsored the testimony of Mark Higgins, chief operating officer, Strategen Consulting, LLC. Acadia Center sponsored the testimony of Mark LeBel, staff attorney, Acadia Center. ChargePoint sponsored the testimony of Michael K. Waters, director of Utility Solutions, ChargePoint. NRDC sponsored the testimony of Noah Garcia, NRDC. Lastly, CLF, Sierra Club, and Mass Energy jointly sponsored the testimony of Douglas B. Jester, partner, 5 Lakes Energy LLC.

On October 19, 2017, the Department received initial briefs from the Attorney General, DOER, Acadia Center, ChargePoint, CLF, Global Partners, NRDC, and National Grid and a joint initial brief from Mass Energy and Sierra Club ("MESC Brief"). Tesla, CFI, and Eversource did not submit an initial brief. On October 26, 2017, the Department received reply briefs from Acadia Center, ChargePoint, Global Partners, and National Grid and a joint reply brief from Mass Energy and Sierra Club ("MESC Reply Brief").[5] The evidentiary record consists of 175 exhibits and responses to seven record requests.

IV. INITIAL MATTERS

A. Introduction

During this proceeding, the Attorney General requested that the Department open a generic investigation to further define the role utility companies should play relative to EVs, i.e., further define the EV-related activities for which EDCs may recover costs, before further consideration of proposed ratepayer-funded EV programs, including National Grid's EV Program (Attorney General Brief at 1-2; Global Partners Brief at 6, 11). In addition, Acadia

[5] The Attorney General, DOER, CLF, NRDC, Tesla, CFI, and Eversource did not submit a reply brief.

Center argued that the Department should require National Grid to meet the standard of review for grid modernization infrastructure established in Grid Modernization, D.P.U. 12-76-B (2014) and D.P.U. 12-76-C (2014).

B. Positions of the Parties

1. Intervenors

According to the Attorney General, Massachusetts lacks a comprehensive plan for EV-related infrastructure development and related policy matters (Attorney General Brief at 3-4). Therefore, she contends, a specific role for utilities in these efforts has not been discussed or evaluated (Attorney General Brief at 3-4). She claims that there are issues pertaining to the state's EV goals that should be considered in a broader, statewide context, including further discussion on whether ratepayer-funded programs are necessary for the state to reach its 2025 ZEV goal, the number of chargers that are needed, non-ratepayer sources of funding for EV infrastructure development such as the Volkswagen Clean Air Act Civil Settlement,[6] and the impact that greater adoption of EVs in the Commonwealth will have on the electric grid (Attorney General Brief at 4-6). The Attorney General maintains that in order to ensure that proposals put forth by EDCs are consistent with the Commonwealth's ZEV goals, the Department should open a generic investigation to debate these issues and establish cohesive statewide policy goals and standards before authorizing ratepayer-funded programs (Attorney General Brief at 4).

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[6] Among other things, the Volkswagen Clean Air Act Civil Settlement requires Volkswagen to fund a $2.7 billion mitigation trust fund to pay for defined eligible projects that reduce oxides of nitrogen (NO_x). See https://www.epa.gov/enforcement/volkswagen-clean-air-act-civil-settlement.

Global Partners argues that the input of public and private stakeholders in a generic proceeding will allow the Department to develop the most appropriate EV polices for achieving the state's goals; Global Partners supports the Attorney General's proposal (Global Partners Brief at 6, 11). Global Partners maintains a generic investigation is necessary to establish statewide policies regarding optimal locations for charging equipment, accurately determine the number and type of charging stations necessary to meet the state's needs, and coordinate other incentives and sources of funding (Global Partners Brief at 6, 11-19).

In opposition to the Attorney General's proposal, several intervenors contend that the Department already conducted a full investigation and solicited several rounds of stakeholder input in D.P.U. 13-182 and any delays in implementing EV programs will disserve the interests of the Commonwealth (ChargePoint Reply Brief at 3-4; MESC Reply Brief at 4-5).

Next, Acadia Center contends that National Grid's proposal is a form of grid modernization (Acadia Center Brief at 11). As such, Acadia Center contends that, consistent with the grid modernization process, National Grid should be required to produce a business case with a benefit-cost analysis and performance metrics in support of its proposal (Acadia Center Brief at 11-12; Acadia Center Reply Brief at 2-4). Acadia Center maintains that applying these grid modernization standards is reasonable, if not necessary, and will ensure that National Grid's program is beneficial to the public and accountable to stakeholders and the Department (Acadia Center Brief at 12; Acadia Center Reply Brief at 2-4).

2. Companies

The Companies argue that delaying the implementation of its EV program in order to open a generic proceeding is ill-advised, inconsistent with prior Department actions, and

unnecessary to address the intervenors' concerns (Companies Reply Brief at 18-19). The Companies assert that the call for a separate generic proceeding would unnecessarily delay the implementation of the program because any benefits that could potentially be realized through a generic statewide proceeding are outweighed by the benefits of promptly approving the Companies' proposal (Companies Reply Brief at 18). Also, the Companies allege that delaying the EV Program in order to conduct an investigation is inconsistent with the Departments denial of similar requests (Companies Reply Brief at 18 (citing, NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05, Interlocutory Order (February 23, 2017); D.P.U. 17-13, Interlocutory Order (June 16, 2017). The Companies state that an investigation is unnecessary to address the intervenors' concerns because (1) the Companies will continue coordination with Eversource on implementation issues such as siting, (2) the instant proposal includes cost control measures such as ensuring that other sources of funding are used prior to ratepayer funding, and (3) the Companies will coordinate with DOER on developing guidance for program participants related to non-ratepayer funding sources (Companies Reply Brief at 19).[7] The Companies also contend that the EV Program does not require a benefit-cost analysis because the EV Program and its standard of review are separate and distinct from grid modernization proceedings (Companies Reply Brief at 20).

C. Analysis and Findings

Regarding the request that the Department initiate a generic proceeding, the Department recognizes the importance of the issues raised by the intervenors. Nevertheless, the Department

[7] The Department approved NSTAR Electric Company's EV program, with modifications. D.P.U. 17-05, at 501-503.

finds that there is insufficient evidence to warrant deferring the review of National Grid's limited three-year EV Program in order to reconsider the standard of review governing EDCs' role in the deployment of EV infrastructure at this nascent stage of the EV charging market in the Commonwealth. With regard to the need for further discussion and evaluation of non-ratepayer sources of funding for charging infrastructure, National Grid has provided substantial evidence demonstrating that it will work with site hosts to leverage other available sources of funding to pay for the program overseeing the construction of and funding for charging stations ("Charging Program") costs and to ensure that the program's rebates are not duplicative (Exhs. KAB/BJC-1 (Rev.) at 38; NG-1-Rebuttal-1, at 6; AG 2-12). To avoid waste, it will be important to continuously evaluate the number of and optimal locations for charging station investments; however, the record demonstrates that while the Companies' proposal represents a significant increase from the stations currently deployed, it is only a modest percentage of the stations needed for the Commonwealth to reach its policy goals (see, e.g., Exhs. KAB/BJC-1 (Rev.) at 18-19; NRDC-1, at 3 ("The charging stations National Grid proposes to help deploy will comprise only a small fraction of the amount of charging infrastructure required to meet this growing market."); AG 2-1).

Moreover, the Department acknowledges the value of including the perspective of statewide and regional stakeholders in discussions that will shape potential future EV programs, including discussions on optimizing charging locations, leveraging possible funding sources, and preparing for the impact on the electric grid of widespread EV adoption. We note that in our Grid Modernization Order the Department ordered a separate EV metrics stakeholder process to develop performance metrics for Eversource's EV infrastructure program. Grid Modernization,

D.P.U. 15-120; D.P.U 15-121; D.P.U. 15-122, at 187 (May 10, 2018). To better address the issues that the intervenors have raised here, the Department will include all EDCs (National Grid, Eversource, and Fitchburg Gas and Electric Light Company)[8] in the future EV metrics stakeholder process. This EV metrics stakeholder process will serve as a platform for the stakeholders and EDCs to discuss statewide issues related to EV charging infrastructure.

In light of this evidence and in consideration of the limited three-year term of National Grid's EV Program, the Department finds insufficient evidence to delay review of the Companies' program in order to conduct, at this time, an investigation on the issues presented by the intervenors. Indeed, the Department finds that the record contains substantial evidence supporting our decision to review EDC proposals under our existing standard of review in order to gain experience and information in the short term that will inform future discussions and potential future investigations of these important issues.

Next, we consider Acadia Center's argument that the standards applied to grid modernization investments should be applied to the review of EV-related proposals. While the Department acknowledges the value of benefit-cost analyses and well-developed performance metrics, applying the grid modernization standard of review to EV proposals at this juncture would be inconsistent with our decisions to (1) investigate the role of EDCs in the EV market in D.P.U. 13-182 separately from investigation on modernizing the grid in D.P.U. 12-76; (2) establish a standard of review in D.P.U. 13-182-A for EV proposals on August 4, 2014, distinct from the standard of review established in D.P.U. 12-76-B on June 12, 2014; and

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8 At this time, Fitchburg Gas and Electric Light Company has not proposed an EV program.

(3) decide in D.P.U. 15-120; D.P.U 15-121; D.P.U. 15-122 that we would conduct the forthcoming stakeholder process on EVs separately from the stakeholder process in grid modernization. Further, Acadia Center has submitted arguments describing why it prefers the standards established in D.P.U. 12-76-B and D.P.U. 12-76-C but provided insufficient evidence to demonstrate that the standard of review established in D.P.U. 13-182-A is insufficient to protect ratepayers. At this time, the Department finds insufficient evidence to warrant amending the standard of review established in D.P.U. 13-182-A to include the standard applicable to grid modernization investments.

V. NATIONAL GRID'S PROPOSAL

National Grid requests that the Department approve an EV program that recovers costs associated with the design, construction, and funding of two types of EV charging equipment, Level 2 charging stations ("Level 2 stations") and direct current fast charging ("DCFC") stations (Exh. KAB/BJC-1 (Rev.) at 26-27).[9] The Companies' proposal includes a Charging Program in coordination with the program's participants ("site hosts"); a marketing, communications and education ("MC&E") plan to promote the Charging Program and increase customers' knowledge about EVs and EV charging ("Education Campaign"); and a research and development ("R&D") plan to collect data from the sites developed through the Charging Program and perform outside research on potential demand response program designs (Exh. KAB/BJC-1 (Rev.) at 5-8, 26-63). In addition, the proposal includes the details of an evaluation plan to assess the results of the EV

[9] Level 2 chargers rely on a 240-volt connection and are capable of fully charging most existing EVs in approximately eight hours or less depending on battery capacity. D.P.U. 17-05, at 472 n.234. DCFC chargers use direct current and are the fastest method for charging an EV. D.P.U. 17-05, at 472, n.233.

Program (Exh. KAB/BJC-1 (Rev.) at 4, 56-58). Lastly, the proposed EV Program Provision describes the method to recover the costs associated with the EV Program as well as the proposed performance incentive through an annual reconciling charge (EV factor) (Exhs. KAB/BJC-1 (Rev.) at 58-61; JAL-2 (Rev.)).

The Companies' proposal includes details on the components of the EV Program and an estimated budget for each component (Exhs. KAB/BJC-1 (Rev.) at 5-8, 26-63). The Companies' cost estimates for the components of the program are (1) $2.2 million for the construction of EDC equipment[10]; (2) $8.5 million for rebates available to site hosts for customer equipment[11]; (3) $2 million for Level 2 EVSE rebates; (4) $5.8 million for program management; (5) $1.2 million for Charging Program marketing; (6) $2.8 million for the Education Campaign; (7) $0.8 million for the R&D plan; and (8) $0.5 million for the evaluation plan (Exhs. KAB/BJC-2; KAB/BJC-4; KAB/BJC-5; KAB/BJC-6; KAB/BJC-8; KAB/BJC-9; KAB/BJC-11).

The Companies propose to recover EV Program costs following the end of each program year (Exh. JAL-1, at 4). Accordingly, National Grid proposes to submit a filing to the Department in which it will request approval to recover EV Program costs that were incurred the prior year, plus any prior year reconciliation of costs (Exh. JAL-1, at 5). The Companies expect to make annual filings on January 15, with a March 1 effective date (Exh. DPU 1-43). The Companies propose to allocate EV program costs to rate classes using the distribution revenue

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10 Equipment necessary to upgrade an existing service connection or establish a dedicated service connection for the EV charging station, including transformers, utility services, and meters (Exh. KAB/BJC-3, at 2).

11 Equipment such as electric panels, conduit, and wiring (Exh. KAB/BJC-3, at 2).

allocator ("DRA") and collect costs through a rate class-specific volumetric rate (Exh. JAL-1, at 6). The Companies propose to include the EV Factors with the distribution kilowatt hour ("kWh") charge on customers' bills (Exh. JAL-1, at 6).

VI. ANALYSIS OF NATIONAL GRID'S EV PROGRAM[12]

A. Standard of Review

In D.P.U. 13-182-A, the Department held that it would not allow recovery of costs for distribution company ownership or operation of EV supply equipment ("EVSE") for new investments going forward, with a few exceptions. D.P.U. 13-182-A at 13. First, EDCs may recover the cost of EVSE ownership and operation for their own vehicle fleet charging and employee vehicle charging. Further, the Department allows -- and, in fact, encourages-- investment in and cost recovery for research, development, and design ("RD&D") related to EVs, EVSE, and EV charging as part of an EDC's RD&D proposal in its grid modernization plan, or as a separate, approved pilot. D.P.U. 13-182-A at 13. Finally, the Department may grant cost recovery for an EDC's EVSE ownership and operation in response to a company proposal. D.P.U. 13-182-A at 13. For Department approval and allowance of cost recovery, any proposal must be in the public interest, meet a need regarding the advancement of EVs in the Commonwealth that is not likely to be met by the competitive EV charging market, and not hinder the development of the competitive EV charging market. D.P.U. 13-182-A at 13.

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[12] The Department established the standard of review for utility EV proposals in D.P.U. 13-182-A, and affirmed and applied that standard in D.P.U. 17-05. That standard of review remains in effect; in this case, we apply that portion of the standard relevant to National Grid's EV proposal.

In addition, the Department is charged with ensuring that any rates are just and reasonable. Attorney General v. Department of Telecommunications and Energy, 438 Mass. 256, 264 n.13 (2002); Attorney General v. Department of Public Utilities, 392 Mass. 262, 265 (1984); Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 371 Mass. 881, 882 (1977); New England Gas Company, D.P.U. 10-114, at 22 (2011); Boston Gas Company, D.P.U. 93-60, at 212 (1993). The term "just and reasonable rates" is not defined by statute, but rather has developed through case law and Supreme Judicial Court decisions. Succinctly put, a utility's rates are just and reasonable when its rates afford it the opportunity to meet its cost of service, including a fair and reasonable return on honestly and prudently invested capital. See Boston Gas Company v. Department of Public Utilities, 367 Mass. 92, 97 (1975); Lowell Gas Company v. Department of Public Utilities, 324 Mass. 80, 94, cert. denied, 338 U.S. 825 (1949); Donham v. Public Service Commission, 232 Mass. 309, 326 (1919).

The Department reviews tariffs to determine whether they are consistent with applicable law, Department precedent, and the public interest. Model Net Metering Tariff, D.P.U. 12-01-A at 3 (2012). When new rates are proposed, "the burden is on the utility to show that they are proper." Metropolitan District Commission v. Department of Public Utilities, 352 Mass. 18, 24 (1967) (citing Wannacomet Water Company v. Department of Public Utilities, 346 Mass. 453, 463 (1963)); see also, Town of Hingham v. Department of Telecommunications and Energy, 433 Mass. 198, 213-214 (2001).

B. Meet a Need Regarding the Advancement of EVs in the Commonwealth that is Not Likely to Be Met by the Competitive EV Charging Market

1. Introduction

National Grid states that there is a need to increase the availability of charging stations in its service territory to support the increased adoption of EVs and encourage EV adoption by easing consumers' concerns about the range of EVs on a single charge, the availability of charging options, and concerns about charging convenience (Exh. KAB/BJC-1 (Rev.) at 12, 14, 18, 19, 21). In addition, the Companies state that charging stations' current lack of profitability and limited automaker incentive to install charging stations have stunted their deployment (Exh. KAB/BJC-1 (Rev.) at 21). The Companies propose to increase the development of charging stations in their service territory over a three-year period by assisting site hosts with design, construction, and funding of infrastructure to support charging stations (Exh. KAB/BJC-1 (Rev.) at 5, 26-27).

2. Positions of the Parties

a. Intervenors

The intervenors generally agree that National Grid's proposal will meet a need regarding the advancement of EVs in the Commonwealth that is not likely to be met by the competitive EV charging market (DOER Brief at 5; Acadia Center Brief at 8; ChargePoint Brief at 6; CLF Brief at 7, 9-10; MESC Brief at 10-11; NRDC Brief at 13-14). Some contend that installation of EDC equipment and customer equipment typically needed to power the charging equipment is costly and technically challenging, forming a significant barrier to the development of charging stations (DOER Brief at 5; Acadia Center Brief at 8, citing Exh. AC-ML-1, at 4-5; ChargePoint Brief at 6; CLF Brief at 9-10; MESC Brief at 10-11). Acadia Center argues that National Grid's proposal

will significantly reduce installation cost barriers for site hosts (Acadia Center Brief at 9). Acadia Center asserts that the lack of charging options at multi-unit dwellings presents a barrier to EV adoption for those residents, and that National Grid's proposal addresses this market failure (Acadia Center Brief at 9). Further, Mass Energy and Sierra Club assert that utility investment is particularly appropriate at the early stage of EV deployment to create the conditions whereby the private sector can play a larger role in accelerating charging infrastructure deployment in the future (MESC Brief at 11).

Global Partners asserts that the Companies have failed to show that the EV Program will meet a need regarding the advancement of EVs in the Commonwealth that is not likely to be met by the competitive EV charging market (Global Partners Brief at 9-10). Global Partners contends that the Companies' assessment of future market investment in charging stations is flawed because it relies on assumptions regarding private investors' behavior (Global Partners Brief at 10). Global Partners maintains that EV forecasts are being revised upward, thereby increasing charging station profitability and the likelihood that the need for future installations will be met by the market (Global Partners brief at 10).

b. Companies

The Companies assert that the current rate of charging infrastructure development in Massachusetts is insufficient for the state to reach its target for EVs on the road by 2025 (Companies Brief at 18). The Companies contend that "a lack of direct financial returns from charging station installations in the early stage of EV adoption, limited automaker incentive to invest in infrastructure, and the challenge of recruiting property owners to install and operate charging services" hinder the progress of charging infrastructure development (Companies Brief

at 18). The Companies maintain that the EV Program is designed to address these market barriers to charging infrastructure development by (1) directly enabling the deployment of more sites and charging stations, (2) expediting the identification and development of sites; (3) increasing the geographic reach of EV charging development, and (4) including certain charging locations that have not seen sufficient charging development to date (Companies Brief at 18-19).

3. Analysis and Findings

Based on substantial record evidence, the Department finds that there is a need for increased charging station deployment in the Companies' service territory to encourage EV adoption, which will meet a public policy goal in the interest of ratepayers and the general public (Exhs. KAB/BJC-1 (Rev.) at 11-12, 18, 19; CP-MKW-1, at 27; ME-1, at 24-25; NRDC-1, at 5-9). In addition, the Department finds that there is substantial evidence demonstrating that there are significant barriers to the development of charging stations at this time (Exhs. KAB/BJC-1 (Rev.) at 21; CP-MKW-1, at 27; ME-1, at 25-26). Accordingly, the Department finds that the Companies' proposed EV Program meets a need regarding the advancement of EVs in the Commonwealth that is not likely to be met by the competitive EV charging market.

C. Hinder the Development of the Competitive EV Charging Market

1. Introduction

The Companies propose to construct, own, and operate the EDC equipment required to provide sufficient power to participating sites (Exh. KAB/BJC-1 (Rev.) at 24). The Companies do not propose, however, to own customer equipment or the Level 2 and DCFC stations

(Exh. KAB/BJC-1 (Rev.) at 24-25, 29, 33-34). Further, the Companies will not require site hosts to install charging equipment from a particular vendor; rather, the Companies will qualify equipment vendors from whom the site hosts may choose (Exhs. KAB/BJC-1 (Rev.) at 32; NG-Rebuttal-1, at 15; AG 1-12).

2. Positions of the Parties

a. Intervenors

Several intervenors agree that National Grid's proposal will not hinder the development of the competitive EV charging market (Acadia Center Brief at 9; ChargePoint Brief at 7; CLF Brief at 7; MESC Brief at 11; NRDC Brief at 18). A few intervenors contend that the proposed EV Program will significantly lower cost barriers for site hosts without limiting the site hosts' ability to choose EV charger vendors (Charge Point Brief at 6-7; CLF Brief at 10-11; MESC Brief at 11-12). Mass Energy and Sierra Club argue that National Grid's proposal to coordinate with site hosts to choose from qualified EVSE retailers rather than preselecting an EVSE retailer for the whole program will leave EVSE vendors free to compete for installation; and, therefore, the proposal does not hinder the development of the competitive EV charging market (MESC Brief at 11).

Global Partners contends that the Companies have failed to provide sufficient evidence that the EV Program will not hinder the development of the competitive EV charging market (Global Partners Brief at 10). Global Partners asserts that more data on whether the private EVSE market is sufficiently meeting the needs of EV users would be helpful to ensure that National Grid's program will not hinder the market (Global Partners Brief at 11). Global

Partners alleges that National Grid has provided no analysis on the effect that the EV Program will have on private investment in the EV charging market (Global Partners Brief at 11).

b. Companies

The Companies state that the use of rebates in their program provides maximum flexibility to the charging station owners and operators, and it is designed to complement and not compete with charging equipment vendors and service providers (Companies Brief at 23). As a result, the Companies argue, the EV Program will not hinder the development of the competitive charging market because they will not own the charging stations (Companies at 23).

3. Analysis and Findings

The Department finds that the Companies will not own or operate EVSE though their EV Program and do not intend to participate in the competitive EV charger market (Exh. KAB/BJC-1 (Rev.) at 24, 29-33). Further, the Department finds that there is substantial evidence demonstrating that the EV Program will help facilitate the development of the private EVSE market by supporting the costs to site hosts and allowing site hosts to choose from a range of technologies, ownership models, and pricing approaches (Exhs. KAB/BJC-1, at Rev. 24; KAB/BJC-12, at 2-17; CP-MKW-1, at 28). As such, the Department finds that the Companies' proposed EV Program will not hinder the development of the competitive EV charging market.

D. Public Interest

1. Introduction

The Companies state that the purpose of the proposed EV Program is to incentivize the adoption of EV in the Commonwealth by increasing the availability of Level 2 and DCFC stations in their service territory and increasing customers' knowledge about EVs

(Exh. KAB/BJC-1 (Rev.) at 5-6). National Grid aims to facilitate the deployment of up to 600 Level 2 stations located at approxiamately120 sites and up to 80 DCFC stations located at approximately 20 sites over a three-year period (Exh. KAB/BJC-1 (Rev.) at 30).[13] The proposed EV Program will fund staffing to assist potential site hosts with site design and the coordination of vendors and contractors and rebates for the cost of customer equipment and a portion of the cost of Level 2 EVSE (Exhs. KAB/BJC-1 (Rev.) at 29, 35; KAB/BJC-3 at 1-2, 7). In addition, the EV Program will fund the MC&E plan to inform the Companies' customers about EVs and to educate potential site hosts about the EV Program and benefits to hosting charging equipment (Exh. KAB/BJC-1 (Rev.) at 43-48). The EV Program will also fund the research of potential approaches to future grid integration of EVs, including demand response programs (Exh. KAB/BJC-1 (Rev.) at 52). Lastly, the EV Program will fund the plan to evaluate the performance of the EV Program and, if the Companies reach their target for the sites developed, a performance incentive (Exh. KAB/BJC-1 (Rev.) at 56-58).

The Companies state that their proposal will further Massachusetts's public policy goal to realize widespread EV use in the state by 2025 (Exh. KAB/BJC-1 (Rev.) at 12). The Companies' testimony endorses a number of studies that report several formidable challenges to EV market growth, and the Companies hope to use their strengths and experiences with electric

[13] A minimum of four charging ports will be required at each long dwell-time site, and at least two DCFC ports will be required at each high traffic site (Exh. KAB/BJC-1 (Rev.) at 61). The Companies count the number of connections available for EVs to be charging simultaneously at a station in terms of "ports" (Exh. KAB/BJC-1 (Rev.) at 18 n.21). "For example, a charging site with five Level 2 stations each capable of charging two vehicles at once is considered a 10-port site. A dedicated parking spot is required at each port to allow for simultaneous charging" (Exh. KAB/BJC-1 (Rev.) at 18 n.21).

infrastructure planning to help the Commonwealth transform the transportation sector (Exhs. KAB/BJC-1 (Rev.) at 12; AG 2-12).

2. Positions of the Parties

a. Intervenors

Most intervenors express strong support for the program because, they argue, the Companies' plan to incentivize the development of charging infrastructure will increase EV adoption in the state thereby making progress toward significant public benefits, including the reduction of GHG emissions, public health benefits, economic benefits, and benefits to ratepayers and the electric grid (Attorney General Brief at 1; ChargePoint Brief at 5; ChargePoint Reply Brief at 2; CLF Brief at 5, 12-13; MESC Brief at 2, 4, 5; DOER Brief at 2, 6; NRDC Brief at 6). Nonetheless, they also contend that the proposal must be changed in several respects to fully align with the public interest, including modifications to the siting criteria, level of and eligibility for rebates, cost recovery for the MC&E and R&D plans, and criteria for awarding the proposed performance incentive (Attorney General Brief at 8-19; CLF Brief at 2; MESC Brief at 19, 20, 23-24; Acadia Center Brief at 14, 16; DOER Brief at 9, 10; NRDC Brief at 17; CLF Brief at 26-26). Furthermore, several intervenors request that the Department direct the Companies to adopt several additions to their proposal, such as EV rate structures, load management, demand response, coordination with stakeholders, and reporting requirements (Attorney General Brief at 8-19; Acadia Center Brief at 17; MESC Brief at 13-19, 22-23; BRDC Brief at 9, 10, 12-13; ChargePoint Brief at 7, 11-12; CLF Brief at 17, 22-23; DOER Brief at 8, 11).

Global Partners, however, argues that National Grid's proposal has failed to meet the public interest standards in D.P.U. 13-182-A (Global Partners Brief at 2, 7-11; Global Partners Reply Brief at 1-2). Global Partners asserts that the Companies have not provided sufficient information to demonstrate that the Charging Program will result in an increase in EV adoption that would justify the program's costs (Global Partners Brief at 6; Global Partners Reply Brief at 1-4).

b. Companies

The Companies assert that the EV Program serves the public interest by advancing public policy goals, reducing emissions, mitigating climate change, and supporting economic benefits by accelerating Massachusetts residents' adoption of EVs (Companies Brief at 17). The Companies contend that the EV Program will reduce barriers to investment in charging infrastructure and help the Commonwealth meet its goals related to EV ownership and use (Companies Brief at 1). The Companies claim that 120,000 of their customers will need to be driving EVs within ten years for the state to achieve the goals set forth in the Massachusetts ZEV Action Plan and the multi-state ZEV Memorandum of Understanding (Companies Brief at 2). The Companies' allege that the deployment of 1,200 Level 2 ports and 80 DCFC ports across the Companies' service territory will increase general EV awareness among the Companies' customers and accelerate EV adoption in the Commonwealth (Companies at 16). The Companies argue that the EV Program will facilitate EV adoption by improving the ability of Massachusetts residents to realize significant environmental and economic benefits (Companies Brief at 17).

In response to the intervenors' recommended additions and modifications to the EV Program, National Grid states its proposal is not intended to address all issues concerning the increased use of EVs in the Commonwealth in this proceeding (Companies Reply Brief at 3). The Companies maintain that the EV Program is a strategic market development initiative primarily focused on facilitating and accelerating charging infrastructure deployment over the next three years at a reasonable cost to customers (Companies Reply Brief at 3-4). The Companies implore the Department to evaluate the EV Program in that context (Companies Reply Brief at 4).

3. Analysis and Findings

The Department finds that there is substantial evidence demonstrating that National Grid's proposal will likely result in a meaningful increase in the charging stations in the state (Exh. KAB/BJC-1 (Rev.) at 5, 7, 8). Further, the Department finds that there is substantial evidence demonstrating that, based on the current level of EVs in the state, the proposed increase in charging stations will likely stimulate the adoption of EVs, consistent with the Commonwealth's public policy goals (Exhs. KAB/BJC-1 (Rev.) at 9-13; DPU 1-14, DPU 1-25, DPU 1-31). Moreover, the record contains compelling evidence regarding the benefits that this proposal may provide to the Companies' customers, whether they use EVs or not, and the general public (Exh. KAB/BJC-1 (Rev.) at 14-15, 17-18, 23-24, 51-52). However, the support provided for specific components of the EV Program and the recommended modifications of the program put forth by the intervenors warrant further discussion below.

a. Charging Program

i. Introduction

The Companies' goal is to facilitate the deployment of 140 sites in the first three years of the EV Program (Exh. KAB/BJC-1 (Rev.) at 30). To oversee the Charging Program, National Grid proposes to staff a Program Management Office ("PMO") that will recruit site hosts; consult on site design; oversee National Grid's construction of EDC equipment; qualify third-party contractors to install customer equipment; coordinate with site hosts and outside agencies to acquire funding for customer equipment; provide rebates for allowable customer equipment costs if no outside funding is available; and designate charging station suppliers, maintenance providers, and equipment specifications eligible for Level 2 EVSE rebates (Exhs. KAB/BJC-1 (Rev.) at 28; KAB/BJC-3, at 2-8; AG 2-3; AG 2-6; AG 2-7; AG 2-12). Since the Companies propose to require site hosts to commit to the operation and maintenance of the charging stations for five years, the PMO will remain staffed at a reduced level for years four through eight to continue to monitor the stations and site host compliance with their program responsibilities (Exh. KAB/BJC-1 (Rev.) at 37).

National Grid's Charging Program proposal describes the minimum requirements for potential site hosts to be eligible to participate (Exh. KAB/BJC-3, at 3). The Companies also list site attributes and estimated costs that the Companies will evaluate to prioritize applications that will best leverage program funding and maximize charging station utilization across the program (Exh. KAB/BJC-3, at 3). Further, the Companies propose to explain the types of site locations it

tends to target for the two different types of charging equipment, "long dwell-time sites"[14] for Level 2 stations and "high-traffic"[15] for DCFC stations (Exh. KAB/BJC-1 (Rev.) at 39).

In addition, the EV Program proposal also describes how the Companies intend to recruit site hosts by providing financial assistance (Exh. KAB/BJC-1 (Rev.) at 33-36). The Companies intend to provide rebates to site hosts for the construction of EDC equipment and the customer equipment necessary for site hosts to install a charging station (Exhs. KAB/BJC-1 (Rev.) at 29; KAB/BJC-3 at 1-2, 7). Also, for Level 2 EVSE, the EV Program will fund rebates up to a 50 percent to workplace/business site hosts and up to 75 percent to multi-unit dwelling owners, public entities, and non-profits (Exh. KAB/BJC-1 (Rev.) at 35).

Additionally, National Grid proposes to develop ten percent of Level 2 charging sites in disadvantaged communities and will offer up to a 100 percent rebate for the EVSE to participants at these locations (Exh. KAB/BJC-1 (Rev.) at 35). The Companies define qualifying locations in disadvantaged communities as multi-unit dwellings in Environmental Justice ("EJ") communities where the Companies serve as the EDC (Exh. KAB/BJC-1 (Rev.) at 35).[16] Further, for the site to qualify as a location in a disadvantaged community, the Companies require that the site be located within the boundary of a population meeting two or more Massachusetts EJ

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14 Such as workplaces, multi-unit dwellings, mass transit stations, colleges, fleet parking, destination locations, municipal facilities and hotels (Exh. KAB/BJC-1 (Rev.) at 17).

15 Such as highways and retail locations (Exh. KAB/BJC-1 (Rev.) at 17).

16 Generally, EJ communities are defined in terms of demographic and socioeconomic characteristics, with certain environmental policy implementation practices aimed at these communities because of race/ethnicity - class-based environmental inequities. Environmental Justice Policy of EOEEA (January 31, 2017).

criteria[17]: annual median household income is equal to or less than 65 percent of the statewide median ($62,072 in 2010); 25 percent or more of the residents identify as minority; or 25 percent or more of households have no one over the age of 14 who speaks English only or very well - Limited English Proficiency (Exh. KAB/BJC-1 (Rev.) at 35).

ii. Positions of the Parties

(A) Intervenors

Several intervenors argue that modifications to the Charging Program are necessary for the EV Program to meet the public interest standard. The Attorney General maintains that the Department should separate implementation of the Charging Program into two phases, with a formal review after the first phase to determine the need for the program to continue in the second phase (Attorney General Brief at 16). She proposes that the first phase last 18 months, during which time the Companies should deploy as many Level 2 sites as it can, but deploy only up to 25 percent of its target for DCFC sites (Attorney General Brief at 16). The Attorney General argues that a two-phase approach would provide protection for ratepayers by ensuring that the need for the program's target number of charging stations is reevaluated to see if market conditions change during the program (Attorney General Brief at 15-16).

CLF argues that proper location and design of charging infrastructure is critical to increased EV adoption (CLF Brief at 18). To ensure that charging sites are properly located, CLF argues that the Companies' siting criteria must be modified (CLF Brief at 18). First, CLF contends that the siting criteria must be clarified to prioritize infrastructure that supports

[17] In Massachusetts, a community is recognized as an EJ community if it meets any one of the criteria (Exh. KAB/BJC-1 (Rev.) at 35).

recurrent parking, such as multi-unit dwellings and workplaces, and deemphasize other public parking places, such as shopping districts, hotels, and hospitals (CLF Brief at 18-19). Second, CLF asserts that the proposed siting criteria needs to specify a plan to locate DCFC stations that would serve drivers who do not have dedicated parking spaces in order for the proposal to successfully incent adoption of EVs amongst that demographic (CLF Brief at 19; citing Exh. ME-1, at 61). Lastly, CLF states that the Companies' proposal should include plans to facilitate Level 1 charging infrastructure where parking for longer than eight hours is expected (CLF Brief at 19, citing Exh. ME-1, at 78). Additionally, Mass Energy and Sierra Club argue that the Department must require National Grid to amend its proposed site host criteria to include prioritization for site hosts that would be regularly visited by individual EV drivers and establish minimum proportions of sites that are workplaces or multi-unit dwellings (MESC Brief at 19).

Mass Energy and Sierra Club also argue that to ensure deployment of charging stations that equitably accounts for disadvantaged communities, National Grid's goal for targeting site hosts in EJ Communities should be a requirement (MESC Brief at 20). Further, Mass Energy, Sierra Club, and CLF assert that the Companies have presented unduly restrictive criteria for what qualifies as an EJ Community by requiring that they meet two of the three EEA criteria rather than any one of the criteria (MESC Brief at 21; CLF Brief at 20). DOER supports the Companies' plan to address the charging infrastructure needs of disadvantaged communities (DOER Brief at 7).

DOER argues that DCFC stations have not developed as quickly as Level 2 stations in the state, so there is a strong potential to realize significant public benefits should the Companies provide rebates for DCFC stations through their proposal (DOER Brief at 9-10). DOER argues

that any unspent Level 2 rebate funds should be applied to DCFC rebates (DOER Brief at 10). DOER requests that the Department require the Companies to clarify that rebates shall be available for site hosts who chose to purchase and own EVSE (DOER Brief at 9). DOER requests that the Companies work with DOER to set guidance for applicants about the availability of public and independent funding (DOER Brief at 9). Acadia Center suggests that the Department should, in coordination with other state agencies, ensure that the rebates funded by ratepayers are not redundant with funding from other sources (Acadia Center Brief at 16).

NRDC argues that to successfully facilitate charging stations at multi-unit dwellings the Companies should increase the EVSE rebate available from 75 percent to 90 percent (NRDC Brief at 17). NRDC argues that an increased incentive for installations at multi-unit dwellings is necessary due to the split incentives between tenants and property owners (NRDC Brief at 17). ChargePoint argues that NRDC's analysis of multi-unit dwellings is deeply flawed because it lacks an equal comparison of the referenced pilot programs (ChargePoint Brief at 15).

(B) Companies

The Companies argue that the short time frame and small scope of the EV Program make two phases unnecessary (Companies Reply Brief at 19). The Companies maintain that the Department will have the opportunity to monitor program spending through annual cost recovery filings (Companies Reply Brief at 19).

The Companies also assert that their siting criteria should remain flexible in order to better leverage funding and maximize EVSE charging station utilization (Companies Brief at 10). The Companies agree with Sierra Club and CLF that certain long-dwell time sites may end up being the best charging site solution to a particular user's needs, but argue that the

proposal for site selection affords the Companies critical flexibility to evaluate all potential site hosts and select the best possible locations (Companies Reply Brief at 10-11). Therefore, the Companies argue against the additional siting criteria intervenors proposed (Companies Reply Brief at 10-11). For DCFC stations, the Companies maintain that they will target locations where fast charging is most needed using the Federal Highway Administration's Alternative Fuel Corridors[18] and input from state agencies (e.g., Massachusetts Department of Transportation, DOER) but expect to devote a portion of their DCFC initiative to locations that may be useful to drivers that lack access to dedicated parking spaces at their residences (Companies Reply Brief at 11). The Companies argue that the site selection criteria and guidelines set forth in their proposal are designed to best achieve their goals, and the Department should not restrict the Companies' discretion to select optimum sites (Companies Reply Brief at 11). The Companies assert that they will consider recommendations for disadvantaged community sites from local groups closely affiliated with those communities and also will work with DOER and EEA to identify disadvantaged community locations (Companies Reply Brief at 13).

In response to recommendations to revise the EVSE rebate levels, both in terms of increasing the rebates to cover a greater percentage of EVSE costs and setting a minimum percentage of rebates available for certain types of sites, the Companies maintain that the design of proposed rebates will create significant cost reductions for charging-infrastructure development, while also managing overall program costs (Companies Reply Brief at 13). The

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[18] The U.S. Department of Transportation has designated national plug-in electric vehicle charging and hydrogen, propane, and natural gas fueling corridors in strategic locations along major highways to improve the mobility of alternative fuel vehicles. https://www.afdc.energy.gov/laws/11675.

Companies elected not to include rebates for DCFC stations in the program because they expect that there are other sources of funding available for those costs (Companies Brief at 20).

In response to concerns about duplicative funding, the Companies refer to the program's requirements (Companies Brief at 20-21). According to the Companies, the program mandates that, before site hosts can be eligible for Level 2 EVSE rebates, they must use public incentives and other funding sources (e.g., Massachusetts Electric Vehicle Incentive Program, Volkswagen Environmental Mitigation Trust) (Companies Brief at 20-21). Therefore, the Companies argue that the program balances contributions from the Companies' customers and other funding sources (Companies Brief at 20-21).

iii. Analysis and Findings

We agree with the Attorney General that it is important to closely monitor the progress of the proposed EV Program. The Department finds that annual reconciliation filings for the EV Program and the future statewide EV stakeholder process will serve as appropriate venues for National Grid to inform stakeholders on its EV Program implementation, especially on the intervenors' issues and concerns. Therefore, the Department declines to separate the EV Program into two phases.

The Companies propose to target site hosts for Level 2 charging stations at locations with long-dwell time parking patterns that match the speed of charging with the existing parking patterns. These locations include public parking areas, multi-unit dwellings, and workplaces (Exh. KAB/BJC-1 (Rev.) at 39). The Department finds that multi-unit dwellings and workplaces are important charging locations because they provide owners with regular access to EV charging away from home (Exh. KAB/BJC-1 (Rev.) at 39). In consideration of the public

interest, the Companies' proposed EV Program must demonstrate benefits for ratepayers. The success of the proposed EV Program is based on the Companies' ability to obtain site hosts, and, therefore, the Department will not restrict EV charging locations. However, the Department finds that it is in the public interest for the Companies to select site locations that are publicly accessible, and, therefore, the Companies shall give priority to site hosts who serve the public at large. The Department directs the Companies to prioritize the selection of Level 2 EV charging sites in the following order: (1) public parking areas such as garages, parks, stadiums, beaches, airports, train stations, hotels, hospitals, clinics, dining, entertainment and shopping venues; (2) workplaces and multi-unit dwelling parking areas that the public can access, including offices, colleges, universities, and government properties; and (3) parking areas at workplaces and multi-unit dwellings.

Some intervenors suggest that the Companies' definition of a disadvantaged community should be amended to require any one of the Commonwealth's EJ criteria rather than two or more (MESC Brief at 20; MESC Reply Brief at 11-12). The Department finds that the Companies provided a reasonable explanation for requiring that multi-unit dwellings be in locations that meet two EJ criteria in order to be eligible for a 100-percent rebate of Level 2 EVSE as opposed to a 75-percent rebate (Exh. NG-Rebuttal-1, at 28-29). At this point, the Department declines to make changes to National Grid's rebate eligibility criteria for charging locations at disadvantaged communities.

The Department finds that the proposed rebates serve to reduce the financial barriers to site hosts adopting EV charging stations, as a mechanism to help customers pay for the installation of their equipment and for EV supply equipment (Exhs. KAB/BJC-3 at 2;

KAB/BJC-1 (Rev.) at 27). In addition, the Department finds that it is reasonable to encourage site hosts to exhaust outside funding before applying for rebates from National Grid on the customer equipment and EVSE investments (Exh. KAB/BJC-3 at 1-2, 7). However, National Grid has not provided a clear description of what qualifies as exhausting outside funding (Exh. KAB/BJC-3 at 1-2, 7). National Grid states that it will work with the stakeholders, DOER in particular, to set guidance for applicants about the availability of public and independent funding (Companies Reply Brief at 19; DOER Brief at 8-9). Based on the above, and because of the early stage of EV infrastructure development, the Department declines to make changes to the proposed rebates, and accepts National Grid's commitment to work with the stakeholders on details of site selection criteria, including rebate eligibility and process.

b. MC&E Plan

i. Introduction

National Grid proposes to recover the costs of an MC&E plan that includes two components, the Education Campaign and marketing for the Charging Program (Exhs. KAB/BJC-1 (Rev.) at 43, 47; KAB/BJC-2, line 7; KAB/BJC-6, line 30). The Education Campaign targets all electric customers in the Companies' service territory to educate them about EVs (Exh. KAB/BJC-1 (Rev.) at 44-47). The $2.8 million cost estimate for the Education Campaign includes costs for staff, a call center, EV events, a website, social media and other digital marketing, billboards, radio, conferences, events, research, and content development (Exh. KAB/BJC-6). The rest of the MC&E plan involves marketing targeted at potential site hosts for the Charging Program (Exhs. KAB/BJC-1 (Rev.) at 48). The $1.2 million cost estimate for Charging Program marketing includes costs for staff, ride and drive events, a website, social

media and other digital marketing, presentations, conferences, events, research, and content development (Exh. KAB/BJC-5).

ii. Positions of the Parties

(A) Intervenors

The Attorney General argues that National Grid's efforts to coordinate with Eversource on consumer marketing have been inadequate (Attorney General Brief at 8). She maintains that considerable, earnest coordination is critical to the success of these programs (Attorney General Brief at 8-9). Acadia Center contends that the Companies' proposed Education Campaign functions as a general marketing campaign for EVs, which is not pertinent for a utility company to undertake (Acadia Center Brief at 16). Acadia Center recommends that unless specifically shown to be beneficial via a benefit-cost analysis, marketing should be confined to the promotion of the EV Program itself (Acadia Center Brief at 16). NRDC argues that National Grid's proposal to increase awareness regarding EVs is in the public interest (NRDC Brief at 8).

(B) Companies

The Companies contend that it is in a unique position to leverage its existing communication channels and expertise to facilitate reaching the Commonwealth's EV objectives (Companies Brief at 22-23). The Companies assert that auto manufacturers are not incentivized to promote new EVs because EV sales provide lower margins relative to gasoline-powered vehicles (Companies Brief at 22). The Companies argue that the Education Campaign is essential to achieving meaningful gains in the adoption of EVs (Companies Brief at 22). The Companies maintain that the Charging Program marketing will help identify site hosts and drive participation in the Charging Program (Companies Brief at 22).

iii. Analysis and Findings

In D.P.U. 17-05, at 499-500, the Department disallowed cost recovery for a consumer education plan similar to the Education Campaign proposed by the Companies because the record contained substantial evidence of the potential for overlap between the proposal and existing statewide marketing initiatives, and the record contained insufficient details to support the reasonableness of the proposed costs. In this case, record evidence demonstrates that: (1) automakers are expected to offer several new models of EVs and are expected to increase promotion of EVs over the next several years; and (2) there is potential to combine Education Campaign and program marketing activities to make the MC&E plan more cost efficient (Exh. KAB/BJC-1 (Rev.) at 14-15; Tr. at 92). Based on the record before us, the Department finds that the Companies have produced insufficient evidence to support the reasonableness of the Education Campaign's costs (Exh. KAB/BJC-1 (Rev.) at 14-15; Tr. at 92). For these reasons, the Department will not allow cost recovery for the proposed Education Campaign.

Regarding Charging Program marketing, the primary goal of the Companies' proposed EV Program is to increase the availability of charging stations; and recruiting site hosts through the marketing plan is necessary to achieve that goal (Exh. KAB/BJC-1 (Rev.) at 5-6, 47-48). The Department finds that there is substantial record evidence demonstrating that the marketing plan is a necessary component of the EV Program and that the proposed costs are reasonable (Exh. KAB/BJC-1 (Rev.) at 5-6, 47-48). Accordingly, the Department will allow the Companies to seek cost recovery for the marketing of the Charging Program described in its proposal.

c. Research and Development Plan

i. Introduction

In the Companies' proposal, the EV Program will recover the costs of an R&D plan proposed to evaluate grid impacts of charging stations and potential demand response programs (Exh. KAB/BJC-1 (Rev.) at 52). National Grid's proposal for the Charging Program requires site hosts to install Level 2 or DCFC EVSE capable of reporting utilization and transaction data and receiving and executing real-time instructions of demand response (Exhs. KAB/BJC-1 (Rev.) at 53; KAB/BJC-3 at 7-8). The first component of the R&D plan is the analysis of the site hosts' EVSE data (Exh. KAB/BJC-1 (Rev.) at 52). The second and third components of the R&D Plan are to research future potential demand response programs that can be conducted via charging equipment and direct communication to vehicles, respectively (Exh. KAB/BJC-1 (Rev.) at 52). Lastly, the EV Program will recover the costs necessary to install five DCFC stations on National Grid's properties to test the potential to manage the demand impacts of these stations through on-site technology (Exh. KAB/BJC-1 (Rev.) at 52).

ii. Positions of the Parties

(A) Intervenors

The Attorney General suggests that the Department should reject the Companies' proposal to recover the cost of installing five DCFC stations on the Companies' properties because National Grid has failed to articulate a specific need for this aspect of its R&D budget (Attorney General Brief at 11-12). Further, the Attorney General maintains that it is unclear whether the data from DCFC stations on National Grid's properties would be helpful to researching DCFC charging behavior and potential demand response technology for DCFC

EVSE since driving behavior on the Companies' properties would be much different than the driving behavior typical of high traffic locations, i.e., the primary locations where DCFC EVSE are deployed (Attorney General Brief at 11-12). ChargePoint argues that the Companies' R&D plan has been sufficiently justified and should be approved (ChargePoint Reply Brief at 12).

(B) Companies

The Companies argue that the proposed R&D plan will inform the demand response offerings they anticipate offering in the future (Companies Reply Brief at 7-9, citing Exhs. KAB/BJC-1 (Rev.) at 55; NG-Rebuttal-1, at 25). The Companies also state that the proposed R&D plan seeks to analyze grid impacts of EVs and to evaluate potential approaches to mitigate costs or obtain benefits for the distribution grid from EV charging (Companies Reply Brief at 8).

The Companies state that the proposal to own and operate five DCFC stations as part of its R&D plan should be allowed because owning the stations will allow the Companies to conduct more innovative research (Companies Reply Brief at 9). The Companies argue that they intend to operate the five DCFC stations for purely R&D purposes (Companies Reply Brief at 9). The Companies believe that the best way to conduct R&D is to own and operate the stations independently so that they are not subject to any conditions imposed by an external charging operator that would restrict the Companies' research efforts (Companies Reply Brief at 9).

iii. Analysis and Findings

EDCs have a public service obligation to provide safe and reliable service to their customers. D.P.U. 11-01/D.P.U. 11-02, at 19, citing Commonwealth Electric Company v. Department of Public Utilities, 397 Mass. 361, at 368 n.4 (1986); Fitchburg Gas and Electric

Light Company v. Department of Public Utilities, 394 Mass. 671 (1985)). The Department's goal as the oversight agency of electric distribution companies is to ensure that such companies provide safe and reliable service in the Commonwealth. D.P.U. 11-01/D.P.U. 11-02, at 19 & n.10. The record contains substantial evidence demonstrating that at higher EV adoption levels, the demand from EVSEs will impose a significant impact upon the electric grid during peak hours, and the failure to prepare for the increased demand from EVSEs would jeopardize some of the benefits of increased EV adoption (Exhs. KAB/BJC-1 (Rev.) at 52-53; NG-Rebuttal-1, at 18-19; AG-MH at 43; ME-1, at 34, 46-47, 56). Consequently, the Department finds that there is substantial evidence demonstrating the first three R&D plan components are reasonable and in the public interest (i.e., the analysis of site hosts' EVSE data, research on potential future demand response programs, and direct communications to vehicles).

In its proposal for the Charging Program, National Grid justifiably reasons that high-traffic locations, such as highway corridors and retail locations, should be targeted for DCFC EVSE given the fit between drivers' behavior in those locations (i.e., parking for less than one hour), the capability of the technology (i.e., up to 200 miles of range per hour of charging), and the cost of DCFC EVSE (i.e., DCFC EVSE is higher cost, so for long-dwell sites Level 2 EVSE may be more cost effective) (Exh. KAB/BJC-1 (Rev.) at 16, 18, 40, 41). For the purpose of studying the data from the five R&D DCFC stations, however, National Grid proposes to build the charging stations at its own properties, which do not meet the criteria of high-traffic locations (Exh. KAB/BJC-1 (Rev.) at 55; Tr. at 107). Since the five R&D DCFC stations would not serve the same charging needs as DCFC stations in their most suitable locations, the assertion that the use of the DCFC stations would provide useful data for future demand response

programs is questionable. (Exh. KAB/BJC-1 (Rev.) at 40). Further, the Companies require site hosts to operate DCFC equipment capable of reporting utilization and transaction data and receiving and executing real-time instructions of demand response (Exh. KAB/BJC-1 (Rev.) at 53; Exh. KAB/BJC-3 at 7-8). Thus, the Companies will be able to analyze the data from the DCFC stations deployed through its Charging Program, instead of the five R&D DCFC stations. Lastly, to the extent that the Companies seek to test the potential to manage the demand impacts of these stations through on-site technology such as solar panels, the Companies can recruit site hosts for the Charging Program where such testing would be possible. Based on record evidence, the Department finds that the Companies have provided insufficient evidence to demonstrate that the cost of the proposed deployment of five DCFC stations for R&D is reasonable or in the public interest.

In sum, the Department will allow cost recovery for analyzing EVSE data and researching potential demand response programs[19] as proposed in the R&D plan and disallow cost recovery for the five DCFC stations proposed in the R&D plan (Exhs. KAB/BJC-8; KAB/BJC-9).

d. Evaluation Plan

i. Introduction

National Grid proposes an evaluation plan that includes (1) periodic surveys of a broad sample of residential customers, (2) pre and post surveys of residents and site host employees, (3) surveys or interviews of participating and non-participating sites, and (4) analysis of program

19 The Department anticipates that the Company will coordinate its R&D plan with its evaluation plan as to not duplicate research efforts.

data (Exh. KAB/BJC-1 (Rev.) at 56-57). National Grid plans to hire an independent evaluation expert to complete this work (Exhs. KAB/BJC-1 (Rev.) at 56-57; KAB/BJC-10, at 1-4). The goals of the proposed evaluation plan are to assess the impact of the Education Campaign and increased charging station availability on consumer awareness, attitudes, and behaviors; to understand the characteristics and experiences of site hosts and program recruits that chose not to participate; and to measure technical impacts such as utilization and costs (Exhs. KAB/BJC-1 (Rev.) at 57; KAB/BJC-10, at 1-4). The proposed evaluation plan aims at addressing such questions as how much increased availability of charging infrastructure increases consumer purchases or leases of EVs; what are the impacts of charging stations on the electric distribution system including the Companies' system peak; what are the impacts of charging stations on site hosts' electric demand; and what are feasible and cost-effective options for managing station demand based on driver usage patterns (Exhs. KAB/BJC-1 (Rev.) at 57-58; KAB/BJC-10, at 1-4).

ii. Positions of the Parties

(A) Intervenors

NRDC supports the evaluation plan, stating that it will provide valuable opportunities to inform future utility EV proposals (NRDC Brief at 8). Charge Point maintains that the Companies should supplement the proposed customer surveys and program review in the EV Program evaluation plan with a process to receive input from industry stakeholders in an open dialogue, and to develop alternative approaches to load management (ChargePoint Brief at 11-12). CLF maintains that the National Grid proposal must include robust data collection,

reporting, and review requirements to support sufficient learning and program adjustment (CLF Brief at 22).

(B) Companies

The Companies argue that the cost of the evaluation plan is reasonable and sufficiently supported (Companies Brief at 13, 28).

iii. Analysis and Findings

Ongoing evaluation of the EV Program is essential to ensure that the program's components fulfill their intended purpose and to provide opportunities to make adjustments to the program that may improve results. The Department finds that the Companies have sufficiently demonstrated the importance of the evaluation plan to the EV Program's success and that the proposal to recover the costs of the evaluation plan is reasonable.

e. Performance Incentive

i. Introduction

National Grid proposes to earn performance incentives based on the number of EV charging sites developed and activated by site hosts as part of the proposed EV Charging Program (Exh. KAB/BJC-1 (Rev.) at 58-62). National Grid proposes that if it achieves the target of developing 140 EV charging sites within three years it would receive a $1 million performance incentive (Exh. KAB/BJC-1 (Rev.) at 60). In order to receive any performance incentive, National Grid needs to develop at least 105 EV charging sites, or 75 percent of the performance target (Exh. KAB/BJC-1 (Rev.) at 60). With each additional site developed after achieving 75 percent of the performance target, the performance incentive percentage would increase proportionally, until it reaches 125 percent (175 EV charging sites) at which point

National Grid would earn the maximum performance incentive of $1.25 million (Exh. KAB/BJC-1 (Rev.) at 60).

ii. Positions of the Parties

(A) Intervenors

The Attorney General is not opposed to the Companies' receiving a performance incentive for achieving particular goals, but argues that relying on the number of sites as the sole target is not sufficient to determine the success of the Companies' program because an increase in EV charging sites in the Companies' service territory does not necessarily mean that those sites are in the most optimal locations or are being used at all (Attorney General Brief at 13-15). The Attorney General asserts that the Companies should tie the performance incentive to their ability to control costs because National Grid's costs per charging port ($18,610) are 41 percent higher than Eversource's costs, and higher than all three utility-run EV infrastructure programs in California (Attorney General Brief at 14, 17). A few intervenors suggest that aligning performance incentive with increased EV adoption and EV miles traveled would help ensure that the Companies' program is working in furtherance of the Commonwealth's ZEV goals (Attorney General Brief at 13; CLF Brief at 24-26; Acadia Center Brief at 14-15; Acadia Center Reply Brief at 4-5; Global Partners Brief at 9; Global Partners Reply Brief at 3).

Mass Energy and Sierra Club argue that there are fatal flaws in the Companies' proposed performance incentive (MESC Brief at 23; CLF Brief at 25). They contend that a performance incentive may be appropriate in some instances (MESC Brief at 24). In this instance, however, they argue that an incentive is not appropriate because there is no disincentive for the Companies to develop charging sites (MESC Brief at 24). Alternatively, if the Department approves a

performance incentive, Mass Energy and Sierra Club argue that the incentive must be tied to different metrics, such as increased EV deployment and charging station use, and they content that the target goal should represent a stretch for the Companies to achieve (MESC Brief at 24; CLF Brief at 25-26).

Acadia Center asserts that a well-crafted performance incentive can be a very effective tool (Acadia Center Brief at 14, citing Exh. ME-1, at 49; Acadia Center Reply Brief at 4-5). Acadia Center argues that the Companies' proposed single-metric performance incentive, however, is neither well-crafted nor effective because it does not incent the achievement of a stretch goal or counteract a disincentive that the utility would otherwise face (Acadia Center Brief at 14, citing Exh. ME-1, at 49; Acadia Center Reply Brief at 4-5).

(B) Companies

To support its proposed incentive, National Grid compares its EV Program to energy efficiency programs (Companies Brief at 32). National Grid contends the EV Program is similar to energy efficiency programs in that it is designed to provide benefits for customers and society that would not be achieved absent a program administered by the Companies (Companies Brief at 32). Also, the Companies argue that the amount of incentive is consistent with the amount allowed in the similar energy efficiency programs (i.e., 5.5 percent of the Companies' budget) (Companies Brief at 34). Further, the Companies contend that the performance incentive rewards the Companies for taking on activities that are outside of its normal business and that while the EV Program does not earn a return for the Companies, it contributes toward the Commonwealth's energy, climate, and transportation policy goals (Companies Brief at 32).

Also, the Companies argue that the performance incentive encourages the Companies to prioritize the achievement of the program's goals (Companies Brief at 32).

The Companies contend that Department precedent regarding incentive proposals requires petitioners to "demonstrate the incentive is more likely than current regulation to advance the Department's traditional goals of safe, reliable, and least-cost energy service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation" (Companies Brief at 32-33, citing Incentive Regulation, D.P.U. 94-158, at 57 (1995). The Companies argue that their proposal is compliant with the requirements established by the Department in D.P.U. 94-158 because the incentive is: (1) not focused on cost recovery issues; (2) tied to specific, measurable results with clear targets in place; (3) verified by an independent evaluation expert; and (4) proposed to incentivize the Companies to achieve benefits for customers and society that would not otherwise be achieved absent a program (Companies Brief at 34).

iii. Analysis and Findings

The focus of our investigation in D.P.U. 94-158 was broad-based incentive regulation as an alternative to cost-of-service/rate-of-return regulation, and not on a form of narrowly-targeted incentives like the performance incentive presented by National Grid in its EV Program. D.P.U. 94-158, at 52; see Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company, D.T.E./D.P.U. 06-107-B at 23 (2009). Nonetheless, the Department has since looked to the guidelines and principles established in D.P.U. 94-158 to ensure that a company's proposed performance incentive is appropriately

designed and results in just and reasonable rates. D.T.E./D.P.U. 06-107-B at 23; see D.P.U. 94-158, at 52.[20]

In D.P.U. 94-158, the Department recognized that first and foremost incentive plans must assign benefits to customers, whether in the form of lower prices or increased service. D.P.U. 94-158, at 54. As discussed above, the record contains substantial evidence demonstrating that the deployment of charging stations through the EV Program will provide direct benefits to National Grid's customers that use or wish to use EVs in the form of increased service (Exh. KAB/BJC-1 (Rev.) at 13, 18-19). There is also substantial record evidence demonstrating that the EV Program will stimulate EV adoption—thereby providing benefits for all of National Grid's customers in the form of diluted fixed costs of transmission and distribution services and lower electricity rates, the reduction of GHG emissions, public health benefits, fuel security, and economic benefits (Exhs. KAB/BJC-1 (Rev.) at 9-13, 18, 19, 63-64; NG-Rebuttal-1, at 4; ME-1, at 15-24; NRDC-1, at 5-9).

Moreover, National Grid has demonstrated that its proposed performance incentive results in a lower cost to ratepayers compared with the revenue requirement National Grid would be entitled to under traditional ratemaking if it were to capitalize the EDC Equipment portion of the Charging Program (Exhs. KAB/BJC-1 (Rev.) at 61-62; AG-1-20, Att.).[21]

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[20] Here, the Department does not consider all the elements of incentive regulation discussed in D.P.U. 94-158, which was issued at a time of regulatory changes and in consideration of the increasing influence of competitive market forces. See D.T.E./D.P.U. 06-107-B at 25 n.30, citing, D.P.U. 94-158, at 40, 51. In addition to complementing the changes then underway, the Department sought to develop guidelines that would also adjust to future changes. D.P.U. 94-158, at 40.

[21] Based on the Companies' "EV Revenue Requirement Calculation," the net present value of the return and taxes under an historic capital adjustment method would be $1,051,253,

Even considering potential lower costs, we are concerned with the Companies' proposal to earn the performance incentive based on the number of sites developed. The Companies state that the EV Program aims to increase the availability of charging stations; the Companies set the Charging Program goals to develop 140 sites, 680 stations, and 1,280 ports in order to effectuate "a significant impact on the amount of available charging in its service territory" (Exhs. KAB/BJC-1 (Rev.) at 5, 30; CLF 1-1). Nonetheless, based on the minimum number of ports required for a site to be developed under the Charging Program, it would be possible for the Companies to significantly underachieve the Charging Program's goals of stations and ports deployed while still developing the minimum number of sites to trigger the performance incentive (Exh. KAB/BJC-1 (Rev.) at 61).[22] As a result, the Department finds it more appropriate to set the number of stations in use as the target the Companies must achieve to earn the performance incentive, with a target goal of 680 stations to receive a $1 million performance incentive (see Exh. KAB/BJC-1 (Rev.) at 60).[23]

Accordingly, the Department will allow the Companies to earn a performance incentive based on the number of EVSE charging stations in use as a result of the Charging Program. Consistent with the Companies' proposal, at least 75 percent of the target goal (i.e., 510 stations)

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with the capital additions depreciated over 29 years; the net present value of a $1 million performance incentive collected in year 4 of the program would be $659,919 (Exh. AG 1-20, Att.).

22 On brief, Mass Energy and Sierra Club present a credible analysis, with record cites, of this potential misalignment of the performance incentive with the EV Program goals (MESC Brief at 24 n.6).

23 The target goal of 680 charging stations is based on National Grid's target of 600 Level 2 stations and 80 DCFC stations (Exh. KAB/BJC-1 (Rev.) at 60).

must be deployed through the EV Program before National Grid is eligible to collect any performance incentive (Exhs. KAB/BJC-1 (Rev.) at 30, 62; KAB/BJC-4; AG-1-20, Att.).[24] Also, the performance incentive earned will reflect the percentage of the target number of charging stations developed; with each additional station developed after the minimum of 510 stations, the performance incentive will increase proportionally within the following range: $750,000 for 75 percent of the target goal and $1.25 million for 125 percent of the target goal (i.e., 850 stations) (see Exh. KAB/BJC-1 (Rev.) at 60).

Regarding the cost of the proposed EV Program, we acknowledge that the Attorney General argues that the proposed program cost is much higher than other existing EV charging programs in the country (Attorney General Brief at 14). The Department notes that, in particular, the capital investment and rebates for customer equipment and EV supply equipment only account for approximately half of the proposed total cost of the proposed EV Program (Exh. KAB/BJC-2). As discussed in the Cost Recovery section, National Grid will need to demonstrate that its spending is reasonable and prudent for final cost recovery. Nevertheless, the Department urges the Company to consider performance incentive designs in the future that encourage cost containment, including containment for non-capitalized costs. Further, we will closely monitor National Grid's spending practices through the annual cost recovery filings and the stakeholder process.

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[24] The minimum of 510 charging stations is based on National Grid's target of 450 Level 2 stations and 60 DCFC stations (Exh. KAB/BJC-1 (Rev.) at 60).

In sum, we determine that it is appropriate for National Grid to receive an incentive payment for the work that it carries out in the proposed EV Program.[25] Importantly, our determination is significantly influenced by: (1) the fact that the performance incentive is earned following the successful implementation of a limited-term proposal that we encouraged the Companies to develop in order to effect progress toward the Commonwealth's EV goals and (2) the fact that the incentive is proposed in lieu of the return on capital investment that could cost the ratepayers more than the incentive (Exhs. KAB/BJC-1 (Rev.) at 11-12, 61-62; DPU 1-34; DPU 1-35; DPU 2-1).

f. Recommended Additions to the EV Program

i. Load Management, Demand Response, and Time-of-use or Time-varying Rates

(A) Introduction

As discussed above, the proposal requires site hosts to select from EVSE capable of participating in future demand response programs, and the Companies propose to collect data from EVSEs to help them understand how charging stations are used by drivers (Exhs. KAJ/BJC-1, Rev. at 53; NG-Rebuttal-1, at 10). However, the Companies do not propose

[25] In an effort to persuade the Department to allow the performance incentive, the Companies compare the EV Program to energy efficiency programs. The Department, however, finds that there are more differences between the two programs than similarities. For instance, unlike the proposed EV Program, energy efficiency programs have to be cost-effective. Also, performance incentives for energy efficiency programs are permitted by statute, but there is no statute permitting incentives for EV charging infrastructure. To be clear, in allowing the Companies' performance incentive as modified above, the Department does not hold that a proposed performance incentive mechanism designed to accomplish a public policy goal may be allowed simply because it is similar to the energy efficiency programs in that regard, nor does the Department expand the energy efficiency programs to include this EV-related proposal.

to conduct demand response during the course of the program (Exh. KAJ/BJC-1 (Rev.) at 55). The Companies do not expect a significant amount of new load on the distribution system because the program is limited in scope and duration (Exh. NG-Rebuttal-1, at 18). The Companies state that implementation of new rates will increase the administration expense of the program and delay its implementation (Exh. NG-Rebuttal-1, at 19). Also, the proposal does not include any new rate design or structures related to EVs (Exh. NG-Rebuttal-1, at 3). The Companies also state that it is premature to adopt new rates for EVs until EV charging use has been further studied and the Company develops its broader strategy for time-varying basic service rates under the Department's framework in Policy Framework For Time-Varying Rates, D.P.U. 14-04-C (2014) (Exh. NG-Rebuttal-1, at 3, 8, 26). The Companies explain that site hosts eligible for the Time-of-Use Rate G-3 for delivery service would be able to take advantage of that time-varying rate, and site hosts interested in time-varying commodity charges can seek that service through their competitive supplier (Exh. NG-Rebuttal-1, at 19).

(B) Positions of the Parties

(1) Intervenors

A few intervenors maintain that the Companies' current rate design is not optimized for EV charging, and that the Companies should propose EV time-of-use ("TOU") rates without delay as such rates can influence EV driver charging behavior and provide public benefits (Attorney General Brief at 17; MESC Brief at 16-17; MESC Reply Brief at 10-11; CLF Brief at 15-16; Acadia Center Brief at 17-18; Global Partners Reply Brief at 4; NRDC Brief at 9-10;). CLF argues that the Companies should exclude demand charges from rates charged to site hosts because they disincentivize EV usage and distort fueling costs for EV drivers (CLF Brief at 17).

Similarly, Charge Point asserts that while TOU rates can influence site host and driver behavior, EV rate structures should be appropriately adapted to different EV charging use cases, including pilots for single-family residential smart charging programs and DCFC commercial rate structures (Charge Point Reply Brief at 9-12). Charge Point also suggests a special tariff for DCFC (Charge Point Brief at 12-13). Charge Point contends that advanced technical specifications, including collecting 15-minute interval data and two-way communication capability, are necessary to assist the Companies in future distribution planning and design (Charge Point Brief at 7-8).

Several intervenors raise concerns over commercial customer demand charges that site hosts may receive, arguing that demand charges may become a barrier to EV charging, especially for DCFC (Acadia Center Brief at 18; Global Partners Reply Brief at 4; NRDC Brief at 16).

(2) Companies

The Companies state a new EV-specific TOU rate is not part of the proposal and should not be required by the Department because developing a new rate design would unnecessarily delay implementation of the program and, therefore, delay progress toward the Commonwealth's public policy goals; and nothing in their EV Program prevents implementation of a new rate design at a later time (Companies Reply Brief at 4-5). The Companies argue that designing a new rate is a complicated matter, and that they are open to the design of an EV-specific rate design within a separate proceeding (Companies Reply Brief at 5).

(C) Analysis and Findings

Effective rate design for EV charging and the integration of demand response with EV charging will promote efficient charging behavior and can assist in securing societal benefits

related to EV infrastructure deployment. The Department recognizes that the Companies need time to collect data and information from site hosts before they can design and implement effective rate design and EV demand response programs. The initial goal of the Companies' proposed EV Program is to increase the availability of EV charging stations in the Companies' service territory by recruiting and working with site hosts (Exh. KAB/BJC-1 (Rev.) at 5; Companies Reply Brief at 4). Without site hosts, the Companies will not be able to collect data or develop effective rate design and EV demand response programs (Exh. KAB/BJC-1 (Rev.) at 6, 52). The Department finds that there is substantial evidence that the Companies will not experience a significant increase in load on the distribution system as a result of the EV Program because of its limited scope and duration (Exh. NG-Rebuttal-1, at 18). Therefore, the Department will not require the Companies to adopt the intervenors' rate design, demand response, or load management modifications at this time. During the EV Program, the Department directs the Companies, to collect EV charging data that can be used to develop TOU rates and a potential EV demand response program (Exh. KAB/BJC-1 (Rev.) at 54, 57-58).

The Department anticipates that the Companies will work closely with stakeholders during the data collection process (Exh. KAB/BJC-1 (Rev.) at 56-58). Specifically, the Department finds that data collection is essential in the development of EV charging TOU rates, alternative demand charges, and potential demand response programs.[26] See Order Adopting

[26] For example, in its grid modernization Order the Department decided to open an investigation to consider the next steps for cost-effective deployment of customer-facing grid modernization investments. This investigation will include exploring a targeted deployment of advanced metering functionality to certain customer groups such as new net metering and electric vehicle customers. National Grid shall fully participate in this investigation and coordinate its EV charging TOU rate design efforts accordingly. D.P.U. 15-120; D.P.U 15-121; D.P.U. 15-122, at 135-136.

Policy Framework for Time Varying Rates, D.P.U. 14-04-C at 7-8 (2014). In addition, the Companies plan to require site hosts to install EV supply equipment that is capable of reporting utilization and transaction data and receiving and executing real-time instructions of demand response (Exh. KAB/BJC-3, at 7-8). To that end, the Companies shall deploy service meters capable of two-way communications with the Companies' grid system when installing a new service meter on newly constructed EV charging sites, in order to avoid stranded costs (see Exh. KAB/BJC-3, at 1-2).

ii. EVSE Terms of Service

(A) Introduction

Under the Companies' proposal, whether a site host will charge a fee for drivers to use the EVSEs or otherwise restricts the use of the ESVEs will be at the discretion of the site host not governed by the Companies (Exh. KAJ/BJC-1 (Rev.) at 39).

(B) Positions of the Parties

(1) Intervenors

Some intervenors suggest that the Department should establish safeguards for rates charged to EV drivers such as limiting the effective mark-up on electricity that site hosts can impose (MESC Brief at 13-15; MESC Reply Brief at 8-9; CLF Brief at 17-18; NRDC Brief at 10-12).

Charge Point argues that the Department has no jurisdiction to impose conditions on the terms of service provided by site hosts, including conditions on how site hosts set charging prices (Charge Point Brief at 10-11, Charge Point Reply Brief at 4-5). Charge Point maintains that site

hosts should have flexibility in how they provide charging service based on their unique business needs (Charge Point Reply Brief at 5-7).

(2) Companies

The Companies assert that restrictions on pricing charged by site hosts are not appropriate as regulating end-use pricing charged by non-utility operators of EVSE is not within the Department's authority (Companies Reply Brief at 5). The Companies contend that pricing restrictions may disincentivize EV Program participation by site hosts (Companies Reply Brief at 6-7). The Companies emphasize that they will collect and report EV Program pricing data that may be used to inform pricing structure design in the future (Companies Reply Brief at 7).

(C) Analysis and Findings

The Department has determined that an EVSE owner/operator is selling a service and not electricity within the meaning of G.L. c. 164, and that the provision of EV charging service is not within the Department's jurisdiction under G.L. c. 164. D.P.U 13-182-A at 9. Accordingly, it is not within the Department's jurisdiction to regulate the terms of service for charging services that are not owned or operated by an EDC. D.P.U 13-182-A at 9. Therefore, the Department will not adopt the intervenors' suggestions.

iii. Coordination with Stakeholders and Reporting Requirements

(A) Introduction

The Companies state that they coordinated with Eversource on the design of the EV Program and have discussed coordinating education campaigns with Eversource (Exhs. KAJ/BJC-1 (Rev.) at 47; NG-Rebuttal-1, at 6). The Companies propose to seek observations from stakeholders on an ongoing basis as part of program planning and

implementation to identify improvements needed in the program (Exh. KAJ/BJC-1 (Rev.) at 26). The Companies propose to report the data collected through its R&D plan as part of its evaluation (Exh. KAJ/BJC-1 (Rev.) at 54). The Companies believe that sharing analysis and evaluation surveys will be essential to learning from the EV Program and proposes to do so on an annual basis (Exh. NG-Rebuttal-1, at 27). During the program, the Companies will collect and report on the fee paid to site hosts by drivers using charging stations (Exh NG-Rebuttal-1, at 32).

(B) Positions of the Parties

(1) Intervenors

The Attorney General and DOER recommend that the Department require National Grid to coordinate its efforts with Eversource and other entities involved in EV initiatives and report on these efforts in its annual EV Program cost recovery proceeding (Attorney General Brief at 8-11; DOER Brief at 8). Further, DOER recommends that the Companies work with DOER to set guidance for the availability and definition of public and independent funding sources (DOER Brief at 8-9). DOER states that it is imperative for the Companies to coordinate their efforts with other EDCs as well as other state, regional, and national initiatives (DOER Brief at 8). ChargePoint requests that the Department establish a stakeholder review and input mechanism as part of the evaluation plan (ChargePoint Brief at 11). ChargePoint asserts that the stakeholder review mechanism should take the form of a collaborative process to develop alternative approaches to load management, such as rate design, and ensure that stakeholder concerns are addressed and fully considered (ChargePoint Brief at 12).

Mass Energy, Sierra Club, and CLF recommend that the Department schedule a formal review of National Grid's program based on data collected and reported during the first two years of the EV Program's implementation (MESC Brief at 23; CLF Brief at 24). Mass Energy and Sierra Club recommend that the Department formalize National Grid's data collection and reporting commitments with a reporting interval no less than semi-annually alongside an opportunity for stakeholder feedback (MESC Brief at 23-24; MESC Reply Brief at 12). CLF argues that the Department must condition approval of the EV Program on incorporation of adequate and sufficiently frequent stakeholder engagement (CLF Brief at 22-23). CLF maintains that more and better metrics and establishment of a formal stakeholder engagement process would allow the Department and stakeholders to rigorously assess the performance of the EV Program (CLF Brief at 23). Further, CLF requests that the Department direct the Companies to coordinate with local governments, EJ community service providers, and other trusted community leaders and liaisons to develop initiatives to ensure that all Massachusetts residents have access to the benefits of the EV Program (CLF Brief at 22)

(2) Companies

National Grid states that it will continue to coordinate with Eversource and other stakeholders on program design and implementation, and National Grid claims that it has measures in place to ensure that its incentives are not duplicative of other available funding sources (Companies Brief at 20-21; Companies Reply Brief at 19, citing Exh. NG-Rebuttal-1, at 5-6). National Grid also states its willingness to work with DOER to set guidance for applicants about the availability of public and independent funding (Companies Reply Brief at 19).

(C) Analysis and Findings

As discussed above, the Department recognizes the value of stakeholders' contribution in initiatives to increase the adoption of EVs in the Commonwealth, and the Department will include all EDCs in the forthcoming EV metrics stakeholder process. Rather than delaying the implementation of the proposed EV Program until a formal proceeding on coordination can begin, the Department directs the Companies to continue their ongoing coordination with other EDCs and state and regional programs to make the best use of available resources to advance EV charging infrastructure development in the Commonwealth. Further, the Department directs the Companies to include a complete and detailed description of its coordination activities in their annual cost recovery filings consistent with their proposals, including coordination with (1) DOER to set guidance for applicants about the availability of public and independent funding; (2) stakeholders on the selection of site locations, especially DCFC sites, and site host selection criteria; and (3) local groups closely affiliated with EJ communities to consider recommendations on their unique charging needs (Companies Reply Brief at 19; see Exh. KAB/BJC-1 (Rev.) at 36, 39-40). Moreover, to ensure that the benefits of coordination are fully realized and to promote opportunities to learn from the EV Program, the Department directs the Companies to include with their annual cost recovery filings the data collected from the R&D plan and the survey results from the evaluation plan. Also, the Department directs the Companies to submit their analysis of the demand response research and EVSE data from the R&D plan with its proposed final evaluation report (Exh. KAB/BJC-10, at 4).

4. Conclusion

With the modifications described above, we find that National Grid's proposed EV Program is in the public interest. D.P.U. 13-182-A at 75.

VII. COST RECOVERY

A. Introduction

To recover program costs, National Grid proposes to implement EV factors on a reconciling basis that recover the costs discussed above (Exh. JAL-1, at 3). The Companies propose that the site hosts will not be responsible for any contribution in aid of construction ("CIAC") and that the full amount of any capital investment or O&M costs incurred for each site host be funded as an EV Program expense (Exh. JAL-1, at 4). Therefore, the Companies will not record in its general ledger any capital investment associated with the EV Program (i.e., the capital investment will be recorded in the general ledger at a zero value; and will be recorded as a regulatory asset) (Exh. JAL-1, at 4).

B. Positions of the Parties

1. Companies

National Grid argues that it has demonstrated that its proposed EV Program Provision and associated cost recovery method are reasonable (Companies Brief at 30). According to the Companies, they have provided ample evidence in support of their cost estimates that show the costs, including those devoted to program management, are reasonable (Companies Reply Brief at 14). Moreover, National Grid asserts that it will diligently manage the program to control incentive costs and program management costs in order to achieve the program's goals for the number of sites activated within the projected program budget (Companies Brief at 29; Companies Reply Brief at 14). Further, National Grid contends that actual costs are subject to

review (Companies Reply Brief at 14, citing Exh. JAL-1, at 3). The Companies assert that the Department will have an opportunity to conduct a thorough investigation to determine if the Companies' actual program costs are prudent as part of the Companies' filings for approval of EV Program cost recovery following the end of each program year (Companies Reply Brief at 14, citing Exh. JAL-1, at 5). Therefore, the Companies maintain that, given the nature of this program, its limited scope, and the diversified benefits associated with increased adoption of EVs, their proposed EV Program Provision is just and reasonable (Companies Brief at 32). No other party addressed the Companies' proposed tariff or cost recovery proposal.

2. Analysis and Findings

a. Costs Eligible for Recovery

Only EV Program capital investments and incremental O&M expenses are eligible for cost recovery through the EV Factors. First, with respect to capital investments, EV Program capital investments may be treated as incremental if their primary purpose is to accelerate progress in achieving the objectives of the Companies' EV Program.

The capital investment necessary to implement the EV Program will be recorded in the Companies' general ledger at zero dollar value through an accounting process similar to an eligible customer paying a CIAC for 100 percent of the costs associated with any utility make-ready work for the EVSE (Exhs. DPU 1-34; DPU 1-35).[27] The funds collected through the EV Factor pay for the construction costs that would normally be recovered directly from the customer in the form of a CIAC (Exh. DPU 2-1). National Grid will establish a regulatory asset

[27] This process will also reimburse the Company for any O&M costs incurred (Exh. DPU 1-35).

on its balance sheet (Exh. DPU 2-1). The Companies will credit this account each month with revenue billed to customers through the EV Factors (Exh. DPU 2-1). When a construction project has been completed on a site host's premises, the Companies will transfer the cost of the construction from the general ledger plant and expense accounts to the regulatory asset account (Exh. DPU 2-1). This accounting will be accomplished through a journal entry that will debit the regulatory asset account for the capital costs associated with the installation of infrastructure necessary to support the installation of EV charging stations and will credit Account 107, Construction Work In Progress (Exh. DPU 2-1). If the work order includes costs that are expensed, rather than capitalized, these costs will be recorded in the appropriate O&M account (Exh. DPU 2-1). The journal entry for this transaction will record a debit to the regulatory asset for the amount of the expense and a credit to the O&M account (Exh. DPU 2-1). The Companies will recover their EV Program investment through the EV Factors, not through base distribution rates or any through other reconciling mechanism (Exh. DPU 1-34).

With respect to O&M expenses, National Grid must demonstrate that all O&M expenses proposed for recovery through the EV Factors are (1) incremental to the representative level of O&M expenses recovered through base distribution rates and (2) solely attributable to preauthorized EV Program expenses.

A representative level of O&M costs already is recovered through base distribution rates. Allowing recovery of costs through a targeted cost recovery mechanism increases the risk that a company could recover a portion of these costs more than once. D.P.U. 12-76-B at 23; D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, at 218. In order to prevent this result, as described in detail below, National Grid must develop a rigorous method to demonstrate that only

incremental EV Program-related costs are proposed for targeted cost recovery, subject to our findings above. See D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, at 218.

As is the case with any costs to be recovered from ratepayers, all EV Program expenditures must be prudently incurred to be eligible for targeted 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). Department preauthorization of the EV Program means that the Department will not revisit the prudence of the Companies' decision to proceed with those categories of investments. The Department will, however, review the prudence of National Grid's implementation of these investments. D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, at 220. The Department will review EV Program expenditures annually to review the actual expenditures to determine if they are reasonable and prudently incurred. All costs recovered from ratepayers for any expenditures determined to be imprudent shall be refunded through the reconciliation component of the EV Factors, with associated carrying charges.[28]

Moreover, the Department emphasizes the importance of the Companies' developing and maintaining systematic, ample, and contemporaneous documentation of all EV Program costs for which they seek targeted cost recovery. A failure to provide clear, cohesive, and reviewable evidence demonstrating eligibility will result in disallowance of targeted cost recovery of the expenditures in question. Massachusetts Electric Company, D.P.U. 95-40, at 7 (1995); Boston

[28] The Companies' proposed Electric Vehicle Market Development Provision provides for interest at the customer deposit rate (M.D.P.U. No. 1334, Sheet 3).

Gas Company, D.P.U. 93-60, at 26-27 (1993); The Berkshire Gas Company, D.P.U. 92-210, at 24 (1993). National Grid must submit contemporaneous project documentation and other evidence demonstrating that each of these conditions has been met. The Department will review the Companies' submissions and disallow targeted cost recovery of all expenses where the proper showing has not been made.

To assist the Department in our review of EV Program costs, and to ensure that double recovery does not occur, the Department directs the Companies to develop and propose a rigorous protocol to demonstrate that the expenses are incremental to the costs already recovered through base distribution rates. See, e.g., D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, at 222. National Grid shall include its proposed protocol together with the compliance tariff filed in compliance with this Order.

Although we will not prescribe in this Order all elements of the protocol to demonstrate that EV Program costs are incremental to the costs already recovered through base distribution, the Department identifies certain expectations. First, the Department will limit eligible O&M labor expense to new positions created after the issuance of this Order, unless the Companies can demonstrate that the associated costs are attributed solely to EV Program activities and are not otherwise recovered through base distribution rates. Accordingly, the Companies must be prepared to identify and track the costs for positions created to perform EV Program activities since the test-year in its most recent rate case. Expenses for existing employees who have been moved to a new position performing EV Program activities will not be eligible for recovery through the EV Factors, as these costs already are recovered through base distribution rates. In addition, there shall be a presumption that all overhead and burdens are ineligible for recovery

through the EV Factors. These costs are indirectly incurred and, therefore, will be ineligible for recovery through the EV Factors unless the Companies develop a protocol to demonstrate otherwise. As part of the proposed protocol, we expect National Grid to provide a detailed description of the method it proposes to implement to track and clearly identify the increase in expensed costs (including capital investments recovered as an expense) over the costs currently recovered through base distribution rates. With this method, the Companies must be able to track the employees who are working specifically on EV Program activities and track the associated increase in employee hours as well as non-labor costs in a manner that clearly demonstrates that the costs are (1) directly related to the EV Program and (2) incremental to the costs already recovered through base distribution rates. Finally, we emphasize that National Grid is responsible for tracking such costs in a reviewable manner that reduces the administrative burden for the Department. Accordingly, we expect that the proposed protocol will incorporate a system to clearly segregate preauthorized EV Program investments from non-EV Program investments in National Grid's accounting systems.

b. Annual EV Factor Filing

The Companies shall make annual EV Factor rate adjustment and reconciliation filings comprised of (1) actual, eligible expenditures from the prior EV Program year and (2) a reconciliation component in the second year and beyond. Interest on over- or under-recovery of the revenue requirement shall be calculated on the average monthly balance using the customer deposit rate (Exh. JAL-2, at 3).

With each annual EV Factor filing, the Companies shall provide testimony and supporting exhibits, including full project documentation of all EV Program capital projects

placed into service during the plan investment year and documentation of O&M expenses, describing in detail how the Companies' proposed costs meet the eligibility requirements set forth in Section VI.D, above. Specifically, annual filings shall contain testimony and supporting documentation demonstrating that the costs sought for recovery are preauthorized, incremental (consistent with protocol and the tests described above), prudently incurred, in service, and used and useful (where applicable). Additionally, the filing also shall describe any cost variances as defined in the Companies' capital authorization policies, provide a demonstration that the proposed EV Factors are calculated appropriately, and provide bill impacts.

c. Billing

The Companies propose to include the EV Factors with the distribution kWh charge on customers' bills (Exh. JAL-1, at 6). However, the EV Program is a public policy initiative. Therefore, the Department directs the Companies to implement the EV Factor as a separate line item on a customer's bill. The Companies may collect the costs that they incur to implement the EV Factor as a separate line item through the annual EV Program cost recovery filing.

Accordingly, the EV Factor shall not be included in the following kWh charges: (1) basic service; (2) distribution; (3) transmission; (4) transition; (5) energy efficiency; or (6) renewable energy. For the majority of net metering facilities, the charges that constitute a customer's net metering credit include some or all of the following kWh charges: (1) basic service; (2) distribution; (3) transmission; and (4) transition. 220 CMR 18.04. Accordingly, for the purposes of net metering credit calculation, net metering credits shall exclude the EV Factor line item.

d. Tariff Modifications

Above, we directed the Companies to include its proposed protocol with the tariff filed in compliance with this Order. The Department additionally directs the Companies to make four modifications in the Companies' compliance tariff: (1) delete the referenced "Electric Vehicle Program Adjustment Provision" in the last paragraph of its proposed tariff, and instead insert "Electric Vehicle Market Development Program Provision" (Exh. DPU 1-44); (2) include the formula for calculating the annual EV Factor (Exh. DPU 1-45), (3) modify the language regarding the performance incentive to make it consistent with the directive contained in this Order; and (4) include that, for billing purposes, the EV Factor will be a separate line item on a customer's bill.

3. Conclusion

The Department has denied cost recovery of the company-owned DCFC stations in National Grid's R&D Plan. Additionally, the Department has denied cost recovery for the proposed Education Campaign. Accordingly, the Companies are directed to file for cost recovery consistent with the Department's above directives in this Order.

VIII. ORDER

Accordingly, after notice, hearing, and due consideration, it is

ORDERED: That Massachusetts Electric Company and Nantucket Electric Company's proposed Electric Vehicle Market Development Program is APPROVED, subject to the modifications contained in this Order; and it is

FURTHER ORDERED: Massachusetts Electric Company and Nantucket Electric Company's proposed Electric Vehicle Market Development Program Provision, M.D.P.U. No. 1334, is DISALLOWED; and it is

FURTHER ORDERED: That Massachusetts Electric Company and Nantucket Electric Company shall file a new Electric Vehicle Market Development Program Provision consistent with the directives contained in this Order; and it is

FURTHER ORDERED: That Massachusetts Electric Company and Nantucket Electric Company comply with all of the directives contained in this Order.

By Order of the Department,

/s/
Angela M. O'Connor, Chairman

/s/
Robert E. Hayden, Commissioner

/s/
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.

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 21-90 December 30, 2022

Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative Proposal.

D.P.U. 21-91

Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III Electric Vehicle Market Development Program and Electric Vehicle Demand Charge Alternative Proposal.

D.P.U. 21-92

Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of its Electric Vehicle Infrastructure Program, Electric Vehicle Demand Charge Alternative Proposal, and Residential Electric Vehicle Time-of-Use Rate Proposal.

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I. INTRODUCTION AND PROCEDURAL HISTORY

On July 14, 2021, NSTAR Electric Company d/b/a Eversource Energy ("NSTAR Electric"), Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid"), and Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil") (collectively "Companies"; individually, "company") each filed for approval by the Department of Public Utilities ("Department") an electric vehicle ("EV") charging infrastructure program proposal and a EV demand charge alternative ("DCA") proposal. Additionally, in D.P.U. 21-92, Unitil proposed a residential EV time-of-use ("TOU") rate. 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. 21-90, D.P.U. 21-91, and D.P.U. 21-92, respectively.[1]

On July 28, 2021, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a notice of intervention pursuant to G.L. c. 12, § 11E(a) in all three dockets. Additionally, the Department granted full party intervenor status to each of the following entities: (1) the Massachusetts Department of Energy Resources ("DOER") (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92); (2) the Conservation Law Foundation ("CLF") (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92); (3) Tesla, Inc. ("Tesla") (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92); (4) ChargePoint, Inc. ("ChargePoint") (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92); (5) Global Partners LP (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92); (6) FreeWire Technologies, Inc. ("FreeWire") (D.P.U. 21-90; D.P.U. 21-91;

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

D.P.U. 21-92); (7) Green Energy Consumers Alliance ("GECA") (D.P.U. 21-90; D.P.U. 21-91); (8) Natural Resources Defense Council, the Sierra Club, and Union of Concerned Scientists ("CEP") (D.P.U. 21-90; D.P.U. 21-91); (9) Electrify America (D.P.U. 21-90; D.P.U. 21-91); (10) EVgo Services LLC ("EVgo") (D.P.U. 21-90; D.P.U. 21-91); (11) Zeco Systems, Inc. d/b/a Shell EV Charging Solutions Americas ("Shell")[2] (D.P.U. 21-90; D.P.U. 21-91); (12) Cape Light Compact JPE ("Compact") (D.P.U. 21-90); (13) Low-Income Weatherization and Fuel Assistance Program Network (D.P.U. 21-91). The Department also allowed the following entities to participate as limited participants: (1) National Grid (D.P.U. 21-90; D.P.U. 21-92), and (2) NSTAR Electric (D.P.U. 21-91; D.P.U. 21-92).

On September 9, 2021, the Department bifurcated its investigation of the Companies' filings into two separate, parallel tracks. The Department designated Track 1 to review the EV charging infrastructure program and associated cost recovery proposals and Track 2 to review the DCA rate proposals and Unitil's residential EV TOU rate proposal. D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Procedural Notice at 2, 4 (September 9, 2021).[3] Pursuant to notices duly issued, the Department conducted a joint public hearing and procedural conference in these proceedings on September 14, 2021. On October 12, 2021, pursuant to notice duly issued, the Department held a second public hearing in D.P.U. 21-92.

During the course of the Track 1 investigation, each company sponsored witness testimony. In D.P.U. 21-90, NSTAR Electric sponsored the testimony of the following

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[2] At the time Shell was granted intervenor status in these proceedings, Shell conducted business as Greenlots.

[3] The Department addresses issues raised in Track 1 and Track 2 in this Order.

Eversource Energy Service Company ("ESC") employees: (1) Kevin Boughan, Manager, Research and Business; (2) Richard Chin, Manager, Rates; and (3) Robert Frank, Director, Revenue Requirements. In D.P.U. 21-91, National Grid sponsored the testimony of the following National Grid USA Service Company, Inc. ("NGSC") employees: (1) Rishi Sondhi, Manager, Clean Transportation Team; (2) Julia Gold, Principal Policy and Strategy Analyst, Clean Transportation Team; (3) Jake Navarro, Director, Clean Transportation Team; (4) Sharon Daly, Lead Analyst, U.S. Retail Regulatory Strategy Group; (5) Thomas Chorman, Senior Engineer, Clean Transportation Team; (6) Scott McCabe, Manager, New England Pricing Group; (7) Theresa Burns, Director, New England Pricing Group; (8) Mindy Rosen, Lead Analyst, New England Pricing Group; (9) Stephanie Briggs, Director, Revenue Requirements; and (10) Jared Goldfarb, Director, New England Financial Planning and Analysis. In D.P.U. 21-92, Unitil sponsored the testimony of the following Unitil Service Corporation ("USC") employees: (1) Cindy Carroll, Vice President, Customer Energy Solutions; (2) Carleton Simpson, Regulatory Counsel; (3) Carol Valianti, Vice President, Communications and Public Affairs; and (4) Christopher Goulding, Director, Rates and Revenue Requirements. In addition, Unitil sponsored the testimony of John Taylor, Managing Partner, Atrium Economics LLC.

The Attorney General sponsored the testimony of the following witnesses in each proceeding: (1) Ron Nelson, Senior Director, Strategen Consulting, and (2) Caroline Palmer, Senior Regulatory Consultant, Strategen Consulting. Additionally, the following intervenors sponsored witness testimony in each proceeding as follows: (1) DOER sponsored the testimony of Joanna Troy, Director of Energy Policy, DOER; (2) ChargePoint sponsored the testimony of Kevin Miller, Director of Public Policy, ChargePoint; (3) FreeWire sponsored the testimony of

Peter Olmsted, Director of Regulatory Affairs, FreeWire; and (4) CLF sponsored the testimony of Layne Benton, Lead Environmental Justice Organizer, GreenRoots, Inc. In D.P.U. 21-90 and D.P.U. 21-91, GECA sponsored the testimony of the following witnesses: (1) Larry Chretien, Executive Director, GECA; (2) Anna Vanderspek, Electric Vehicle Program Director, GECA; (3) Mal Skowron, Transportation Policy & Program Coordinator, GECA; (4) Alexis Walls, Assistant Campaign Director, Massachusetts Public Health Association; (5) Elizabeth Stanton, Director, Applied Economics Clinic; and (6) Joshua Castigliego, Researcher, Applied Economics Clinic. Also, in D.P.U. 21-90 and D.P.U. 21-91, the following intervenors sponsored witness testimony as follows: (1) EVgo sponsored the testimony of Carine Dumit, Director of Market Development and Public Policy, EVgo; (2) Electrify America sponsored the testimony of Tyler Stoff, Government Affairs and Public Policy Lead, Electrify America; (3) Shell sponsored the testimony of Thomas Ashley, Vice President of Policy and Market Development, Shell; (4) CEP sponsored the testimony of Kathleen Harris, Clean Vehicles and Fuels Advocate, Natural Resources Defense Council; and (5) Tesla sponsored the testimony of William Ehrlich, Senior Policy Advisor for EV Charging Policy and Rates, Tesla.

From March 21, 2022 to March 24, 2022, the Department held four days of joint evidentiary hearings for Track 1 issues. On April 15, 2022, initial briefs were filed by: (1) the Attorney General (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92); (2) DOER (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92); (3) ChargePoint (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92); (4) FreeWire (D.P.U. 21-90; D.P.U. 21-91); (6) CLF (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92); (7) GECA (D.P.U. 21-90; D.P.U. 21-91); (8) EVgo (D.P.U. 21-90; D.P.U. 21-91); (9) Electrify America (D.P.U. 21-90; D.P.U. 21-91); (10) Shell (D.P.U. 21-90;

D.P.U. 21-91); (11) CEP (D.P.U. 21-90; D.P.U. 21-91); (12) Tesla (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92); and (13) the Compact (D.P.U. 21-90). On May 2, 2022, NSTAR Electric and National Grid filed a joint initial brief in D.P.U. 21-90 and D.P.U. 21-91, and Unitil filed an initial brief in D.P.U. 21-92.

On May 18, 2022, reply briefs were filed by: (1) the Attorney General (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92); (2) ChargePoint (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92); (3) FreeWire (D.P.U. 21-90; D.P.U. 21-91); (4) CLF (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92); (5) EVgo (D.P.U. 21-90; D.P.U. 21-91); (6) Electrify America (D.P.U. 21-90; D.P.U. 21-91); (7) Shell (D.P.U. 21-90; D.P.U. 21-91); (8) CEP (D.P.U. 21-90; D.P.U. 21-91); (9) Tesla (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92); and (10) the Compact (D.P.U. 21-90). On May 25, 2022, NSTAR Electric and National Grid filed a joint reply brief in D.P.U. 21-90 and D.P.U. 21-91, and Unitil filed a reply brief in D.P.U. 21-92.

Each company also sponsored witness testimony in Track 2 of these proceedings. In D.P.U. 21-90, NSTAR Electric sponsored the testimony of Richard Chin, Manager, Rates, ESC. In D.P.U. 21-91, National Grid sponsored the testimony of the following NGSC employees: (1) Thomas Chorman, Lead Engineer, Clean Transportation Team; (2) Scott McCabe, Manager, New England Pricing Group; (3) Theresa Burns, Director, New England Regulation Department; and (4) Sharon Daly, Lead Analyst, U.S. Retail Regulatory Strategy Group. In D.P.U. 21-92, for Track 2, Unitil sponsored the testimony of the following USC employees: (1) Cindy Carroll, Vice President, Customer Energy Solutions, and (2) Christopher Goulding, Director, Rates and Revenue Requirements. In addition, Unitil sponsored the testimony of John Taylor, Managing Partner, Atrium Economics LLC.

Additionally, in each proceeding, the following intervenors sponsored witness testimony for Track 2 as follows: (1) the Attorney General sponsored the testimony of Ron Nelson, Senior Director, Strategen Consulting; (2) DOER sponsored the testimony of Joanna Troy, Director of Energy Policy, DOER; (3) ChargePoint sponsored the testimony of Matthew Deal, Manager of Utility Policy, ChargePoint; and (4) CLF sponsored the testimony of Christopher Villarreal, President, Plugged In Strategies. Further, in D.P.U. 21-90 and D.P.U. 21-91, (1) GECA sponsored the testimony of Larry Chretien, Executive Director, GECA and Joshua Castigliego, Researcher, Applied Economics Clinic, (2) CEP sponsored the testimony of Melissa Whited, Senior Principal, Synapse Energy Economics, (3) Tesla sponsored the testimony of William Ehrlich, Senior Policy Advisor of EV Charging Policy and Rates, Tesla, (3) EVgo sponsored the testimony of R. Thomas Beach, Principal Consultant, Crossborder Energy, and (4) Electrify America sponsored the testimony of Jigar Shah, Manager, Electrify America.

From August 1, 2022 to August 3, 2022, the Department held three days of joint evidentiary hearings on Track 2 issues. On September 15, 2022, initial briefs were filed by (1) NSTAR Electric and National Grid jointly (D.P.U. 21-90; D.P.U. 21-91); (2) Unitil (D.P.U. 21-92); (3) the Attorney General (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92) (4) DOER (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92); (5) ChargePoint (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92); (6) CLF (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92); (7) FreeWire (D.P.U. 21-90; D.P.U. 21-91); (8) Electrify America (D.P.U. 21-90; D.P.U. 21-91); (9) CEP (D.P.U. 21-90; D.P.U. 21-91); (10) Tesla (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92); (11) GECA (D.P.U. 21-90; D.P.U. 21-91); (12) EVgo (D.P.U. 21-90; D.P.U. 21-91); and (13) Shell (D.P.U. 21-90; D.P.U. 21-91). On September 30, 2022, reply briefs were filed by

(1) NSTAR Electric and National Grid jointly (D.P.U. 21-90; D.P.U. 21-91); (2) Unitil (D.P.U. 21-92); (3) the Attorney General (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92); (4) FreeWire (D.P.U. 21-90; D.P.U. 21-91); (5) CLF (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92); (6) EVgo (D.P.U. 21-90; D.P.U. 21-91); (7) Electrify America (D.P.U. 21-90; D.P.U. 21-91); (8) CEP (D.P.U. 21-90; D.P.U. 21-91); and (9) Tesla (D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92).

The evidentiary record in each docket includes the company's initial filing exhibits, corresponding revisions to those exhibits, company and intervenor testimony from both Track 1 and Track 2, responses to all information requests issued during these proceedings, and record request responses from both Track 1 and Track 2 evidentiary hearings.[4] The record in D.P.U. 21-90 includes responses to 391 information requests and twelve record requests. The record in D.P.U. 21-91 includes responses to 426 information requests and twelve record requests. The record in D.P.U. 21-92 includes responses to 138 information requests and nine record requests.

II. BACKGROUND

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, D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, at 1, citing Modernization of the Electric Grid, D.P.U. 12-76-B (2014). The Department's vision of the modern grid includes

[4] During the Track 2 evidentiary hearings, all exhibits filed in each docket were moved into the evidentiary record for that docket (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 8, at 1386-1387).

support for emerging technologies such as EVs. Modernization of the Electric Grid, D.P.U. 12-76, at 3-4 (2013). In Electric Vehicles, D.P.U. 13-182-A (2013), the Department established a regulatory construct governing the Department's review of an electric distribution company's EV infrastructure program proposal. Since then, the Department has reviewed and approved EV program proposals by NSTAR Electric and National Grid. NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05, at 501-503 (2017); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 17-13, at 62 (2018); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 18-150, at 384-394 (2019).

On July 2, 2020, in D.P.U. 20-69-A, the Department directed each electric distribution company to submit an EV proposal consistent with the Department's directives. Specifically, the Department required each company to file an EV proposal consisting of: (1) any new or expanded EV charging infrastructure proposal, and (2) a commercial EV rate design proposal addressing alternatives to demand charges as required by An Act Authorizing and Accelerating Transportation Investment, St. 2020, c. 383, § 29 ("Transportation Act"). D.P.U. 20-69-A at 40-41, 49. In developing a new or expanded EV charging infrastructure program proposal, the Department required the Companies to: (1) incorporate lessons learned from existing EV charging infrastructure programs to increase the accessibility of EV chargers in environmental justice ("EJ") communities; (2) ensure a consistent approach for host recruitment and incentives; (3) avoid duplication with other EV charging infrastructure build-out incentive programs offered in the Commonwealth (e.g., the Massachusetts EV Incentive Program ("MassEVIP"), Volkswagen settlement-funded incentive programs, municipal rebate programs for EV charging

infrastructure, etc.); (4) include proposals to mitigate barriers that impeded the recruitment of DCFC site hosts for strategic locations in the Commonwealth; (5) incorporate analyses of traffic and EV charging patterns to identify priority locations for future public EV charging stations; and (6) coordinate and propose statewide and company-specific performance metrics associated with their EV charging infrastructure programs. D.P.U. 20-69-A at 46-48. Additionally, to avoid any potential overlap between the EV programs and other programs, the Department required each company to coordinate and streamline its EV charging incentive offerings. D.P.U. 20-69-A at 49.

Regarding the commercial EV rate design proposal addressing alternatives to demand charges, the Department directed the Companies to consider: (1) converting kW-based charges to kilowatt-hour-based charges; (2) off-peak charging demand charge rebates or discounts; and (3) sliding scale demand charges based on the load factor of the EV charging site. D.P.U. 20-69-A at 42. Moreover, the Department stated that all DCA rate proposals should be based on EV charging data collected through: (1) smart chargers or networked chargers; (2) EV telematics; or (3) interval meters installed at the request of the customer. D.P.U. 20-69-A at 42-43. To the extent feasible, the Department required the Companies to coordinate the development of their DCA rate proposals for commercial and industrial ("C&I") EV customers to facilitate a consistent EV charging experience across service territories and to identify a timeline and approach to transition all proposed DCA rates to the future demand charge rate designs that would be enabled through the full deployment of AMI meters. D.P.U. 20-69-A at 43. In addition, the Department held that any proposed tariff included as part of the Companies' DCA rate proposals must be filed as an exemplar tariff. D.P.U. 20-69-A at 43.

Further, the Department encouraged Unitil to propose a residential EV TOU rate as part of its EV proposal to provide appropriate price signals to encourage customer behaviors that will contribute to reducing peak demand. D.P.U. 20-69-A at 44. The Department determined that Unitil's metering infrastructure and supporting systems were capable of accommodating simple time-varying rates ("TVRs") for EV customers without major expenditures. D.P.U. 20-69-A at 44.

Finally, the Department sought to establish a level of consistency in charging experiences for EV customers as they travel across utility service territories within the Commonwealth. D.P.U. 20-69-A at 41. Accordingly, the Department directed the Companies to coordinate their EV proposals for consistency and uniformity across service territories to the greatest extent practicable. D.P.U. 20-69-A at 41.

III. ELECTRIC VEHICLE PROGRAM PROPOSALS

A. Description of the Proposals

1. NSTAR Electric

a. Overview

NSTAR Electric proposes a four-year Phase II EV program with an associated budget of approximately $191.9 million (D.P.U. 21-90, Exh. ES-KB-2). The company's Phase II EV program proposal consists of three components: (1) make-ready[5] and EV supply equipment

[5] Generally, EV charging make-ready infrastructure includes the electrical infrastructure between the utility grid interconnection and the EVSE (D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 36; see also D.P.U. 17-05, Exhibit ES-GMBC-1, at 91).

("EVSE") incentive proposal;[6] (2) two equity pilot proposals; and (3) other supporting proposals, including funding for additional employees, a marketing and outreach plan, supporting system upgrades, and a joint workforce development and electrician training proposal (D.P.U. 21-90, Exh. ES-KB-1, at 7-8). Last, the company seeks budget flexibility to shift program funds and adjust program components, as well as the ability to initiate a mid-term review for review of EV program modifications (D.P.U. 21-90, Exh. ES-KB-1, at 89-90).

b. Make-Ready and EVSE Incentive Proposal

The company's make-ready and EVSE incentive proposal seeks to support the deployment of Level 2 EV chargers and direct current fast chargers ("DCFCs") by providing financial incentives for their installation and includes three components: (1) a public and workplace offering; (2) residential offering; and (3) a fleet offering (D.P.U. 21-90, Exh. ES-KB-1, at 6). For its public and workplace offering, the company proposes a budget of approximately $109.1 million, consisting of: (1) $85.0 million for make-ready incentives; (2) $17.2 million for EVSE rebates; (3) $1.2 million for networking incentives; and (4) $5.6 million for DCFC hubs in EJ communities (D.P.U. 21-90, Exh. ES-KB-2). The company proposes financial incentives for its public and workplace offering as follows:

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[6] EVSEs are the charging equipment that provide electric power to the vehicle and use that to recharge the vehicle's batteries. EVSE equipment is generally divided into three types: Level I, Level II, and direct current fast chargers ("DCFC"). Level 2 chargers rely on a 240-volt connection and are capable of fully charging most existing EVs in approximately eight hours or less depending on battery capacity. D.P.U. 17-05, at 472 n.234. DCFC chargers use direct current and are the fastest method for charging an EV. D.P.U. 17-05, at 472 n.233. Level 1 chargers plug directly into a standard 120-volt AC outlet and are the slowest method for charging an EV (D.P.U. 17-05, Exhibit ES-GMBC-1, at 97; D.P.U. 17-13, Exhibit KAB/BJC-1, at 15).

(1) 100 percent of make-ready costs (i.e., the infrastructure on the utility side of the meter); (2) up to 100 percent of the average installation costs of the infrastructure on the customer side of the meter,[7] not to exceed actual installation costs; (3) for Level 2 EVSE, 100 percent of the installed costs for up to ten ports in EJ communities, 50 percent of the installed costs for ports three to ten for municipalities, and 50 percent of the installed costs for ports five to ten for all other customers; (4) for public DCFC EVSE in EJ communities, $40,000 per port, up to $400,000, for ports between 50 kilowatts ("kW") and 150 kW, and up to $80,000 per port for ports 150 kW and above; (5) for public DCFC EVSE outside of EJ communities, $40,000 per port above 50 kW, with a minimum of 100 kW per site, up to $400,000; (6) four years of networking at $480 per port for municipal Level 2 and DCFC customers and any EVSE in EJ communities; and (7) 100 percent of the costs for four to five charging hubs with approximately four 175 kW DCFCs in EJ communities[8] (D.P.U. 21-90, Exh. ES-KB-1, at 45-47).

For its residential make-ready and EVSE incentive offering, the company proposes a budget of $52.7 million, comprised of: (1) $32.9 million for make-ready incentives; (2) $9.2 million for EVSE rebates; (3) $1.0 million for networking incentives; (4) $6.2 million for low-income/EJ communities turnkey installation; (5) $1.2 million for EV site ready plans;

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7 To account for certain site-specific characteristics and potential cost-shifts in the industry, the company proposes to provide make-ready incentives for up to 150 percent of the average installation costs of the infrastructure on the customer side of the meter on a case-by-case basis (D.P.U. 21-90, Exh. ES-KB-1, at 43). NSTAR Electric also proposes to periodically recalculate the average customer-side infrastructure costs for each installation type to reflect current market dynamics (D.P.U. 21-90, Exh. ES-KB-1, at 43).

8 NSTAR Electric proposes to issue a request for proposals to solicit interested owners/operators of the DCFC charging hubs (D.P.U. 21-90, Exh. ES-KB-1, at 47).

and (6) $2.1 million for vendor-based administrative costs (D.P.U. 21-90, Exh. ES-KB-2). For customers in one to four-unit properties, NSTAR Electric proposes to provide financial incentives, not to exceed actual costs, of up to: (1) $700 for customers in one-unit properties; (2) $1,400 for customers in two to four-unit properties; (3) $300 per customer for networked Level 2 EVSE; and (4) for low-income customers and customers in EJ communities, 100 percent of Level 2 EVSE costs, $1,700 for customers in one-unit proprieties, and $2,700 for customers in two to four-unit properties (D.P.U. 21-90, Exh. ES-KB-1, at 50, 56-57). NSTAR Electric also proposes to require these residential customers to enroll in the company's managed charging program, ConnectedSolutions, for at least one year, with an option to opt out after the first year (D.P.U. 21-90, Exh. ES-KB-1, at 56-58).

For multi-unit dwellings ("MUDs") with five or more units, NSTAR Electric proposes to provide financial incentives of: (1) 100 percent of the infrastructure on the utility side of the meter; (2) up to 100 percent of the infrastructure on the customer side of the meter, with the ability to provide make-ready incentives of up to 150 percent of the average cost per port on a case-by-case basis; (3) up to 100 percent of the average cost per port for sites in EJ communities, up to $4,000 per Level 2 port, not to exceed actual costs, and 50 percent of the average cost per port for other sites, up to $2,000 per Level 2 port, not to exceed actual costs; and (4) $120 per port per year for four years for networking costs upon request (D.P.U. 21-90, Exh. ES-KB-1, at 50-51, 60-61). For MUDs with 20 or more units, NSTAR Electric proposes to provide financial support of up to $6,000 for the cost of an EV ready site plan on the long-term infrastructure and equipment approach to installing at least one Level 2 port per residential unit (D.P.U. 21-90, Exh. ES-KB-1, at 51, 61-63).

Turning to the fleet offering, NSTAR Electric proposes a budget of $2.0 million to support light duty electric fleets as follows: (1) 100 percent of the infrastructure on the utility side of the meter; (2) up to 100 percent of the average installation costs per port of the infrastructure on the customer side of the meter, not to exceed actual costs, with the ability to provide make-ready incentives of up to 150 percent of the average cost per port on a case-by-case basis; and (3) 100 percent of the EVSE costs for fleet customers in EJ communities,[9] up to $4,000 per Level 2 port, and 50 percent of the EVSE costs for all other passenger vehicle fleet customers after the first four ports (i.e., excluding the first four ports for which the customer receives no financial assistance), up to $2,000 per Level 2 port, not to exceed actual costs (D.P.U. 21-90, Exh. ES-KB-1, at 67-68).[10] The company also proposes to provide fleet assessment services for up to 100 private and non-profit fleet customers and to develop online fleet planning and total cost of ownership ("TCO") tools for fleet customers (D.P.U. 21-90, Exh. ES-KB-1, at 67, 69).[11]

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9 For fleets to be eligible for the EJ community level of support, NSTAR Electric proposes that the fleet operators must either be registered in or operate more than 50 percent of the time within census block groups that meet any of the Commonwealth's EJ community criteria (D.P.U. 21-90, Exh. ES-KB-1, at 68-69).

10 NSTAR Electric also proposes to periodically recalculate the rebate incentive levels based on station price benchmark changes, the availability of third-party funding, and customer interest in the program (D.P.U. 21-90, Exh. ES-KB-1, at 68).

11 To maintain a consistent customer experience for fleet operators across the state, NSTAR Electric and National Grid propose to collaborate on the development of the online fleet planning and TCO tools for fleet customers and issue a joint RFP to select a single vendor (D.P.U. 21-90, Exh. ES-KB-1, at 69-70).

c. Equity Pilot Proposals

NSTAR Electric proposes two equity pilots: (1) $2.0 million for a EJ communities car sharing pilot; and (2) $3.0 million for a medium- and heavy-duty fleet pilot for EJ communities (D.P.U. 21-90, Exhs. ES-KB-1, at 6; ES-KB-2). The company proposes to develop and implement an equity-focused electric car sharing pilot in partnership with other entities, which may include vehicle providers, community-based organizations, carsharing platform operators, municipalities, and other EJ community stakeholders (D.P.U. 21-90, Exh. ES-KB-1, at 72-73). As part of the car sharing pilot, the company proposes to provide financial support for charging infrastructure and other operational and financial support necessary to support the pilot (D.P.U. 21-90, Exh. ES-KB-1, at 72-73).

Regarding the EJ communities medium- and heavy-duty EV fleet pilot, the company proposes to provide financial support for charging infrastructure and EVSE to approximately 120 medium- and heavy-duty fleet vehicles that serve EJ communities, including, but not limited to, school buses, community transport services, and last mile delivery fleets (D.P.U. 21-90, Exh. ES-KB-1, at 73-74).

d. Other Supporting Proposals

To implement its Phase II EV program proposal, NSTAR Electric proposal also includes: (1) $10.0 million to hire twelve incremental full-time employees to support the expanded Phase II EV program, including a EV implementation manager, a construction lead, a project coordinator, four program managers, three EV account executives, and two analysts; (2) $10.1 million for a marketing and outreach plan to drive awareness of and participation in the proposed EV offerings through a variety of channels; (3) $0.3 million for information technology

and back-office system upgrades, including investment in a workflow management platform to manage customer applications to the public and workplace, MUD, and fleet segment offerings and to track and document program deployment progress; and (4) a joint workforce development and electrician training program (D.P.U. 21-90, Exhs. ES-KB-1, at 85-89, 90-93; ES-KB-5).

Regarding the workforce development and electrician training proposal, NSTAR Electric proposes to co-sponsor with National Grid and Unitil a workforce development and electrician training program to: (1) support approximately 75 underrepresented entrants to the EV workforce, and (2) educate approximately 1,000 electricians on electrical work related to EV charging infrastructure (D.P.U. 21-90, Exh. ES-KB-1, at 74-78). More specifically, the Companies propose to partner with a vendor with expertise in workforce development to identify market needs, develop a curriculum, outline a structure to the initiative, and execute the program (D.P.U. 21-90, Exh. ES-KB-1, at 76). Additionally, the Companies propose to coordinate with key partners, such as the International Brotherhood of Electrical Workers, the Massachusetts Clean Energy Center ("MassCEC"), the Massachusetts Clean Cities Coalition, and MassHire, to develop proposed initiatives, avoid duplication with other available workforce development and electrician training initiatives, and ensure consistency (D.P.U. 21-90, Exh. ES-KB-1, at 77). The Companies also propose to explore opportunities to recruit additional sponsors, such as automakers and charging station provides, to expand the initiative's reach and decrease each sponsor's costs (D.P.U. 21-90, Exh. ES-KB-1, at 77). NSTAR Electric's share of the joint workforce development and electrician training proposal is $1.2 million (D.P.U. 21-90, Exh. ES-KB-1, at 8).

NSTAR Electric also proposes that it be allowed the flexibility to move up to 20 percent of program funds from one segment to another or within each segment without prior Department approval (D.P.U. 21-90, Exh. ES-KB-1, at 89-90). Moreover, the company proposes to have the flexibility to adjust components within the programs, including incentives and rebate levels, customer eligibility requirements, and the distribution of port types (D.P.U. 21-90, Exh. ES-KB-1, at 89-90). Additionally, NSTAR Electric proposes to have the flexibility to initiate a mid-term review at the end of the second year of the Phase II EV program during which the company could propose substantial modifications to the EV program, including EVSE ownership models, pilot program scale and scope, and program administration costs and considerations (D.P.U. 21-90, Exh. ES-KB-1, at 90).

2. National Grid

a. Overview

National Grid proposes a four-year Phase III EV program with associated costs of approximately $277.8 million (D.P.U. 21-91, Exhs. NG-EVPP-1, at 9, 123; NG-EVPP-2). The proposed Phase III EV program consists of three components: (1) make-ready and EVSE incentive proposal; (2) an expanded off-peak charging rebate offering; and (3) other supporting proposals, including a co-located battery energy storage pilot, funding for additional employees, a marketing and outreach plan, supporting system upgrades, and a joint workforce development and electrician training proposal (D.P.U. 21-91, Exh. NG-EVPP-1, at 10).

b. Make-Ready and EVSE Incentive Proposal

National Grid's make-ready and EVSE incentive proposal includes three segments: (1) a public and workplace offering; (2) a residential offering; and (3) a fleet offering (D.P.U. 21-91,

Exh. NG-EVPP-1, at 31). The proposed public and workplace offering includes a budget of approximately $96.8 million, consisting of: (1) $72.85 million for make-ready incentives; (2) $18.62 million for EVSE rebates; (3) $1.38 million for networking incentives; (4) $1.58 million for pole-mounted EVSE; (5) $0.5 million for DCFC commitments; and (6) $1.84 million for program management (D.P.U. 21-91, Exhs. NG-EVPP-1, at 52-53, 123; NG-EVPP-2). Through the public and workplace offering, National Grid proposes to provide financial incentives for: (1) 100 percent of the infrastructure costs on the utility side of the meter for proprietary[12] and non-proprietary network EVSE; (2) up to 100 percent of the average installation costs of the infrastructure on the customer side of the meter for non-proprietary network EVSE and 50 percent of the average installation costs of the infrastructure on the customer side of the meter for proprietary network EVSE,[13,14] not to exceed actual installation costs; (3) for Level 2 EVSE, 100 percent of the installed costs for up to ten ports in EJ communities, 50 percent of the installed costs for ports three through ten for municipalities, and

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12 Proprietary networks either use proprietary hardware or restrict charging access to specific vehicle brands (D.P.U. 21-90, Exh. NG-EVPP-1, at 43).

13 To account for certain site-specific characteristics and potential cost-shifts in the industry, the company proposes to provide make-ready incentives for up to 150 percent of the average installation costs of the infrastructure on the customer side of the meter on a case-by-case basis (D.P.U. 21-91, Exh. NG-EVPP-1, at 43). National Grid also proposes to periodically recalculate the average customer-side infrastructure costs for each installation type to reflect current market dynamics (D.P.U. 21-91, Exh. NG-EVPP-1, at 43).

14 For projects that co-locate proprietary network EVSE with non-proprietary network EVSE at a four to one ratio of proprietary network EVSE ports to non-proprietary network EVSE ports, National Grid proposes to provide financial incentives equal to 65 percent of the average installation costs of the infrastructure on the customer side of the meter (D.P.U. 21-91, Exh. NG-EVPP-1, at 43-44).

50 percent of the installed costs for ports five through ten for all other customers; (4) for public DCFC EVSE in EJ communities, $40,000 per port for ports between 50 kW and 150 kW, up to $400,000, and up to $80,000 per port for ports 150 kW and above; (5) for public DCFC EVSE outside of EJ communities, $40,000 per port above 50 kW, with a minimum of 100 kW per site, up to $400,000; and (6) four years of networking at $480 per port for public Level 2 chargers and any Level 2 chargers in EJ communities (D.P.U. 21-91, Exh. NG-EVPP-1, at 43-45). Additionally, for sites with access to long-dwell time parking, National Grid proposes to provide make-ready incentives for up to 500 Level 1 chargers (D.P.U. 21-91, Exh. NG-EVPP-1, at 40).

National Grid also proposes to install, own, and operate approximately 200 ports on company-owned electric distribution poles in up to ten municipalities over the course of the four-year Phase III EV program (D.P.U. 21-91, Exh. NG-EVPP-1, at 47-48). At the end of the four-year EV program, the company proposes to sell the pole-mounted EVSE to the municipalities in which the electric distribution poles are located or the open market (D.P.U. 21-91, Exh. NG-EVPP-1, at 47).

Additionally, National Grid proposes to build, own, and operate up to 20 150-kw DCFC ports across up to ten pre-identified underserved or high-need EJ communities if gaps in DCFC deployment exist at the mid-point of the EV program (D.P.U. 21-91, Exh. NG-EVPP-1, at 46-47). The company states that it will provide notice to station developers that these gaps in DCFC deployment exist six months prior to DCFC deployment to allow the private market to address these gaps before the company does (D.P.U. 21-91, Exh. NG-EVPP-1, at 46-47).

Turning to the residential program, National Grid proposes a budget of $64.08 million, comprised of: (1) $41.86 million for make-ready incentives; (2) $10.41 million for EVSE

rebates; (3) $1.0 million for networking incentives; (4) $3.97 million for low-income/EJ communities turnkey installation; (5) $1.2 million for EV site ready plans; and (6) $6.64 million for program management (D.P.U. 21-91, Exh. NG-EVPP-1, at 10, 70, 123). For customers in one to four-unit properties, National Grid proposes to provide EVSE rebates, not to exceed actual costs, of up to: (1) $700 for customers in one-unit properties; (2) $1,400 for customers in two to four-unit properties; (3) an additional rebate of $300 per customer for installation of networked Level 2 EVSE; and (4) 100 percent of Level 2 EVSE costs for low-income customers and customers in EJ communities, $1,700 for customers in one-unit proprieties, and $2,700 for customers in two to four-unit properties (D.P.U. 21-91, Exh. NG-EVPP-1, at 62-64). National Grid also proposes to require these customers to enroll in one of the company's managed charging programs, either the expanded off-peak charging rebate program[15] or the EV demand response program through its energy efficient program,[16] with an option to opt out after the first year (D.P.U. 21-91, Exh. NG-EVPP-1, at 63, 87-91).[17]

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15 The expanded off-peak charging rebate proposal incentivizes customers to charge their EVs during off-peak periods, at times when electrical demand on the company's distribution system is low (D.P.U. 21-91, Exh. NG-EVPP-1, at 63). This proposal is a continuation and expansion of the company's off-peak charging rebate program within its Phase II EV program (D.P.U. 21-91, Exh. NG-EVPP-1, at 87-91).

16 The EV demand response program incentivizes customers to limit EV charging on system peak days (i.e., days with the most electrical demand on the company's distribution system) (D.P.U. 21-91, Exh. NG-EVPP-1, at 63).

17 The company states that it will consider good cause exceptions to the managed charging enrollment requirement for a portion of customers in two to four-unit properties because these customers have shared parking or do not own or lease an EV (D.P.U. 21-91, Exh. NG-EVPP-1, at 63).

Regarding MUDs with five or more units, National Grid proposes to provide financial rebates of: (1) 100 percent of the infrastructure cost on the utility side of the meter; (2) up to 100 percent of the infrastructure cost on the customer side of the meter, with the ability to provide make-ready incentives of up to 150 percent of the average cost per port on a case-by-case basis; (3) up to 100 percent of the average cost per port for sites in EJ communities, up to $4,000 per Level 2 port, not to exceed actual costs, and 50 percent of the average cost per port for other sites, up to $2,000 per Level 2 port, not to exceed actual costs; and (4) $120 per port per year for four years for networking costs upon request (D.P.U. 21-91, Exh. NG-EVPP-1, at 65-66). For MUDs with 20 or more units, National Grid proposes to provide financial support of up to $6,000 for the cost of an EV ready site plan on the long-term infrastructure and equipment approach to installing at least one Level 2 port per residential unit (D.P.U. 21-91, Exh. NG-EVPP-1, at 66-67).

For the fleet offering, National Grid proposes a budget of $98.23 million, consisting of: (1) $17.81 million for make-ready incentives; (2) $8.47 million for EVSE rebates; (3) $3.25 million for fleet assessment services; (4) $52.5 million for rebates for school buses in EJ communities; (5) $15 million for utility-side system expansion; and (6) $1.2 million for program management (D.P.U. 21-91, Exh. NG-EVPP-1, at 10, 82, 123). The proposed fleet offering would provide financial incentives to all fleet types for: (1) 100 percent of all infrastructure costs; (2) for Level 2 EVSE, 100 percent of the EVSE costs for fleet customers in

EJ communities,[18] up to $4,000 per Level 2 port, and 50 percent of the EVSE costs for all other fleet customers, up to $2,000 per Level 2 port, not to exceed actual costs; and (3) for DCFC EVSE, 100 percent of the EVSE costs for fleet customers in EJ communities, up to $80,000 per port, and 50 percent of the EVSE costs for all other fleet customers, up to $40,000 per port (D.P.U. 21-91, NG-EVPP-1, at 73, 76).[19] National Grid also proposes to: (1) provide fleet assessment services for up to 150 private and non-profit fleet customers;[20] (2) conduct an additional 25 public fleet assessments by 2025 through the company's Phase II EV program; and (3) develop online fleet planning and TCO tools for fleet customers (D.P.U. 21-91, Exh. NG-EVPP-1, at 73-74, 76-77, 80).[21] Additionally, the company proposes to provide approximately 300 rebates to cover the incremental purchase price of electric school buses operating in EJ communities (D.P.U. 21-91, Exh. NG-EVPP-1, at 74, 77-79, 80). National Grid also proposes a utility-side system expansion budget of approximately $15 million for system

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18 For fleets to be eligible for the EJC level of support, the fleet operators must either be registered in or operate more than 50 percent of the time within census block groups that meet any of the Commonwealth's EJC criteria (D.P.U. 21-91, Exh. NG-EVPP-1, at 80-81).

19 The company proposes to target 40 percent of its fleet make-ready funding in EJCs (D.P.U. 21-91, Exh. NG-EVPP-1, at 13, 73, 80).

20 National Grid proposes to target 40 percent of its 150 fleet assessments in EJCs (D.P.U. 21-91, Exh. NG-EVPP-1, at 13, 80).

21 To maintain a consistent customer experience for fleet operators across the state, National Grid and NSTAR Electric propose to collaborate on the development of the online fleet planning and TCO tools for fleet customers and issue a joint RFP to select a single vendor (D.P.U. 21-91, Exh. NG-EVPP-1, at 77).

upgrades to accommodate estimated large-scale fleet loads (D.P.U. 21-91, Exh. NG-EVPP-1, at 83).

c. Expanded Off-Peak Charging Rebate Proposal

National Grid proposes a budget of $3.8 million comprised of: (1) $1.6 million for its off-peak charging rebate program for up to 1,000 medium- and heavy-duty electric vehicles, such as trucks and buses; and (2) $2.2 million to continue the residential off-peak rebate program through 2025 (D.P.U. 21-91, Exh. NG-EVPP-1, at 74, 79, 84-87, 93-94, 123).[22] In addition, the company proposes to offer customers the ability to opt-in to an automated, flexible scheduling EV charging service through a third-party implementation vendor that would allow the vendor to schedule their charging to help maximize their off-peak charging rebates (D.P.U. 21-91, Exh. NG-EVPP-1, at 87-89).

d. Other Supporting Proposals

National Grid proposes a co-located energy storage pilot with a $2.0 million budget (D.P.U. 21-91, Exh. NG-EVPP-1, at 123). National Grid proposes to provide financial support for DCFC and energy storage integrated technologies at up to five project sites where current distribution system capacity may be insufficient to support DCFCs without costly system upgrades (D.P.U. 21-91, Exh. NG-EVPP-1, at 51-52).

National Grid also proposes a budget of: (1) $9.17 million to hire seventeen incremental full-time employees, including ten employees for program management roles and seven for

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22 In D.P.U. 18-150 as part of the company's Phase II EV program, the Department approved National Grid's off-peak charging rebate program, which provides rebates of three or five cents per kWh for EV charging during off-peak hours (i.e., between 9:00 pm and 1:00 pm) (D.P.U. 21-90, Exh. NG-EVPP-1, at 85).

dedicated support roles due to the expansion of the previous EV programs; (2) $5.6 million for a marketing and outreach plan to increase awareness of and participation in the proposed EV offerings through a variety of channels; (3) $1.78 million for information technology and back-office system upgrades, including the development of a web portal to accept and manage customer applications; and (4) $1.51 million for its share of the joint workforce development and electrician training proposal described in Section III.A.1.d, above (D.P.U. 21-91, Exhs. NG-EVPP-1, at 97-98, 112-117, 119-123; NG-EVPP-4).

In addition, National Grid proposes to have the flexibility to move up to 20 percent of program funds from one program segment to another or within each segment without prior Department approval (D.P.U. 21-91, Exh. NG-EVPP-1, at 118). The company also proposes to have the flexibility to adjust components within the programs, including incentives and rebate levels, customer eligibility requirements, and the distribution of port types (D.P.U. 21-91, Exh. NG-EVPP-1, at 118). Further, National Grid proposes to have the flexibility to initiate a mid-term review at the end of the second year of the Phase III EV program during which the company could propose substantial modifications to the EV program (D.P.U. 21-91, Exh. NG-EVPP-1, at 118).

National Grid also requests a waiver of the transformer surcharge associated with the company's general service rate for small C&I customers, Rate G-1, because the company's proposed public and workplace program would provide rebates for the costs the transformer

surcharge was designed to recover (D.P.U. 21-91, Exh. NG-EVPP-1, at 95).[23] The company also proposes certain revisions to its approved General Service – Small C&I G-1 tariff (M.D.P.U. No. 1471 (proposed)).

3. Unitil

a. Overview

Unitil proposes a five-year EV program with an associated budget of approximately $1.02 million (D.P.U 21-92, Exh. CSVG-1 (Rev.) at 32-33, 40, 56). Unitil's proposed EV program consists of: (1) a make-ready and EVSE incentive proposal; and (2) other supporting proposals, including a marketing, communications, and education plan and a joint workforce development and electrician training proposal (D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 5).

b. Make-Ready and EVSE Incentive Proposal

Unitil's make-ready and EVSE incentive proposal includes two components: (1) a public EV infrastructure offering, and (2) a residential offering (D.P.U 21-92, Exh. CSVG-1 (Rev.) at 32). For the public EV infrastructure offering, Unitil proposes a budget of approximately $538,000 to cover all infrastructure costs for five Level 2 sites and one DCFC site (D.P.U 21-92, Exh. CSVG-1 (Rev.) at 36, 38). Customers participating in the company's public EV infrastructure offering would be required to provide a minimum of two of their own EVSEs with non-proprietary charging plugs and networked functionality (D.P.U 21-92, Exh. CSVG-1 (Rev.)

[23] The transformer surcharge recovers the capital expense associated with the installation of a larger transformer than is typically needed for a small C&I customer (D.P.U. 21-91, Exh. NG-EVPP-1, at 95).

at 36-38). All customers enrolled in the company's public EV infrastructure offering would be eligible to enroll in the company's DCA program (D.P.U 21-92, Exh. CSVG-1 (Rev.) at 42).

Regarding the residential offering, Unitil proposes a budget of $300,000 (D.P.U 21-92, Exh. CSVG-1 (Rev.) at 32-33). For customers in one to four-unit properties, Unitil proposes to provide rebates of up to: (1) $700 for the installation of Level 2 chargers; (2) an additional $300 rebate for the procurement of smart, managed Level 2 chargers; and (3) for low-income customers, 100 percent of the installation and procurement costs for smart, managed Level 2 EVSE chargers, up to $1,700 (D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 32). The company also proposes to require these customers to enroll in the company's residential EV TOU rate (D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 32).[24]

c. Other Supporting Proposals

Unitil's EV program proposal also includes: (1) a budget of approximately $160,000 for an EV and TOU marketing, communications, and education plan to increase consumer awareness, interest in and adoption of EVs, EV charging infrastructure, and EV/TOU rates, and (2) $23,000 for Unitil's share of the joint workforce development and electrician training proposal described in Section III.A.1.d, above (D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 43-50, 52-54, 56).

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[24] Unitil states that it intends to assess EVSE alternative metering capabilities via data collected through its residential EV program (D.P.U 21-92, Exh. CSVG-1 (Rev.) at 33-35). Further, the company states that it will submit an annual report to the Department outlining the number of residential customer participants in the program, incentives distributed, third-party partners within the program, and periodic findings related to embedded EVSE meters and future use cases (D.P.U 21-92, Exh. CSVG-1 (Rev.) at 35).

B. Positions of the Parties

1. Introduction

Intervenors generally support the Companies' EV charging infrastructure proposals (see e.g., D.P.U. 21-90, Attorney General Track 1 Brief at 8; D.P.U. 21-91, Attorney General Track 1 Brief at 11; D.P.U. 21-92, Attorney General Track 1 Reply Brief at 1; D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 5, 16, 19; D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, CLF Track 1 Brief at 4, 35-36; D.P.U. 21-90, CEP Track 1 Brief at 1, 11-16; D.P.U. 21-92, ChargePoint Track 1 Brief at 1; D.P.U. 21-90/D.P.U. 21-91, EVgo Track 1 Brief at 1-2; D.P.U. 21-91, Electrify America Track 1 Brief at 4-5; D.P.U. 21-90/D.P.U. 21-91, GECA Track 1 Brief at 3-4, 16; D.P.U. 21-90/D.P.U. 21-91, FreeWire Track 1 Reply Brief at 3; D.P.U. 21-90/D.P.U. 21-91, Shell Track 1 Brief at 1-2, 8-13, 16-22; D.P.U. 21-90, Compact Track 1 Brief at 1-2). Nevertheless, many intervenors recommend modifications to the Companies' proposals, as summarized below.

2. Make-Ready and EVSE Incentive Proposal

a. General Issues

i. Program Funding Prioritization

(A) Attorney General

The Attorney General urges the Department to reprioritize the Companies' proposed make-ready and EVSE incentive offerings in order to maximize public benefits and to target spending towards segments with the most barriers to transportation electrification and those least likely to be served by the competitive market (D.P.U. 21-90, Attorney General Track 1 Brief at 11-12; D.P.U. 21-91, Attorney General Track 1 Brief at 13-14). Specifically, the Attorney

General recommends that the Department direct the Companies to adopt the following general prioritization framework: (1) the highest level of funding is targeted at load management and EV energy management systems ("EMS"),[25] low-income and income-qualified customers in EJ communities, and mass transit fleet electrification; (2) a high level of funding is focused on publicly accessible public charging; (3) a medium level of funding is targeted at publicly accessible workplace and multi-unit dwellings, restricted access public charging, one to four-unit income-qualified residential customers, state and local government fleets, and small business fleets operating in EJ communities; (4) a low level of funding is focused on restricted access workplaces and multi-unit dwellings; and (5) the lowest level of funding is targeted at private fleets and proprietary networks (D.P.U. 21-90, Attorney General Track 1 Brief at 11-12; D.P.U. 21-91, Attorney General Track 1 Brief at 13-14).

The Attorney General maintains that her proposed prioritization recommendations takes into account the following factors: (1) the broad public benefits, irrespective of individual program participation, from load management and EV EMS programs; (2) the availability of state and federal funding in addition to private investment for transportation electrification efforts and the need for financial incentives for higher-income individuals and large private fleets, given that transportation electrification is becoming an increasingly cost-effective and beneficial option; and (3) the widespread benefits from targeting underserved market segments and those with the most barriers to EV adoption (D.P.U. 21-90, Attorney General Track 1 Brief at 8-9, 12-14, 27; D.P.U. 21-91, Attorney General Track 1 Brief at 11-12, 15-17;

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[25] EV EMS is a means of controlling on-site EV loads to minimize infrastructure costs (D.P.U. 21-90, Exh. ES-KB-1, at 61; D.P.U. 21-91, Exh. NG-EVPP-1, at 67).

D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 4-5; D.P.U. 21-92, Attorney General Track 1 Brief at 8-12). The Attorney General also contends that her proposed prioritization framework provides a meaningful level of protection for low-income ratepayers that is absent from the Companies' proposals (D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 6-7; D.P.U. 21-92, Attorney General Track 1 Reply Brief at 4). In addition to her general prioritization framework, the Attorney General also proposes specific prioritization recommendations for each component of the Companies' make-ready and EVSE incentive proposals. For the public and workplace program proposals, the Attorney General recommends the following prioritization framework: (1) the highest level of incentives to publicly accessible EV charging sites located in EJ communities; (2) a high level of incentives to publicly accessible EV charging sites located in non-EJ communities; (3) a high level of incentives to restricted access EV charging sites in EJ communities; and (4) a medium level of incentives to restricted access EV charging sites in non-EJ communities (D.P.U. 21-90, Attorney General Track 1 Brief at 35; D.P.U. 21-91, Attorney General Track 1 Brief at 38; D.P.U. 21-92, Attorney General Track 1 Brief at 26).

For the purposes of prioritizing EV charging infrastructure at publicly accessible locations, the Attorney General urges the Department to adopt the New York Public Utilities Commission's ("NY PUC") definition of "publicly accessible" EV charging stations[26] because it

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[26] The NY PUC defines "publicly accessible" EV charging stations as those that are accessible to the public without an access fee or restricted access, except for paid municipal parking. New York Public Service Commission, Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs, No. 18-E-0138, at 41-42 (2020).

would: (1) maximize the public interest by prioritizing the most widely available and accessible parking locations for utility-funded rebates; (2) incentivize program participants to make their parking facilities free to the public for charging; and (3) eliminate unnecessary and redundant financial incentives to private program participants (D.P.U. 21-90, Attorney General Track 1 Brief at 28-29; D.P.U. 21-91, Attorney General Track 1 Brief at 32-33; D.P.U. 21-92, Attorney General Track 1 Brief at 20). While the Attorney General recommends an increased level of incentive funding for program participants that meet the NY PUC's definition of publicly accessible, she does not advocate entirely eliminating financial incentives to program participants that do not meet this definition (D.P.U. 21-90, Attorney General Track 1 Brief at 29; D.P.U. 21-91, Attorney General Track 1 Brief at 32; D.P.U. 21-92, Attorney General Track 1 Brief at 21).

The Attorney General opposes adoption of the definition of "public electric vehicle charging station" contained in G. L. c. 25A, § 16 as recommended by ChargePoint because: (1) the statute was neither debated nor designed with ratepayer-funded utility incentives, or the equitable distribution thereof, in mind; (2) the definition includes all private site hosts, irrespective of access fees; and (3) the definition's "temporal flexibility" could allow private parties to collect ratepayer-funded subsidies without making their facilities publicly available (D.P.U. 21-90, Attorney General Track 1 Brief at 31-32; D.P.U. 21-91, Attorney General Track 1 Brief at 33-34; D.P.U. 21-92, Attorney General Track 1 Brief at 21-23). The Attorney General, therefore, requests that the Department adopt a definition of publicly accessible that limits the extent to which private program participants can take advantage of ratepayer subsidies while also restricting access to their facilities with either exorbitant parking rates, temporal restrictions, or

both (D.P.U. 21-90, Attorney General Track 1 Brief at 32; D.P.U. 21-91, Attorney General Track 1 Brief at 34; D.P.U. 21-92, Attorney General Track 1 Brief at 23).

Finally, to ensure success in prioritization of investments in EJ communities, the Attorney General argues that the Companies should be required to incorporate community and stakeholder input and to prioritize EVSE deployment in locations that have stakeholder and community support to avoid unintended consequences related to EV charger siting and to ensure that the EV chargers provide the intended benefits and meet the particular needs of that community (D.P.U. 21-90, Attorney General Track 1 Brief at 26; D.P.U. 21-91, Attorney General Track 1 Brief at 30; D.P.U. 21-92, Attorney General Track 1 Brief at 18).

Turning to the residential offerings, the Attorney General recommends the following prioritization framework for the residential offerings: (1) a medium to high level of incentives for low-income customers in one to four-unit households (i.e., four-person household income of up to $105,001 annually); (2) a medium level of incentives for moderate-income customers in one to four-unit households (i.e., four-person household income up to $157,502 annually); (3) no incentives to non-income qualified customers in one to four-unit households; (3) a medium to high level of incentives for publicly accessible MUDs, MUDs located in EJ communities, or MUDS that are an affordable housing facility or have at least 50 percent of households that are low- or moderate-income households; (4) a medium level of incentives to publicly accessible MUDs in non-EJ communities; (5) a low level of incentives for restricted access MUDs in EJ communities; and (6) a low level of incentives for restricted access MUDs in non-EJ communities (D.P.U. 21-90, Attorney General Track 1 Brief at 42; D.P.U. 21-91, Attorney General Track 1 Brief at 48; D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief

at 10; D.P.U. 21-92, Attorney General Track 1 Brief at 30; D.P.U. 21-92, Attorney General Track 1 Reply Brief at 8-9). According to the Attorney General, this prioritization framework would maximize the public interest and effectively target spending toward customers that are least likely to be served by the competitive market and with the most barriers to EV adoption (D.P.U. 21-90, Attorney General Track 1 Brief at 34, 41; D.P.U. 21-91, Attorney General Track 1 Brief at 37; D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 11-12; D.P.U. 21-92, Attorney General Track 1 Brief at 19; D.P.U. 21-92, Attorney General Track 1 Reply Brief at 2, 6-8). Even if the Department does not adopt her recommended residential prioritization framework, the Attorney General recommends, at a minimum, that the Department direct the Companies to limit program funding to customers who own or lease a new or used EV with a purchase price of less than $50,000 (D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 12; D.P.U. 21-92, Attorney General Track 1 Reply Brief at 9).

Finally, for NSTAR Electric's and National Grid's fleet proposals, the Attorney General recommends the following prioritization framework: (1) a high level of incentives for mass transit; (2) a medium level of incentives for state and local government-owned fleets; (3) a medium level of incentives for small fleets operating in EJ communities;[27] and (4) no incentives for private fleets in non-EJ communities (D.P.U. 21-90, Attorney General Track 1 Brief at 47; D.P.U. 21-91, Attorney General Track 1 Brief at 52; D.P.U. 21-90/D.P.U. 21-91, Attorney

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[27] To define small fleets, the Attorney General recommends using the definition in the energy efficiency programs, which defines small and micro businesses as businesses with account consumption of less than 1.5 gigawatt-hours (D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 13, citing Three Year Energy Efficiency Plans, D.P.U. 21-120 through D.P.U. 21-129, Exhibit DPU-Comm 2-8, Att. (c) at 15 (2021)).

General Track 1 Reply Brief at 12-13). Moreover, the Attorney General argues that the Department should deny NSTAR Electric's and National Grid's proposed fleet assessment services offering because: (1) they offer nothing unique from fleet assessment services offered by public and private vendors, and (2) they could interfere with the competitive market (D.P.U. 21-90, Attorney General Track 1 Brief at 46; D.P.U. 21-91, Attorney General Track 1 Brief at 51).

(B) Other Intervenors

Several intervenors object, in whole or in part, to the Attorney General's prioritization framework. CLF opposes the Attorney General's recommendation to prioritize funding for publicly accessible MUD sites because: (1) MUD parking lots are likely to be used almost exclusively by residents and their visitors; and (2) MUDs are often located in EJ communities (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 1 Reply Brief at 7-8). CLF also urges the Department to reject the Attorney General's recommendation to restrict incentives for one to four-unit residential sites to low- and moderate-income customers because limiting the residential rebates to only a small subset of customers would unnecessarily delay the Commonwealth's achievement of its transportation electrification goals (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 1 Reply Brief at 8). CLF, however, urges the Department to approve the proposed size and scale of the Companies' EV charging infrastructure programs because a reduction to the proposed program budgets could prevent the Commonwealth from achieving its greenhouse gas ("GHG") emissions reduction mandates and interim transportation electrification goals in Chapter 8 of the Acts of 2021, An Act Creating a Next Generation Roadmap for Massachusetts Climate Policy ("2021 Climate Act")

(D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 1 Brief at 4-5, 31, 35, 36; D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, CLF Track 1 Reply Brief at 2-4).

ChargePoint maintains that the Attorney General's proposed prioritization framework: (1) diminishes the importance of certain program segments in abating transportation emissions and would deprive low-income ratepayers of the benefits from broad EV adoption under the Companies' EV program proposals; (2) limits participation to a narrow subset of customers and reduces the number of customers that would modify EV charging behavior and participate in the Companies' managed charging programs; and (3) restricts access to the benefits of the EV charging infrastructure programs, which should be allocated to all sectors and customer classes that contribute to EV program funding (D.P.U. 21-90, ChargePoint Track 1 Brief at 1, 8-10; D.P.U. 21-90, ChargePoint Track 1 Reply Brief at 3-4; D.P.U. 21-91, ChargePoint Track 1 Brief at 1, 15-17; D.P.U. 21-91, ChargePoint Track 1 Reply Brief at 3-4; D.P.U. 21-92, ChargePoint Track 1 Brief at 1, 11-12; D.P.U. 21-92, ChargePoint Track 1 Reply Brief at 3). Further, Electrify America argues that the Attorney General's recommended prioritization matrix: (1) introduces complexity into the EV programs; (2) is unworkable and internally contradictory; (3) underestimates the dynamism of the competitive market and its responsiveness to financial incentives (D.P.U. 21-90, Electrify America Track 1 Brief at 5-8, 12; D.P.U. 21-91, Electrify America Track 1 Brief at 5-9, 15; D.P.U. 21-90/D.P.U. 21-91, Electrify America Track 1 Reply Brief at 5-6, 9).

Additionally, GECA and CEP argue that access to residential EV charging is critical to EV adoption (D.P.U. 21-90/D.P.U. 21-91, GECA Track 1 Brief at 3-4, 7-9; D.P.U. 21-90, CEP Track 1 Brief at 2, 16-18; D.P.U. 21-91, CEP Track 1 Brief at 2, 18-19). CEP therefore requests

that the Department approve the size and scale of the Companies' proposed residential make-ready programs (D.P.U. 21-90, CEP Track 1 Brief at 2, 16-18; D.P.U. 21-91, CEP Track 1 Brief at 2, 18-19). Further, GECA contends that limiting residential customer participation to low- and moderate-income customers would exclude many households from participating in the EV programs while targeting customers that are less likely to participate in the programs due to EV ownership costs and diminishing the effectiveness of the Companies' proposal to require customers to enroll in a load management program (D.P.U. 21-90/D.P.U. 21-91, GECA Track 1 Brief at 3-4, 7-9). ChargePoint, however, supports modified incentive levels based on income for residential participants, but with a minimum 50 percent rebate for qualified EVSE, to ensure customers purchase smart EVSE solutions and enroll in the Companies' managed charging programs (D.P.U. 21-92, ChargePoint Track 1 Brief at 12). Finally, FreeWire asks the Department to reject the Attorney General's recommended prioritization framework with respect to DCFCs because it would likely reduce the number of DCFC ports installed through the EV programs (D.P.U. 21-90, FreeWire Track 1 Brief at 7-8; D.P.U. 21-91, FreeWire Track 1 Brief at 7-8).

Turning to the fleet segment, DOER recommends that the Department approve NSTAR Electric's and National Grid's proposed fleet assessment services proposals and direct them to coordinate with MassCEC on program implementation (D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, DOER Track 1 Brief at 24-25). EVgo urges the Department to reject the Attorney General's prioritization framework with respect to make-ready incentives for private fleets because commercial vehicles contribute significantly to GHG emissions and, therefore, their enrollment in the EV programs is necessary to achieve the Commonwealth's climate goals

(D.P.U. 21-90/D.P.U. 21-91, EVgo Track 1 Brief at 10, 12; D.P.U. 21-90/D.P.U. 21-91, EVgo Track 1 Reply Brief at 6-7, 8). Additionally, CLF recommends that the Department direct National Grid to dedicate at least 50 percent of its proposed fleet offering budget to supporting public transit fleets that operate primarily in EJ communities because residents of EJ communities are less likely to own their vehicles and, therefore, rely more on public transit than other communities (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 1 Brief at 18-19, 36).

Several intervenors take issue with the Attorney General's recommended definition of publicly accessible and prioritizing publicly accessible sites. GECA opposes the Attorney General's recommendation to distinguish incentives between publicly accessible and non-publicly accessible EV chargers in the residential and workplace segments because doing so would create confusion, limit program participation, and limit the flexibility of site hosts that wish to provide EV charging for customers, employees, or residents (D.P.U. 21-90/D.P.U. 21-91, GECA Track 1 Brief at 14). ChargePoint, EVgo, and Electrify America assert that the Attorney General's proposed definition of publicly accessible parking contradicts the statutory definition of "public electric vehicle charging station" in G. L. c. 25A, § 16 (D.P.U. 21-90, ChargePoint Track 1 Brief at 1, 10-11; D.P.U. 21-90, ChargePoint Track 1 Reply Brief at 2-3; D.P.U. 21-91, ChargePoint Track 1 Brief at 1, 17-19; D.P.U. 21-92, ChargePoint Track 1 Brief at 1, 13-14; D.P.U. 21-91, ChargePoint Track 1 Reply Brief at 2-3; D.P.U. 21-92, ChargePoint Track 1 Reply Brief at 2; D.P.U. 21-90/D.P.U. 21-91, EVgo Track 1 Brief at 11-12, 13; D.P.U. 21-90/ D.P.U. 21-91, EVgo Track 1 Reply Brief at 7-8; D.P.U. 21-90, Electrify America Track 1 Brief at 5-8, 12; D.P.U. 21-91, Electrify America Track 1 Brief at 5-9, 15; D.P.U. 21-90/D.P.U. 21-91, Electrify America Track 1 Reply Brief at 5-6, 9).

Further, ChargePoint contends that the Attorney General's recommended definition of publicly accessible: (1) eliminates all privately-owned public parking from EV program eligibility and is too restrictive; (2) adds unnecessary complexity into the programs that could confuse customers about incentive level eligibility; and (3) would eliminate program participants' flexibility to offer public access to charging during various times of the day (D.P.U. 21-90, ChargePoint Track 1 Brief at 1, 10-11; D.P.U. 21-90, ChargePoint Track 1 Reply Brief at 2-3; D.P.U. 21-91, ChargePoint Track 1 Brief at 1, 17-19; D.P.U. 21-92, ChargePoint Track 1 Brief at 1, 13-14; D.P.U. 21-91, ChargePoint Track 1 Reply Brief at 2-3; D.P.U. 21-92, ChargePoint Track 1 Reply Brief at 2). ChargePoint recommends that the Department adopt a more neutral definition of publicly accessible parking that would allow for more nuanced and efficient utilization of EV chargers (D.P.U. 21-90, ChargePoint Track 1 Brief at 12; D.P.U. 21-91, ChargePoint Track 1 Brief at 1, 19; D.P.U. 21-92, ChargePoint Track 1 Brief at 14).

(C) NSTAR Electric and National Grid

NSTAR Electric and National Grid argue that the Attorney General's recommended prioritization framework should be rejected because: (1) the recommendations are arbitrary and impede the companies' ability to assist the Commonwealth in reaching its transportation electrification goals; (2) make-ready incentives and EVSE rebates are necessary to incentivize the development of EV chargers and overcome existing EV market barriers; (3) the Attorney General did not offer specific alternative program targets to those proposed by the companies; (4) the companies require flexibility to implement their programs to reach new market segments that continue to face barriers to EV charging station deployment based on lessons learned

through their respective Phase I EV programs; (5) the Attorney General's prioritization framework is incomplete and, in some categories, inconsistent in its treatment of similar investments; and (6) the distinction between publicly accessible and non-publicly accessible workplaces and MUDs is confusing and would be difficult to administer (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 20-23, 36-38; D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Reply Brief at 8, 10-12).

NSTAR Electric and National Grid also urge the Department to reject the Attorney General's recommended definition of publicly accessible because: (1) it contradicts the statutory definition in G. L. c. 25A, § 16; (2) it excludes sites that are open to the public but charge a fee for parking; and (3) the Attorney General failed to make a compelling argument for departing from the statutory definition of publicly accessible in G. L. c. 25A, § 16 (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 23-26, 37). NSTAR Electric and National Grid, therefore, request that the Department reject the Attorney General's recommended definition of publicly accessible (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 26).

In response to the Attorney General's residential offering prioritization framework, NSTAR Electric and National Grid urge the Department to reject the Attorney General's recommendation to limit participation in the residential program to low- and middle-income customers and reduce incentives for MUDs that are not publicly accessible, located in EJ communities, or in an affordable housing facility or are comprised of at least 50 percent low- or moderate-income residents because it would: (1) add a layer of complexity into the programs;

(2) limit the effectiveness of the programs by excluding a significant portion of the customers in the companies' service territories; (3) slow the adoption of EVs in the Commonwealth because customers are highly influenced by the availability of incentives, and the availability of at-home charging is critical to EV adoption; (4) the companies' proposals are sized to serve only 15 percent of one to four-unit residences in their respective service territories; (5) MUD charging stations mainly serve their residents and their guests; (6) MUDs are often located in EJ communities and serve low-income customers; (7) the Attorney General did not provide analyses to support its recommended rebate and incentive levels or produce evidence to suggest that her recommendations are more cost effective; and (8) the Attorney General's description of program-eligible MUDs is vague and its recommended tiered incentive levels for MUDs is vague and unworkable (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 44-47; D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Reply Brief at 9-10). For these reasons, NSTAR Electric and National Grid request that the Department approve the residential programs as proposed (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 47-48).

NSTAR Electric and National Grid also oppose the Attorney General's recommendation to exclude all private fleets except small private fleets operating in EJ communities from participation in the companies' fleet programs (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 51). NSTAR Electric and National Grid contend that private fleets should be eligible to participate in the companies' fleet programs because: (1) private fleets represent the vast majority of fleets operating in the Commonwealth and emit the most GHGs; (2) the electrification of more fleets benefits all residents of the Commonwealth;

(3) excluding private fleets from eligibility in the program will hamper the Commonwealth's ability to achieve its climate goals; (4) only thirteen percent of the Commonwealth's commercial vehicles are registered to government fleets; and (5) focusing the program primarily on mass transit unfairly excludes rural communities without significant mass transit options that rely on smaller fleets for transportation (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 51-52). NSTAR Electric and National Grid, therefore, urge the Department to reject the Attorney General's recommendation to exclude private fleets from participation in the companies' fleet programs (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 54).

NSTAR Electric and National Grid also encourage the Department to reject the Attorney General's recommendation to deny the fleet assessment services offerings because: (1) the companies are uniquely positioned to perform fleet assessment services because of their experience with distribution and transmission planning; (2) the companies can better plan for their own transmission and distribution upgrades if they are able to gain information and insight on the electrification of private fleets in their respective service territories; (3) the companies have a preexisting relationship with these customers and can assist them throughout the process of transitioning to an electric fleet; and (4) the companies' fleet assessment services offerings will simplify information gathering for all fleet operators, standardize the methodology for the companies' internal tracking, design, and planning, and accelerate the deployment of EV charging infrastructure projects (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 53-54). For these reasons, NSTAR Electric and National Grid request that the Department reject the Attorney General's recommendation to deny the fleet assessment

services offerings (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 54).

(D) Unitil

Unitil contends that its EV program should be approved as proposed because: (1) current EV charging infrastructure investment is not on pace to achieve the Commonwealth's environmental mandates or transportation electrification goals; (2) the Attorney General's position is based on data that provides no useful or relevant evidence about the EV market in the company's service territory; (3) Unitil's EVI-Pro Lite tool assumptions are reasonable because, for planning purposes, EV owners will seek to maximize their electric usage and minimize their gasoline usage if there is sufficient EV charging infrastructure in place; (4) in the absence of a territory-specific vehicle-type forecast, it was reasonable for the company to use the default values in the EVI-Pro Lite model; (5) the size of the proposed EV program is modest relative to the projected need in the company's service territory; and (6) the Attorney General's assertion that the EV program will primarily benefit wealthy homeowners to the detriment of low-income ratepayers is unsubstantiated (D.P.U. 21-92, Unitil Track 1 Brief at 23-30; D.P.U. 21-92, Unitil Track 1 Reply Brief at 6-8).

Unitil also argues that the Department should reject the Attorney General's recommendation to differentiate incentive levels by location because: (1) the Attorney General did not provide analyses to support the assertion that differentiation of incentive levels by location will produce more equitable outcomes, a more efficient or cost-effective program, or generate greater customer benefits, and (2) the Attorney General's recommendation would

increase the complexity of the program, confuse customers, and may increase the cost to administer the program (D.P.U. 21-92, Unitil Track 1 Brief at 36).

Turning to the Attorney General's recommended definition of publicly accessible, Unitil contends that the Attorney General's proposed definition should be rejected because the definition of "publicly available parking space" in G.L. c. 25A, § 16, appears in the same section as the codification of the standard of review applicable in these proceedings and is controlling in these proceedings, whereas the Attorney General's proposed definition of publicly accessible would unduly restrict eligibility for participation in the company's EV program and render the EV program unnecessarily complex and confusing (D.P.U. 21-92, Unitil Track 1 Brief at 37-38).

Unitil also urges the Department to reject the Attorney General's recommendation to limit participation in the residential program to low-income and moderate-income customers because: (1) Unitil already prioritizes income-eligible customers by offering them larger rebates; (2) the Department directed the company in D.P.U. 20-69-A to consider appropriate measures to decrease barriers to EV adoption in all communities across its service territory; (3) market data indicates that 80 percent of EV charging will occur at home; (4) limiting the residential program to only low- and moderate-income customers would impede the Commonwealth's ability to achieve its climate and transportation electrification goals; (5) EV adoption benefits all customers regardless of location because EVs produce cleaner air; (6) the residential program as proposed will encourage customers to install charging equipment that can be actively managed, which benefits all customers; and (7) requiring income-verification would increase the administrative costs of the program (D.P.U. 21-92, Unitil Track 1 Brief at 39-41; D.P.U. 21-92, Unitil Track 1 Reply Brief at 8-10). For these reasons, Unitil requests that the Department reject

the Attorney General's recommendation to limit participation in the residential program to only low- and moderate-income customers (D.P.U. 21-92, Unitil Track 1 Brief at 41; D.P.U. 21-92, Unitil Track 1 Reply Brief at 10).

Unitil also requests that the Department reject the Attorney General's recommendation to limit residential incentives to customers with vehicles with a purchase price of less than $50,000 because: (1) the Attorney General did not provide sufficient justification for this requirement; (2) the additional eligibility requirement would likely increase the administrative costs and complexity of the residential program with no corresponding benefit; and (3) the eligibility requirement would likely delay program implementation and deter customer participation in the residential program (D.P.U. 21-92, Unitil Track 1 Brief at 42, 46-47).

ii. Program Term

(A) Attorney General

The Attorney General asserts that a three-year program term is a more appropriate term for the EV programs and that the budgets should be reduced accordingly because: (1) the EV industry has experienced tremendous growth that is likely to continue in the near term; (2) technology continues to change, improve, and provide new flexibility for how EVs are charged and batteries utilized; and (3) state and federal funding is becoming increasingly available to support EV adoption (D.P.U. 21-90, Attorney General Track 1 Brief at 25; D.P.U. 21-91, Attorney General Track 1 Brief at 28-29; D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 15; D.P.U. 21-92, Attorney General Track 1 Brief at 17). At the conclusion of the three-year program term, the Attorney General argues that the Companies could propose additional program offerings that are tailored to the changes that occurred in the

EV market over the previous three years (D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 15; D.P.U. 21-92, Attorney General Track 1 Brief at 17-18). Further, the Attorney General contends that a three-year program term is preferable to a longer program term with annual reporting and a mid-term review (D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 15).

(B) Other Intervenors

DOER requests that the Department reject the Attorney General's recommendation to limit the EV programs to three-year terms (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 14-15). Instead, DOER recommends that the Department direct the Companies to include recommendations for the fourth year in the annual report at the end of the third year of the EV programs, including recommendations for future EV program development or a reduction in the current EV program incentive levels if competitive market conditions have substantially improved (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 15-16). Shell recommends that the Department leverage the proposed mid-term review to consider potential modifications to or expansion of the companies' EV programs (D.P.U. 21-90/D.P.U. 21-91, Shell Track 1 Brief at 22).

(C) NSTAR Electric and National Grid

NSTAR Electric and National Grid argue that the Attorney General's recommendation to eliminate the fourth year of the EV programs should be rejected because: (1) the companies based the duration of their EV programs on reasonable assumptions and forecasts of the number of EV charging stations needed in each market segment to support the Commonwealth's decarbonization goals while the Attorney General did not analyze the impacts of its

recommendations on the Commonwealth's ability to meet its decarbonization goals; (2) the GHG emissions reduction benefits of EV adoption is shared by all residents; (3) the companies' EV programs are designed to prioritize EV charging where it is needed the most to address barriers to EV adoption; (4) it is unlikely that the need for EV charging incentives will materially diminish over the four-year terms of the EV programs; (5) removing the fourth year of the EV programs would introduce a significant gap between available funding and the Commonwealth's 2025 decarbonization goals, which the private market is unlikely to fill without utility funding; (6) a four-year program term provides longer-term certainty for industry partners, vendors, and customers as they plan EV charging investments and purchasing decisions; (7) a three-year program term would limit the companies' ability to make meaningful mid-term modifications to the EV programs after the first two years of the programs; and (8) the Attorney General has not presented evidence demonstrating that the fourth year of the EV programs will be unnecessary (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 16-19; D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Reply Brief at 8).

(D) Unitil

Unitil contends that the Department should reject the Attorney General's recommendation to reduce the EV program term from five years to three years because: (1) it is arbitrary and not supported by any evidence or analysis; (2) an arbitrary cap on the EV program term will significantly impede the company's ability to make a meaningful contribution to stimulating EV adoption in its service territory; and (3) a five-year program would provide a more significant commitment to entice potential customers, vendors, and other industry stakeholders to participate in the EV program (D.P.U. 21-92, Unitil Track 1 Brief at 31-32).

iii. Budget Flexibility

(A) Attorney General

The Attorney General asserts that the Department should prohibit NSTAR Electric and National Grid from shifting EV program budgets within and between program segments, altering customer eligibility criteria, or modifying rebate incentive levels and port target distributions without Department oversight or opportunity for stakeholder review because: (1) NSTAR Electric and National Grid could provide additional EV program funding to one program or segment at the expense of another, which could disproportionately benefit high-income customers, and (2) any changes to customer eligibility criteria, rebate incentive levels, or port target distributions could have significant consequences for the EV programs (D.P.U. 21-90, Attorney General Track 1 Brief at 20-23; D.P.U. 21-91, Attorney General Track 1 Brief at 22-26).

(B) Other Intervenors

DOER recommends that the Department allow NSTAR Electric and National Grid to propose budget shifting between market segments in their annual reports to the Department with appropriate demonstration of program utilization, changing market trends, or other customer preferences (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 8).

(C) NSTAR Electric and National Grid

NSTAR Electric and National Grid oppose the Attorney General's recommendation to reject the companies' program management proposal because the nascent and evolving EV market requires flexibility to respond to the market and customers' needs and the flexibility requested is limited to shifting no more than 20 percent of the proposed budget between program

segments (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 76). Further, the companies argue that their commitment to low-income customers and customers in EJ communities will not change as a result of the requested budget flexibility but that the flexibility will ensure that the companies can prioritize EJ community investments as the market demands and where the benefits are maximized for communities and EJ community residents (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 76).

iv. Eligibility Requirements

(A) Attorney General

The Attorney General recommends that the Companies: (1) require all applicants to apply for MassEVIP funding and any other applicable state or federal funding, and to certify that they did so as a prerequisite to participation in the Companies' EV programs; (2) reduce the rebate and incentive level received through the EV programs by the amount received from external funding sources; (3) ensure that all incentives received by the program participant do not exceed the program participants' actual infrastructure and EVSE costs; and (4) coordinate with state agencies to monitor available external funding sources and track program participant usage of such funding (D.P.U. 21-90, Attorney General Track 1 Brief at 24; D.P.U. 21-91, Attorney General Track 1 Brief at 27; D.P.U. 21-92, Attorney General Track 1 Brief at 16). The Attorney General also recommends that the Department deny cost recovery for EV program rebates or incentives paid to program participants that fail to apply for available external funding prior to applying for funding through the EV programs (D.P.U. 21-90, Attorney General Track 1 Brief at 24; D.P.U. 21-91, Attorney General Track 1 Brief at 27).

(B) Other Intervenors

Several intervenors oppose the Attorney General's recommendation to require EV program applicants to certify that they applied for MassEVIP or other applicable funding prior to applying for funding through the EV programs (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 13; D.P.U. 21-90, ChargePoint Track 1 Reply Brief at 4; D.P.U. 21-91, ChargePoint Track 1 Reply Brief at 4; D.P.U. 21-92, ChargePoint Track 1 Reply Brief at 3-4; D.P.U. 21-90, Electrify America Track 1 Brief at 10, 12; D.P.U. 21-91, Electrify America Track 1 Brief at 12, 14; D.P.U. 21-90/D.P.U. 21-91, Electrify America Track 1 Reply Brief at 8, 9). These intervenors argue that the Attorney General's recommendation would add to the administrative burden of the Companies' EV programs and disincentivize EV adoption, is overly prescriptive and could delay or eliminate viable projects, may deter potential applicants from enrolling in the EV programs due to a delay in the receipt of external program funding, or would create uncertainty regarding the available program incentives (D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, DOER Track 1 Brief at 13; D.P.U. 21-90, ChargePoint Track 1 Reply Brief at 4; D.P.U. 21-91, ChargePoint Track 1 Reply Brief at 4; D.P.U. 21-92, ChargePoint Track 1 Reply Brief at 3-4; D.P.U. 21-90/D.P.U. 21-91, EVgo Track 1 Brief at 4-5, 12; D.P.U. 21-90/ D.P.U. 21-91, EVgo Track 1 Reply Brief at 1-4, 8; D.P.U. 21-90, Electrify America Track 1 Brief at 10, 12; D.P.U. 21-91, Electrify America Track 1 Brief at 12, 14; D.P.U. 21-90/ D.P.U. 21-91, Electrify America Track 1 Reply Brief at 8, 9). Electrify America argues that EV program applicants should be given the choice to apply for either all available financial incentives or only financial incentives for utility-side work, customer-side work, or EVSE

(D.P.U. 21-90, Electrify America Track 1 Brief at 10, 12; D.P.U. 21-91, Electrify America Track 1 Brief at 11, 14).

Additionally, to maximize administrative efficiency, ChargePoint argues that the EV programs should operate independently from other incentive programs (D.P.U. 21-90, ChargePoint Track 1 Reply Brief at 4; D.P.U. 21-91, ChargePoint Track 1 Reply Brief at 4; D.P.U. 21-92, ChargePoint Track 1 Reply Brief at 4). Further, ChargePoint disagrees with the Attorney General's recommendation that, in aggregate, the combined financial incentives between the EV programs and outside funding should not exceed the program participant's actual project costs (D.P.U. 21-90, ChargePoint Track 1 Reply Brief at 4; D.P.U. 21-91, ChargePoint Track 1 Reply Brief at 5; D.P.U. 21-92, ChargePoint Track 1 Reply Brief at 4).

(C) NSTAR Electric and National Grid

NSTAR Electric and National Grid oppose the Attorney General's recommendation for the Department to deny cost recovery for rebates or incentives issued to program participants that do not apply for external funding prior to enrolling in the EV programs (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 26). As an initial matter, NSTAR Electric and National Grid argue that they intend to promote MassEVIP and other state and federal funding sources through their marketing materials and to require program applicants to apply for such funds to the extent that they are available, applicable, and align with the companies' EV program offerings (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 27, 29). Moreover, NSTAR Electric and National Grid state that they propose to require program participants to report any external funding received and to deduct that amount from the rebates issued for the utility side of the

make-ready offerings (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 29). NSTAR Electric and National Grid also contend that the Attorney General's recommendation would prevent the companies from providing funding to program applicants in the event that MassEVIP or other state or federal funding is depleted or unreasonably delayed, which could, in turn, negatively impact customer interest and engagement with the EV programs (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 27-29). Further, to the extent that state or federal funding becomes available in the future and overlaps with the companies' EV program offerings, the companies state that they will work with customers to access those funds, provided that the outside funds are reasonably available to their customers (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 29). Accordingly, NSTAR Electric and National Grid request that the Department approve their EV programs as proposed (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 29).

(D) Unitil

Unitil asserts that the Department should reject the Attorney General's recommendation to require program applicants to apply for outside funding as a prerequisite to participation in its EV program (D.P.U. 21-92, Unitil Track 1 Brief at 41-42). First, Unitil contends that the Attorney General has not produced evidence that EV adoption will be overfunded if multiple sources of funding are available to customers or that external funding would supplant, rather than complement, funding through the EV program (D.P.U. 21-92, Unitil Track 1 Brief at 42). Second, Unitil argues that a strict, inflexible mandate for customers to obtain outside funding would compromise the effectiveness of the EV program because there may be longer lead times

for some incentives offered at the state and federal level, the timeline for outside funding may be inconsistent with the EV program, outside funding sources are susceptible to disruption, reduction, expiration, and discontinuation, and outside funding is not robust enough to achieve the Commonwealth's transportation electrification goals and climate objectives (D.P.U. 21-92, Unitil Track 1 Brief at 43-44).

v. Proprietary Charging Networks

(A) Attorney General

The Attorney General recommends that the Department reject National Grid's proposal to provide incentives for proprietary charging networks because: (1) proprietary charging networks are exclusive and designed to benefit only a certain subset of customers; (2) program funding for exclusive, restrictive networks will not achieve the Commonwealth's goal of widespread EV adoption because proprietary charging networks primarily benefit wealthy individuals; (3) program funding should be reserved for universal EV charging equipment and infrastructure that does not exclude any subset of EV drivers from accessing and taking advantage of EV charging options; and (4) proprietary charging networks do not need financial incentives to drive business decisions because the exclusivity of those EV chargers is part of the reason that these products are more attractive to consumers (D.P.U. 21-91, Attorney General Track 1 Brief at 39-41).

(B) Other Intervenors

GECA argues that the Department should reject National Grid's proposal to provide program funding for EVSE that use proprietary hardware or restrict access to certain vehicle

brands because program incentives for such ports limits the public benefits of investing in public EV charging infrastructure (D.P.U. 21-90/D.P.U. 21-91, GECA Track 1 Brief at 13).

Tesla, however, urges the Department to direct NSTAR Electric to expand its public and workplace program to include financial support for proprietary networks (D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, Tesla Track 1 Brief at 1, 4, 7). Tesla argues that NSTAR Electric's proposal to exclude proprietary networks from its EV program should be rejected because: (1) Tesla chargers are critical to the Commonwealth's ability to achieve its EV adoption targets, and (2) it is inconsistent with NSTAR Electric's EV programs in neighboring jurisdictions, which allow proprietary chargers to be co-located with non-proprietary chargers (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tesla Track 1 Brief at 4, 7, 8; D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, Tesla Reply Track 1 Brief at 2). Accordingly, Tesla requests that the Department approve NSTAR Electric's proposed public and workplace program with a modification to allow proprietary networks to participate in the program (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tesla Track 1 Brief at 9).

If Tesla chargers are excluded from participation in NSTAR Electric's EV program, Tesla contends that the program is inappropriately sized because the company incorrectly relied on the assumption that Tesla vehicles can charge at universal EV chargers (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tesla Track 1 Brief at 7-8; D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, Tesla Track 1 Reply Brief at 5). In the event that the Department approves NSTAR Electric's proposal to exclude proprietary networks from its public and workplace program, Tesla argues that the Department should reduce the company's public and

workplace program budget by 50 percent (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tesla Track 1 Reply Brief at 5).

(C) NSTAR Electric and National Grid

National Grid encourages the Department to reject the Attorney General's and GECA's recommendation to deny the company's proposal to provide program incentives for propriety network EVSE ports because: (1) approximately 50 percent of EVs in the Commonwealth are Tesla vehicles, and (2) incentives for proprietary network EVSE ports are limited to 65 percent of those available to non-proprietary network EVSE ports and the proprietary network EVSE ports must be co-located with non-proprietary network EVSE ports at a four to one ratio in order to be eligible for the incentives (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 70-71). National Grid, therefore, requests that the Department approve the inclusion of incentives for proprietary networks in its EV program (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 71).

In response to Tesla's recommendation to either direct the company to provide incentives for proprietary network EVSE ports or reduce the public and workplace program budget by approximately 50 percent, NSTAR Electric argues that its public and workplace program is appropriately sized and was developed based on an internal analysis of the availability of Tesla Supercharger installations in the Commonwealth, which showed that over 60 percent of proprietary network EVSE port installations are located in the company's service territory without ratepayer investment, and the company made no assumption about the composition of the market for any individual manufacturer (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 71-72). Accordingly, NSTAR Electric requests that the

Department reject Tesla's recommendations regarding EV program funding for proprietary network EVSE ports (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 72).

vi. Networking

(A) Attorney General

The Attorney General argues that networking should be required for program participants in the public and workplace and MUD programs in order to support managed charging capabilities (D.P.U. 21-90, Attorney General Track 1 Brief at 51, 53; D.P.U. 21-91, Attorney General Track 1 Brief at 57, 62).

(B) Other Intervenors

CEP requests that the Department approve the proposed networking rebates for the residential programs (D.P.U. 21-90, CEP Track 1 Brief at 15; D.P.U. 21-91, CEP Track 1 Brief at 16; D.P.U. 21-90/D.P.U. 21-91, CEP Track 1 Reply Brief at 6).

vii. Data Issues

(A) Attorney General

The Attorney General encourages the Department to direct the Companies to: (1) require residential EV program participants to provide EV charging data for predetermined intervals for a minimum of five years, and (2) use this data to inform the load management process recommended by the Attorney General, described in Section III.B.4.b below (D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 22-23).

(B) Other Intervenors

CEP asserts that the Department should require residential program participants to provide charging data at predetermined intervals for a minimum of five years to assist the Companies in the development of TOU rates and other managed charging programs (D.P.U. 21-90, CEP Track 1 Brief at 17; D.P.U. 21-91, CEP Track 1 Brief at 19; D.P.U. 21-90/D.P.U. 21-91, CEP Track 1 Reply Brief at 8). According to EVgo, the companies' markedly different and voluminous data collection requirements are confusing and may deter potential program participants from enrolling in the EV programs; therefore, EVgo recommends that the Department direct NSTAR Electric and National Grid to propose streamlined data collection requirements based on stakeholder input (D.P.U. 21-90/D.P.U. 21-91, EVgo Track 1 Brief at 6-9, 12; D.P.U. 21-90/D.P.U. 21-91, EVgo Track 1 Reply Brief at 4-6, 8).

Electrify America contends that the Department should direct NSTAR Electric and National Grid to require program participants to install interval meters and provide the data from these meters to the companies (D.P.U. 21-90, Electrify America Track 1 Brief at 9; D.P.U. 21-91, Electrify America Track 1 Brief at 10, 14). For DCFC stations, Electrify America argues that EV charging network operators should not be required to meet arbitrary data requirements when interval meters can meet the data requirement needs of the EV programs (D.P.U. 21-90, Electrify America Track 1 Brief at 9, 11; D.P.U. 21-91, Electrify America Track 1 Brief at 10, 14; D.P.U. 21-90/D.P.U. 21-91, Electrify America Track 1 Reply Brief at 7).

Finally, ChargePoint recommends that an additional process be conducted to develop statewide data and reporting processes and protocols (D.P.U. 21-90, ChargePoint Track 1 Reply Brief at 7; D.P.U. 21-91, ChargePoint Track 1 Reply Brief at 8). ChargePoint also requests that

the Department explicitly protect confidential customer information collected through the EV programs from public disclosure or misuse (D.P.U. 21-90, ChargePoint Track 1 Reply Brief at 7; D.P.U. 21-91, ChargePoint Track 1 Reply Brief at 8).

viii. Strategic Deployment of EV Chargers

(A) Intervenors

The Attorney General contends that the Companies have not complied with the Department's directive in D.P.U. 20-69-A to include proposals to mitigate barriers that impede the recruitment of DCFC site hosts for strategic locations in the Commonwealth and incorporate analyses of traffic and EV charging patterns to identify priority locations for future public EV charging stations because the Companies have not yet identified strategic locations for deployment of DCFCs or analyzed traffic and EV charging patterns to identify strategic locations for public EV charging stations (D.P.U. 21-90, Attorney General Track 1 Brief at 66; D.P.U. 21-91, Attorney General Track 1 Brief at 75). Accordingly, the Attorney General requests that the Department direct the Companies to include proposals to mitigate barriers that impede the recruitment of DCFC site hosts for strategic locations in the Commonwealth and incorporate analyses of traffic and EV charging patterns to identify priority locations for future public EV charging stations in their next EV program phases (D.P.U. 21-91, Attorney General Track 1 Brief at 75-76).

DOER asserts that the Companies should continue their work on assessing traffic and researching EV charging patterns so that customer preference and behavior is captured in the Companies' EV program budgets (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 8).

ix. Program Neutrality

(A) Intervenors

ChargePoint contends that the Companies should provide program participants a choice of at least two EVSE providers and networking services to prevent hindering the development of the competitive market and to ensure that all marketing materials and outreach are competitively neutral (D.P.U. 21-90, ChargePoint Track 1 Brief at 1, 18-19, 20; D.P.U. 21-91, ChargePoint Track 1 Brief at 1, 26, 27; D.P.U. 21-92, ChargePoint Track 1 Brief at 1, 7, 16). Further, Electrify America argues that EV charging network providers should be permitted to use their own contractors for customer-side make-ready work (D.P.U. 21-90, Electrify America Track 1 Brief at 9-10, 12).

b. Specific Issues

i. EV EMS for Public and Workplace Offering

(A) Attorney General

To support EV EMS adoption, the Attorney General encourages the Department to require NSTAR Electric and National Grid to: (1) develop a standard site evaluation methodology to determine whether EV EMS can support EV charging infrastructure installation at a lesser cost than hardware-based capacity upgrades while still meeting the customers' charging needs; (2) modify make-ready incentives to provide a clear financial motivation for program participants to consider EV EMS; (3) incorporate load management, including EV EMS, into several program offerings; (4) track data related to EV EMS, including cost savings realized through EV EMS; (5) develop a program, rule, and/or tariff to support EV EMS deployment if deployment of EV EMS is low after the first two years of the EV programs; and

(6) work with affiliates and other utilities to establish standards for EV EMS data (D.P.U. 21-90, Attorney General Track 1 Brief at 58-64; D.P.U. 21-91, Attorney General Track 1 Brief at 67-74).

If the Department declines to adopt its recommendation, the Attorney General requests that the Department direct NSTAR Electric and National Grid to: (1) develop a site evaluation methodology to determine whether EV EMS would be cost-effective at a particular site and, if so, the appropriate level of financial support for the installation of the EV EMS; (2) if EV EMS is determined to be cost-effective for a particular site, apply the cost savings as either an increase to the customer-side incentive levels or the applicable rebate cap; and (3) refrain from providing financial support for EV EMS unless EV EMS deployment is expected to generate overall cost savings for a particular project (D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 17-18).

Additionally, the Attorney General urges the Department to direct Unitil to use average installation costs rather than actual installed costs as the measure for make-ready financial support for EV EMS (D.P.U. 21-92, Attorney General Track 1 Brief at 26).

(B) Other Intervenors

FreeWire asserts that NSTAR Electric's and National Grid's proposed public and workplace programs would hinder the competitive market because they do not incentivize program participants to install EVSE with integrated battery storage, which can reduce total installation costs by avoiding costly upgrades to the companies' distribution systems (D.P.U. 21-90, FreeWire Track 1 Brief at 8-11; D.P.U. 21-91, FreeWire Track 1 Brief at 8-11). In essence, by providing rebates for all utility-side make-ready costs and 100 percent of the

average customer-side make-ready costs of a DCFC project, FreeWire contends that the companies' program would eliminate the incentive for program participants to purchase and install EVSE with integrated battery storage (D.P.U. 21-90, FreeWire Track 1 Brief at 9; D.P.U. 21-91, FreeWire Track 1 Brief at 9; D.P.U. 21-90/D.P.U. 21-91, FreeWire Track 1 Reply Brief at 3). Therefore, FreeWire requests that the Department direct NSTAR Electric and National Grid to modify their proposed public and workplace programs to include additional financial support for EVSE with EMS (D.P.U. 21-90, FreeWire Track 1 Brief at 9-10; D.P.U. 21-91, FreeWire Track 1 Brief at 9-10; D.P.U. 21-90/D.P.U. 21-91, FreeWire Track 1 Reply Brief at 2). FreeWire suggests that the Department direct the companies to implement a cap on EV EMS incentives at 100 percent of the average utility-side make-ready costs of conventional DCFC deployments (D.P.U. 21-90, FreeWire Track 1 Brief at 12; D.P.U. 21-91, FreeWire Track 1 Brief at 12-13). Alternatively, FreeWire requests that the Department direct the companies to offer a discrete incentive for deploying EV EMS that uses avoided distribution upgrade costs as the baseline for determining the value of the incentives (D.P.U. 21-90, FreeWire Track 1 Brief at 13; D.P.U. 21-91, FreeWire Track 1 Brief at 13).

FreeWire also urges the Department to direct NSTAR Electric and National Grid to develop standard site evaluation methodologies to assist customers in determining whether load management and EV EMS can deliver benefits and offer an optimal EV charging solution (D.P.U. 21-90, FreeWire Track 1 Brief at 14; D.P.U. 21-91, FreeWire Track 1 Brief at 14). Specifically, FreeWire requests that the Department direct NSTAR Electric and National Grid to develop a more robust site evaluation methodology for larger sites where utility-side make-ready

is required and a more streamlined site evaluation methodology for smaller sites (D.P.U. 21-90, FreeWire Track 1 Brief at 14; D.P.U. 21-91, FreeWire Track 1 Brief at 14).

(C) NSTAR Electric and National Grid

NSTAR Electric and National Grid disagree with consideration of EV EMS for projects sites below 100 KVa because EV EMS is less likely to be cost-effective and may limit customer flexibility to expand the number of EV charging ports in the future (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 32). Moreover, the companies do not recommend tiering incentives based on EV EMS deployment and, instead, recommend selectively considering EV EMS as a potential solution on an as needed basis (D.P.U. 21-90/ D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 33). Additionally, the companies contend that their proposal to cover EV EMS costs as part of the customer-side make-ready program provides sufficient incentive for program participants to pursue EV EMS (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 33). With respect to potential reporting requirements on EV EMS, the companies state that they may be able to collect data and report on whether EV EMS was installed and the installation costs but is unable to report on the usage rate of the EV EMS or whether EV EMS is installed after the project is placed into service (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 33).

ii. National Grid Level 1 Charger Offering

(A) Intervenors

ChargePoint recommends that the Department reject National Grid's proposal to deploy 500 Level 1 chargers at long-dwell time sites because: (1) Level 1 chargers are inconsistent with

the broader requirements of the EV program; (2) smart, networked Level 2 chargers offer numerous benefits that Level 1 chargers do not provide; and (3) Level 1 chargers are becoming increasingly obsolete and would not be a cost-effective use of ratepayer funds (D.P.U. 21-91, ChargePoint Track 1 Brief at 1, 6, 14).

(B) National Grid

National Grid asserts that Level 1 charging stations may play an important role in the context of a larger project, especially for sites that support long-dwell time vehicles (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 41-42). Accordingly, the company requests that the Department approve its Level 1 charger proposal (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 42).

iii. Unitil Fleet Make-Ready Offering

(A) Intervenors

CLF requests that the Department direct Unitil to develop and propose a fleet make-ready infrastructure pilot program with 50 percent of the pilot program budget dedicated to supporting transit electrification in EJ communities (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 1 Brief at 18, 25, 36).

(B) Unitil

Unitil argues that the Department should reject CLF's recommendation because this is the company's first proposed EV program (D.P.U. 21-92, Unitil Track 1 Brief at 54). Therefore, it would not be prudent for the company to conduct a municipal fleet program at this time (D.P.U. 21-92, Unitil Track 1 Brief at 54).

iv. NSTAR Electric Coordination with Compact for Residential Offering

(A) Intervenors

The Compact requests that the Department direct NSTAR Electric to allow the Compact's customers unrestricted access to participate in the company's residential program and work cooperatively with the Compact to develop a managed charging program and marketing plan (D.P.U. 21-90, Compact Track 1 Brief at 1-2, 4, 6, 8, 9; D.P.U. 21-90, Compact Track 1 Reply Brief at 1, 4-5). As part of that process, the Compact recommends that the Department direct NSTAR Electric to submit a compliance filing explaining its residential managed charging program and examine the program design to ensure that all distribution customers will benefit from the program (D.P.U. 21-90, Compact Track 1 Reply Brief at 5).

The Attorney General encourages the Department to direct NSTAR Electric to: (1) allow Compact customers to participate in the company's residential program, and (2) coordinate a managed charging program with the Compact so that Compact residential customers can participate in NSTAR Electric's approved managed charging programs (D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 22).

(B) NSTAR Electric

NSTAR Electric states that it will consider whether any EV managed charging program the Compact proposes is sufficient for program participation purposes (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 48).

v. National Grid Utility-Side Expansion Budget

(A) Attorney General

The Attorney General recommends that the Department reject National Grid's $15 million utility-side system expansion budget because it is an ad hoc request for a $15 million increase to rates above the rates authorized by the Department in the company's last base distribution rate case in D.P.U. 18-150, which is inconsistent with traditional ratemaking practices, and also inconsistent with the company's treatment of public DCFC sites as well as the company's statement that it does not expect significant system expansion due to transportation electrification within the proposed EV program term (D.P.U. 21-91, Attorney General Track 1 Brief at 53).

(B) National Grid

National Grid urges the Department approve its utility-side system expansion budget proposal because: (1) the distribution system upgrades would be necessary for all customers on the local distribution network and would be a shared cost for all ratepayers; (2) the company's multi-year rate plan includes a budget for load-related system expansion, but that budget does not include funding for projects related to large-scale fleet electrification; and (3) if the utility-side system expansion budget is denied, the company may be required to spend its base distribution rate plan budget on fleet-related projects, thereby reducing the available funds for new non-EV-related activity as well as system capacity and performance improvements for the rest of the electric grid (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 55-56).

vi. Unitil Rebate Calculation

(A) Attorney General

The Attorney General recommends that the Department direct Unitil to use National Grid's average cost data to estimate comparable average costs for Level 2 chargers for the first year and a half of the EV program because: (1) National Grid has a similarly-situated service territory; (2) National Grid is the furthest along in its EV program implementation; and (3) Unitil proposes to install Level 2 chargers similar to the Level 2 chargers that National Grid proposes to install (D.P.U. 21-92, Attorney General Track 1 Brief at 26).

(B) Unitil

Unitil opposes the Attorney General's recommendation to require the company to use National Grid's Level 2 cost data for the first year and a half of the EV program because the Attorney General's recommendation is unsupported by record evidence while Unitil based its cost data on estimates developed for and by the company (D.P.U. 21-92, Unitil Track 1 Brief at 36-37).

vii. Co-Located Energy Storage Pilot

(A) Intervenors

FreeWire recommends that the Department direct NSTAR Electric to implement a co-located energy storage pilot similar to that proposed by National Grid (D.P.U. 21-90, FreeWire Track 1 Brief at 13).

viii. Default Pricing Arrangement for Public and Workplace Offering

(A) Intervenors

CEP recommends that the Department require the Companies to establish a default arrangement that site hosts pass through time-varying price signals to drivers with an opt-out to allow site hosts to implement their own pricing plans (D.P.U. 21-90, CEP Track 1 Brief at 20-21; D.P.U. 21-91, CEP Track 1 Brief at 21; D.P.U. 21-90/D.P.U. 21-91, CEP Track 1 Reply Brief at 11).

ChargePoint opposes CEP's recommendation, arguing that the Department has previously held that owners and operators of EVSE are not subject to the Department's jurisdiction (D.P.U. 21-90, ChargePoint Track 1 Brief at 15, citing D.P.U.13-182-A at 5; D.P.U. 21-90, ChargePoint Track 1 Reply Brief at 4-5; D.P.U. 21-91, ChargePoint Track 1 Brief at 22; D.P.U. 21-91, ChargePoint Track 1 Reply Brief at 5). Additionally, ChargePoint contends that site hosts should be empowered to price EV charging in a manner that best supports their own goals for installing EV charging stations (D.P.U. 21-90, ChargePoint Track 1 Brief at 15; D.P.U. 21-90, ChargePoint Track 1 Reply Brief at 5; D.P.U. 21-91, ChargePoint Track 1 Brief at 22-23; D.P.U. 21-90, ChargePoint Track 1 Reply Brief at 5). Instead, ChargePoint urges the Department to allow for flexible pricing and EV tariffs that encourage off-peak charging across all charging use cases without setting a requirement for site hosts to pass through time-varying price signals to end users (D.P.U. 21-90, ChargePoint Track 1 Brief at 17; D.P.U. 21-91, ChargePoint Track 1 Brief at 24).

3. Environmental Justice-Related Proposals

a. EJ Community Targets and Incentives

i. Attorney General

The Attorney General recommends binding port deployment and EV site plan targets for EJ communities due to the higher barriers to transportation electrification and the lower likelihood that the competitive market will serve EJ communities (D.P.U. 21-90, Attorney General Track 1 Brief at 15-16; D.P.U. 21-91, Attorney General Track 1 Brief at 18; D.P.U. 21-92, Attorney General Track 1 Brief at 13).[28] For NSTAR Electric and National Grid, the Attorney General recommends a binding port target of 40 percent in EJ communities (D.P.U. 21-90, Attorney General Track 1 Brief at 15; D.P.U. 21-91, Attorney General Track 1 Brief at 18). For Unitil, the Attorney General recommends that all ports be deployed in EJ communities (D.P.U. 21-92, Attorney General Track 1 Brief at 13, 14).

According to the Attorney General, without binding targets or another mechanism to ensure equitable distribution of EV program benefits, the Companies' EV programs are likely to disproportionally benefit higher-income individuals and large private fleets that have more financial flexibility to purchase EVs without financial assistance through the EV programs (D.P.U. 21-90, Attorney General Track 1 Brief at 16-17; D.P.U. 21-91, Attorney General Track 1 Brief at 19-20; D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 7, 8-9;

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28 The Attorney General also states that she would not oppose a program modification that would allow for additional financial incentives to customers that meet more than one EJ community criteria (D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 17-18).

D.P.U. 21-92, Attorney General Track 1 Brief at 13).[29] If the Companies do not meet these targets, the Attorney General recommends barring the Companies from reallocating any associated budget components to non-EJ community ports (D.P.U. 21-90, Attorney General Track 1 Brief at 18; D.P.U. 21-91, Attorney General Track 1 Brief at 21). Additionally, the Attorney General rejects the Companies' claim that market uncertainty is a sufficient reason not to prescribe binding port deployment targets particularly given the Companies' unique role in shaping the EV market and the market indications that early adopters of light-duty EVs in the Commonwealth are primarily higher-income individuals (D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 7-8; D.P.U. 21-92, Attorney General Track 1 Reply Brief at 6-7).

Alternatively, the Attorney General states that she would not object to a binding port deployment target in EJ communities of at least 30 percent per customer segment provided that at least 40 percent of the overall ports deployed through NSTAR Electric's and National Grid's EV programs are deployed in EJ communities (D.P.U. 21-90, Attorney General Track 1 Brief at 17-18; D.P.U. 21-91, Attorney General Track 1 Brief at 20-21). For Unitil, the Attorney General states that she would not oppose a binding port deployment target of 65 percent in EJ communities if the Department is not inclined to direct Unitil to deploy all of its ports in EJ communities (D.P.U. 21-92, Attorney General Track 1 Brief at 14-15).

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[29] The Attorney General urges the Department to require NSTAR Electric and National Grid to dedicate additional ports to low-income ratepayers because: (1) EJ community ratepayers are not synonymous with low-income ratepayers; (2) some low-income customers reside outside of EJ communities; and (3) the companies' residential programs do not include port deployment targets or associated benefits targeting low-income ratepayers outside of EJ communities (D.P.U. 21-90, Attorney General Track 1 Brief at 18-19; D.P.U. 21-91, Attorney General Track 1 Brief at 21-22).

ii. Other Intervenors

DOER urges the Department to reject the Attorney General's recommendations to dedicate a certain percentage of port deployments in low-income communities and for EJ community port deployment targets and, instead, allow for programmatic flexibility that can respond to community and stakeholder feedback (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 10). Electrify America claims that there is no support in the record for the Attorney General's recommended port deployment targets in EJ communities (D.P.U. 21-90, Electrify America Track 1 Brief at 6; D.P.U. 21-91, Electrify America Track 1 Brief at 6-7).

CLF, however, argues that NSTAR Electric and National Grid should be required to dedicate at least 30 percent of public and workplace program EV charging ports in EJ communities (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 1 Brief at 4, 29, 34, 36). CLF also recommends that the Companies modify their rebate program proposals to provide additional financial support to program participants based on the number of EJ community criteria satisfied (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 1 Brief at 4, 26-27, 36). Further, CLF urges the Department to approve the Companies' proposed one to four-unit residential offering with the inclusion of a sliding scale of incentives that provides additional financial support to residential program customers based on the number of EJ community criteria met (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 1 Reply Brief at 10-11).

Finally, CEP recommends that the Department direct the Companies to increase their funding targets in EJ communities to a level that is at least proportionate to the percentage of EJ community customers in each company's respective service territory (D.P.U. 21-90, CEP

Track 1 Brief at 20; D.P.U. 21-91, CEP Track 1 Brief at 20; D.P.U. 21-90/D.P.U. 21-91, CEP Track 1 Reply Brief at 9-10).

iii. NSTAR Electric and National Grid

NSTAR Electric and National Grid urge the Department to reject the Attorney General's recommendation to direct the companies to deploy 40 percent of all ports in EJ communities and CEP's recommendation to increase funding for port deployments in EJ communities in proportion to the number of EJ community customers in each company's service territory because: (1) strict port deployment targets do not reflect the needs of EJ communities; (2) the Attorney General did not base its recommended 40 percent port deployment target in EJ communities on the level of demand for EV charging in EJ communities; (3) there may be unintended consequences for siting EV chargers in EJ communities due to low EV ownership; (4) the companies cannot unilaterally site EV charging infrastructure in EJ communities; (4) due to evolving market dynamics and variability in EV adoption, flexibility in EV program deployment approaches is necessary to allow the companies to prioritize EJ community investments where there is the most market demand; and (5) the companies already propose to work with EJ community stakeholders to identify their EV charging needs (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 65-66). As such, NSTAR Electric and National Grid contend that the Department should reject the Attorney General's and CEP's recommendation to direct the companies to implement binding port deployment targets in EJ communities (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 66).

iv. Unitil

Unitil asserts that the Attorney General's recommendation to direct the company to deploy 65 percent of its charging ports in EJ communities or low-income communities should be rejected because: (1) Unitil cannot unilaterally deploy EV charging infrastructure in EJ communities, and (2) there is no correlation between the percentage of customers living in the city of Fitchburg and the need for public EV charging locations in specific neighborhoods (D.P.U. 21-92, Unitil Track 1 Brief at 35-36). Further, Unitil contends that CLF's recommendation to implement a sliding scale of EJ community incentives for the residential program should be rejected because: (1) Unitil does not have data on whether individual customers meet one or more EJC criteria, and (2) the inclusion of incentive tiers would unnecessarily complicate the residential program and could lead to program implementation delays and increased administrative costs (D.P.U. 21-92, Unitil Track 1 Brief at 55-56).

b. NSTAR Electric Equity Pilots

i. Attorney General

The Attorney General urges the Department to deny NSTAR Electric's proposed car sharing program in EJ communities because: (1) the company can better support transportation electrification in EJ communities through implementation of the Attorney General's prioritization framework and recommendations; (2) a car sharing program is outside the scope of the normal business operations of a utility; and (3) providing financial support for car insurance is an inappropriate use of ratepayer funds (D.P.U. 21-90, Attorney General Track 1 Brief at 67).

Additionally, the Attorney General recommends that NSTAR Electric's medium- and heavy-duty fleet pilot program include financial support for electrification of mass transit

because: (1) mass transit will provide clean transportation benefits to a broad section of the public, including low-income households and customers who do not own personal vehicles, and (2) electrification of mass transit will significantly reduce GHG emissions and provide large battery power for the electric grid through vehicle to grid ("V2G") services[30] (D.P.U. 21-90, Attorney General Track 1 Brief at 45). The Attorney General also asserts that NSTAR Electric should be more proactive in supporting fleets, including mass transit and medium- and heavy-duty fleets, and recommends that the Department direct the company to submit an expanded fleet proposal in the near term (D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 19).

ii. Other Intervenors

CLF contends that the Department should direct NSTAR Electric to propose: (1) a medium- and heavy-duty fleet program scaled to match National Grid's medium- and heavy-duty fleet program; (2) a school bus rebate program; and (3) a public transit bus pilot program that would provide rebates for the purchase of up to 30 public transit buses that operate primarily in EJ communities[31] (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 1 Brief at 18, 24, 25, 36). With respect to the medium- and heavy-duty fleet program, CLF recommends that at least

30 V2G is a technology that enables electricity to be exported back to the electric grid from the battery of an EV by EV chargers (D.P.U. 21-92, Exh. AG 6-9).

31 CLF also recommends that the Department direct National Grid to propose a public transit bus rebate pilot program to provide financial support for the purchase of up to 30 public transit buses that operate primarily in EJ communities (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 1 Brief at 18, 24-25, 36).

50 percent of the program budget be dedicated to supporting the electrification of public transit in EJ communities (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 1 Brief at 18, 19, 21).

CEP recommends that the Department direct NSTAR Electric to expand its medium- and heavy-duty fleet program and develop an electric school bus rebate program before 2024 (D.P.U. 21-90, CEP Track 1 Brief at 18; D.P.U. 21-91, CEP Track 1 Brief at 19; D.P.U. 21-90/ D.P.U. 21-91, CEP Track 1 Reply Brief at 8). Additionally, GECA recommends that the Department direct NSTAR Electric to develop and implement a make-ready program for medium- and heavy-duty vehicles (D.P.U. 21-90/D.P.U. 21-91, GECA Track 1 Brief at 4, 16).

iii. NSTAR Electric

NSTAR Electric argues that the Department should reject the Attorney General's recommendation to deny the car sharing program in EJ communities because: (1) car sharing is an important transportation option for EJ community residents; (2) the car sharing program will reduce emissions by removing internal combustion vehicles from the roadways, relieve traffic congestion, and reduce parking needs; (3) the company proposes to partner with organizations that have experience with these types of programs; and (4) few car sharing programs are designed to serve low-income customers (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 68-69). NSTAR Electric, therefore, requests that the Department approve its car sharing program in EJ communities (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 69).

Further, NSTAR Electric disagrees with the Attorney General's and CEP's recommendation to expand its proposed medium- and heavy-duty fleet pilot program because the company needs to first gather data on fleet types, opportunities for fleet electrification, and costs

and equipment necessary for fleet electrification and incorporate any lessons learned into any expanded medium- and heavy-duty fleet program (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 69-70). After the second year of its fleet assessment services program, NSTAR Electric states that it will develop an offering that will cost effectively enable medium- and heavy-duty fleet electrification in its service territory (D.P.U. 21-90/ D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 69-70). Accordingly, the company requests that the Department approve the medium- and heavy-duty fleet pilot program as proposed (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 70).

c. National Grid School Bus Rebate Program

i. Attorney General

The Attorney General recommends that the Department deny National Grid's proposed school bus rebate program and direct the company to reevaluate its proposal in light of newly available federal and state funding for the purchase of electric school buses (D.P.U. 21-91, Attorney General Track 1 Reply Brief at 78). If the Department approves the school bus rebate program, the Attorney General requests that the Department direct National Grid to condition program funding on customer participation in V2G services (D.P.U. 21-91, Attorney General Track 1 Reply Brief at 78).

ii. Other Intervenors

DOER urges the Department to reject the school bus rebate program because: (1) school bus rebates will be addressed through state and federal programs; (2) a rebate program for school buses exceeds the role of a utility in the EV market; and (3) the proposed budget of over

$50 million is approximately 20 percent of National Grid's total budget and would substantially increase its customers' electric rates (D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, DOER Track 1 Brief at 23-24). Instead, DOER recommends that the company provide support for electric school buses through its fleet program and fleet advisory services offerings (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 23).

In contrast, CLF, CEP, and GECA urge the Department to approve National Grid's school bus rebate proposal (D.P.U. 21-91, CEP Track 1 Brief at 19; D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, CLF Track 1 Reply Brief at 6-7; D.P.U. 21-90/D.P.U. 21-91, GECA Track 1 Brief at 15) More specifically, CLF contends that: (1) state and federal funding sources will complement, not supplant, National Grid's school bus rebate proposal; (2) diesel-powered school buses have dangerous health impacts for children, especially in EJ communities; and (3) medium- and heavy-duty vehicles, like school buses, emit considerably more GHG emissions than light duty vehicles and contribute a disproportionate share of the localized pollution that harms public health (D.P.U. 21-91, CLF Track 1 Reply Brief at 6-7). CLF, CEP, and GECA also recommend that the Department direct NSTAR Electric to develop a school bus rebate program (D.P.U. 21-90, CLF Track 1 Brief at 4; D.P.U. 21-90, CEP Track 1 Brief at 18; D.P.U. 21-90/ D.P.U. 21-91, GECA Track 1 Brief at 4, 16). Finally, GECA requests that the Department direct National Grid to develop a V2G program (D.P.U. 21-90/D.P.U. 21-91, GECA Track 1 Brief at 15).

iii. National Grid

National Grid disagrees with the Attorney General's and DOER's recommendation to deny the school bus rebate program (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National

Grid Joint Track 1 Brief at 59). National Grid acknowledges that there is some external funding available for the purchase of electric school buses, but the company states that utility funding for the purchase of electric school buses is still necessary given the uncertainty on the extent of available state and federal funding for the purchase of electric school buses and because any available external funding is likely to only contribute to a small portion of the school buses operating in the Commonwealth (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 59).

Regarding the Attorney General's and CEP's recommendation to require participating school buses to participate in a V2G program, National Grid is not opposed to such a requirement; however, the company recommends allowing school districts to opt out of the V2G program because V2G services may increase school bus, EVSE, interconnection, and operations and maintenance ("O&M") costs for the school district (D.P.U. 21-90/ D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 60). The company also recommends limiting the number of participating V2G buses at a particular site to reduce the expenses and energy management burdens on any particular school district (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 60). Further, National Grid contends that it must maintain discretion to decide not to pursue V2G capability at a site contingent on the results of an interconnection study, as the potential value from V2G services at a particular site may be limited (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 60).

iv. NSTAR Electric

NSTAR Electric opposes CLF's, CEP's, and GECA's recommendation for NSTAR Electric to propose a school bus rebate program, arguing that it has not yet evaluated the charging requirements and demand for fleet customers in its service territory (D.P.U. 21-90/ D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 60). In addition, NSTAR Electric contends that it would be more prudent for the company to evaluate the results of National Grid's program before determining whether to offer a similar program (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 61).

d. National Grid Utility-Owned DCFCs in EJ Communities

i. Attorney General

The Attorney General opposes National Grid's proposal to own and operate DCFCs in EJ communities because the company did not demonstrate that: (1) there will be a market failure to provide DCFCs in EJ communities; (2) DCFC installation in EJ communities would not occur without utility ownership; or (3) the proposed number of utility-owned DCFCs is appropriate (D.P.U. 21-91, Attorney General Track 1 Brief at 74-75).

ii. Other Intervenors

GECA recommends that the Department allow utility ownership of DCFCs in EJ communities if the private market fails to meet the needs of those communities (D.P.U. 21-90/D.P.U. 21-91, GECA Track 1 Brief at 14). Similarly, ChargePoint contends that the Department should require National Grid to demonstrate that there is need for utility-owned DCFC in EJ communities before approving the proposal because: (1) DCFCs in EJ communities will not necessarily result in increased access to and equitable deployment of EV charging

stations; (2) the proposal is premature, particularly in light of federal funds from the Infrastructure and Jobs Acts,[32] which provides financial support for these types of investments in EJ communities; and (3) utility-ownership of DCFCs in EJ communities could undermine the ability of the competitive market to meet that need and result in unnecessary costs for ratepayers (D.P.U. 21-91, ChargePoint Track 1 Brief at 1, 8, 12-13). In lieu of this proposal, ChargePoint recommends that National Grid report to the Department and stakeholders on the development of DCFCs in EJ communities at the midpoint of the EV program and assess whether utility intervention is appropriate at that time (D.P.U. 21-91, ChargePoint Track 1 Brief at 13). If so, ChargePoint suggests that National Grid then submit a proposal for utility ownership of DCFCs in EJ communities for Department and stakeholder input and Department approval (D.P.U. 21-91, ChargePoint Track 1 Brief at 13).

Additionally, Electrify America recommends that the Department require National Grid to notify the private market of any plans to construct and own DCFC stations in EJ communities at least one year in advance of construction (D.P.U. 21-91, Electrify America Track 1 Brief at 13, 14).

iii. National Grid

National Grid requests that the Department reject the Attorney General's recommendation to deny its proposal to own and operate DCFC in EJ communities because: (1) the company has developed a reasonable allocation of DCFC ports to serve EJ communities; (2) the offering is designed to encourage the private EV market to deploy DCFC in EJ

32 Infrastructure and Jobs Act of 2021, Pub. L. No. 117-58.

communities; and (3) prior to installing, owning, and operating DCFCs in EJ communities, the company proposes to provide EV charging station developers with advance notice of the identified gaps in DCFC deployment in EJ communities and an additional opportunity to deploy DCFCs in that location before the company does (D.P.U. 21-90/ D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 38-39).

e. NSTAR Electric EJ Community Charging Hub

i. Attorney General

The Attorney General recommends that the Department approve NSTAR Electric's EJ community charging hub proposal with modifications, including: (1) limiting the DCFC hubs to three to four DCFC hubs, rather than permitting the proposed four to five DCFC hubs; (2) directing the company to engage with EJ community stakeholders, including municipalities and community organizations, prior to issuing a request for proposals ("RFP") for a vendor to own and operate the hubs; and (3) directing the company in its next proposed EV program to include proposals to mitigate barriers that impede the recruitment of DCFC site hosts for strategic locations in the Commonwealth and to incorporate analyses of traffic and EV charging patterns to identify priority locations for future public EV charging stations (D.P.U. 21-90, Attorney General Track 1 Brief at 64-66).

f. Utility-Ownership of EVSE for MUDs in EJ Communities

i. Intervenors

CEP recommends that the Department consider utility ownership of EV charging stations for MUDs in EJ communities to address barriers to EV adoption at MUDs, such as landlord/tenant relationships (D.P.U. 21-90, CEP Track 1 Brief at 17-18; D.P.U. 21-91, CEP

Track 1 Brief at 19). ChargePoint, however, contends that CEP's recommendation that the Department consider proposals for utility ownership of EVSE at MUDs in EJ communities should be rejected because: (1) the Department has previously found that the electric distribution companies have not demonstrated a need for utility ownership of EVSE to address a market failure or that utility ownership of EVSE would effectively address gaps in the EV charging market; (2) the competitive market already provides alternatives to utility ownership of EVSE for site hosts that do not wish to own and operate EVSE; and (3) utility ownership of EVSE would hinder the development of the private EV charging market (D.P.U. 21-90, ChargePoint Track 1 Brief at 13-14; D.P.U. 21-90, ChargePoint Track 1 Reply Brief at 5-6; D.P.U. 21-91, ChargePoint Track 1 Brief at 21-22; D.P.U. 21-90, ChargePoint Track 1 Reply Brief at 6-7).

4. Other Proposals

a. Workforce Development and Electrician Training

i. Attorney General

The Attorney General argues that the Department should only approve the Companies' proposed workforce development and electrician training program if the Companies agree to develop and commit to meaningful metrics to tangibly assess the program's success and demographic targets for program participants (D.P.U. 21-90, Attorney General Track 1 Brief at 78-79; D.P.U. 21-91, Attorney General Track 1 Brief at 93; D.P.U. 21-92, Attorney General Track 1 Brief at 30). This, in turn, according to the Attorney General, will allow for a tangible assessment of the progress towards the program's equity goals and an opportunity for course correction if the Companies fail to make sufficient progress towards meetings those goals

(D.P.U. 21-90, Attorney General Track 1 Brief at 79; D.P.U. 21-91, Attorney General Track 1 Brief at 94; D.P.U. 21-92, Attorney General Track 1 Brief at 30).

ii. NSTAR Electric and National Grid

NSTAR Electric and National Grid do not oppose the Attorney General's recommendation for the companies to collect data on the demographic makeup of the participants in the program and are willing to commit to working with key stakeholders to determine best practices and strategies for reaching targeted populations to increase the diversity of the program (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 62). The companies, however, state that they cannot commit to ensuring a diverse group of program participants because they do not control who chooses to participate in the program (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 62). Accordingly, NSTAR Electric and National Grid request that the Department not condition approval of the workforce development and electrician training program on the development of certain metrics related to demographic targets for program participants (D.P.U. 21-90/ D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 62).

iii. Unitil

Unitil encourages the Department to reject the Attorney General's recommendation to condition approval of the workforce development and electrician training program on the development of metrics that demonstrate success in increasing workforce diversity (D.P.U. 21-92, Unitil Track 1 Brief at 47). As an initial matter, Unitil argues that the recommendation is unnecessary because the company has already stated that it intends to consult with key stakeholders to develop the workforce development and electrician training program

(D.P.U. 21-92, Unitil Track 1 Brief at 47). Further, Unitil states that it has already agreed to collect data on the number of participants enrolled in the program, demographic information about the participants, and the number of participants that complete the program and report that information in an annual compliance filing to the Department (D.P.U. 21-92, Unitil Track 1 Brief at 47-48). Moreover, Unitil contends that the Attorney General's recommendation is not feasible because the company cannot control program participation rates with the level of precision that the Attorney General requests (D.P.U. 21-92, Unitil Track 1 Brief at 48). For these reasons, Unitil requests that the Department reject the Attorney General's proposed condition on the workforce development and electrician training program (D.P.U. 21-92, Unitil Track 1 Brief at 48).

b. Load Management

i. Attorney General

The Attorney General recommends that the Department: (1) direct the Companies to coordinate to develop a comprehensive load management plan[33] that details current and future managed charging offerings for residential and commercial customers for Department review by June 2023, and (2) open a proceeding into load management that would, among other things, establish a timeline and approach for developing and implementing more advanced managed charging programs for all customer groups and the transition of the proposed DCA rates to future

33 The Attorney General asserts that the load management plan should include a suite of services to enable and incentivize load flexibility from EVs and other distributed energy resources and align with the Companies' deployment of grid modernization investments (D.P.U. 21-90, Attorney General Track 2 Brief at 38; D.P.U. 21-91, Attorney General Track 2 Brief at 42; D.P.U. 21-92, Attorney General Track 2 Brief at 45).

demand charge rate designs that will be enabled through the full deployment of AMI meters (D.P.U. 21-90, Attorney General Track 1 Brief at 51, 53; D.P.U. 21-91, Attorney General Track 1 Brief at 56-57, 63; D.P.U. 21-92, Attorney General Track 1 Reply Brief at 11, 13; D.P.U. 21-90, Attorney General Track 2 Brief at 28, 31; D.P.U. 21-91, Attorney General Track 2 Brief at 32, 42; D.P.U. 21-92, Attorney General Track 2 Brief at 38, 45; D.P.U. 21-92, Attorney General Track 2 Reply Brief at 15-16. 17-18). Through this process, the Attorney General argues that a comprehensive evaluation of all customer rates and load management programs across customer segments and technology types is necessary to ensure that distribution system costs are minimized, variable renewable resources are integrated in a cost-effective manner, and the most cost-effective load types are prioritized (D.P.U. 21-90, Attorney General Track 2 Brief at 38; D.P.U. 21-91, Attorney General Track 2 Brief at 41; D.P.U. 21-92, Attorney General Track 2 Brief at 44). To assist in the development of the load management plan, the Attorney General urges the Department to require the Companies to convene a load management working group within 30 days following the Department's Order in this proceeding (D.P.U. 21-90, Attorney General Track 1 Brief at 54; D.P.U. 21-91, Attorney General Track 1 Brief at 63; D.P.U. 21-92, Attorney General Track 1 Reply Brief at 13). The Attorney General also asserts that the load management process should establish a mechanism by which the Department and stakeholders can reevaluate the Companies' rates at predictable intervals, either every two or three years or aligned with distribution system planning or base distribution rate cases (D.P.U. 21-90, Attorney General Track 2 Brief at 39; D.P.U. 21-91, Attorney General Track 2 Brief at 42-43; D.P.U. 21-92, Attorney General Track 2 Brief at 46). In addition, the Attorney General contends that the load management process should include performance metrics to

measure the Companies' success in managing load and incentivizing load flexibility (D.P.U. 21-90, Attorney General Track 2 Brief at 39; D.P.U. 21-91, Attorney General Track 2 Brief at 43; D.P.U. 21-92, Attorney General Track 2 Brief at 46). Regarding EV-specific rates, the Attorney General contends that the load management plan should include several types of rate designs that can support and facilitate EV charging in the Commonwealth, such as TOU rates, critical peak pricing, dynamic rates, demand response rates, and export rates (D.P.U. 21-90, Attorney General Track 2 Brief at 40-42; D.P.U. 21-91, Attorney General Track 2 Brief at 43-46; D.P.U. 21-92, Attorney General Track 2 Brief at 47-49).

The Attorney General encourages the Department not to delay action on the load management plan until after the Companies have had the opportunity to incorporate managed charging questions into their evaluations reports because: (1) managed charging options should be developed now so that a range of attractive options are available to customers before increased load from EVs leads to unnecessary distribution system upgrade costs; (2) the load management plan should inform an iterative load management process that consistently integrates new data and learnings to create new offerings and evaluate current load management offerings; and (3) the Companies can use the load management working group to get additional information and input from stakeholders, including from EV manufacturers and service providers with experience in managed charging (D.P.U. 21-90, Attorney General Track 1 Brief at 55-56; D.P.U. 21-91, Attorney General Track 1 Brief at 64-66; D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 14).

The Attorney General also recommends that the Department condition approval of the third year of NSTAR Electric's EV program expenditures on its ability to successful develop

additional managed charging options (D.P.U. 21-90, Attorney General Track 1 Brief at 51, 56-57). According to the Attorney General, a failure to adequately integrate managed charging into the EV programs is a missed opportunity to reduce costs for ratepayers (D.P.U. 21-90, Attorney General Track 1 Brief at 51).

In addition, the Attorney General argues that National Grid should require fleet program participants to participate in a managed charging program, which could provide meaningful benefits to the company's distribution system and, by extension, its customers (D.P.U. 21-91, Attorney General Track 1 Brief at 61-62).

ii. FreeWire

FreeWire supports the Attorney General's recommendation for the Department to require the Companies to: (1) timely file comprehensive load management plans that include an EV component; (2) develop rate designs and other programs that incentivize load flexibility; and (3) participate in a Department-led stakeholder EV load management working group (D.P.U. 21-90, FreeWire Track 1 Brief at 15; D.P.U. 21-90, FreeWire Track 1 Brief at 14-15; D.P.U. 21-90, FreeWire Track 2 Brief at 9-11, 13; D.P.U. 21-91, FreeWire Track 2 Brief at 9-10, 12).

iii. Electrify America

Electrify America opposes the Attorney General's recommendation for the Department to direct the Companies to develop a load management plan because: (1) it would overlap with existing energy efficiency programs; (2) it would be premature to develop load management programs before at least one year of program data is collected; (3) DCFC load is largely inelastic and load management programs would increase EV charging time and frustrate EV drivers; and

(4) the record does not support the urgent need for EV-related load management programs (D.P.U. 21-90, Electrify America Track 1 Brief at 6-8; D.P.U. 21-91, Electrify America Track 1 Brief at 7-9; D.P.U. 21-90, Electrify America Track 2 Brief at 9-11; D.P.U. 21-91, Electrify America Track 2 Brief at 9-11; D.P.U. 21-90, Electrify America Track 2 Reply Brief at 5-7; D.P.U. 21-91, Electrify America Track 2 Reply Brief at 5-7). According to Electrify America, any future load management programs for EV charging loads should be coordinated with the Companies' energy efficiency programs and informed by actual EV charging data collected during program operation (D.P.U. 21-90, Electrify America Track 2 Brief at 11; D.P.U. 21-91, Electrify America Track 2 Brief at 11).

iv. CEP

CEP recommends that the Department direct the companies to develop TOU rates or strengthen their load management programs to send more appropriate price signals to customers (D.P.U. 21-90, CEP Track 1 Brief at 20; D.P.U. 21-91, CEP Track 1 Brief at 20-21; D.P.U. 21-90/D.P.U. 21-91, CEP Track 1 Reply Brief at 10-11).

v. NSTAR Electric and National Grid

NSTAR Electric and National Grid argue that the Attorney General's recommendation to open a generic proceeding on load management is unnecessary and outside the scope of this proceeding (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 26). Nevertheless, NSTAR Electric and National Grid state that they would be amenable to providing a framework that outlines current and future solutions for management of EV-related load and provide it and any relevant updates as part of their respective annual compliance filings to the Department (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National

Grid Joint Track 2 Reply Brief at 26). Furthermore, NSTAR Electric and National Grid do not oppose the formation of a load management working group but recommend that the companies first capture and report on initial lessons learned during the first year of program implementation before initiating the load management working group because the initial lessons learned will help inform the stakeholder engagement (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 31; D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 26-27).

Additionally, NSTAR Electric requests that the Department reject the Attorney General's recommendation to condition approval of its program expenditures in the third year of the EV program on the successful development of additional managed charging options because: (1) the company already provides managed charging options for different devices and supports opt-in participation for select non-residential customers with inflexible EV loads, and (2) the company will use lessons learned from more widespread EV charger deployment to evaluate the efficacy and cost of current and future managed charging solutions (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 30).

vi. Unitil

Unitil asserts that the Attorney General's load management and advanced rate design recommendations should be dismissed because: (1) they are beyond the scope of this proceeding, impractical, and irrelevant; (2) it is premature for the company to develop a comprehensive load management plan because there is not enough EV-related load on the company's distribution system to warrant its development; and (3) the company has not yet had the opportunity to test and evaluate embedded EVSE metering technology in the field and does

not have sufficient data to create a comprehensive load management plan (D.P.U. 21-92, Unitil Track 1 Reply Brief at 10-11; D.P.U. 21-92, Unitil Track 2 Brief at 23-27). In addition, Unitil notes that this is the company's first EV program and argues that it would be prudent for the company to first collect data on utilization factors, peak demands, and cost implications before developing a load management plan or developing complex rate design proposals (D.P.U. 21-92, Unitil Track 2 Brief at 23-24, 26, 27-28). Accordingly, Unitil requests that the Department reject the Attorney General's load management and advanced rate design recommendations at this time (D.P.U. 21-92, Unitil Track 1 Reply Brief at 11).

c. Marketing and Outreach Plan

i. Attorney General

The Attorney General recommends that the Department direct NSTAR Electric and National Grid to file a detailed marketing and outreach plan in a compliance filing in these proceedings that is subject to Department and stakeholder review and Department approval that: (1) identifies and prioritizes certain customers that align with the Attorney General's recommended prioritization framework; (2) includes a messaging strategy and sample communications for conveying the importance of and options for load management as an accompaniment to EV charging infrastructure; (3) provides a timeline for communications that identifies specific communication types or each communication touchpoint; (4) includes a strategy for implementing dedicated outreach to ensure that NSTAR Electric and National Grid are reaching low-income and EJ community customers, including plans to work with community action program agencies and community organizations; (5) includes a detailed strategy for reaching customers through a variety of channels; and (6) describes how iterations of the

marketing and outreach process will integrate results from the program evaluation (D.P.U. 21-90, Attorney General Track 1 Brief at 77; D.P.U. 21-91, Attorney General Track 1 Brief at 90-92).

ii. Other Intervenors

DOER encourages the Department to direct the Companies to conduct direct outreach to customers regarding the availability of the DCA rates through multiple venues, which could include direct mail, bill inserts, emails, website postings, and communication with municipal officials (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 2 Brief at 8).

iii. NSTAR Electric and National Grid

NSTAR Electric and National Grid urge the Department to reject the Attorney General's recommendation to direct the companies to submit a detailed marketing and outreach plan in a compliance filing for Department and stakeholder review and Department approval because the companies have committed to working with stakeholders on the development of their marketing and outreach strategies (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 74). Moreover, the companies state that the Department and stakeholders will have the ability to review the companies' marketing collateral as part of their annual cost recovery filings (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 74). NSTAR Electric and National Grid, therefore, request that the Department approve the companies' marketing and outreach proposals (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 74).

Regarding outreach on the DCA rate offerings, NSTAR Electric and National Grid propose to publicize the DCA rate offerings to existing and prospective customers through a number of channels, including: (1) EVSE vendors with existing relationships with customers;

(2) direct outreach to EV charging station developers and customers with multiple EV charging sites with existing relationships with the companies; and (3) outreach (e.g., via brochures or other materials) to EVSE customers on National Grid's G-1, G-2, and G-3 rates; (4) for new customers, the make-ready application will include an option for customers to learn more about and/or sign up for the DCA rates; and (5) additional information that will be sent to customers along with the commitment letter for the project, which will include an option to opt-in to the DCA rates (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 14).

d. National Grid Off-Peak Charging Rebate Program

i. Attorney General

The Attorney General encourages the Department to direct National Grid to make the following four modifications to its proposed off-peak charging rebate program: (1) customers should be provided with the option to participate via vehicle telematics and networked EVSE; (2) the program should be expanded to public, workplace, and MUD customers; (3) the program should be implemented within six months of Department approval in this proceeding; and (4) the company should develop a program evaluation plan for its proposed flexible scheduling offering (D.P.U. 21-91, Attorney General Track 1 Brief at 59-60).

ii. Other Intervenors

GECA argues that the Department should direct National Grid to increase the value of its off-peak charging rebate and extend the rebate program to weekend hours (D.P.U. 21-90/D.P.U. 21-91, GECA Track 1 Brief at 4, 10-12). GECA also recommends that the Department direct NSTAR Electric to develop and implement an off-peak charging rebate

program that includes rebates for off-peak EV charging during weekend hours (D.P.U. 21-90/D.P.U. 21-91, GECA Track 1 Brief at 4, 12). DOER, however, contends that the Department should not require NSTAR Electric to propose an off-peak charging rebate program similar to National Grid's because NSTAR Electric's existing managed charging program is sufficient to manage its current peak demand (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 21).

iii. NSTAR Electric and National Grid

National Grid opposes the Attorney General's recommendation to expand the off-peak charging rebate program to public, workplace, and MUD customers with networked EVSE because EV drivers alone are responsible for the charging decisions for their vehicles and expanding the off-peak charging rebate program to EV charging station operators increases the odds of duplicate incentives for a single act of EV charging (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 57). Accordingly, National Grid encourages the Department to reject the Attorney General's recommendation to expand the off-peak charging rebate program (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 57).

In response to GECA's recommendation for NSTAR Electric to develop an off-peak charging rebate program similar to National Grid's proposal, NSTAR Electric argues that it would be more prudent for the company to evaluate the results of National Grid's pilot program before developing its own off-peak charging rebate program (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 57).

e. National Grid Pole-Mounted EVSE Program

i. Attorney General

The Attorney General recommends that the Department deny National Grid's proposal to deploy pole-mounted EV chargers because the proposal is inconsistent with Department precedent (D.P.U. 21-91, Attorney General Track 1 Brief at 74-77). According to the Attorney General, third-party ownership of EVSE is preferable and the company failed to demonstrate that the private market would not address the gap in EV charging in the absence utility ownership (D.P.U. 21-91, Attorney General Track 1 Brief at 74-77). Alternatively, the Attorney General recommends that the Department direct National Grid to identify optimal pole locations and to issue a RFP to provide the opportunity for private developers to enter the pole-mounted EVSE market before the company does (D.P.U. 21-91, Attorney General Track 1 Brief at 77).

ii. Other Intervenors

DOER supports approval of National Grid's proposed pole-mounted EVSE program but recommends that the Department direct the company to develop metrics for the program and to work with municipalities on strategies to support the program (D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 22). Further, DOER contends that the company should be required to evaluate the success of the program in reaching customers, how the program design contributed to that success, and any improvements that could be made to the program (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 22). DOER also argues that National Grid should be required to resolve outstanding concerns with the program, including the manner in which the company will coordinate with municipalities and stakeholders

in implementing the program and any appropriate parking restrictions, prior to program implementation (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 23).

ChargePoint, however, opposes National Grid's proposed pole-mounted EVSE program because it does not provide municipalities the ability to set the prices for the EV charging services, which, in turn, could allow the company to undercut the competitive industry's EV charging pricing (D.P.U. 21-91, ChargePoint Track 1 Brief at 1, 8-12; D.P.U. 21-91, ChargePoint Track 1 Reply Brief at 7). ChargePoint also argues that the company claims without evidence that it needs to own the pole-mounted EVSE for it to run efficiently, fails to support the basis for its ownership and operation of these assets for a four-year period, or what will occur if no third-party is interested in purchasing these assets after four years (D.P.U. 21-91, ChargePoint Track 1 Brief at 1, 8-12; D.P.U. 21-91, ChargePoint Track 1 Reply Brief at 7). If the Department approves National Grid's pole-mounted EVSE proposal, ChargePoint recommends that the Department direct the company to: (1) allow municipalities to set pricing policies for EVSE within their cities and towns; (2) sell the pole-mounted EVSE to the competitive market once these stations have been energized and are operable; and (3) if the company is unable to sell the pole-mounted EVSE after four years, to refrain from seeking recovery for costs related to the program (D.P.U. 21-91, ChargePoint Track 1 Brief at 1, 9, 11; D.P.U. 21-91, ChargePoint Track 1 Reply Brief at 7).

iii. National Grid

National Grid urges the Department to approve its pole-mounted EVSE proposal because: (1) utility ownership of pole-mounted EVSE eliminates the need to adhere to the complex third-party attachment process, accelerates the timeline for EVSE deployment, and

reduces EVSE deployment costs; (2) it would provide EV charging options for customers without access to at-home charging; (3) the EVSE would be located in publicly accessible locations; and (4) 50 percent of the EVSE deployed through this program would be located in EJ communities (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 39-41).

C. Analysis and Findings

1. Introduction

In Electric Vehicles, D.P.U. 13-182-A at 13 (2014), the Department established three criteria that an electric distribution company EV charging infrastructure proposal must meet in order to receive Department approval. Specifically, any EV charging infrastructure proposal must: (1) be in the public interest; (2) meet a need regarding the advancement of EVs in the Commonwealth that is not likely to be met by the competitive EV charging market; and (3) not hinder the development of the competitive EV charging market. D.P.U. 13-182-A at 13.

Generally, the parties to these proceedings support the Department's approval of the Companies' EV program proposals but recommend certain modifications. Below, the Department first addresses whether the Companies' EV program proposals comply with the requirements established in D.P.U. 13-182-A. Then, the Department addresses the proposed modifications to the Companies' EV program proposals.

2. Compliance with D.P.U. 13-182-A

The Companies maintain that their proposed EV charging programs will help accelerate deployment of EV charging infrastructure in the state, expand the opportunities for market participants to gain experience owning and operating EVSE, and support the Commonwealth's

public policy goals (D.P.U. 21-90, Exh. ES-KB-1, at 32-33; D.P.U. 21-91, Exh. NG-EVPP-1, at 32-33; D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 8). No intervenor to this proceeding contests that the Companies' proposed EV programs meet the Department's three-part standard of review for EV program approval established in D.P.U. 13-182-A. Indeed, all of the intervenors urge the Department to approve the Companies' proposed EV programs with some modifications.

Based on our review of the EV proposals, the Department determines that NSTAR Electric's and National Grid's proposed Phase II and Phase III EV programs, respectively, build on their experience with their Phase I EV programs and include a variety of offerings to meet the diverse needs of EV drivers in the Commonwealth (D.P.U. 21-90, Exh. ES-KB-1, at 6; D.P.U. 21-91, Exh. NG-EVPP-1, at 8). Unitil's proposed EV program will be its first and will support the deployment of EV charging infrastructure within its service territory (D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 8). Together, these EV program proposals will help to put the Commonwealth on the path to achieving its ZEV MOU targets through the deployment of EV charging infrastructure, which will, in turn, contribute to more EV adoption in the Commonwealth (D.P.U. 21-90, Exh. ES-KB-1, at 6; D.P.U. 21-91, Exh. NG-EVPP-1, at 8; D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 8).

The Companies' proposed investments in make-ready infrastructure will lower the financial barriers to EVSE ownership (D.P.U. 21-90, Exhs. ES-KB-1, at 40; CEP-1, at 46; D.P.U. 21-91, Exhs. NG-EVPP-1, at 40; CEP-1, at 50; D.P.U. 21-92, Exh. CSVG (Rev.) at 32). The EV charging infrastructure that will be deployed through the proposed EV programs will incentivize the deployment of EV charging infrastructure necessary to support the Commonwealth's transportation electrification goals and assist the Commonwealth in its

transition to a clean transportation future (D.P.U. 21-90, Exhs. ES-KB-1, at 6; CEP-1, at 46-47; CP-KGM-1, at 6-7; D.P.U. 21-91, Exhs. NG-EVPP-1, at 8; CEP-1, at 50-51; CP-KGM-1, at 8-9; D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 8). Further, the EV program proposals aim to deploy EV charging infrastructure equitably, which will help address the disproportionate environmental burdens borne by EJ communities (D.P.U. 21-90, Exhs. ES-KB-1, at 9-11; CEP-1, at 47; CP-KGM-1, at 7; D.P.U. 21-91, Exhs. NG-EVPP-1, at 11-13; CEP-1, at 51; CP-KGM-1, at 9; D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 12, 54). Therefore, the Department finds that the Companies' EV program proposals are in the public interest.

Second, the Companies' proposed EV programs would recruit site hosts to promote and accelerate the construction of EV charging stations (D.P.U. 21-90, Exh. ES-KB-1, at 28-29; D.P.U. 21-91, Exh. NG-EVPP-1, at 53; D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 37). Through the recruitment of public and workplace site hosts, residential customers, and fleet customers and incentivizing the deployment of EV charging infrastructure, the Companies' proposed EV programs would assist the Commonwealth to meet a need regarding the advancement of EVs in the Commonwealth that is not likely to be met by the competitive EV charging market in the near term and help the Commonwealth achieve its ZEV MOU goals (D.P.U. 21-90, Exh. ES-KB-1, at 6-9; D.P.U. 21-91, Exh. NG-EVPP-1, at 8-11; D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 31-43). Accordingly, the Department finds that the proposed EV programs meet the second prong of the standard of review for EV program approval outlined in D.P.U. 13-182-A.

Finally, the Companies' EV program proposals seek to install EV charging infrastructure up to the EVSE and lower cost barriers for site hosts without limiting their ability to choose an EVSE vendor (D.P.U. 21-90, Exhs. ES-KB-1, at 6-9; CEP-1, at 49-50; D.P.U. 21-91,

Exhs. NG-EVPP-1, at 8-11; CEP-1, at 55; D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 31-43). Moreover, given the current EV market and the limited EV charging options available, the proposed EV programs will incentivize EVSE deployment, which will support increased EV adoption and improve EV charging station utilization and, importantly, the business case for further EV charging station development funded by the competitive market (D.P.U. 21-90/ D.P.U. 21-91, Exh. GL-TA-1, at 7; D.P.U. 21-90, CEP-1, at 24-25; D.P.U. 21-91, CEP-1, at 25). Thus, the Department finds that the Companies' EV program proposals do not hinder the development of the competitive EV charging market.

In sum, the Department finds that the Companies' proposed EV programs are in the public interest and will support the Commonwealth's public policy goals, meet a need for more EV charging infrastructure and EVSE that has not been met by the competitive market, and will support, rather than hinder, the competitive EV charging market. Therefore, as a general matter, the Department finds that the Companies' EV program proposals meet the three-part standard established in D.P.U. 13-182-A and, after review of the proposals and intervenor arguments, the Department finds it reasonable and appropriate to approve the Companies' EV program proposals with certain modifications, as discussed below.

Notwithstanding this determination, the Department acknowledges that, during the course of these proceedings and after the close of the evidentiary record, the General Court adopted several policies that change the policy landscape for encouraging the deployment of EV charging infrastructure in the Commonwealth. An Act Driving Clean Energy and Offshore Wind, St. 2022, c. 179 ("2022 Clean Energy Act"). These policies include the establishment of the Charging Infrastructure Deployment Fund, and the formation of an intergovernmental

coordinating council ("EV Coordinating Council") to implement a statewide, coordinated approach to EV charging infrastructure deployment. St. 2022, c. 179, § 81. The law requires the Massachusetts Department of Transportation to analyze operation of charging stations at service plazas, as well as install and maintain EV charging stations at various public locations. St. 2022, c. 179, § 89. The 2022 Clean Energy Act further requires the development of TOU rate proposals by the Companies for review by the Department. St. 2022, c. 179, § 90. The Legislature also required that, going forward, electric distribution company proposals for facilitating transportation electrification be developed and incorporated in the electric sector modernization plans established pursuant to G.L. c. 164, § 92B. The 2022 Clean Energy Act also establishes a stakeholder group to review and provide input on such plans. St. 2022, c. 179, § 53. Accordingly, the Department expects that the Companies will implement their programs in a manner that aligns with the 2022 Clean Energy Act. Further, future EV charging infrastructure program proposals, including, at a minimum, any distribution system-related investments, will be developed through the process set forth in St. 2022, c. 179, § 53, described in further detail in Section VI, below.

3. Make-Ready Rebates

a. Make-Ready Proposals

NSTAR Electric and National Grid propose to offer rebates for 100 percent of the make-ready costs on the utility side of the meter for all program segments (D.P.U. 21-90, Exh. ES-KB-1, at 43, 50, 60, 67-68; D.P.U. 21-91, Exh. NG-EVPP-1, at 43, 56, 65, 73). NSTAR Electric and National Grid also propose to offer rebates for up to 100 percent of the average installation costs of the infrastructure on the customer side of the meter, not to exceed actual

installation costs, for the public, workplace, MUD, and fleet segments, and 100 percent of the customer-side make-ready costs for one to four-unit residential customers, up to a specific dollar amount cap (D.P.U. 21-90, Exh. ES-KB-1, at 43, 50, 60, 67-68; D.P.U. 21-91, Exh. NG-EVPP-1, at 43, 56, 65, 73).[34] Unitil proposes to offer rebates to cover 100 percent of infrastructure costs on both sides of the meter for all program segments (D.P.U 21-92, Exh. CSVG-1 (Rev.) at 36, 38).

The Attorney General recommends three restrictions on make-ready rebate eligibility. First, the Attorney General suggests that make-ready rebates be limited to 80 percent of the average installation costs of infrastructure on both the utility side and the customer side of the meter, not to exceed actual costs, for non-publicly accessible, non-EJ community sites,[35] publicly-owned fleets operating outside of EJ communities, and small private fleets operating in EJ communities (D.P.U. 21-90, Attorney General Track 1 Brief, App. Table A, C; D.P.U. 21-91, Attorney General Track 1 Brief, Appendix Table A, C; D.P.U. 21-92, Attorney General Track 1 Brief at 26). Second, the Attorney General recommends restricting make-ready rebates for the residential segment to low- and moderate-income customers (D.P.U. 21-90, Attorney General

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34 To account for certain site-specific characteristics and potential cost-shifts in the industry, NSTAR Electric and National Grid propose to provide up to 150 percent of the average installation costs of the infrastructure on the customer side of the meter on a case-by-case basis for the public and workplace and MUD segments (D.P.U. 21-90, Exh. ES-KB-1, at 43, 50; D.P.U. 21-91, Exh. NG-EVPP-1, at 43, 57, 65). In addition, NSTAR Electric proposes to provide up to 150 percent of the average installation costs of the infrastructure on the customer side of the meter on a case-by-case basis for the fleet segment (D.P.U. 21-90, Exh. ES-KB-1, at 68).

35 This recommendation refers to sites in both the public and workplace and MUD segments (D.P.U. 21-90, Attorney General Track 1 Brief, App. Tables A-B; D.P.U. 21-91, Attorney General Track 1 Brief, App. Tables A-B).

Track 1 Brief, App. Table B; D.P.U. 21-91, Attorney General Track 1 Brief, App. Table B; D.P.U. 21-92, Attorney General Track 1 Brief at 27, 30). Finally, the Attorney General suggests eliminating fleet make-ready rebates for large private fleet customers (D.P.U. 21-90, Attorney General Track 1 Brief, App. Table C; D.P.U. 21-91, Attorney General Track 1 Brief, App. Table C). In response, the Companies and CLF argue that the Attorney General's proposal to restrict make-ready rebates for certain program segments will hinder the Commonwealth's ability to achieve its ZEV MOU and decarbonization goals (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 16-17; D.P.U. 21-90, CLF Track 1 Brief at 4-5, 31; D.P.U. 21-92, Unitil Track 1 Reply Brief at 2-4).

Rebates serve to reduce the financial barriers for site hosts to adopt EV charging stations. D.P.U. 17-13, at 30. In these proceedings, the Department is persuaded that, without incentives, the high costs of EV charging infrastructure would likely dissuade the private EV market from investing in EVSE and DCFCs, in particular, where the cost of EV charging infrastructure is a significant, and sometimes prohibitive, barrier to DCFC installation (D.P.U. 21-90, Exhs. ES-KB-1, at 18; CEP-1, at 24-25; GL-TA-1, at 6-7; CP-KGM-1, at 7-8; EVG-CD-1, at 11; FW-1, at 17; D.P.U. 21-91, Exhs. NG-EVPP-1, at 20-21; CEP-1, at 25-26; GL-TA-1, at 8-10; CP-KGM-1, at 9; EVG-CD-1, at 12; FW-1, at 17; D.P.U. 21-92; Exhs. CSVG-1 (Rev.) at 31-32; CP-KGM-1, at 8). While the EV charging market continues to develop in the Commonwealth, the Department finds that make-ready rebates will play an important role in the achievement of the Commonwealth's transportation electrification and decarbonization goals by incentivizing the installation of EVSE, which will, in turn, support an increase in EV adoption in the Commonwealth (D.P.U. 21-90, Exhs. ES-KB-1, at 6; CEP-1, at 46-47; CP-KGM-1, at 6-7;

D.P.U. 21-91, Exhs. NG-EVPP-1, at 8; CEP-1, at 50-51; CP-KGM-1, at 8-9; D.P.U. 21-92, Exh. CSVG-1, at 8).

Given the level of EV charging deployment to date and because EV charging infrastructure costs constitute the majority of the costs associated with deploying EV charging stations, the Department determines that the Companies' make-ready rebate proposals are reasonable. On the other hand, we find that the reductions proposed by the Attorney General to the make-ready rebates could impact the deployment of EV charging stations significantly, and, in turn, has the potential to hinder the Commonwealth's ability to achieve its transportation electrification and decarbonization goals. The Department recognizes that, as the competitive EV charging market grows, and additional funds enabled by the Legislature become available, the need for significant financial incentives to deploy EV charging sites will likely diminish. See D.P.U. 13-182-A at 13 (finding that a utility proposal must meet a need unlikely to be met by the competitive market). But, given the current status of EV charging station deployment in the Commonwealth, the Department declines to adopt the Attorney General's recommended reductions to the make-ready rebates.[36]

Finally, the Department determines that the Companies' proposed EV program budgets properly allocate the majority of budgeted costs towards addressing the high cost of EV charging infrastructure. Specifically, the Companies' proposed make-ready rebates comprise more than

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[36] The Department notes that, in Section III.C.4.a-d, below, the Department requires certain modifications to the Companies' EVSE rebates that are in line with the intent of the Attorney General's recommended reductions to the make-ready rebates. For instance, the Department limits EVSE rebates to public fleets and prioritizes EJ communities, particularly those that meet the EJ criteria based on income.

77 percent of the total public and workplace segment budget and more than 70 percent of the total residential segment budget (D.P.U. 21-90, Exhs. ES-KB-6, ES-KB-7, ES-KB-8; D.P.U. 21-91, Exhs. NG-EVPP-5, NG-EVPP-7, NG-EVPP-8; D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 35-36).[37] Based on the foregoing reasons, the Department declines to restrict make-ready rebates for the public and workplace, residential, and fleet segments, as proposed by the Attorney General, except that make-ready rebates must not exceed actual make-ready installation costs. Accordingly, the Department approves the Companies' make-ready rebate proposals.

b. Unitil Make-Ready Rebate Calculation

Unitil proposes to offer make-ready rebates for 100 percent of the actual infrastructure costs on both the utility and the customer side of the meter (D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 36, 39). The Attorney General argues that Unitil's public segment make-ready rebates should be based on average make-ready installation costs rather than actual make-ready installation costs because, under the current proposal, customers have no incentive to adopt EV EMS (D.P.U. 21-92, Attorney General Track 1 Brief at 26). Due to the absence of historical cost data to calculate company-specific average make-ready installation costs, the Attorney General recommends that Unitil apply National Grid's average make-ready installation cost data to

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37 National Grid's fleet budget includes the proposed budgets for its EJ community school bus rebate offering proposal, utility-side system expansion proposal, and fleet assessment services proposal (D.P.U. 21-91, Exh. NG-EVPP-1, at 123). Removing those costs from the fleet budget, make-ready rebates comprise 65 percent of National Grid's total fleet segment budget. NSTAR Electric's fleet segment budget is intertwined with its public and workplace segment budget and, therefore, a similar comparison of the percentage of make-ready budget to total fleet segment budget could not be readily calculated (D.P.U. 21-90, Exh. ES-KB-4).

estimate comparable average make-ready installation costs for the first 18 months of Unitil's EV program and to use average make-ready installation costs to determine make-ready financial support for EV EMS (D.P.U. 21-92, Attorney General Track 1 Brief at 26). For the following reasons, we decline to adopt the Attorney General's recommendations.

Unitil's program budget is based on cost estimates developed by and for the company (D.P.U. 21-92, Exh. CVG-Rebuttal-1 (Rev.) at 26). Nothing in the record suggests that Unitil's make-ready infrastructure cost estimates are inaccurate or inappropriate for purposes of calculating make-ready installation costs, or that National Grid's company-specific average make-ready installation costs are more appropriate than the Unitil-specific cost estimates proposed. Accordingly, based on our review of Unitil's cost estimates, the Department determines that Unitil's proposed make-ready installation cost calculations are reasonable and appropriate.[38]

c. EV Energy Management Systems

As part of their proposed make-ready rebates, NSTAR Electric and National Grid propose to offer incentives for EV EMS to public, workplace, and MUD customers (D.P.U. 21-90, Exh. ES-KB-1, at 61-62; D.P.U. 21-91, Exh. NG-EVPP-1, at 66-67; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 4, at 811-819). The Attorney General recommends that the Department direct NSTAR Electric and National Grid to develop a standard site evaluation methodology to determine whether EV EMS can support EV charging

[38] Unitil's proposal is silent on whether the company proposes to offer rebates for EV EMS to public segment customers. Unitil is not precluded from offering rebates for EV EMS to public segment customers and, should the company decide to do so, it shall follow the same procedure outlined in Section III.C.3.c, below.

infrastructure installation at a cost less than hardware-based capacity upgrades while still meeting the customers' charging needs and, if so, to develop guidelines to support EV EMS deployment if deployment is low after two years (D.P.U. 21-90, Attorney General Track 1 Brief at 58-64; D.P.U. 21-91, Attorney General Track 1 Brief at 67-74). Alternatively, the Attorney General proposes that NSTAR Electric and National Grid develop a site evaluation method to assess the cost-effectiveness of EV EMS at a particular site and to allow EV program funding for EV EMS only to sites where EV EMS deployment would generate overall cost savings for the project (D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 17-18). NSTAR Electric and National Grid oppose the Attorney General's recommendations and assert that their proposal to include rebates for EV EMS costs in customer-side make-ready offerings provides sufficient incentive for program participants to pursue EV EMS (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 33).

NSTAR Electric and National Grid acknowledge that EV EMS may, in certain circumstances, reduce a project's overall infrastructure costs (D.P.U. 21-90, Exh. ES-KB-Rebuttal-1 (Rev.) at 35; D.P.U. 21-91, Exh. NG-EVPP-Rebuttal-1 (Rev.) at 39). Nevertheless, the companies argue that, based on their experience and examples from Southern California Edison and Pacific Gas & Electric, EV EMS is less likely to be a cost-effective option for sites below 100 KVa and urge a case-by-case consideration of EV EMS for sites with new services of at least 100 KVa (D.P.U. 21-90, Exh. ES-KB-Rebuttal-1 (Rev.) at 35-37; D.P.U. 21-91, Exh. NG-EVPP-Rebuttal-1 (Rev.) at 39-41).

Based on the record, the Department determines that a case-by-case evaluation of the cost-effectiveness of EV EMS for public and workplace and MUD customers is reasonable. A

case-by-case evaluation will allow for a more nuanced review of the cost-effectiveness of EV EMS for a particular site. Therefore, the Department declines to adopt the Attorney General's recommendation. Nonetheless, the Department directs the companies to inform public, workplace, and MUD customers about the availability of additional incentives for EV EMS for project sites likely to have on site load constraints.

Next, FreeWire requests modifications to NSTAR Electric's and National Grid's proposed public and workplace segment offerings to include additional financial support for EVSE with EMS or, in the alternative, for the companies to offer a discrete incentive for deploying EV EMS that uses avoided distribution upgrade costs as the baseline for determining the value of the incentives (D.P.U. 21-90, FreeWire Track 1 Brief at 9-10; D.P.U. 21-91, FreeWire Track 1 Brief at 9-10; D.P.U. 21-90/D.P.U. 21-91, FreeWire Track 1 Reply Brief at 2; D.P.U. 21-90, FreeWire Track 1 Brief at 13; D.P.U. 21-91, FreeWire Track 1 Brief at 13). We decline to do so. The Department finds that EV EMS may be a cost-effective solution for some projects, but declines to allow the use of ratepayer funds for incentives that uniformly encourage EMS offerings before EMS is determined to be a cost-effective solution for a particular site. Therefore, the Department approves financial incentives for EV EMS as determined on a case-by-case basis, as described above.

4. EVSE Rebates

a. Environmental Justice Communities

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. Further, as part of any new or revised EV charging infrastructure

program proposal, the Department expected the Companies to use their experience implementing existing programs to further increase the accessibility of EV chargers in EJ communities and to consider appropriate measures to decrease barriers to the installation of EV chargers in all communities across their service territories, including EJ communities. D.P.U. 20-69-A at 46, 49-50.

EOEEA defines an environmental justice population as a neighborhood that meets one or more of the following EJ criteria: (1) the annual median household income is 65 percent or less of the statewide annual median household income; (2) minorities comprise 40 percent or more of the population; (3) 25 percent or more of households lack English language proficiency; or (4) minorities comprise 25 percent or more of the population and the annual median household income of the municipality in which the neighborhood is located does not exceed 150 percent of the statewide annual median household income. Environmental Justice Policy of the Executive Office of Energy and Environmental Affairs at 4 (June 24, 2021).[39] Additionally, EOEEA's Secretary may designate a geographic portion of a neighborhood as an EJ population in accordance with law. Environmental Justice Policy of the Executive Office of Energy and Environmental Affairs at 4 (June 24, 2021). Previously, in D.P.U. 17-05, at 473, 478 and D.P.U. 17-13, at 24, 30, the Department approved NSTAR Electric's and National Grid's respective Phase I EV program proposals to provide enhanced EVSE rebates to customers located in communities that meet at least two of the Commonwealth's EJ criteria, with the

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39 Available at https://www.mass.gov/doc/environmental-justice-policy6242021-update/download. We note that, in the instant proceedings, NSTAR Electric and National Grid rely on the definition of EJ population that was contained in an earlier version of EOEEA's EJ policy.

exception of NSTAR Electric's Western Massachusetts service territory where customers in communities that met at least one of the Commonwealth's EJ criteria were eligible for enhanced rebates.

In these proceedings, NSTAR Electric and National Grid propose to offer enhanced rebates to public, workplace, MUD (i.e., dwellings with five or more units), and fleet customers who are located or operate in a community that meets at least one of the Commonwealth's EJ criteria (D.P.U. 21-90, Exh. ES-KB-1, at 55 n.75; D.P.U. 21-91, Exh. NG-EVPP-1, at 62).[40,41] Specifically, for the public and workplace, NSTAR Electric and National Grid propose to offer 100 percent EVSE rebates to customers located in EJ communities that meet one EJ criteria (D.P.U. 21-90, Exh. ES-KB-1, at 45; D.P.U. 21-91, Exh. NG-EVPP-1, at 12). For MUDs, the companies propose to offer up to 100 percent of the average cost per port for sites in EJ communities and 50 percent of the average cost per port for other sites, not to exceed actual costs. (D.P.U. 21-90, Exh. ES-KB-1, at 50-51 D.P.U. 21-91, Exh. NG-EVPP-1, at 57, 65-67). For its light-duty fleet segment and its medium- and heavy-duty fleet pilot proposal, NSTAR Electric proposes to offer 100 percent EVSE rebates to fleet customers registered in an EJ community or who operate more than 50 percent of the time within census block groups that meet at least one of the Commonwealth's EJ criteria (D.P.U. 21-90, Exh. ES-KB-1, at 11,

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40 Unitil does not propose EVSE rebates for public, MUD, or fleet customers.

41 Although MUDs serve residential customers, those receiving EVSE rebates as MUD owners or operators are non-residential customers. The rebates discussed in this section do not apply to residents residing in MUDs. We address NSTAR Electric's, National Grid's, and Unitil's EVSE rebate proposals for residential customers in one to four-unit dwellings separately in Section III.C.4.c.i, below.

67-68). For its fleet segment, National Grid proposes to offer 100 percent EVSE rebates to all fleet customers that are either registered in an EJ community or operate more than 50 percent of the time within census block groups that meet at least one EJ criteria (D.P.U. 21-91, Exh. NG-EVPP-1, at 13, 73, 80).

The Department is committed to ensuring the equitable distribution of EV program benefits in the Commonwealth. To that end, the Department finds that it is reasonable and appropriate for NSTAR Electric and National Grid to offer enhanced rebates for EVSE for public, workplace, MUD, and fleet customer segments located in EJ communities that meet one EJ criteria, including fleets that operate more than 50 percent of the time within census block groups that meet at least one EJ criteria.[42] To ensure consistency, the Department directs the companies to incorporate the updated definitions and EJ criteria provided in EOEEA's most recent EJ Policy issued on June 24, 2021 and to rely on 2020 U.S. Census data to assess whether a location qualifies as an EJ community. We expect the enhanced rebates to incentivize the deployment of EVSE in EJ communities which, in turn, will enhance opportunities for EJ populations to more readily participate in the companies' electrification offerings and to benefit from the positive environmental impacts from transportation electrification. In sum, the Department approves NSTAR Electric's and National Grid's proposal to offer enhanced EVSE rebates based on a community satisfying at least one EJ criteria for non-residential customers, subject to the additional requirements outlined below.

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42 Here, we define EJ fleet customers to include those that are either registered in an EJ community or operate more than 50 percent of the time within census block groups that meet at least one EJ criteria (D.P.U. 21-90, Exh. ES-KB-1, at 55 n.75; D.P.U. 21-91, Exh. NG-EVPP-1, at 62).

While the Department agrees with the companies' proposals to provide enhanced EVSE rebates for certain customer segments within EJ communities, the Department seeks to balance the use of ratepayer funding in a manner that maximizes the goals of the EV programs. As discussed above, the criteria for EJ communities are not solely income-based, and some higher-income communities may meet the criteria of an EJ community.[43] As the Attorney General noted, higher-income communities are more likely to have access to public and residential EV charging (D.P.U. 21-90, Exh. AG-REN-CP-Surrebuttal-1, at 8-9). Therefore, the Department finds that a sliding scale of incentives that places a higher priority on communities that meet the Commonwealth's EJ criteria based on income (i.e., communities where the annual median household income is 65 percent or less of the statewide annual median household income) is appropriate across all non-residential customer segments to support participation in areas with the greatest financial barriers to EV adoption which, in turn, will allow for a more equitable distribution of benefits.[44] The Department has previously adopted a sliding scale of incentives based on certain customer characteristics. Specifically, in D.P.U. 17-13, at 25, 30, the

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43 For example, the Town of Lexington, Block Group 4, Census Tract 3584 is an EJ community but has a median household income of over $190,000 or over 225 percent of state median household income. Similarly, the Seaport Area of Boston, Block Group 1, Census Tract 606.04 is an EJ community but has a median household income of over $240,000 or over 285 percent of state median household income. See The EOEEA EJ Map Viewers, available at, https://mass-eoeea.maps.arcgis.com/apps/webappviewer/index.html?id=1d6f63e7762a48e5930de84ed4849212 (last visited December 28, 2022).

44 In Section III.C.4.c.i, below, the Department addresses CLF's recommendation for a sliding scale of incentives that provides higher incentives to residential program customers based on the number of EJ criteria that a community meets (see D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 1 Reply Brief at 10-11).

Department approved a tiered level of EVSE rebates based on site type.[45] Accordingly, the Department finds that the highest level of funding should be reserved for the installation of EVSE in communities that meet the EJ criterion based on income and directs NSTAR Electric and National Grid to implement the following sliding scale of EVSE rebates for EJ community customers as part of their public and workplace, MUDs (i.e., five or more units), and fleet programs: (1) a 100 percent EVSE rebate for non-residential customers in EJ communities that meet the EJ criteria based on income; and (2) a 75 percent EVSE rebate for non-residential customers in EJ communities that meet any of the other EJ criteria.[46,47]

The Department emphasizes that our limitation of eligibility for rebates of 100 percent of EVSE costs, and the reduction to 75 percent for EVSE rebates for customers in communities that meet any of the other three EJ criteria, is not intended to diminish the importance of the other EJ criteria. Rather, the record shows that EV charging infrastructure deployment disproportionately benefits higher-income customers and communities with greater financial resources (D.P.U. 21-90, Exhs. AG-REN-CP-Surrebuttal-1, at 8-9, 10-11; AG-REN-1, at 27; D.P.U. 21-91, Exhs. AG-REN-CP- Surrebuttal-1, at 7-11; AG-REN-1, at 27-28; D.P.U. 21-92,

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45 In D.P.U. 17-13, at 25, as part of National Grid's Phase I EV program, the Department approved EVSE rebate levels of: (1) up to 50 percent of costs for workplace/business site hosts; (2) up to 75 percent of costs for multi-unit dwelling owners, public entities, and non-profits; and (3) up to 100 percent of costs for participants in EJ communities. D.P.U. 17-13, at 25, 30. NSTAR Electric's Phase I EV program did not include rebates for EVSE.

46 See Sections III.C.4.b-d, below, for additional directives concerning EVSE eligibility criteria for customers in public, workplace, MUD, and fleet segments.

47 See Sections III.C.4.b-d for discussion of EVSE rebates for public, workplace, MUD, and fleet customers that are not in EJ communities.

Exhs. AG-REN-CP-Surrebuttal-1, at 6-9; AG-REN-1, at 26). As the Commonwealth strives to achieve its transportation electrification and decarbonization goals, our intention is to focus these ratepayer-funded EV programs on those communities with the least financial resources and that may otherwise be underserved by the competitive market. The Department emphasizes that our directives on EVSE rebate eligibility does not impact the make-ready rebates proposed and approved above.[48] Further, the EVSE budget for each of these program segments remains unchanged.

The Department recognizes that the implementation of a sliding scale of incentives for non-residential customers may increase the complexity of the companies' EV programs by requiring differences in eligibility for incentives. The Department, however, notes that adequate customer education and communication can mitigate any customer confusion. As noted above, National Grid has previous experience implementing tiered incentive levels as part of its prior EV program. Further, the two-tiered incentive scale for non-residential customers based on a single EJ criterion we adopt, above, is limited and straightforward. Accordingly, the Department expects the companies to explain the available incentives to non-residential customers in a clear and simple manner in their customer education materials.

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48 All customer segments remain eligible to receive rebates for 100 percent of the make-ready costs on the utility side of the meter and, for NSTAR Electric and National Grid, up to 100 percent of the average installation costs of the infrastructure on the customer side of the meter, not to exceed actual installation costs, and, for Unitil, 100 percent of the infrastructure costs on the customer side of the meter, which constitute the majority of EV charging station deployment costs.

b. Public and Workplace Segment

NSTAR Electric's and National Grid's public and workplace segment proposals include EVSE rebates while Unitil does not (D.P.U. 21-90, Exh. ES-KB-1, at 45-47; D.P.U. 21-91, Exh. NG-EVPP-1, at 43-45; D.P.U 21-92, Exh. CSVG-1 (Rev.) at 36-38). The Attorney General recommends that the companies offer a higher level of EVSE rebates to publicly accessible public and workplace sites (D.P.U. 21-90, Attorney General Track 1 Brief at 11; D.P.U. 21-91, Attorney General Track 1 Brief at 14).

Rebates serve to reduce the financial barriers for site hosts to deploy EV charging stations. D.P.U. 17-13, at 30. As such, like make-ready rebates, EVSE rebates are an important tool to assist the Commonwealth in meeting its transportation electrification and decarbonization goals. Nonetheless, the Department recognizes that, as the competitive EV charging market grows, the need for financial incentives for private site hosts will likely diminish. See D.P.U. 13-182-A at 13 (finding that a utility proposal must meet a need unlikely to be met by the competitive market). Further, the Department is persuaded that, without some parameters, the companies' public and workplace offerings may be inequitably distributed, with EV charging infrastructure concentrated in higher income areas (D.P.U. 21-90, Exhs. AG-REN-CP-Surrebuttal-1, at 8-9, 10-11; AG-REN-1, at 27; D.P.U. 21-91, Exhs. AG-REN-CP-Surrebuttal-1, at 9, 10; AG-REN-1, at 27-28). Therefore, the Department finds it appropriate to limit the availability of EVSE rebates to publicly accessible sites, which serve the general public and provide access to the greatest number of customers. Accordingly, the Department directs NSTAR Electric and National Grid to restrict the availability of EVSE rebates to publicly accessible sites.

The Department must now determine how to define publicly accessible sites. The Companies propose to define publicly accessible consistent with G.L. c. 25A, § 16, which places no restriction on the applicable fees to access the parking space or the number of hours per day the parking space must be made available for public access (D.P.U. 21-90, RR-DPU-1; D.P.U. 21-91, RR-DPU-2; D.P.U. 21-92, RR-DPU-3). In contrast, the Attorney General supports adoption of the NY PUC's definition of publicly accessible, which defines publicly accessible EV charging stations as those that are accessible to the public without an access fee or restricted access, except for paid municipal parking (D.P.U. 21-90, Attorney General Track 1 Brief at 28-29; D.P.U. 21-90, AG-REN-1, at 40-41; D.P.U. 21-91, Attorney General Track 1 Brief at 32-33; D.P.U. 21-91, AG-REN-1, at 43; D.P.U. 21-92, Attorney General Track 1 Brief at 20-21; D.P.U. 21-92, AG-REN-1, at 36). The Companies and several intervenors argue that the NY PUC definition of publicly accessible contradicts the definition of "public electric vehicle charging station" in G.L. c. 25A, § 16, eliminates privately-owned public parking from EV program eligibility, complicates the EV programs and incentive level eligibility, and eliminates a program participant's flexibility to determine the timing of access by the public (D.P.U. 21-90, ChargePoint Track 1 Brief at 1, 10-11; D.P.U. 21-91, ChargePoint Track 1 Brief at 1, 17-19; D.P.U. 21-92, ChargePoint Track 1 Brief at 1, 13-14; D.P.U. 21-90/D.P.U. 21-91, EVgo Track 1 Brief at 11-12; D.P.U. 21-90, Electrify America Track 1 Brief at 8; D.P.U. 21-91, Electrify America Track 1 Brief at 9; D.P.U. 21-90/D.P.U. 21-91, GECA Track 1 Brief at 14; D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 23-26, 37; D.P.U. 21-92, Unitil Track 1 Brief at 37-38).

The Department recognizes the importance of publicly accessible EV charging to achieving the Commonwealth's transportation electrification and decarbonization goals. Nevertheless, the Department also acknowledges that some restrictions on public access and parking fees may be necessary for the economic and operational viability of a charging station (D.P.U. 21-90, Exh. CP-KGM-Surrebuttal-1, at 5-7; RR-DPU-1; D.P.U. 21-90, RR-DPU-2; D.P.U. 21-92, RR-DPU-3). To determine the appropriate definition, the Department considers the MassEVIP program. Like the Companies' proposed public and workplace programs, the MassEVIP program is an incentive program designed to incentivize the installation of public EV charging stations.[49] To qualify for funding through the MassEVIP program, the MassEVIP program participant must allow the general public practical access to, and use of, the parking space and charging station for seven days per week, 24 hours per day. The MassEVIP program participant is permitted to charge a parking fee and, if the location has access restrictions, may reduce the hours of public access to no less than twelve hours per day, seven days per week.[50]

Given the similarities between the Companies' public and workplace offerings and the MassEVIP program, the Department determines that aligning the definition of publicly

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49 MassDEP administers the MassEVIP Public Access Charging program, one of several rolling grant programs aimed at making EVs and EV charging stations more widely available across Massachusetts. The MassEVIP Public Access Charging Program provides incentives for property owners or managers with publicly accessible parking to acquire and install Level 1 and Level 2 EV charging stations. Non-residential locations with publicly accessible parking are eligible to enroll in the program. See https://www.mass.gov/how-to/apply-for-massevip-public-access-charging-incentives (last visited December 13, 2022).

50 See MassEVIP Public Access Charging Program Application available at https://massgov.formstack.com/forms/massevip_pac_20 (last visited December 13, 2022).

accessible parking between the Companies' public and workplace offerings and the MassEVIP program will promote a consistent parking experience for EV owners across the Commonwealth. The Department also finds that this definition strikes an appropriate balance between the use of ratepayer funds to promote publicly accessible EV charging in the Commonwealth and the flexibility necessary for program participants to operate their parking facilities in an economically viable manner. Accordingly, the Department directs the Companies to incorporate MassEVIP's definition of publicly accessible into their public and workplace offerings. In sum, and consistent with our findings above in Section III.C.4.a, we approve: (1) 100 percent EVSE rebates for publicly accessible sites in EJ communities that meet the EJ criteria based on income; (2) 75 percent EVSE rebates for publicly accessible sites in EJ communities that meet any of the other EJ criteria; (3) 50 percent EVSE rebates for municipality-owned publicly accessible sites for ports three through ten; and (4) 50 percent EVSE rebates for non-municipality-owned publicly accessible sites for ports five through ten (D.P.U. 21-90, Exh. ES-KB-1, at 45; D.P.U. 21-91, Exh. NG-EVPP-1, at 45).

c. Residential Segment

i. Residential One to Four-Unit Dwellings

NSTAR Electric and National Grid each propose to offer EVSE rebates to all residential customers, with enhanced rebates to residential customers on their low-income discount rate or residing in an EJ community (D.P.U. 21-90, Exh. ES-KB-1, at 49-50; D.P.U. 21-91, Exh. NG-EVPP-1, at 55-56). Specifically, NSTAR Electric and National Grid propose to offer a rebate of up to a $300 per residential customer enrolled in their managed charging offerings towards the cost of a networked Level 2 EVSE and a rebate of 100 percent to residential

customers on the low-income discount rate or residing in an EJ community who enroll in the managed charging offerings, up to a cap of $1,700 for one-unit homes and $2,700 for two to four-unit homes (D.P.U. 21-90, Exh. ES-KB-1, at 50, 55; D.P.U. 21-91, Exh. NG-EVPP-1, at 56). (D.P.U. 21-90, Exh. ES-KB-1, at 50, 55; D.P.U. 21-91, Exh. NG-EVPP-1, at 56). Unitil's proposal consists solely of 100 percent EVSE rebates to residential customers on its low-income discount rate who enroll in its residential EV TOU rate, up to $1,700 (D.P.U. 21-92, Exhs. CSVG-1 (Rev.) at 32-33 & n.39; AG 3-3).

The Attorney General recommends restricting the residential EVSE rebates to low- and moderate-income customers in order to target spending towards customer that are the least likely to be served by the competitive market (D.P.U. 21-90, Attorney General Track 1 Brief at 42 & App., Table B; D.P.U. 21-91, Attorney General Track 1 Brief at 48, & App., Table B; D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 10; D.P.U. 21-92, Attorney General Track 1 Brief, at 30; Attorney General Track 1 Reply Brief at 8).[51] The Companies and GECA oppose the Attorney General's recommendations to limit EVSE rebates to only a subset of residential customers (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 44-47; D.P.U. 21-90/ D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Reply Brief at 9-10; D.P.U. 21-92, Unitil Track 1 Brief at 39-41; D.P.U. 21-92, Unitil Track 1 Reply Brief at 8-10; D.P.U. 21-90/D.P.U. 21-91, GECA Track 1 Brief at 3-4, 7-9). CLF

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51 The Attorney General proposes to define moderate-income as an annual household income of between 61 percent and 80 percent of the state annual median income, which is consistent with the definition of moderate-income customers in NSTAR Electric's and National Grid's respective energy efficiency programs (D.P.U. 21-90, Exhs. AG-REN-1, at 66; AG 6-5; D.P.U. 21-91, Exhs. AG-REN-1, at 73; AG 6-5).

also disagrees with the Attorney General's recommendation and suggests that the Companies instead implement a sliding scale of incentives that provides higher incentives to residential program customers based on the number of EJ criteria that a community meets (D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, CLF Track 1 Reply Brief at 10-11). The Companies and several intervenors argue that restricting enrollment in the residential programs to low- and moderate-income customers would preclude most residents in the Commonwealth from participating in the programs, thereby limiting their effectiveness (D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, CLF Track 1 Reply Brief at 8; D.P.U. 21-90, CEP Track 1 Brief at 2, 16-18; D.P.U. 21-91, CEP Track 1 Brief at 2, 18-19; D.P.U. 21-90/ D.P.U. 21-91, GECA Track 1 Brief at 3-4, 7-9; D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 44-47; D.P.U. 21-90/ D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Reply Brief at 9-10; D.P.U. 21-92, Unitil Track 1 Brief at 39-41; D.P.U. 21-92, Unitil Track 1 Reply Brief at 8-10). Unitil adds that an income-based eligibility screening or multi-tiered incentives could impose additional administrative constraints and costs, or delay program implementation (D.P.U. 21-92, Unitil Track 1 Brief at 55-56; Unitil Track 1 Reply Brief at 9-10).

The Attorney General based her recommendation, in part, on statistics from the MOR-EV program, which show that MOR-EV program funding has disproportionately benefited households in wealthier municipalities in the Commonwealth (D.P.U. 21-90, Exh. AG-REN-1, at 27; D.P.U. 21-91, Exh. AG-REN-1, at 28). The Department is persuaded that, without some parameters, the Companies' residential programs may disproportionately benefit higher-income

customers. At the same time, the Department acknowledges that an income-based eligibility screening could increase the administrative burden and costs of the EV programs.

While the Department is not opposed to including EVSE rebates for moderate-income customers, the Department determines that it is impractical and premature for the Companies to incorporate an income-based eligibility screening for moderate-income customers as part of their residential segment offerings at this time. As acknowledged by the Attorney General, NSTAR Electric and National Grid have not yet developed income-verification methods for their respective energy efficiency programs (D.P.U. 21-90, RR-CLF-1; D.P.U. 21-91, RR-CLF-1; D.P.U. 21-92, RR-CLF-1). Accordingly, the Department declines to adopt the Attorney General's recommendation.

The Department also declines to apply a sliding scale of incentives based on satisfaction of the EJ criteria for residential one to four-unit dwellings. The Department recognizes that not all customers residing in one to four-unit properties, including those in EJ communities that meet the EJ criteria based on income, have an annual median household income of less than 65 percent of the statewide annual median household income. Instead, the Department finds it appropriate to limit the availability of residential program EVSE rebates for one to four-unit properties to low-income customers, who face the greatest financial barriers to EV adoption. Accordingly, the Department approves Unitil's proposal to provide 100 percent EVSE rebates to residential customers in one to four-unit dwellings who qualify for its low-income residential discount rate and are enrolled in its EV TOU rate, up to the company's proposed project cap. Additionally, the Department limits NSTAR Electric's and National Grid's EVSE rebates for residential customers to those residential customers enrolled in the companies' respective

low-income discount rates and enrolled in their managed charging programs and that these residential customers are eligible for a rebate of 100 percent of EVSE costs. The Department acknowledges that limiting EVSE rebates to low-income residential customers in one to four-unit dwellings precludes a significant number of residential customers from EVSE rebates through these programs; however, as approved in Section III.C.3.a, above, all residential customers are eligible to receive make-ready rebates for EV charging infrastructure, which comprises the majority of costs associated with EV charging station deployment. Further, as noted above, the Commonwealth has established multiple EVSE rebate programs, which may provide rebates to a broader range of customers.

ii. MUDs

NSTAR Electric and National Grid propose to offer EVSE incentives to MUDs through their proposed residential segment offerings (D.P.U. 21-90, Exh. ES-KB-1, at 50-51; D.P.U. 21-91, Exh. NG-EVPP-1, at 65-67).[52] The Attorney General supports a higher level of

[52] NSTAR Electric proposes the standard use case for infrastructure at MUDs be sized to accommodate 20 EV charging ports (D.P.U. 21-90, Exh. DPU 8-28). Neither NSTAR Electric nor National Grid propose any cap or limit on eligibility for rebates to install EV infrastructure to accommodate EVSE to be installed in the future (i.e., "future-proofing") (D.P.U. 21-90, Exhs. ES-KB-1, at 60; DPU 8-28; DPU 12-2; D.P.U. 21-91, Exhs. NG-EVPP-1, at 57; DPU 11-2; RR-DPU-11, Att.; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 2, at 346-352). The Department did not contemplate rebates for future-proofing purposes in previously approved EV programs and has denied the use of ratepayer funds for such purposes. D.P.U. 20-64-A at 20. The Department acknowledges that some level of infrastructure upgrades to enable charging ports to be installed in the future at MUD sites may be cost-effective in the long-term. As part of these new EV programs, the Department cautions the Companies that, if a company seeks cost recovery for future-proofing, the company must justify the basis for the associated infrastructure upgrades and submit testimony and supporting exhibits demonstrating that such upgrades are reasonable and the associated costs are eligible EV program expenditures. The Department cautions the Companies that a failure to provide

incentives for publicly accessible MUDs, MUDs located in EJ communities, or MUDs that are an affordable housing facility or where at least 50 percent of the households are low- or moderate-income (D.P.U. 21-90, Attorney General Track 1 Brief at 42; D.P.U. 21-91, Attorney General Track 1 Brief at 48). The Companies and CLF disagree with the Attorney General's recommendation to narrow the eligibility of MUDs for rebates, arguing that MUDs have significant overlap with low-income customers and EJ communities and MUD parking lots serve residents and their visitors (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 47-48; D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Reply Brief at 9-10; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 1 Reply Brief at 7-8). CEP asserts that MUD customers face some of the greatest barriers to EVSE installation due to split incentives and lack of clear cost-sharing structures between property owners and tenants (D.P.U. 21-90, Exh. CEP-1, at 50; D.P.U. 21-91, Exh. CEP-1, at 53-54).

In Section III.C.4.a, above, the Department approved rebates for 100 percent of EVSE costs for MUDs in communities that meet the EJ criteria based on income, but limited EVSE rebates for MUDs in communities that meet an EJ criterion other than income to 75 percent of EVSE costs and to 50 percent for MUDs in non-EJ communities. The tiered EVSE incentive levels prioritize communities that meet the EJ criteria based on income while still incentivizing EV charging deployment in MUDs in other locations. Further, the Department notes the overlap between MUDs, low-income individuals, and EJ communities (D.P.U. 21-90,

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clear, cohesive, and reviewable evidence demonstrating eligibility will result in disallowance of targeted cost recovery. D.P.U. 17-13, at 58, citing 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).

Exh. ES-KB-Rebuttal-1 (Rev.) at 49; D.P.U. 21-91, Exh. NG-EVPP-Rebuttal-1 (Rev.) at 58). Accordingly, the Department finds that this approach addresses the Attorney General's concerns and, therefore, we decline to adopt her further recommendations for the MUD offerings.

d. Fleet Segment

NSTAR Electric proposes to offer fleet EVSE rebates for light-duty fleets and for medium- and heavy-duty fleets enrolled in its medium- and heavy-duty fleet pilot offering (D.P.U. 21-90, ES-KB-1, at 67-68, 73-74). National Grid proposes to offer EVSE incentives to all fleet types (D.P.U. 21-91, NG-EVPP-1, at 73, 76).[53] The Attorney General supports eliminating fleet segment incentives for all private fleets except small private fleets operating in EJ communities (D.P.U. 21-90, Attorney General Track 1 Brief at 47; D.P.U. 21-91, Attorney General Track 1 Brief at 52; D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 12-13). CLF recommends that the Department direct National Grid to dedicate at least 50 percent of its proposed fleet segment budget to supporting public transit fleets that operate primarily in EJ communities (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 1 Brief at 18-19, 36). The Companies and EVgo oppose the Attorney General's recommendation and assert that private fleets contribute significantly to GHG emissions and, therefore, their enrollment in the fleet offering is necessary to achieve the Commonwealth's decarbonization goals (D.P.U. 21-90/ D.P.U. 21-91, EVgo Track 1 Brief at 10, 12; D.P.U. 21-90/D.P.U. 21-91, EVgo Track 1 Reply Brief at 6-7, 8; D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 51-52).

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53 Unitil does not propose a fleet segment offering.

As stated above, the Department recognizes that, as the competitive EV market grows, the need for financial incentives for private customers may diminish. See D.P.U. 13-182-A at 13 (finding that a utility proposal must meet a need unlikely to be met by the competitive market). Although the Department acknowledges that private fleets are likely a significant contributor to GHG emissions in the Commonwealth, the Department also recognizes that private fleets are likely to have greater resources with which to transition to EVs than public fleets and are also more likely to have their needs met by the competitive market (D.P.U. 21-90, Exh. AG-RENCP-Surrebuttal-1, at 39; D.P.U. 21-91, Exh. AG-RENCP-Surrebuttal-1, at 39). On the other hand, public fleet customers face some of the greatest barriers to EVSE installation due to lack of funds and unique charging needs (D.P.U. 21-90, Exhs. AG-REN-1, at 41; CEP-1, at 50; D.P.U. 21-91, Exhs. AG-REN-1, at 44; CEP-1, at 53-54). Previously, in D.P.U. 18-150, at 392-393, the Department limited participation in National Grid's fleet advisory services program to public transit and government fleets and encouraged the company to prioritize eligible fleets that provide services in disadvantaged communities. For the reasons stated above, and consistent with D.P.U. 18-150, at 392-393, the Department finds it appropriate to restrict the availability of EVSE rebates to public fleets only.

5. Networking Rebates

NSTAR Electric and National Grid propose to provide networking rebates to eligible public, workplace, and MUD customers while Unitil does not (D.P.U. 21-90, Exh. ES-KB-1, at 46; D.P.U. 21-91, Exh. NG-EVPP-1, at 45; D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 37). The Attorney General recommends limiting networking rebates to publicly accessible sites and publicly accessible MUDs (D.P.U. 21-90, Attorney General Track 1 Brief, App. Tables A-B;

D.P.U. 21-91, Attorney General Track 1 Brief, App. Tables A-B). NSTAR Electric and National Grid argue that, as a recurring cost, networking fees present a significant barrier to EV adoption (D.P.U. 21-90, Exh. ES-KB-1, at 46; D.P.U. 21-91, Exh. NG-EVPP-1, at 45). The companies also contends that networking allows customers to more effectively locate and efficiently use chargers via mapping and queueing in EV charging applications and provides the companies with charging data which can be leveraged for current EV program refinements and future EV program design (D.P.U. 21-90, Exh. ES-KB-1, at 46; D.P.U. 21-91, Exh. NG-EVPP-1, at 45).

The Department recognizes the value networking provides (D.P.U. 21-90, Exh. ES-KB-1, at 46; D.P.U. 21-91, Exh. NG-EVPP-1, at 45). The Department finds that rebates for ongoing, recurring costs will help to address the financial barriers to EV charging infrastructure deployment (D.P.U. 21-90, Exh. ES-KB-1, at 46; D.P.U. 21-91, Exh. NG-EVPP-1, at 45). The Department also notes that no party to these proceedings object to the companies' proposal to offer networking rebates as part of their EV programs. Based on the foregoing, the Department approves the companies' networking rebates proposal (D.P.U. 21-90, Exh. ES-KB-1, at 46; D.P.U. 21-91, Exh. NG-EVPP-1, at 45). Nonetheless, consistent with our findings and directives limiting EVSE rebates to publicly accessible sites in Section III.C.4.b, above, the Department directs NSTAR Electric and National Grid to provide networking rebates only to publicly accessible sites and MUDs.

6. Program Design Construct

a. EV Program Term

NSTAR Electric and National Grid propose a four-year EV program term while Unitil proposes a five-year EV program term (D.P.U. 21-90, Exh. ES-KB-1, at 7; D.P.U. 21-91,

Exh. NG-EVPP-1, at 10; D.P.U. 21-92, Exh. CSVG-1, at 33). The Attorney General asserts that a three-year EV program term is more appropriate because the EV industry is experiencing tremendous growth, EV-related technological is rapidly advancing, and state and federal funding is becoming increasingly available to support EV adoption (D.P.U. 21-90, Attorney General Brief at 25; D.P.U. 21-91, Attorney General Brief at 28-29; D.P.U. 21-90/D.P.U. 21-91, Attorney General Reply Brief at 15; D.P.U. 21-92, Attorney General Brief at 17).

NSTAR Electric and National Grid developed their proposed four-year EV program budgets based on assumptions and forecasts of the number of EV charging stations needed in each market segment to support the adoption of EVs consistent with the Commonwealth's ZEV MOU goals (D.P.U. 21-90, Exh. ES-JB-Rebuttal-1 (Rev.) at 6; D.P.U. 21-91, Exh. ES-JB-Rebuttal-1 (Rev.) at 6). Specifically, NSTAR Electric and National Grid used their experiences with their existing EV programs, their service territory size, the National Renewable Energy Laboratory's EV infrastructure projection tool ("EVI-Pro Lite tool"), and expected EV sales to size their proposed EV programs (D.P.U. 21-90, Exh. ES-KB-1, at 22-24; D.P.U. 21-91, Exh. NG-EVPP-1, at 24-26). Unitil developed its five-year EV program budget based on data from the MORE-EV program, forecasts developed using the EVI-Pro Lite tool, and expected EV sales (D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 17, 38).

The term of a program is an important consideration. A program term that is too lengthy risks misalignment with the current state of the EV market or technological advances in the EV industry. On the other hand, a program term that is too short may jeopardize the Companies' ability to achieve the EV program goals (D.P.U. 21-90, Exh. ES-KB-Rebuttal-1 (Rev.) at 8; D.P.U. 21-91, Exh. NG-EVPP-Rebuttal-1 (Rev.) at 10). The Attorney General concedes that she

did not analyze the impact that her recommendation to reduce the term of the EV programs to three years could have on achieving the Commonwealth's ZEV MOU goals (D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, Tr. 3, at 606). The Companies, on the other hand, based the term of their EV programs on reasonable assumptions and forecasts developed, in part, on the EVI-Pro Lite tool to determine the number of EV charging ports needed in each market segment to support the adoption of EVs consistent with the Commonwealth's ZEV MOU goals (D.P.U. 21-90, Exh. ES-KB-Rebuttal-1 (Rev.) at 6-8; D.P.U. 21-91, Exh. NG-EVPP-Rebuttal-1 (Rev.) at 8; D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 38).

Based on these considerations, the Department finds that a four-year term for NSTAR Electric's and National Grid's EV programs and a five-year term for Unitil's EV program is appropriate and consistent with the Commonwealth's overall energy and emission reduction goals. Therefore, the Department approves a four-year term for NSTAR Electric's Phase II EV program and National Grid's Phase III EV program, and a five-year term for Unitil's EV program.[54]

b. Outside Funding Requirements

NSTAR Electric and National Grid propose to require customers approved for make-ready and EVSE rebates through the companies' EV programs to apply for MassEVIP rebates and other available state or federal funding that is directly aligned with the companies'

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54 The Department recognizes that the approved EV program terms will overlap, in part, with the initial electric sector modernization plans pursuant to G.L. c. 164, § 92B. Accordingly, consistent with G.L. c. 164, § 92B(c)(ii), the companies shall include a summary of the investments approved herein as previously Department-approved investments within their electric sector modernization plans.

EV program offerings (D.P.U. 21-90, Exh. ES-KB-Rebuttal-1 (Rev.) at 26; D.P.U. 21-91, Exh. NG-EVPP-Rebuttal-1 (Rev.) at 30). The companies also propose to retain the flexibility to modify this requirement if funding from third-party sources is depleted or delayed beyond a one or two-month period (D.P.U. 21-90, Exh. ES-KB-Rebuttal-1 (Rev.) at 26; D.P.U. 21-91, Exh. NG-EVPP-Rebuttal-1 (Rev.) at 30; D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, Tr. 2 at 295, 299-300). Additionally, NSTAR Electric and National Grid propose to require customers to report whether they receive funding from third-party sources and to deduct any duplicative funding for the same offering from the utility side of the customer offering (D.P.U. 21-90, Exh. ES-KB-Rebuttal-1 (Rev.) at 30; D.P.U. 21-91, Exh. NG-EVPP-Rebuttal-1 (Rev.) at 35; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 2 at 300). Unitil proposes to inform customers about the availability of third-party rebates and incentives and to encourage customers to apply for them but does not propose to require customers to obtain outside funding as a condition to participation in the company's EV program (D.P.U. 21-92, Exh. CVG-Rebuttal-1 (Rev.) at 14; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 2, at 319).

The Attorney General recommends that the Department direct the Companies to require customers to: (1) apply for applicable state and federal funding; (2) certify that they did so and reduce the rebate and incentive level received through the EV programs by the corresponding amount received from external funding sources; (3) ensure that customers' total incentives do not exceed their actual infrastructure and EVSE costs; and (4) coordinate with state program administrators on the availability of external funding sources (D.P.U. 21-90, Attorney General Track 1 Brief at 24; D.P.U. 21-91, Attorney General Track 1 Brief at 27; D.P.U. 21-92, Attorney General Track 1 Brief at 16). The Companies and a number of intervenors oppose the Attorney

General's recommendations (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 27-29; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 13; D.P.U. 21-90, ChargePoint Track 1 Reply Brief at 4; D.P.U. 21-91, ChargePoint Track 1 Reply Brief at 4; D.P.U. 21-92, ChargePoint Track 1 Reply Brief at 3-4; D.P.U. 21-90/ D.P.U. 21-91, EVgo Track 1 Brief at 4-5, 12; D.P.U. 21-90/D.P.U. 21-91, EVgo Track 1 Reply Brief at 1-4, 8; D.P.U. 21-90, Electrify America Track 1 Brief at 10, 12; D.P.U. 21-91, Electrify America Track 1 Brief at 12, 14; D.P.U. 21-90/D.P.U. 21-91, Electrify America Track 1 Reply Brief at 8, 9).

In D.P.U. 20-69-A at 46, the Department stated that, to ensure the prudent expenditure of ratepayer funds, any EV charging infrastructure program proposal should not be duplicative of other EV charging infrastructure build-out incentive programs offered in the Commonwealth. Further, the Department notes that the General Court has required the formation of an EV Coordinating Council to coordinate the implementation of an EV charging infrastructure deployment plan. St. 2022, c. 179, § 81. Consistent with our findings in D.P.U. 20-69-A, the Department finds that it is reasonable and appropriate to require customers to apply for MassEVIP rebates and other state or federal funding to the extent that it is available and aligned with the Companies' EV program offerings and to report any amounts received (D.P.U. 21-90, Exh. ES-KB-Rebuttal-1 (Rev.) at 26; D.P.U. 21-91, Exh. NG-EVPP-Rebuttal-1 (Rev.) at 30). This requirement will help to limit the use of ratepayer funds where funding from other sources is available for the same purpose. Therefore, the Department directs the Companies to require customers to apply for available MassEVIP and other state or federal funding to the extent that it is available and aligned with the Companies' EV program offerings and to report the receipt of

any such funding to the Companies. We find that this approach is sufficient and decline to require any additional certification.

The Department also determines that the Companies must deduct any third-party funding received by the customer from the EV program rebates provided to the customer (D.P.U. 21-90, Exh. ES-KB-Rebuttal-1 (Rev.) at 30; D.P.U. 21-91, Exh. NG-EVPP-Rebuttal-1 (Rev.) at 35). The Department determines that the total amount of third-party funding received must be applied against the combined make-ready and EVSE incentives that a customer is eligible to receive through the EV program absent outside funding regardless of whether the outside funding received was designated for utility-side infrastructure, customer-side infrastructure, or EVSE costs (D.P.U. 21-90, Exh. ES-KB-Rebuttal-1 (Rev.) at 30; D.P.U. 21-91, Exh. NG-EVPP-Rebuttal-1 (Rev.) at 35). The Department also directs the Companies to ensure that the combined rebate amount provided by the outside funding sources and by the Companies does not exceed the customer's actual infrastructure and EVSE costs. The Department determines that these requirements for outside funding ensures that ratepayer-funded incentives do not result in a potential windfall for program participants at the expense of ratepayers.

Finally, in D.P.U. 20-64-A at 26, the Department stated that mandating site hosts to seek or exhaust outside funding sources prior to enrolling in the EV program, or as a prerequisite to receiving a rebate through the program, may have unintended consequences, such as potentially deterring deployment of EV charging infrastructure upgrades due to regulatory burdens. Consistent with these findings, the Department declines to impose a strict requirement at this time, as recommended by the Attorney General, that would result in a disallowance of cost recovery of rebates provided to program participants who fail to apply for third-party funding.

Given the still-developing EV industry, such action could jeopardize the effectiveness of the EV programs (D.P.U. 21-92, Exh. CVG-Rebuttal-1 (Rev.) at 14; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 2, at 319). Additionally, the Department finds it reasonable to allow the Companies the flexibility to modify the requirement for customers to apply for third-party funding if funding from third-party sources becomes depleted or is delayed beyond a one or two-month period (D.P.U. 21-90, Exh. ES-KB-Rebuttal-1 (Rev.) at 26; D.P.U. 21-91, Exh. NG-EVPP-Rebuttal-1 (Rev.) at 30; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 2 at 295, 299-300).

c. Budget Flexibility

NSTAR Electric and National Grid seek flexibility to move EV program funding between offerings within each program segment and move up to 20 percent of EV program funds from one program segment to another without prior Department approval in order to respond to changes in the EV charging market and customers' needs (D.P.U. 21-90, Exh. ES-KB-1, at 89; D.P.U. 21-91, Exh. NG-EVPP-1, at 118; D.P.U. 21-90/ D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 76). The companies also seek flexibility to adjust components within the program segments, including incentive and rebate levels, customer eligibility requirements, and the distribution of port types without prior Department approval (D.P.U. 21-90, Exh. ES-KB-1, at 89-90; D.P.U. 21-91, Exh. NG-EVPP-1, at 118). The Attorney General opposes NSTAR Electric's and National Grid's request for budget and programmatic flexibility without prior Department approval and stakeholder review (D.P.U. 21-90, Attorney General Track 1 Brief at 20-23; D.P.U. 21-91, Attorney General Track 1 Brief at 22-26). DOER recommends that the Department allow NSTAR Electric and National Grid to propose shifts in

EV program budget and other appropriate programmatic changes in their annual reports with an appropriate demonstration of program utilization, changing market trends, and customer preferences (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 8, 14).

In 2022-2025 Grid Modernization Plans, D.P.U. 21-80-A/D.P.U. 21-81-A/ D.P.U. 21-82-A at 76-77, 88-89, 97-98 (October 7, 2022) ("Grid Mod Track 1 Order"), the Department permitted the Companies to shift not more than 15 percent of their total grid modernization budget between each investment category to respond to evolving market conditions. The Department also allowed the Companies to shift spending between years over the four-year term of the program, subject to the 15 percent budget cap variance for each investment category. Grid Mod Track 1 Order at 77, 89, 97-98. Finally, the Department stated that any spending over the overall total budget cap variance in each category is not eligible for targeted recovery and, instead, may be recovered by the Companies in a base distribution rate proceeding subsequent to a prudency finding by the Department. Grid Mod Track 1 Order at 77, 89, 98.

Here, the Department also determines that allowing the companies a certain level of flexibility to adjust their program segment budgets in response to EV market trends and customer preferences will improve overall program implementation. However, the Department shares the Attorney General's concern that a significant shift in EV program funding from one program segment to another could jeopardize the effectiveness of certain segments for the benefit of others. Therefore, consistent with Grid Mod Track 1 Order, the Department allows NSTAR Electric and National Grid the flexibility to shift spending among and between program segments by not more 15 percent of its total approved EV program budget. NSTAR Electric and

National Grid may shift spending between years over the four-year term of their EV programs, subject to the 15 percent cap. While Unitil did not seek budget flexibility, and notwithstanding the modest scale of its EV program, the Department determines that it is important to provide the company some flexibility to deviate from its budget estimates and projections to respond to changes that inevitably will take place over the term of the EV program. Accordingly, Unitil may shift spending between program segments and between years over the five-year term of its EV program, subject to a 15 percent cap. Further, any spending over a company's total approved EV program budget or above the 15 percent cap for each program segment is not eligible for targeted cost recovery through the EV program factor for NSTAR Electric and National Grid or through the GMF for Unitil and, instead, may be recovered by the Companies in a base distribution rate proceeding subsequent to a prudency finding by the Department.[55] The Department expects the Companies to report any EV program budget shifting among and between program segments in their annual reports accompanied by an explanation for the basis for the budget shifting.

Regarding NSTAR Electric's and National Grid's request for the flexibility to adjust customer eligibility criteria, incentive and rebate levels, and port target distributions without prior Department approval, the Department shares the Attorney General's concern that any such change could have significant consequences for the EV programs. The Department also recognizes that changes to customer eligibility criteria, incentive and rebate levels, and port

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55 As discussed in Section V.C.1, below, the Department directs NSTAR Electric to recover EV program expenditures through an annual reconciling EV program factor and Unitil to recover EV program expenditures through its annual reconciling grid modernization factor.

target distributions may be appropriate due to evolving market trends and customer preferences. In 2024, the Companies must file their respective electric sector modernization plans with the Department for review. Pursuant to G.L. c. 164, § 92B, these plans must include each company's proposals to improve the distribution system to facilitate transportation electrification. Accordingly, the Companies may propose adjustments to their EV programs consistent with the requirements of G.L. c. 164, § 92B as part of their electric sector modernization plans.

d. EJ Community Targets

A number of intervenors urge the Department to consider binding deployment targets for EV charging ports in EJ communities or a requirement that a percentage of the Companies' EV program budgets be reserved for EJ communities (D.P.U. 21-90, Attorney General Track 1 Brief at 15, 18-19; D.P.U. 21-91, Attorney General Track 1 Brief at 18, 21-22; D.P.U. 21-92, Attorney General Track 1 Brief at 13, 14; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 1 Brief at 4, 29, 34, 36; D.P.U. 21-90, CEP Track 1 Brief at 20; D.P.U. 21-91, CEP Track 1 Brief at 20; D.P.U. 21-90/D.P.U. 21-91, CEP Track 1 Reply Brief at 9-10). The Attorney General specifically recommends a 40 percent binding port deployment target for NSTAR Electric and National Grid, with additional ports dedicated to low-income customers, and a 100 percent binding port deployment target for Unitil (D.P.U. 21-90, Attorney General Track 1 Brief at 15, 18-19; D.P.U. 21-91, Attorney General Track 1 Brief at 18, 21-22; D.P.U. 21-92, Attorney General Track 1 Brief at 13, 14). The Attorney General additionally recommends that NSTAR Electric and National Grid conduct 40 percent of their EV ready site plans for MUDs in EJ

communities (D.P.U. 21-90, Attorney General Track 1 Brief at 15; D.P.U. 21-91, Attorney General Track 1 Brief at 18).

The Companies, DOER, and Electrify America oppose binding EV charging port deployment targets and, instead, support programmatic flexibility that can respond to community and stakeholder feedback (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 10; D.P.U. 21-90, Electrify America Track 1 Brief at 6; D.P.U. 21-91, Electrify America Track 1 Brief at 6-7; D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 65-66; D.P.U. 21-92, Unitil Track 1 Brief at 35-36). The companies also oppose the Attorney General's recommendation to require 40 percent of EV ready site plans to be conducted for MUDs in EJ communities because it is not based on EJ community demand, but they commit to working with EJ stakeholders in order to meet the evolving needs of EJ community residents (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 66).

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. Further, as part of any new or revised EV charging infrastructure program proposal, the Department expected the Companies to use their experience implementing existing programs to further increase the accessibility of EV chargers in EJ communities and to consider appropriate measures to decrease barriers to the installation of EV chargers in all communities across their service territories, including EJ communities. D.P.U. 20-69-A at 46, 49-50. Here, the issue before us is the appropriate level to establish for deployment targets in EJ communities and whether these targets should be binding.

Generally, to ensure an equitable distribution of EV program benefits and maximize the public interest, the Department finds that EV charging port deployment targets for EJ communities is appropriate. Nonetheless, the Department acknowledges the voluntary nature of the public and workplace, MUD, and fleet programs and, thus, the level of participation in EJ communities cannot be predicted with any certainty. The Department therefore declines to make EV charging port deployment targets for EJ communities, or a certain percentage of EV ready site plans for MUDs in EJ communities, binding.

Next, the Department must determine the appropriate non-binding EV charging port deployment target for EJ communities. To do so, we consider the Companies' Phase I EV program targets for EJ communities as well as the characteristics of each company's service territory. For their Phase I EV program, the Department approved a deployment target of up to ten percent of the EV charging infrastructure in EJ communities for NSTAR Electric and ten percent of the Level 2 charging sites for National Grid. D.P.U. 17-05, at 473, 478; D.P.U. 17-13, at 24, 30. NSTAR Electric exceeded its proposed EJ community deployment target for its Phase I EV program and installed 15 percent of ports in communities that met two or more EJ criteria and 18 percent of ports in communities that met one or more EJ criteria (D.P.U. 21-90, Exh. AG 6-1, Att. (a)). Similarly, in its Phase I EV program, National Grid exceeded its proposed EJ community deployment target and installed 21 percent of stations in communities that met two or more EJ community criteria and 46 percent of stations in communities that met one or more EJ community criteria (D.P.U. 21-91, Exh. AG 6-1, Atts. (a), (b)).

Further, NSTAR Electric estimates that 35 percent of its residential and commercial customers live or operate in a community that meets at least one of the Commonwealth's EJ criteria while National Grid estimates that 28 percent of its residential and 29 percent of its commercial customers live or operate in a community that meets at least one of the Commonwealth's EJ criteria (D.P.U. 21-90, Exh. DPU 2-3, Atts. (c), (d); D.P.U. 21-91, Exh. DPU 2-3, Atts. (c), (d)). Therefore, the Department finds that an EV charging port deployment and EV ready site plan target of 35 percent for NSTAR Electric and 28.5 percent for National Grid for EJ communities is appropriate for NSTAR Electric's and National Grid's public and workplace and MUD programs, as these figures represent the percentage of customers living and operating in an EJ community across the companies' service territories. The Department also finds that an EV charging port deployment target of 40 percent for EJ communities is appropriate for NSTAR Electric's and National Grid's fleet programs, as proposed by National Grid (D.P.U. 21-91, Exh. NG-EVPP-1, at 13).[56]

Finally, to allow the Department and stakeholders to monitor the companies' progress in achieving their EV charging port deployment targets, the Department directs the companies to include EV charging port deployment data in EJ communities in their annual reports.[57]

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[56] Unitil maintains that 65 percent of its service territory is located in the city of Fitchburg, which meets three of the Commonwealth's EJ community criteria (i.e., English isolation, income, and minority status) (D.P.U. 21-92, Exhs. CSVG-1 (Rev.) at 32-33 & n.39; AG 2-2 (Rev.); AG 3-3). Given the characteristics of Unitil's service territory, coupled with the enhanced rebates proposed for low-income residential customers, as discussed above in Section III.C.4.c.i, the Department finds it unnecessary to establish port deployment targets in EJ communities for Unitil.

[57] As discussed in Section IV.A.3.a, below, the Department intends to establish performance metrics in a compliance phase of these proceedings and anticipates

e. Eligibility of Phase I EV Program Participants

NSTAR Electric and National Grid propose to allow program participants who previously participated in their respective Phase I EV programs to apply for additional EV program incentives and rebates through their Phase II and Phase III EV programs, respectively (D.P.U. 21-90, Exh. DPU 8-20; D.P.U. 21-91, Exh. DPU 9-18). No party briefed these issues.

For the following reasons, the Department limits EVSE rebates and networking rebates to new program participants and prior program participants that propose deployment of EV charging stations in a different site from the EV charging sites deployed as part of earlier phases of the EV program. The Department expects that the additional incentive of EVSE rebates and networking rebates for new program participants, or a new site for prior program participants, will encourage EV charging stations to be deployed in a variety of new locations. As such, EV drivers will have more options for where to charge, which, in turn, will support further EV adoption in the Commonwealth. Additionally, we note that make-ready costs constitute the largest proportion of the costs associated with deployment of EV charging facilities and, thus, continued eligibility of prior program participants for make-ready rebates as part of the EV programs we approve in this Order will serve as a strong incentive for prior program participants should they seek to expand their existing EV charging facilities notwithstanding their ineligibility for EVSE rebates or networking rebates at those sites.

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including metrics on ports deployed in EJ communities. We note that progress in achieving the port deployment targets in EJ communities would also be an appropriate area for assessment as part of the EV program evaluation plan.

f. Residential Managed Charging Requirement

NSTAR Electric proposes to require residential customers to enroll in the ConnectedSolutions program, a load management program offered through the company's energy efficiency program, that incentivizes customers to reduce electricity demand (D.P.U. 21-90, Exh. ES-KB-1, at 56-58). National Grid proposes to require residential customers to enroll in either its energy efficiency ConnectedSolutions program or its off-peak charging rebate program, a load management program offered through the company's Phase II EV program, that incentivizes customers to charge their EVs during off-peak times (D.P.U. 21-91, Exh. NG-EVPP-1, at 62-63). No party briefed these issues.

In D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, at 101 and D.P.U. 20-69-A at 47-48, the Department stated that it is important that EV customers are provided with appropriate pricing signals, through load management incentive programs, to encourage the EV charging behavior that will advance the Commonwealth's climate goals and the Department's grid modernization objectives. The Department also stated that establishing these pricing signals now can help prepare EV customers to navigate the future electric grid where EV charging and discharging may play a greater role in reducing system peak and local peak demand. D.P.U. 20-69-A at 48.

The Department determines that the companies' proposal to require residential program customers to enroll in their load management programs is consistent with the Department's directives in D.P.U. 20-69-A. Therefore, the Department approves a requirement for NSTAR Electric and National Grid residential program customers to enroll in the companies' respective load management programs as a precondition to EV program participation. For example, all

residential customers, including those not on the low-income discount rate, must enroll in a managed charging program to be eligible for make-ready incentives.

However, the Department is concerned that the companies' proposals could unjustly reward the companies through performance incentives the companies would be eligible to receive through the energy efficiency programs and result in a change to the underlying assumptions in the benefit-cost ratio analyses for the companies' respective ConnectedSolutions programs[58] (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 4, at 832, 838-839). Therefore, the Department directs the companies to explain how each relevant component of the benefit-cost ratio analyses will account for the mandatory enrollment of residential program customers in the ConnectedSolutions programs and describe the method by which the companies will exclude the participation of these customers from the calculation of energy efficiency performance incentives as part of their next energy efficiency annual report.

7. Marketing and Outreach Plan

The Companies each propose a marketing and outreach plan (D.P.U. 21-90, Exh. ES-KB-1, at 86-87; D.P.U. 21-91, Exh. NG-EVPP-1, at 114-115; D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 43-44). The Attorney General recommends that NSTAR Electric and National Grid submit detailed marketing and outreach plans for stakeholder input and Department review and approval during a compliance phase of these proceedings (D.P.U. 21-90,

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58 A benefit-cost ratio is a test to determine the cost-effectiveness of an energy efficiency program and involves a calculation of the total benefits and the total costs to determine whether the overall benefits of the program exceed the costs. Updating Energy Efficiency Guidelines, D.P.U. 20-150, App. A, § 3.4 (2021); Electric Industry Energy Efficiency Cost Effectiveness, D.T.E. 98-100, at 4 (1999); G.L. c. 25, §§ 19(a)-(c), 21(b)(3).

Attorney General Track 1 Brief at 77; D.P.U. 21-91, Attorney General Track 1 Brief at 90-92). NSTAR Electric and National Grid contend that such plans are unnecessary because the companies have committed to working with stakeholders on the development of their marketing and outreach strategies (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 74).

The Department has recognized that customer education, marketing, and outreach are crucial to enabling the successful implementation of utility programs. D.P.U. 12-76-B at 2. Furthermore, the Department acknowledges that stakeholder input on marketing and outreach strategies is valuable, particularly in reaching hard to reach customers and underserved and overburdened populations. Nonetheless, for the following reasons, the Department determines that further process on the proposed marketing and outreach plans is unnecessary and declines to adopt the Attorney General's recommendation.

The Companies intend to conduct marketing and outreach through their existing communication channels and by leveraging community and stakeholder relationships to target hard to reach customers, underserved and overburdened populations, as well as other customer segments (D.P.U. 21-90, Exh. ES-KB-1, at 86-89; D.P.U. 21-91, Exh. NG-EVPP-1, at 114-117; D.P.U. 21-92, Exh. CSVG-1, at 43-52). Further, the Companies intend to engage an advertising vendor to develop their marketing and outreach plans (D.P.U. 21-90, Exh. ES-KB-1, at 88; D.P.U. 21-91, Exh. NG-EVPP-1, at 116; D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 48). NSTAR Electric and National Grid have also committed to work with stakeholders to develop their marketing and outreach plans (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 74; D.P.U. 21-90, Exh. AG 4-20; RR-AG-3; D.P.U. 21-91, Exh. AG 4-20;

RR-AG-4). As such, the Department expects the Companies to incorporate stakeholder input into their marketing and outreach plans. Additionally, because customer education, marketing, and outreach activities should not remain static, the Department expects the Companies to refine their marketing and outreach efforts based on evolving market trends, customer preferences, lessons learned, and continued dialogue with stakeholders. The Department directs the Companies to submit their respective marketing and outreach plans with their first annual report filing and to explain in the annual report how stakeholder input was incorporated into their plans. The Department further directs the Companies to identify lessons learned, strategy changes, and other relevant information about their marketing and outreach plans in the annual reports.

8. Other Company Offerings and Proposals

a. Fleet Assessment Services

NSTAR Electric proposes to offer fleet assessment services for up to 100 private and non-profit fleet customers and National Grid proposes to offer fleet assessment services for up to 150 private and non-profit fleet customers and 25 incremental public fleet assessments through 2025 (D.P.U. 21-90, Exh. ES-KB-1, at 67, 69, 70; D.P.U. 21-91, Exh. NG-EVPP-1, at 76, 83). The Attorney General recommends that the Department direct the companies to limit fleet assessment services to publicly-owned fleets and small private fleets that operate in EJ communities because large private fleets have more financial flexibility to electrify their fleets without ratepayer funding (D.P.U. 21-90, Attorney General Track 1 Brief at 45; D.P.U. 21-91, Attorney General Track 1 Brief at 50-51).

As stated above, the Department recognizes that, as the competitive EV market grows, the need for financial incentives for private customers may diminish. See, D.P.U. 13-182-A

at 13 (finding that a utility proposal must meet a need unlikely to be met by the competitive market). Although the Department acknowledges that private fleets are likely a significant contributor to GHG emissions in the Commonwealth, the Department also recognizes that private fleets are likely to have greater resources with which to transition to EVs than public fleets and are also more likely to have their needs met by the competitive EV market (D.P.U. 21-90, Exh. AG-REN-CP-Surrebuttal-1, at 39; D.P.U. 21-91, Exh. AG-REN-CP-Surrebuttal-1, at 39). Additionally, the Department notes that, in D.P.U. 18-150, at 392-393, the Department limited participation in National Grid's fleet advisory services program to public transit and government fleets and encouraged the company to prioritize eligible fleets that provide services in disadvantaged communities. Consistent with our directives in D.P.U. 18-150 and our findings and directives limiting EVSE rebates to public fleets in Section III.C.4.d, above, the Department allows NSTAR Electric and National Grid to provide fleet assessment services to public fleets only and encourages the companies to prioritize eligible fleets that provide services in EJ communities. The Department approves each company's respective fleet assessment services budget proposal, with the exception of the online fleet assessment tools discussed below, and subject to our directives above. Notwithstanding our denial of fleet assessment services for non-public fleets, the Department does not reduce the proposed budgets for fleet assessment services, with the exception of the online fleet assessment tools discussed below, but directs the companies to dedicate the associated budget amounts for non-public fleets to public fleets.

b. Online Fleet Assessment Tools

NSTAR Electric and National Grid propose to develop online fleet planning and TCO tools for fleet customers (D.P.U. 21-90, Exh. ES-KB-1, at 69-70; D.P.U. 21-91, Exh. NG-EVPP-1, at 76-77). NSTAR Electric and National Grid maintain that their experience with distribution and transmission planning, and preexisting relationships with fleet customers places them in a unique position to perform fleet assessment services and assist with the transition to an electric fleet (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 53-54). Further, the companies argue that the online fleet assessment tools will simplify information gathering for all fleet operators (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 53-54).

DOER supports approval of NSTAR Electric's and National Grid's online fleet assessment proposals but recommends that the companies coordinate with MassCEC on program implementation (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 24-25). The Attorney General, however, opposes the proposed online fleet planning and TCO tools, arguing that they offer nothing unique from other private and public fleet assessment services currently available from public and private vendors and could interfere with the competitive market (D.P.U. 21-90, Attorney General Track 1 Brief at 46; D.P.U. 21-91, Attorney General Track 1 Brief at 51).

In D.P.U. 20-69-A at 46, the Department stated that, to ensure the prudent expenditure of ratepayer funds, any EV charging infrastructure program proposal should not be duplicative of other EV charging infrastructure build-out incentive programs offered in the Commonwealth. The Department determines that our directive against duplicative programs is equally applicable

to offerings such as the online fleet assessment tools proposals. As noted by the Attorney General, several public and private online fleet assessment tools currently exist, including the MassCEC fleet advisory services program, EIQ Mobility's EV feasibility assessment tool, ICF's fleet electrification tool, and Argonne National Lab's AFLEET tool (D.P.U. 21-90, Exh. AG-REN-1, at 77; D.P.U. 21-91, Exh. AG-REN-1, at 84). The Department finds no record evidence that clearly distinguishes NSTAR Electric's and National Grid's proposed online fleet assessment tools from those already in existence. Accordingly, the Department concludes that the companies have not clearly demonstrated that the proposed online fleet assessment tools do not merely duplicate other online fleet assessment tools currently available. Consequently, the Department concludes that the proposed online fleet assessment tools could interfere with the competitive EV market and denies these proposals. The Department directs NSTAR and National Grid to reduce their EV program budgets accordingly.

c. NSTAR Electric EJ Community Car Sharing Program

NSTAR Electric proposes to partner in an electric car sharing program in EJ communities (D.P.U. 21-90, Exh. ES-KB-1, at 72-73). The Attorney General contends that the proposed car sharing program should be denied as outside of the scope of the normal business operations of a utility and that the company can better support transportation electrification through other EV program offerings (D.P.U. 21-90, Attorney General Track 1 Brief at 67). NSTAR Electric replied that few car sharing programs are specifically designed to serve low-income customers (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 68-69).

The Department acknowledges that car sharing programs designed to serve low-income customers serve an important function and provide benefits, including a reduction in air pollution

and additional transportation options for those least likely to be served by the competitive market (D.P.U. 21-90, Exh. ES-KB-Rebuttal-1 (Rev.) at 61). However, we agree with the Attorney General that a car sharing program is outside the scope of a utility's normal business operations. Accordingly, the Department denies the proposed electric car sharing program and directs NSTAR Electric to reduce its budget accordingly.

d. NSTAR Electric Medium- and Heavy-Duty Fleet Pilot

NSTAR Electric proposes a pilot program to offer make-ready and EVSE rebates for medium- and heavy-duty fleets that serve EJ communities (D.P.U. 21-90, Exh. ES-KB-1, at 73-74). In Sections III.C.3.a & III.C.4.a, above, the Department addressed make-ready and EVSE incentives for medium- and heavy-duty fleets. The Attorney General contends that the Department should direct the company to expand its medium- and heavy-duty fleet pilot to provide financial support for mass transit (D.P.U. 21-90, Attorney General Track 1 Brief at 45). Additionally, a number of intervenors assert that the Department should direct NSTAR Electric to develop a medium- and heavy-duty fleet make-ready program (D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, CLF Track 1 Brief at 18, 19, 21; D.P.U. 21-90, CEP Track 1 Brief at 18; D.P.U. 21-91, CEP Track 1 Brief at 19; D.P.U. 21-90/D.P.U. 21-91, CEP Track 1 Reply Brief at 8; D.P.U. 21-90/D.P.U. 21-91, GECA Track 1 Brief at 4, 16).

NSTAR Electric's medium- and heavy-duty fleet pilot as proposed includes funding for EV charging infrastructure and EVSE for school buses, community transport services, and last mile delivery fleets among other medium- and heavy-duty fleet vehicles (D.P.U. 21-90, Exh. ES-KB-1, at 73). The medium- and heavy-duty fleet pilot program would, therefore, provide financial support for mass transit, as recommended by the Attorney General, and we

determine no modification is necessary. Consistent with our findings and directives in Section III.C.4.d, above, the medium and heavy-duty fleet pilot program rebates are limited only to public fleets.

Turning to arguments that NSTAR Electric should develop a medium- to heavy-duty fleet program, NSTAR Electric maintains that it will develop an offering to enable medium- to heavy-duty fleet electrification after the second year of its fleet assessment services (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 69-70). Given that the company does not currently have data on or experience with medium- and heavy-duty fleet electrification in its service territory, the Department determines that it would be reasonable for the company to evaluate data gathered over the first two years of its pilot program in considering a medium- and heavy-duty fleet make-ready proposal (D.P.U. 21-90, Exhs. ES-KB-Rebuttal-1 (Rev.) at 61). Therefore, the Department declines to direct NSTAR Electric to propose a medium- and heavy-duty fleet make-ready program at this time.

e. NSTAR Electric EJ Community Charging Hub

NSTAR Electric proposes to install four to five DCFC charging hubs in EJ communities (D.P.U. 21-90, Exh. ES-KB-1, at 46-47). The Attorney General recommends that the Department approve NSTAR Electric's EJ community charging hub proposal with several modifications (D.P.U. 21-90, Attorney General Track 1 Brief at 64-66). NSTAR Electric states that is amendable to limiting the number of DCFC charging hubs as part of its proposal from five to four and to engaging with stakeholders to identify the locations for deployment of the DCFC charging hubs (D.P.U. 21-90, Exh. ES-KB-Rebuttal-1 (Rev.) at 61-62; D.P.U. 21-90/ D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 67). The company also

states that it will issue an RFP to solicit interested owners and operators of the DCFC charging hubs to ensure a consistent and coordinated approach to siting and deployment (D.P.U. 21-90, Exh. ES-KB-1, at 47). Furthermore, the company states that it proposes to use traffic pattern and charging analyses in its future network planning efforts (D.P.U. 21-90, RR-AG-5).

The Department recognizes the many benefits of DCFC charging hubs in EJ communities, including increasing the fast EV charging options for underserved communities, especially those without access to at-home charging (D.P.U. 21-90, Exhs. AG 4-24; CLF-ES 1-1). Given the novelty of the proposal, the Department determines that it is appropriate to provide NSTAR Electric the flexibility to determine whether to deploy four or five DCFC charging hubs as circumstances warrant. Further, the Department finds it reasonable for NSTAR Electric to engage with EJ community stakeholders prior to issuing a RFP for vendors to own and operate the DCFC charging hubs. Accordingly, the Department approves NSTAR Electric's DCFC charging hub proposal and expects the company to incorporate stakeholder input into the RFP process. The Department also expects NSTAR Electric in any future EV charging infrastructure program proposal to include proposals to mitigate barriers that impede the recruitment of DCFC site hosts for strategic locations in the Commonwealth.

f. Proprietary Charging Networks

National Grid proposes to offer make-ready incentives for proprietary networks as part of its proposed EV program while NSTAR Electric does not (D.P.U. 21-91, Exh. NG-EVPP-1, at 43-44). The Attorney General and GECA recommend that the Department reject National Grid's proposed incentives for proprietary charging networks because they are designed to benefit only a certain subset of customers, primarily wealthy individuals, and program funding

should be reserved for universal EV charging equipment that does not exclude any subset of EV drivers (D.P.U. 21-91, Attorney General Brief at 39-41; D.P.U. 21-90/D.P.U. 21-91, GECA Brief at 13). Tesla supports National Grid's proposal to provide incentives for proprietary networks and urges the Department to direct NSTAR Electric to allow proprietary networks to participate in its proposed EV program (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tesla Track 1 Brief at 4, 7, 8; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tesla Reply Track 1 Brief at 2, 9). National Grid argues that the Department should reject the Attorney General's and GECA's recommendations while NSTAR Electric opposes Tesla's recommendation to require the company to provide financial incentives for proprietary networks (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 70-71).

As stated above, the Department recognizes that, as the competitive EV market grows, financial incentives for private customers will likely diminish. See D.P.U. 13-182-A at 13 (finding that a utility proposal must meet a need unlikely to be met by the competitive market). Currently, proprietary Tesla chargers comprise a significant portion of the EV chargers installed in NSTAR Electric's and National Grid's respective service territories (D.P.U. 21-90, Exh. CEP 1-21; D.P.U. 21-91, Exh. NG-EVPP-1, at 43). Specifically, proprietary DCFC stations already make up more than one third of all DCFC stations in National Grid's service territory, which includes 32 Tesla DCFC ports (D.P.U. 21-91, Exhs. NG-EVPP-1, at 43; AG 2-20). Further, over 60 percent of proprietary network installations in the Commonwealth are located in NSTAR Electric's service territory and were installed without ratepayer investment (D.P.U. 21-90, Exh. CEP 1-21). Additionally, adapters exist that allow EVs with proprietary ports to charge at non-proprietary Level 2 chargers, and adapters for DCFC stations are also

possible but are not currently available (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 4, at 723-727). Therefore, the Department determines that the competitive market is adequately meeting the needs of EVs that use proprietary chargers and will continue to do so in the immediate future.

Additionally, the Department is concerned that incentives for the installation of proprietary networks that are dedicated to a single vehicle brand is an inappropriate use of ratepayer funds and would disproportionately benefit higher-income customers (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 1, at 128; Tr. 4, at 725). Accordingly, in order to ensure that ratepayer funds are spent on charging sites that benefit the largest number of customers, the Department denies National Grid's proposal to provide financial incentives for proprietary networks through its Phase III EV program and rejects Tesla's recommendation to require NSTAR Electric to include incentives for proprietary chargers.

Finally, we are not persuaded by Tesla's argument that exclusion of Tesla chargers from participation in NSTAR Electric's Phase II EV program requires a 50 percent reduction in the company's public and workplace program budget because, according to Tesla, the company relied on the assumption that Tesla vehicles can charge at universal EV chargers to determine the size of the proposal (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tesla Track 1 Brief at 7-8; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tesla Track 1 Reply Brief at 5). The Department determines that NSTAR Electric appropriately sized its public and workplace program and that the company made no assumptions about the composition of any individual EV manufacturer in its service territory (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 2, at 246, 252). Accordingly,

the Department declines to adopt Tesla's recommendation to reduce NSTAR Electric's public and workplace program budget by 50 percent.

g. National Grid Level 1 Charger Offering

National Grid proposes to provide the infrastructure necessary to facilitate the deployment of approximately 500 public and workplace Level 1 charging ports for long dwell-time parking (D.P.U. 21-91, Exh. NG-EVPP-1, at 40). National Grid maintains that Level 1 chargers are important in the context of larger projects where Level 1 chargers would support long dwell-time vehicle use cases at a relatively low cost (D.P.U. 21-91, Exh. NG-EVPP-Rebuttal-1 (Rev.) at 48; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 4, at 876-877). ChargePoint opposes National Grid's proposal because of the greater benefits offered by Level 2 chargers and, according to ChargePoint, the approaching obsolesce of Level 1 chargers (D.P.U. 21-91, ChargePoint Track 1 Brief at 1, 6, 14).

The Department recognizes that Level 1 chargers can serve as a cost-effective charging option for customers, particularly in the context of larger projects seeking to provide multiple charging options (D.P.U. 21-91, Exh. NG-EVPP-Rebuttal-1 (Rev.) at 48; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 4, at 876-877). We also note that other programs still seek to spur development of Level 1 charging stations, indicating that Level 1 chargers are not obsolete.[59] Accordingly, the Department approves National Grid's proposal to provide

[59] Mass.gov, Apply for MassEVIP Workplace & Fleet Charging Incentives, https://www.mass.gov/how-to/apply-for-massevip-workplace-fleet-charging-incentives (last visited December 21, 2022).

funding for the infrastructure upgrades needed to deploy multiple Level 1 charging ports in special cases of long-dwell time parking.

h. Off-Peak Charging Rebate Program

National Grid proposes to extend its existing off-peak charging rebate program through 2025 and to expand the program to include up to an additional 1,000 fleet EVs in the off-peak charging rebate program and an automated, flexible scheduling of EV charging functionality (D.P.U. 21-91, Exh. NG-EVPP-1, at 87). The Attorney General supports National Grid's off-peak rebate program proposal with several modifications, including: (1) allowing participation via telematics and networked EVSE; (2) expanding the off-peak charging rebate program to public, workplace, and MUD customers; (3) implementing the flexible schedule offering within six months of Department approval; and (4) developing an evaluation plan for the proposed flexible schedule offering (D.P.U. 21-91, Attorney General Track 1 Brief at 59-60). GECA recommends that the Department require National Grid to increase the level of its proposed off-peak charging rebates and extend the rebate to include weekends (D.P.U. 21-90/D.P.U. 21-91, GECA Track 1 Brief at 4, 10-12). Additionally, NSTAR Electric does not include an off-peak charging rebate program as part of its EV program proposal, but GECA urges the Department to require NSTAR Electric to do so (D.P.U. 21-90/D.P.U. 21-91, GECA Track 1 Brief at 12).

As an initial matter, the Department finds that allowing customers to participate in the off-peak rebate offering via telematics and networked EVSE may eliminate the need for an additional device to participate in the offering and has the potential to reduce program costs (D.P.U. 21-91, Exh. AG-REN-1, at 100). National Grid is amenable to allowing customers to

participate in its off-peak charging rebate program via telematics and networked EVSE, and we therefore direct the company to make the necessary revisions to do so (D.P.U. 21-91, Exh. NG-EVPP-Rebuttal-1 (Rev.) at 37). Further, National Grid is amenable to developing a program evaluation plan for its flexible schedule offering and has already outlined potential research objectives and metrics (D.P.U. 21-91, Exhs. NG-EVPP-Rebuttal-1 (Rev.) at 37; AG 3-21). The Department finds it appropriate to include an assessment of the effectiveness of its flexible scheduling offering in its off-peak charging rebate program as part of the third-party evaluation that we require in Section IV.B.3, below. The Department, however, declines to mandate a date certain by which the company must offer its flexible scheduling offering. Rather, the Department expects the Companies to act with deliberate speed to implement and deploy all offerings that we approve herein.

Second, the Department declines to require an expansion of off-peak charging rebates to public, workplace, and MUD customers who operate EVSEs. Rebates and incentives must be designed in a manner to encourage the behavior sought by those who receive the rebates or incentives. Here, it is EV drivers who decide when to charge their vehicles, not EVSE operators, and the Attorney General fails to specify clearly how the incentives paid to EVSE operators would be translated to charging behavior changes in the EV drivers that they serve. Accordingly, the Department determines that the Attorney General's recommendation needs to be further developed to have the impact intended and we decline to direct National Grid to expand its off-peak charging rebate program to public, workplace, and MUD customers with EVSE at this time.

Next, National Grid first seeks to evaluate the data from its off-peak charging rebate program before considering increasing the level of its proposed off-peak charging rebates and extending the rebate to include weekends, as recommended by GECA (D.P.U. 21-91, Exhs. GECA-NG 2-2; GECA-NG 3-2; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 4, at 851-853). The Department determines that National Grid's approach is reasonable and appropriate. National Grid's off-peak charging rebate program proposal builds on its experiences with the off-peak charging rebate program approved as part of the company's Phase II EV program in D.P.U. 18-150, and National Grid seeks to test customers' responsiveness to the currently proposed rebate pricing (D.P.U. 21-91, Exh. NG-EVPP-1, at 85-86; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 4, at 851). Data collected from the off-peak charging rebate program will allow the company to refine the program design and adjust incentive levels based on lessons learned through the program (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 4, at 851). Accordingly, the Department declines to adopt GECA's recommended modifications.

Likewise, the Department declines to require NSTAR Electric to develop an off-peak charging rebate program proposal as part of its Phase II EV program at this time. NSTAR Electric currently offers a residential demand response offering as part of its energy efficiency program, which, like National Grid's proposed off-peak charging rebate program, incentivizes customers to modify their EV charging behavior during periods of high demand on the company's distribution system (D.P.U. 21-90, Exh. ES-KB-1, at 56). The Department finds it reasonable for NSTAR Electric to evaluate the data from National Grid's off-peak charging rebate program before determining whether to develop a similar off-peak charging rebate

program in addition to its current residential demand response offering (D.P.U. 21-90, Exh. ES-KB-Rebuttal-1 (Rev.) at 39; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 4, at 853).

i. National Grid Pole-Mounted EVSE Program

National Grid proposes to install, own, and operate approximately 200 ports on company-owned electric distribution poles in up to ten municipalities over the course of the four-year Phase III EV program (D.P.U. 21-91, Exh. NG-EVPP-1, at 47-48). At the end of the four-year EV program, the company proposes to sell the pole-mounted EVSE to the municipalities in which the electric distribution poles are located or on the open market (D.P.U. 21-91, Exh. NG-EVPP-1, at 47).

The Attorney General and ChargePoint recommend that the Department deny the pole-mounted EVSE offering (D.P.U. 21-91, Attorney General Track 1 Brief at 74-77; D.P.U. 21-91, ChargePoint Brief at 1, 8-12; D.P.U. 21-91, ChargePoint Reply Brief at 7). DOER, on the other hand, supports the pole-mounted EVSE program proposal (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Brief at 22).

National Grid based its pole-mounted EVSE program on its experiences with its pole-mounted EVSE demonstration project in the city of Melrose (D.P.U. 21-91, Exh. NG-EVPP-1, at 48). Initial results from the demonstration project showed an approximately 70 percent reduction in EVSE installation costs compared to ground-mounted chargers (D.P.U. 21-91, Exh. NG-EVPP-1, at 48). The company also notes that the third-party pole attachments required several highly specialized tasks for which the city of Melrose was not equipped to handle and, therefore, the company provided the necessary support to complete the process (D.P.U. 21-91, Exh. NG-EVPP-1, at 49). National Grid also states that the city of

Melrose incurred several additional costs to comply with the third-party pole attachments process (D.P.U. 21-91, Exh. NG-EVPP-1, at 49). Based on its experience through its partnership with the city of Melrose, National Grid maintains that a similar third-party pole attachments process may be burdensome for other municipalities and hinder scaling up this product (D.P.U. 21-91, Exh. NG-EVPP-1, at 49).

The Department recognizes the benefits associated with pole-mounted EVSE, which include reduced costs associated with pole-mounted EVSE deployments compared to traditional EVSE and the increased charging options for customers without access to at-home charging (D.P.U. 21-91, Exhs. NG-EVPP-1, at 48; NG-EVPP-Rebuttal-1 (Rev.) at 79). The Department also acknowledges that the company's experience with the pole-mounted EVSE demonstration project demonstrates the complexities of coordinating the pole attachments process among multiple parties (D.P.U. 21-91, Exhs. NG-EVPP-1, at 49-50; NG-EVPP-Rebuttal (Rev.), at 50-51). However, a real potential exists for utility owned EVSE to hinder the development of the competitive market. Here, the company did not provide an EV charging rate proposal for use of the pole-mounted EVSE chargers. Furthermore, the record is unclear whether the private market would be unable to address the gap in pole-mounted EVSE charging options in the absence of utility ownership. D.P.U. 13-182-A at 13. The Department determines that the company has failed to demonstrate that its proposal would meet a need regarding the advancement of EVs in the Commonwealth that is not likely to be met by the competitive EV charging market and would not hinder the development of the competitive EV charging market.

D.P.U. 13-182-A at 13. Therefore, the Department denies the pole-mounted EVSE program proposal and directs National Grid to reduce its budget accordingly.[60]

j. National Grid School Bus Rebate Program

National Grid proposes to offer rebates for approximately 300 electric school buses operating in EJ communities to fund the incremental purchase price of an electric school bus (D.P.U. 21-91, Exh. NG-EVPP-1, at 74). The Attorney General and DOER oppose the school bus rebate program while a number of intervenors urge the Department to approve it (D.P.U. 21-91, Attorney General Reply Brief at 78; D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, DOER Brief at 23-24; D.P.U. 21-91, CEP Track 1 Brief at 19; D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, CLF Track 1 Reply Brief at 6-7; D.P.U. 21-90/D.P.U. 21-91, GECA Track 1 Brief at 15).

As noted above, to ensure the prudent expenditure of ratepayer funds, any EV charging infrastructure program proposal should not be duplicative of other EV charging infrastructure build-out incentive programs offered in the Commonwealth. D.P.U. 20-69-A at 46. Here, National Grid concedes that its program overlaps with MassCEC's proposal to operate a similar school bus rebate program to incentivize the purchase of electric school buses that operate in EJ communities (D.P.U. 21-91, Exh. NG-EVPP-Rebuttal-1, at 25). National Grid also acknowledges that federal funding is available through the Infrastructure Investments and Jobs Act for the purchase of electric school buses (D.P.U. 21-91, Exh. NG-EVPP-Rebuttal-1,

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60 The Department encourages the company to conduct outreach to the municipalities within its service territory to determine whether other municipalities may be interested in a similar pole-mounted EVSE partnership akin to the city of Melrose demonstration project.

at 26-27). Given the significant overlap between the company's proposed school bus rebate program and the federal and state funding designated for that same purpose, the Department finds that the school bus rebate program is duplicative. The Department also questions the appropriateness of electric ratepayers funding the purchase of electric vehicles. Based on the foregoing, the Department denies the proposed school bus rebate program and directs the company to reduce its budget accordingly.

k. National Grid Utility-Owned DCFCs in EJ Communities

National Grid proposes to build, own, and operate up to 20 150-kW DCFC ports in up to ten pre-identified underserved or high-need EJ communities if gaps in DCFC deployment exist at the mid-point of the EV program (D.P.U. 21-91, Exh. NG-EVPP-1, at 46-47). Prior to deploying the DCFCs, the company proposes to provide notice to station developers that these gaps in DCFC deployment exist six months in advance to allow the private market to address these gaps before the company does (D.P.U. 21-91, Exh. NG-EVPP-1, at 46-47).

The Attorney General and ChargePoint oppose National Grid's proposal to own and operate DCFCs in EJ communities and assert that the company did not demonstrate that there will be a market failure to provide DCFCs in EJ communities, DCFC installation in EJ communities would not occur without utility ownership, or the proposed number of utility-owned DCFCs is appropriate (D.P.U. 21-91, Attorney General Track 1 Brief at 74-75; D.P.U. 21-91, ChargePoint Track 1 Brief at 1, 8, 12-13). Instead, ChargePoint recommends that National Grid report to the Department and stakeholders on the development of DCFCs in EJ communities at the mid-point of the EV program and submit a proposal for utility ownership of

DCFCs in EJ communities if gaps in DCFC deployment in those locations exist at that time (D.P.U. 21-91, ChargePoint Track 1 Brief at 13).

The Department recognizes the many benefits of DCFCs in EJ communities, including increasing fast EV charging options for underserved communities (D.P.U. 21-91, Exh. NG-EVPP-Rebuttal-1 (Rev.) at 79). However, as the company concedes, it is unclear whether gaps in DCFC deployment in EJ communities will exist at the mid-point of the company's Phase III EV program (D.P.U. 21-90, Exh. NG-EVPP-1, at 46-47). Based on the hypothetical nature of the proposal, the Department finds it inappropriate to approve National Grid's proposal to own and operate DCFCs in EJ communities at this time. Therefore, the Department denies the company's proposal and directs National Grid to reduce its budget accordingly.

l. National Grid Transformer Surcharge Waiver Request

National Grid proposes changes to its G-1 tariff to reflect its make-ready proposal (D.P.U. 21-91, Exh. NG-CRP-3 (proposed M.D.P.U. No. 1472)). The Department has reviewed the proposed tariff change to waive the transformer surcharge for G-1 customers that required a larger dedicated transformer funded through the make-ready components in the EV Phase I and Phase III EV programs (D.P.U. 21-91, Exhs. NG-EVPP-1, at 95; NG-CRP-3 (proposed M.D.P.U. No. 1471)). We find these proposed changes to be reasonable, and, therefore, we approve the changes. The company shall file a revised G-1 tariff, as appropriate, for Department review and approval no later than January 15, 2023.

m. National Grid Utility-Side Expansion Budget

National Grid proposes a $15 million budget for utility-side upgrades to accommodate estimated large-scale fleet loads on the company's distribution system (D.P.U. 21-91, Exh. NG-EVPP-1, at 83). The Attorney General recommends that the Department reject National Grid's $15 million utility-side system expansion budget because it is tantamount to a request for an increase in rates above those authorized in the company's last base distribution rate case in D.P.U. 18-150 and inconsistent with traditional ratemaking practices (D.P.U. 21-91, Attorney General Track 1 Brief at 53). National Grid argues that the Department should approve its utility-side system expansion budget proposal because the distribution system upgrades would be necessary for all customers on the local distribution network and would be a shared cost for all ratepayers and its base distribution rates do not include funding for projects related to large-scale fleet electrification (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 55-56).

The Department determines that costs associated with distribution system upgrades are not appropriate for recovery through an annual reconciling mechanism, such as the EV program factor. Such capital improvements are more appropriately recovered through base distribution rates or another cost recovery mechanism. Accordingly, the Department finds that the proposed utility-side system expansion budget is inconsistent with established ratemaking practices and rejects the company's utility-side system budget expansion proposal.

Lastly, during the pendency of our review in these proceedings, 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 to, among other things, accommodate increased transportation electrification. G.L. c. 21N; G.L. c. 164, § 92B(a). Each electric company must file their first plan with the newly established Grid Modernization Advisory Council by September 1, 2023, and every five years thereafter, and not later than 150 days before filing of the plan with the Department. G.L. c. 164, § 92B(d). The Department must rule on the plan within seven months of submittal. G.L. c. 164, § 92B(d). The Department observes that National Grid's utility-side system expansion proposal, as well as other EV program proposals, fall within the parameters of the electric sector modernization plans.

n. Workforce Development and Electrician Training

The Companies propose to co-sponsor two offerings: (1) a workforce development initiative to support underrepresented entrants to the EV workforce, and (2) an electrician training initiative to upskill electricians (D.P.U. 21-90, Exh. ES-KB-1, at 74-78; D.P.U. 21-91, Exh. NG-EVPP-1, at 96-99; D.P.U. 21-92, Exh. CSVG-1, at 52-56). The Department recognizes the importance of a diverse workforce and acknowledges the need for training for historically underrepresented populations in the workforce. However, as the Companies acknowledge, the proposed workforce development and electrician training programs are voluntary in nature, and whether underrepresented populations participate in the programs is beyond the Companies' control (D.P.U. 21-90, Exh. ES-KB-Rebuttal-1 (Rev.) at 58; D.P.U. 21-91, Exh. NG-EVPP-Rebuttal-1, at 77). Therefore, even though the objective of the proposal is commendable, the Department is reluctant to commit ratepayer funds to proposals where achievement of the intended outcome is uncertain. In sum, the Department denies the proposed

workforce development and electrician training proposals and directs the Companies to reduce their budgets accordingly.

9. Other Intervenor Recommendations

a. EV Charging Data Requirements

NSTAR Electric and National Grid propose to collect charging data from public and workplace Level 2 EVSE, public DCFCs, and residential customers but neither company has finalized the data collection and reporting requirements for their proposed EV programs (D.P.U. 21-90, Exh. AG 3-11; D.P.U. 21-91, Exh. AG 3-11; D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, Tr. 2, at 281-283). A number of intervenors raise concerns with data collection and reporting protocols for the EV programs (D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 22-23; D.P.U. 21-90, CEP Track 1 Brief at 17; D.P.U. 21-91, CEP Track 1 Brief at 19; D.P.U. 21-90/D.P.U. 21-91, EVgo Track 1 Brief at 6-9, 12; D..P.U. 21-90, ChargePoint Track 1 Reply Brief at 7; D.P.U. 21-91, ChargePoint Track 1 Reply Brief at 8; D.P.U. 21-90, Electrify America Track 1 Brief at 9, 11; D.P.U. 21-91, Electrify America Track 1 Brief at 10, 14). In addition, ChargePoint recommends that the Department include appropriate language in its Order protecting confidential customer information collected through the EV programs from public disclosure or misuse (D.P.U. 21-90, ChargePoint Track 1 Reply Brief at 7; D.P.U. 21-91, ChargePoint Track 1 Reply Brief at 8).

The Department acknowledges the intervenors' concerns regarding data collection and reporting protocols. The Department expects the Companies to work cooperatively with stakeholders to reach consensus on as many data collection and reporting protocols as possible. To the extent a consensus cannot be reached on certain issues, the Companies shall identify all

issues on which the Companies and stakeholders have reached consensus and any outstanding issues for which the Companies and stakeholders could not reach a consensus position, including a description of respective positions, in their first annual report. The Department will determine next steps to resolve the remaining issues at that time.

b. Program Neutrality

ChargePoint contends that the Companies should provide program participants a choice of at least two EVSE and network and software providers and to ensure that marketing materials and outreach efforts are implemented in a competitively neutral manner (D.P.U. 21-90, ChargePoint Track 1 Brief at 1, 18-19, 20; D.P.U. 21-91, ChargePoint Track 1 Brief at 1, 26, 27; D.P.U. 21-92, ChargePoint Track 1 Brief at 1, 7, 16). These programmatic adjustments are reasonable to ensure no negative impact on the development of the competitive market and the Companies are amendable to implementing the recommendations (D.P.U. 21-90, Exh. ES-KB-Rebuttal-1, at 38; D.P.U. 21-91, Exh. NG-EVPP-Rebuttal-1 at 42, 59; D.P.U. 21-92, Exh. CVG-Rebuttal-1 at 33, 35). The Department directs the Companies to implement these recommendations and provide program participants with at least two options for EVSE providers and network and software providers as well as ensure that marketing materials and outreach efforts are competitively neutral.[61] Additionally, the Department encourages

[61] The Department notes that NSTAR Electric and National Grid currently maintain a list of qualified EVSE vendors on their websites. The Department expects Unitil to develop and maintain a similar qualified EVSE vendor list on its website. NSTAR Electric Preferred Vendor List, available at https://www.eversource.com/content/wma/residential/save-money-energy/clean-energy-options/electric-vehicles/charging-stations/preferred-vendor-list (last visited December 15, 2022). National Grid Approved EV Contractor List, available at https://www.nationalgridus.com/media/pdfs/bus-ways-to-save/ev/ee8467-ev-approved-contractor-list.pdf (last visited December 15, 2022).

NSTAR Electric and National Grid to work cooperatively with EV charging network providers who seek to use their own contractors for customer-side make-ready work; including consideration of an alternative process for qualifying EV charging network contracting firms for customer side make-ready work provided that safety and other utility requirements are met. Doing so could help to contain construction costs (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 4, at 660-661).

c. Unitil Fleet Offering

Unitil does not propose a fleet make-ready program as part of its EV program proposal. Consequently, CLF recommends that the Department direct Unitil to develop and propose a fleet make-ready pilot program to support mass transit electrification (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 1 Brief at 18, 25, 36). While Unitil agrees that mass transit electrification is important, the company states that it does not have the data or the experience to conduct a municipal fleet program as part of its first EV program proposal (D.P.U. 21-92, Unitil Track 1 Brief at 54)

Mass transit electrification will be crucial to meeting the Commonwealth's decarbonization goals. Nevertheless, given the lack of expertise with EV charging infrastructure program implementation, the absence of EV program implementation data, as well as the relatively small scale of Unitil's first EV program proposal, the Department determines that mandating the development and implementation of a municipal fleet proposal at this time is not an efficient use of time or resources. Accordingly, the Department declines to require Unitil to develop a fleet make-ready program at this time.

d. Rebate Choice

Electrify America asserts that EV program applicants should have the option to choose whether to apply for one or more of the available financial incentives, i.e., utility-side work, customer-side work, or EVSE (D.P.U. 21-90, Electrify America Track 1 Brief at 10, 12; D.P.U. 21-91, Electrify America Track 1 Brief at 11, 14). The Department notes that Electrify America raised this issue for the first time on brief and the Department has no basis to assess the reasonableness of the recommendation. Therefore, the Department declines to direct the Companies to implement this change to their EV programs.

e. Strategic Deployment of EVSE

In D.P.U. 20-69-A at 47, the Department directed the Companies to include proposals to mitigate barriers that impede the recruitment of DCFC site hosts for strategic locations in the Commonwealth in any new EV program charging infrastructure program proposal. The Department also directed the Companies to incorporate analyses of traffic and EV charging patterns to identify priority locations for future public EV charging stations. D.P.U. 20-69-A at 47. The Attorney General asserts that the Companies did not comply with these directives because they have not yet identified strategic locations for deployment of DCFCs or analyzed traffic and EV charging patterns to identify strategic locations for public EV charging stations (D.P.U. 21-90, Attorney General Track 1 Brief at 66; D.P.U. 21-91, Attorney General Track 1 Brief at 75). The Attorney General urges the Department to direct the Companies to include proposals to mitigate barriers that impede the recruitment of DCFC site hosts for strategic locations in the Commonwealth and incorporate analyses of traffic and EV charging patterns to

identify priority locations for future public EV charging stations as part of their next EV program proposals (D.P.U. 21-91, Attorney General Track 1 Brief at 75-76).

The Companies do not yet have charging gap analyses that identify gaps in the public charging network that are well-suited for new EVSE investment (D.P.U. 21-90, RR-DPU-8; D.P.U. 21-91, RR-DPU-9; D.P.U. 21-92, RR-DPU-10). NSTAR Electric and National Grid note, however, that the Commonwealth is currently conducting a RFP selection process for a vendor to study statewide corridor charging site selection, site design, outreach, and many other deliverables as part of its request for funding under the Infrastructure Investment and Jobs Act and that the study has the potential to identify priority locations for future public EV charging stations in the companies' service territories (D.P.U. 21-90, RR-DPU-8; D.P.U. 21-91, RR-DPU-9).

As more data becomes available to the Companies, the Department expects the Companies to coordinate and develop a plan to incorporate analyses of traffic and EV charging patterns to identify priority locations for future public EV charging stations. Additionally, the Department directs the Companies to include traffic and EV charging pattern analyses in their annual reports.

f. NSTAR Electric Coordination with Compact for Residential Offering

The Attorney General and the Compact urge the Department to direct NSTAR Electric to permit Compact customers to participate in the company's residential offering and coordinate with the Compact to develop a managed charging program (D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 1 Reply Brief at 22; D.P.U. 21-90, Compact Track 1 Reply Brief at 5; D.P.U. 21-90, Compact Track 1 Brief at 1-2, 4, 6, 8, 9). NSTAR Electric states that residential

program customers must enroll in the company's managed charging program to participate in the residential offering and that the Compact does not currently have its own EV managed charging program (D.P.U. 21-90, Exh. ES-KB-1, at 56). If the Compact proposes to administer a managed charging program, NSTAR Electric states that it will consider whether the Compact's program includes comparable elements to the company's ConnectedSolutions program and satisfies the company's requirement for residential offering customers to enroll in a managed charging program (D.P.U. 21-90, Exh. CLC-ES 1-1). The Department encourages NSTAR Electric to work cooperatively with the Compact to find an adequate managed charging solution to allow Compact customers the opportunity to participate in the company's residential offering.[62]

g. Default Pricing Arrangement for Public and Workplace Offering

CEP supports a default arrangement by which site hosts would pass through time-varying price signals to drivers with an opt-out to allow site hosts to implement their own pricing plans (D.P.U. 21-90, CEP Track 1 Brief at 20-21; D.P.U. 21-91, CEP Track 1 Brief at 21; D.P.U. 21-90/D.P.U. 21-91, CEP Track 1 Reply Brief at 11). In D.P.U. 13-182-A at 8, the Department held that owners and operators of EVSE are not subject to the Department's jurisdiction as a distribution company or an electric company and that there are no other provisions of G.L. c. 164 under which the Department can assert authority over owners and operators of EVSE or EV charging service. The Department, therefore, does not have

62 Any demand reduction offering proposed by NSTAR Electric or the Compact must comply with the laws and rules governing their respective energy efficiency programs. G.L. c. 25, § 21; Energy Efficiency Guidelines, D.P.U. 20-150-A (2021).

jurisdiction to set the default rates by which site hosts charge their customers. D.P.U. 13-182-A at 8. Accordingly, the Department declines to adopt CEP's recommended default pricing arrangement between EV program site hosts and their customers.

h. Utility-Ownership of EVSE for MUDs in EJ Communities

CEP recommends that the Department consider utility ownership of EV charging stations for MUDs in EJ communities to address barriers to EV adoption at MUDs (D.P.U. 21-90, CEP Track 1 Brief at 17-18; D.P.U. 21-91, CEP Track 1 Brief at 19). ChargePoint opposes CEP's recommendation (D.P.U. 21-90, ChargePoint Track 1 Brief at 13-14; D.P.U. 21-90, ChargePoint Track 1 Reply Brief at 5-6; D.P.U. 21-91, ChargePoint Track 1 Brief at 21-22; D.P.U. 21-91, ChargePoint Track 1 Reply Brief at 6-7).

In these proceedings, NSTAR Electric and National Grid propose to offer EVSE rebates for MUD customers with five or more units (D.P.U. 21-90, Exh. ES-KB-1, at 6, 51; D.P.U. 21-91, Exh. NG-EVPP-1, at 9). The Companies, however, do not propose to own EVSEs in MUDs in EJ communities as part of their EV program proposals and no evidence has been proffered in order for the Department to assess whether utility ownership of EVSE for MUDs in EJ communities would meet a need regarding the advancement of EVs in the Commonwealth that is not likely to be met by the competitive EV charging market and not hinder the development of the competitive EV charging market. D.P.U. 13-182-A at 13. For these reasons, the Department declines to adopt CEP's recommendation.

i. Load Management Plan

Given the absence of a comprehensive load management plan within the Companies' EV programs proposals, the Attorney General recommends that the Department direct the

Companies to convene a load management working group within 30 days following the Department's Order in this proceeding, to coordinate on the development of a comprehensive load management plan for Department review by June 2023, and to open a proceeding into load management to establish a timeline and approach for developing and implementing more advanced managed charging programs and the transition of the proposed DCA rates to future demand charge rate designs that will be enabled through the full deployment of AMI meters (D.P.U. 21-90, Attorney General Track 1 Brief at 51, 53, 54; D.P.U. 21-91, Attorney General Track 1 Brief at 56-57, 63; D.P.U. 21-92, Attorney General Track 1 Reply Brief at 11, 13; D.P.U. 21-90, Attorney General Track 2 Brief at 28, 31; D.P.U. 21-91, Attorney General Track 2 Brief at 32, 42; D.P.U. 21-92, Attorney General Track 2 Brief at 38, 45; D.P.U. 21-92, Attorney General Track 2 Reply Brief at 15-16. 17-18).

FreeWire supports the Attorney General's recommendations but Electrify America disagrees with the recommendations because it contends that any future EV-related load management programs should be coordinated with the Companies' energy efficiency programs and informed by actual EV charging data collected during program operation (D.P.U. 21-90, FreeWire Track 1 Brief at 14-15; D.P.U. 21-90, FreeWire Track 2 Brief at 9-11, 13; D.P.U. 21-91, FreeWire Track 2 Brief at 9-10, 12; D.P.U. 21-90, Electrify America Track 1 Brief at 6-8; D.P.U. 21-91, Electrify America Track 1 Brief at 7-9; D.P.U. 21-90, Electrify America Track 2 Brief at 9-11; D.P.U. 21-91, Electrify America Track 2 Brief at 9-11; D.P.U. 21-90, Electrify America Track 2 Reply Brief at 5-7; D.P.U. 21-91, Electrify America Track 2 Reply Brief at 5-7). The Companies assert that the Attorney General's recommendation to open a generic proceeding on load management and to transition the proposed DCA rates to more

advanced AMI-enabled rates is unnecessary and outside the scope of these proceedings (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 26; D.P.U. 21-92, Unitil Track 1 Reply Brief at 11). NSTAR Electric and National Grid, however, are amendable to developing a framework for EV-related load management as part of their annual reports or to convening a load management working group (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 26-27). NSTAR Electric and National Grid recommend that the companies first capture and report on initial lessons learned during the first year of program implementation before convening a load management working group because lessons learned during the initial phase of the EV programs will help inform the stakeholder engagement (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 31; D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 26-27).

As noted above, the 2022 Clean Energy Act was enacted during the course of these proceedings. As part of the electric section modernization plans required pursuant to the 2022 Clean Energy Act, each electric company must prepare five- and ten-year forecasts and a demand assessment through 2050 to account for future trends in the adoption of renewable energy, DERs, and energy storage and electrification technologies. G.L. c. 164, §92B(c). Additionally, the electric companies must include a summary of investments and solicit input, such as planning scenarios and modeling, from stakeholders and submit their proposals for input from the newly established Grid Modernization Advisory Council. G.L. c. 164, § 92B(c)(ii) & (iii), (d). Further, the 2022 Clean Energy Act created an EV Coordinating Council to develop and implement an EV charging station deployment plan, including state-wide transportation

electrification planning efforts. G.L. c. 179, § 81(a). Finally, the energy efficiency programs, pursuant to G.L. c. 25, § 21, include comprehensive demand reduction and management programs. See 2022-2024 Three-Year Plans Order, D.P.U. 21-120 through D.P.U. 21-129, at 113-120 (January 31, 2022).

The 2022 Clean Energy Act provides a coordinated and comprehensive statewide planning framework to address a broad range of grid modernization and transportation electrification issues, including load management planning and load forecasting, that will include stakeholder input and involvement. Accordingly, given the requirements of, and the actions to be undertaken pursuant to, the 2022 Clean Energy Act, as well as the existing framework for developing demand reduction programs pursuant to G.L. c. 25, § 21, the Department determines that a separate generic proceeding before the Department is unnecessary, redundant, and an inefficient use of resources.

10. Conclusion

Based on the findings above, for NSTAR Electric's Phase II EV program, the Department approves a combined four-year budget of $188 million consisting of: (1) public and workplace segment ($109.1 million); (2) residential segment ($52.7 million); (3) fleet assessment services ($1.25 million); (4) medium- and heavy-duty EJ community fleet pilot ($3 million); (5) company staffing ($9.6 million); (6) marketing ($10.1 million); (7) IT and back-office system upgrades ($280,000); and (8) program evaluation ($2 million) (D.P.U. 21-90, Exh. ES-KB-3).

For National Grid's Phase III EV program, the Department approves a combined four-year budget of $206 million consisting of: (1) public and workplace segment ($94.7 million); (2) residential segment ($64.1 million); (3) fleet segment ($30 million);

(4) off-peak charging rebate program ($3.8 million); (5) company staffing ($9.2 million); (6) IT and back-office system upgrades ($1.8 million); and (7) program evaluation ($2.4 million) (D.P.U. 21-91, Exhs. NG-EVPP-1, at 123; NG-EVPP-2).

For Unitil's EV program, the Department approves a combined five-year budget of $998,000 consisting of: (1) public segment ($538,000); (2) residential segment ($300,000); and (3) marketing and outreach ($160,000) (D.P.U. 21-92, Exhs. CSVG-1 (Rev.) at 32-33, 36, 50; CSVG-9).

Finally, the EV program budget for each company approved herein is a cap. Any spending over the cap will not be eligible for targeted cost recovery. NSTAR Electric and National Grid may shift spending between program segments and between years over the four-year term of their EV programs and Unitil may shift spending between program segments and between years over the five-year term of its EV program, subject to our directives on budget shifting in Section III.C.6.c, above. In Section V.C.1, below, the Department establishes the method by which each company shall recover its EV program expenditures.

IV. METRICS, EVALUATION PLAN, AND REPORTING

A. Performance Metrics

1. Description of the Proposals

a. Statewide Metrics

NSTAR Electric and National Grid propose seven statewide performance metrics to track: (1) the total number of charging sites developed; (2) the total number of ports installed by port type (i.e., Level 2 and DCFC) by market segment (e.g., public, workplace, MUD, fleet, and EJ community); (3) program financial support provided to DCFC stations; (4) program financial

support provided to stations in EJ communities; (5) the total number of participants in the workforce development and electrician training program; (6) EVSE utilization (e.g., kWh delivered per port per year); and (7) carbon dioxide emissions avoided from EVs relative to internal combustion engine vehicles (D.P.U. 21-90, Exh. ES-KB-1, at 38; D.P.U. 21-91, Exh. NG-EVPP-1, at 37-38). Unitil proposes to track six of the seven statewide metrics, excluding the metric on total number of participants in the workforce development and electrician training program (D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 11-12).

b. Company-Specific Metrics

NSTAR Electric proposes five company-specific performance metrics to track: (1) the total number of residential charger rebates distributed; (2) the total number of residential make-ready rebates distributed; (3) the total number of residential low-income and EJ community offerings distributed; (4) the number of medium- and heavy-duty ports deployed and vehicles electrified; and (5) the number of car sharing vehicles supported (D.P.U. 21-90, Exh. ES-KB-1, at 38-39).

National Grid proposes six company-specific performance metrics to track: (1) the total number of residential charger rebates distributed; (2) the total number of residential make-ready rebates distributed; (3) the total number of residential low-income and EJ community offerings distributed; (4) the total number of pole-mounted EVSE installed; (5) the total number of fleet assessments completed; and (6) the total number of electric school buses enabled (D.P.U. 21-90, Exh. ES-KB-1, at 38-39).

Unitil proposes one company-specific performance metric. Specifically, Unitil proposes to track the total number of customers enrolled in the company's residential EV TOU rate

(D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 12).

c. Performance Incentive Mechanisms

NSTAR Electric and National Grid also propose a performance incentive mechanism ("PIM") comprised of two independent metrics, a Level 2 EVSE cost containment metric and a DCFC cost containment metric (D.P.U. 21-90, Exh. ES-KB-1, at 79, 81; D.P.U. 21-91, Exh. NG-EVPP-1, at 100-101, 102). The companies propose to establish a baseline for the Level 2 EVSE cost containment metric and DCFC cost containment metric based on a cost per port and a cost per kW, respectively, and measure the baseline against actual port and kW deployments to determine any savings against the cost targets (D.P.U. 21-90, Exh. ES-KB-1, at 81; D.P.U. 21-91, Exh. NG-EVPP-1, at 102, 104). Each company proposes to retain a 30 percent share of any cost savings achieved through the PIM (D.P.U. 21-90, Exh. ES-KB-1, at 81; D.P.U. 21-91, Exh. NG-EVPP-1, at 102). NSTAR Electric proposes to cap the total cost containment incentive at $7 million over the four-year EV program term while National Grid proposes to cap the total cost containment incentive at $8 million over the four-year EV program term (D.P.U. 21-90, Exh. ES-KB-1, at 81; D.P.U. 21-91, Exh. NG-EVPP-1, at 103).

In addition, National Grid proposes a particulate matter emission reduction PIM, the clean fleet, clean air PIM, designed to reduce the particulate matter emissions of the vehicles supported by the fleet program (D.P.U. 21-91, Exh. NG-EVPP-1, at 100-101, 106). National Grid proposes to establish a baseline mix of vehicles and particulate matter emissions abatement threshold targets of five percent, ten percent, and 15 percent above the baseline mix of vehicles (D.P.U. 21-91, Exh. NG-EVPP-1, at 106-107). The company would then calculate the incremental health benefits of the particulate matter emissions reductions achieved through the

PIM based on the company's actual mix of deployed vehicles under the fleet program (D.P.U. 21-91, Exh. NG-EVPP-1, at 107). The company proposes to retain a 30 percent share of any savings above the threshold targets achieved through the PIM (D.P.U. 21-91, Exh. NG-EVPP-1, at 107).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that NSTAR Electric's and National Grid's proposed cost containment PIM should be rejected because: (1) it does not meet the Department's standard of review for PIM approval; (2) the use of Phase I EV program data may skew the baseline costs in the companies' favor; (3) market changes outside of the companies' control may result in cost reductions irrespective of the companies' cost-containment efforts; (4) it may disincentivize the companies from pursuing projects in strategic or high utilization locations that may be more costly than other projects; (5) there are no penalties for underperformance; and (6) the financial reward for achieving the target cost reductions is too high and accounts for a significant portion of the proposed EV program budgets (D.P.U. 21-90, Attorney General Track 1 Brief at 70-72; D.P.U. 21-91, Attorney General Track 1 Brief at 82-84).

Instead, if the Department wants to consider approval of the cost containment PIM, the Attorney General recommends that the Department do so in a separate adjudicatory proceeding in which the Department considers and evaluates policy goals and other incentives and metrics (D.P.U. 21-90, Attorney General Track 1 Brief at 68; D.P.U. 21-91, Attorney General Track 1 Brief at 79). Further, should the Department approve the cost containment PIM, the Attorney

General argues that the baseline costs should be adjusted annually and account for abnormal or unusual costs (D.P.U. 21-90, Attorney General Track 1 Brief at 70-71).

The Attorney General asserts that National Grid's proposed clean fleet, clean air PIM does not meet the Department's standard of review for PIMs and should, therefore, be rejected because: (1) the proposed baseline and targets are subjective and arbitrary; (2) the targets rely on total lifetime emissions reduction estimates rather than on a more accurate metric, such as actual utilization rates of the vehicles; (3) outside factors, such as EV purchase prices, government incentives, and the availability of EVs, may result in emission reductions regardless of the company's actions, thereby rewarding National Grid for outcomes over which it did not play a distinct and clear role; (4) the company's EV program offerings should be designed and administered in a manner that maximizes emission reductions; and (5) there are no penalties for underperformance (D.P.U. 21-91, Attorney General Track 1 Brief at 85-87).

b. Other Intervenors

DOER opposes approval of the companies' proposed cost containment PIM because it does not incentivize the companies to maximize the amount of infrastructure deployed while reacting to the uncertainties of the growing EV market and may allow the companies to benefit financially for cost reductions outside of their control (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 26). Further, DOER argues that the cost baselines using Phase I EV program data are insufficient to address cost uncertainties for the EV programs proposed in this proceeding (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 26). Instead, DOER argues that NSTAR Electric and National Grid should be incentivized to deploy more EVSE than their annual goals or targets (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER

Track 1 Brief at 26). Similarly, DOER urges the Department to deny National Grid's proposed clean fleet, clean air PIM because: (1) the PIM does not advance specific public policy objectives; (2) the PIM provides an incentive for the company for actions that it should take in the regular course of business; (3) there are other criteria for electrification that should also be included in fleet prioritization, including feasibility of electrification, the presence of EJ communities, and cost savings for fleet managers to identify fleets that are suitable for immediate electrification; and (4) the current PIM design may incentivize the company to focus on electrification of certain fleets that are not the best candidates for immediate financial support (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 27).

CEP recommends that the Department modify the proposed cost containment PIM with appropriate safeguards to prevent the installation of EV chargers with limited or reduced capabilities, deployment of EV chargers in locations that require fewer distribution or make-ready upgrades but are not sited to maximize utilization, and the installation of a large number of ports per site to capture economies of scale at the expense of distributing installations more evenly or equitably (D.P.U. 21-90, CEP Track 1 Brief at 21; D.P.U. 21-91, CEP Track 1 Brief at 21; D.P.U. 21-90/D.P.U. 21-91, CEP Track 1 Reply Brief at 11-12). CEP asserts that the Department should deny National Grid's proposed clean fleet, clean air PIM because it lacks a meaningful baseline (D.P.U. 21-91, CEP Track 1 Brief at 21-22; D.P.U. 21-90/D.P.U. 21-91, CEP Track 1 Reply Brief at 12).

c. NSTAR Electric and National Grid

NSTAR Electric and National Grid contend that the Department should reject the Attorney General's and CEP's recommendation to deny the cost containment PIM because:

(1) the baseline is based on actual costs from the companies' Phase I EV programs and can be sufficiently monitored, quantified, and verified; (2) the baseline includes a built-in performance hurdle to address inflation; (3) EVSE rebate costs and cost per port calculations are not included in the PIM, so the proposed PIM does not create a disincentive to make investments in EJ communities; (4) the PIM will incentivize the companies to allocate incremental financial or human resources to support cost-reducing approaches over and above what is required to successfully manage the program and proactively drive down customer-funded infrastructure support over time based on market signals; and (5) the companies' share of any cost savings would be limited to 30 percent (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 81-82; D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Reply Brief at 12-13).

Regarding its clean fleet, clean air PIM, National Grid argues that: (1) the baseline aligns with the budgeted distribution of vehicles in the fleet program and was developed based on a third-party market forecast; (2) fleet vehicles have a disproportionate impact on air quality compared to passenger vehicles; (3) the PIM is designed to ensure that the company will not be compensated unless it outperforms the emission reductions expected to be achieved under the program in the absence of the PIM; and (4) vehicle availability changes, fleet specific EVSE technology and design, large-scale decision making, and the company's fleet assessment services all provide the company the ability to influence the mix of fleet vehicle procurement (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 82-83; D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Reply Brief

at 12-13). National Grid therefore requests that the Department approve its clean fleet, clean air PIM.

3. Analysis and Findings

a. Performance Metrics

Performance metrics and reporting are key components of ensuring the transparency of the Companies' EV program implementation and performance. In these proceedings, the Companies propose five state-wide implementation metrics and two state-wide program benefit metrics, as well as company-specific metrics (D.P.U. 21-90, Exh. ES-KB-1, at 38; D.P.U. 21-91, Exh. NG-EVPP-1, at 37-38; D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 11-12). As an initial matter, the Department declines to approve the proposed EV program metrics at this time. The Department finds that additional work is needed in collaboration with stakeholders to develop performance metrics that appropriately track the Companies' implementation of their respective EV programs and the associated benefits. Accordingly, the Department will convene an EV stakeholder process and work with the parties through public comments and, as needed, technical conferences and further process in the instant proceedings to finalize the EV program performance metrics.

b. Performance Incentive Metrics

i. Introduction

To determine whether a PIM is appropriate, the Department relies on a two-prong test: (1) whether the PIM satisfies certain threshold principles; and (2) whether the PIM meets the design guidelines. D.P.U. 18-150, at 120-121. First, the Department must determine whether the PIM satisfies the threshold principles designed to weigh whether an action addressed in the

PIM is appropriate to consider for performance incentives. D.P.U. 18-150, at 120. In making this determination, the Department has found that performance incentives can serve as a useful regulatory mechanism when used to positively influence distribution company behavior in the advancement of important public policy goals that are not directly aligned with a distribution company's public service obligations. D.P.U. 18-150, at 120, citing Net Metering, SMART Provision, and the Forward Capacity Market, D.P.U. 17-146-B at 15-16, 56-59 (2019); see also Incentive Regulation, D.P.U. 94-158, at 54 (1995). Conversely, performance incentives are generally not appropriate where the affected activity is within the distribution company's public service obligations. Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company, D.T.E./D.P.U. 06-107-B at 55-60 (2009); see also Western Massachusetts Electric Company, D.T.E. 04-40/D.T.E. 04-109/D.T.E. 05-10, at 5-6 (2006). The Department has found that, to be considered on its design merits, a PIM must first be found to meet the threshold principles that: (1) it advances specific public policy goals, and (2) the affected activity is clearly outside a distribution company's public service obligations. D.P.U. 18-150, at 121.

Second, upon determining that a PIM meets these threshold principles, the Department must determine whether the proposed PIM meets appropriate design guidelines. D.P.U. 18-150, at 121. The Department has determined that an appropriately designed incentive mechanism must: (1) be designed to encourage program performance that best achieves the Commonwealth's energy goals; (2) be designed to enable a comparison of (i) clearly defined goals and activities that can be sufficiently monitored, quantified, and verified after the fact, to (ii) the cost of achieving the target to the potential quantifiable benefits; (3) be available only for

activities where the distribution company plays a distinct and clear role in bringing about the desired outcome; (4) be consistent across all electric and gas distribution companies, where possible, with deviations across companies clearly justified; (5) be created to avoid perverse incentives; and (6) ensure that the distribution company is not rewarded for the same action through another mechanism. D.P.U. 18-150, citing D.P.U. 17-13, at 42-43, 46; Investigation into Updating Energy Efficiency Guidelines, D.P.U. 08-50-A at 49-50 (2009); D.P.U. 94-158, at 52-66.

ii. Cost Containment PIM

NSTAR Electric and National Grid each propose a cost containment PIM to incentivize the companies to contain the make-ready costs associated with their proposed Phase II and Phase III EV programs, respectively, below the average make-ready costs from the companies' respective Phase I EV programs (D.P.U. 21-90, Exh. ES-KB-1, at 81-82; D.P.U. 21-91, Exh. NG-EVPP-1, at 102-103). Several intervenors recommend that the Department deny the proposed cost containment PIM (D.P.U. 21-90, Attorney General Track 1 Brief at 70-72; D.P.U. 21-91, Attorney General Track 1 Brief at 82-84; D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, DOER Track 1 Brief at 26; D.P.U. 21-90, CEP Track 1 Brief at 21; D.P.U. 21-91, CEP Track 1 Brief at 21; D.P.U. 21-90/D.P.U. 21-91, CEP Track 1 Reply Brief at 11-12).

The Department finds that the proposed cost containment PIM does not meet our design guidelines. Specifically, the Department is concerned that the proposed cost containment PIM would include outlier and other atypical Phase I EV program cost data in the calculation of the cost-containment baselines, which may skew the cost targets in the companies' favor (D.P.U. 21-90, Exh. DPU 6-2; D.P.U. 21-91, Exh. DPU 6-2). Additionally, the Department is

concerned that, given the nascent state of the EV charging market, cost targets based on data from the companies' respective Phase I EV programs may not be representative of make-ready costs over the course of the companies' respective new EV program terms proposed in the instant proceedings (D.P.U. 21-90, Exh. AG-REN-1, at 104; D.P.U. 21-91, Exh. AG-REN-1, at 117-118). Stated differently, without a proposed mechanism by which to update the cost-containment baselines during the course of the new EV programs to reflect current make-ready infrastructure costs (i.e., an update to the cost-containment baselines based on actual make-ready infrastructure costs at regular intervals), the cost-containment baselines may not align with the current EV charging market. As a result, an accurate determination of the cost savings achieved under the proposed cost containment PIM cannot be sufficiently monitored, quantified, and verified after the fact. Accordingly, the Department determines that the proposed cost containment PIM is inconsistent with our second PIM design guideline to enable a comparison of (i) clearly defined goals and activities that can be sufficiently monitored, quantified, and verified after the fact, to (ii) the cost of achieving the target to the potential quantifiable benefits.

Additionally, there are many factors outside of the companies' control that may result in significant changes to the make-ready costs of the EV programs over the proposed four-year EV program terms, including price inflation and equipment cost changes (D.P.U. 21-90, Exh. DPU 6-1; D.P.U. 21-91, Exh. DPU 6-1). Accordingly, the proposed cost containment PIM also does not satisfy the Department's third PIM design guideline that requires the distribution company to play a distinct and clear role in bringing about the desired outcome.

Finally, the Department shares CEP's concern that the cost containment PIM may incentivize the companies to commit to projects in locations that require fewer distribution or make-ready upgrades but are not sited to maximize EV charger utilization or that require a large number of ports per site to capture economies of scale at the expense of distributing EV charger installations more evenly or equitably (D.P.U. 21-90, Exh. CEP-1, at 77; D.P.U. 21-91, Exh. CEP-1, at 79). The proposed cost containment PIM, therefore, does not adhere to our fifth PIM design guideline of avoiding perverse incentives.

In conclusion, the cost containment PIM does not satisfy many of the PIM design guidelines. Therefore, the Department denies the companies' proposed cost containment PIM. Nevertheless, the Department expects the companies to minimize the financial impacts of the proposed EV programs on ratepayers.

As mentioned in Section IV.A.3.a, above, the Department intends to convene a stakeholder process on performance metrics. The Department expects the companies to propose metrics to track and report on EV program cost data as part of the stakeholder process.

iii. Clean Fleet, Clean Air PIM

National Grid proposes a clean fleet, clean air PIM to incentivize the company to achieve certain particulate matter emissions abatement threshold targets by influencing the mix of fleet vehicle procurement through its fleet program and fleet assessment services (D.P.U. 21-91, Exh. NG-EVPP-1, at 107). A number of intervenors urge the Department to reject the proposed clean fleet, clean air PIM (D.P.U. 21-91, Attorney General Track 1 Brief at 85-87; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 27; D.P.U. 21-91, CEP Track 1 Brief at 21-22; D.P.U. 21-90/D.P.U. 21-91, CEP Track 1 Reply Brief at 12). The

Department finds that the proposed clean fleet, clean air PIM is not adequately designed and is inconsistent with our second and third PIM design guidelines. Specifically, the Department shares the Attorney General's concern that the clean fleet, clean air PIM could reward the company even if actual particulate matter emissions reductions are higher than expected (e.g., if a fleet program participant shifts fleet vehicles to EVs but does not keep or utilize them) (D.P.U. 21-91, Attorney General Brief at 85-86; D.P.U. 21-91, Exh. DPU 6-6). Additionally, while we acknowledge that the proposed fleet program may have some effect on particulate matter emissions reductions in the company's service territory, the company failed to sufficiently demonstrate how its actions (i.e., devoting additional financial or human resources to support the fleet program) would play a clear and distinct role in the achievement of the proposed particulate matter emissions reductions targets (D.P.U. 21-91, Exh. DPU 6-7). Moreover, there are many factors outside of the company's control that may result in the company achieving its particulate matter abatement targets without company intervention, such as relative vehicle prices, government incentives, and shifts in economic activity (D.P.U. 21-91, Exh. DPU 6-5). Therefore, the Department denies National Grid's proposed clean fleet, clean air PIM.

B. Evaluation Plan

1. Description of the Proposals[63]

a. NSTAR Electric

NSTAR Electric proposes a $2.0 million budget to hire an independent, third-party evaluation expert to conduct a comprehensive evaluation of the Phase II EV program, which

63 Unitil did not propose an evaluation plan.

would focus on, but not be limited to: (1) tracking, documenting, and assessing program performance and participation; (2) understanding the experiences of participating customers in each of the program components; (3) assessing barriers to non-program participants, and identify opportunities to engage them; (4) characterizing the experiences of low-income customers and other disadvantaged groups within each program; (5) evaluating accessibility of charging stations for customers across the company's service territory; (6) studying how program incentives, rebates, and funding sources affect the adoption of EV charging stations and fleet vehicle conversion; (7) identifying program barriers and barriers to electric fleet adoption; and (8) determining how program elements affect customers' charging behaviors at home, in public, and at workplaces (D.P.U. 21-90, Exh. ES-KB-1, at 90, 91, 93). Among other things, the evaluation expert may: (1) conduct periodic surveys of a broad or targeted sample of the company's customers, both residential and non-residential; (2) complete pre- and post-surveys of residential and commercial customers who frequent residential charging stations and site host facilities; (3) conduct surveys or interviews of participating and non-participating site hosts; (4) collect and analyze program and EV charging data; and (5) complete in-depth interviews with program and support staff, external stakeholders, market actors, and industry experts (D.P.U. 21-90, Exh. ES-KB-1, at 92). Additionally, the company proposes to coordinate with the independent evaluator to develop or modify research tasks and identify areas of continued process improvement (D.P.U. 21-90, Exh. ES-KB-1, at 93). NSTAR Electric states that it coordinated with National Grid on many aspects of their evaluation plan proposals (D.P.U. 21-90, Exh. ES-KB-1, at 90-93).

b. National Grid

National Grid proposes a $2.4 million budget to hire an independent, third-party evaluator to evaluate its Phase III EV program (D.P.U. 21-91, Exh. NG-EVPP-1, at 119, 122). National Grid's evaluation report proposal includes the same focus areas and evaluation activities as NSTAR Electric's evaluation report proposal (D.P.U. 21-91, Exh. NG-EVPP-1, at 119-120). The company states that it will coordinate with the independent evaluator to develop additional research tasks and identify areas of continued process improvement (D.P.U. 21-91, Exh. NG-EVPP-1, at 122). National Grid states that it coordinated with NSTAR Electric on many aspects of their evaluation plan proposals (D.P.U. 21-91, NG-EVPP-1, at 119-122).

2. Positions of the Parties

a. Attorney General

The Attorney General asks the Department to direct NSTAR Electric and National Grid to file a detailed program evaluation plan in a compliance phase of these proceedings for Department and stakeholder review and Department approval (D.P.U. 21-90, Attorney General Track 1 Brief at 73; D.P.U. 21-91, Attorney General Track 1 Brief at 87-88). In the program evaluation plan, the Attorney General recommends that NSTAR Electric and National Grid develop and report on the following: (1) metrics to track the achievement of equitable access to the benefits of clean transportation; (2) metrics related to port deployment and cost, including the number of ports serving mass transit, the number of publicly accessible ports, and the number of each of those ports installed in EJ communities, plus anonymized data on the utility- and customer-side make-ready and EVSE costs for each project; (3) metrics related to load

management, such as aggregate EV charging load profile by customer segment, percentage of on-peak to off-peak charging, the timing and size of peak EV charging load, and percentage of EV program customers participating in managed charging programs; and (4) metrics to meaningfully track the success of the workforce development and electrician training program and ensure accountability for the diversity and equity initiatives, such as demographic information, and demographic targets for program participation (D.P.U. 21-90, Attorney General Track 1 Brief at 75; D.P.U. 21-91, Attorney General Track 1 Brief at 90).

b. NSTAR Electric and National Grid

NSTAR Electric and National Grid disagree with the Attorney General's recommendation for submission of a detailed proposed evaluation plan because their evaluation proposal is consistent with that proposed in the 2019-2022 Massachusetts statewide energy efficiency strategic evaluation plan and because the Department and stakeholders will have the opportunity to review an annual evaluation report as part of their annual cost recovery filings (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 77-78).

3. Analysis and Findings

The Department has recognized the value of the information provided through the development and publication of evaluation reports, stating that a systematic collection and analysis of information to document the impact of the EV programs in terms of costs and benefits is necessary to improve the effectiveness of the investments. D.P.U. 17-05, at 484; see also D.P.U. 17-13, at 39 (stating that ongoing evaluation of the EV programs is essential to ensure that the components of the programs fulfill their intended purpose and to provide opportunities to make adjustments to the program that may improve results). Previously, the

Department approved third-party evaluations of NSTAR Electric's and National Grid's respective Phase I EV programs. D.P.U. 17-05, at 484; D.P.U. 17-13, at 39.

In these proceedings, the Department acknowledges the importance of the Companies' proposed EV programs in achieving the Commonwealth's transportation electrification and decarbonization goals and determines that effective program evaluations will be critical to ensuring both the success of the EV programs and the attainment of the Commonwealth's EV adoption and GHG reduction goals. With this in mind, once performance metrics are finalized, the Department will require the Companies to develop a joint state-wide program evaluation plan for Department approval and stakeholder input and will determine next steps at that time.[64]

C. Annual Reports

1. Description of the Proposals

Each company proposes to file an annual report with the Department at the end of each program year (D.P.U. 21-90, Exh. ES-KB-1, at 93; D.P.U. 21-91, Exh. NG-EVPP-1, at 121; D.P.U. 21-92, Exh. CSVG-1, at 35). NSTAR Electric and National Grid propose to summarize the results from their evaluation plans in their respective annual reports (D.P.U. 21-90, Exh. ES-KB-1, at 93; D.P.U. 21-91, Exh. NG-EVPP-1, at 121). In its annual report, Unitil proposes to outline the number of residential customer participants in the program, incentives

64 As noted above, Unitil did not propose an evaluation plan as part of its EV program proposal, however, the Department determines that it is appropriate to require one as part of our approval. Unitil may seek recovery of costs associated with the evaluation plan through the GMF. The Department will review the reasonableness and prudence of any such costs at the end of the program term.

distributed, third-party partners within the program, and periodic findings related to embedded EVSE meters and future use cases (D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 35).

2. Positions of the Parties

a. Intervenors

DOER asserts that the Department should direct the Companies to include specific details and recommendations in their annual reports including: (1) the effectiveness of each make-ready market segment with an annual adjustment to the budgets and goals as appropriate; (2) descriptions of outreach to EJ communities and low-income community organizations, recommendations on adjusting or setting specific goals for EJ communities based on stakeholder and customer feedback, and metrics demonstrating programmatic effectiveness; (3) for NSTAR Electric and National Grid, a metric that tracks the number of the residential one to four-unit EJ community rebates and incentives that were provided to customers that were also on the low-income residential electric rate; (4) customer preferences and equity; (5) growth of the competitive market and any appropriate programmatic changes based on that growth; (6) overlap between EV program funding and offerings and state and federal funding and offerings and a description of actions taken to address the overlap, including budget reductions or budget shifting; (7) the length of the program; (8) for NSTAR Electric and National Grid, all make-ready program charging data and a description of how the data is being used to develop peak demand reduction and maximize flexible load through managed charging programs; (9) for NSTAR Electric and National Grid, the effectiveness of their managed charging programs, including a timeframe for implementation of managed charging programs for non-fleet vehicles, and any progress in developing new managed charging programs; (10) for NSTAR Electric and

National Grid, a description of coordination efforts with MassCEC on the companies' fleet assessment services offerings and any recommended improvements to the offerings; and (11) data regarding enrollment of both new and existing EV charging facility customers in the DCA rates, data and descriptions of outreach efforts, including the specific methods of outreach used, insights into the effectiveness of the DCA rates, and possible tariff revisions to the DCA rates to improve program performance (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 6-15, 19-21, 25; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 2 Brief at 9, 14).

Additionally, DOER suggests that the Department review the annual reports along with any intervenor comments and, as appropriate, direct the Companies to make changes to their respective EV programs and associated budgets and the DCA rates (D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, DOER Track 1 Brief at 10, 12, 14; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 2 Brief at 14, 15). DOER also recommends that the Department seek and incorporate low-income and EJ community and stakeholder feedback on any programmatic changes to the EV programs and direct the Companies to incorporate data from EJ community rebates and community outreach to design and implement future equity-based programs (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 1 Brief at 11 & n.36).

CEP recommends that the Department require the Companies to track and annually report on site host data, load profiles by site, number of charging sessions recorded, costs to drivers to utilize each station, charging station location organized by site host type, installation and equipment costs, and EV infrastructure deployment in EJ communities (D.P.U. 21-90, CEP Track 1 Brief at 21; D.P.U. 21-91, CEP Track 1 Brief at 22; D.P.U. 21-90/D.P.U. 21-91, CEP

Track 1 Reply Brief at 13). Additionally, the Compact recommends that NSTAR Electric track and report on commitments and installations made through all EV program segments in a manner consistent with its Phase I EV program tracking and reporting requirements (D.P.U. 21-90, Compact Track 1 Brief at 2, 7-8, 9; D.P.U. 21-90/D.P.U. 21-91, Compact Track 1 Reply Brief at 1-2).

3. Analysis and Findings

To allow the Department and stakeholders to monitor the status of the Companies' EV programs, DCA rate offerings, and Unitil's residential EV TOU rate offering, the Department directs the Companies to submit annual reports that document their performance during the applicable year. D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, at 112. The Companies' annual reports will be due on or before May 15th of each year. The first EV annual report shall be due on May 15, 2024. The Department will convene a working group as part of the performance metrics stakeholder process to develop the contents of the annual reports, described above in Section IV.A.3.a.

V. EV CHARGING PROGRAM COST RECOVERY AND BILL IMPACTS

A. Description of the Proposals

1. NSTAR Electric

NSTAR Electric proposes to recover its Phase II EV program costs through its existing annual reconciling GMF with expenditures for customer-side make-ready infrastructure deferred to a regulatory asset and recovered through the GMF over a five-year period (D.P.U. 21-90, Exh. ES-RWF-1, at 4-6). The company proposes to apply carrying charges at its weighted average cost of capital to the balance of deferred customer-side make ready costs that have not

been recovered through the GMF (D.P.U. 21-90, Exh. ES-RWF-1, at 7-8). The company also proposes revisions to its approved GMF cost recovery tariff to incorporate its cost recovery deferral proposal (D.P.U. 21-90, M.D.P.U. No. 73C (proposed)).

Further, NSTAR Electric developed an illustrative bill impact analysis of the Phase II EV program costs for residential customers and estimates that, over the course of the Phase II EV program, an eastern Massachusetts residential customer using an average of 516 kWh of electricity per month would experience a monthly bill increase of $0.15 in year one, $0.21 in year two, $0.19 in year three, and $0.19 in year four (D.P.U. 21-90, Exh. DPU 4-1, Att. (f) at 1). A western Massachusetts residential customer using an average of 516 kWh of electricity per month would experience a monthly bill increase of $0.15 in year one, $0.20 in year two, $0.20 in year three, and $0.19 in year four (D.P.U. 21-90, Exh. DPU 4-1, Att. (f) at 3).

2. National Grid

National Grid proposes to recover its Phase III EV program costs through its existing annual reconciling EV program factor, M.D.P.U. No. 1447, with expenditures for customer-side make-ready infrastructure deferred to a regulatory asset and recovered through the EV program factor over a five-year period (D.P.U. 21-91, Exh. NG-CRP-1, at 6-8). The company proposes to apply carrying charges at its weighted average cost of capital to the balance of deferred customer-side make-ready costs that have not been recovered through the EV program factor (D.P.U. 21-91, Exh. NG-CRP-1, at 8). Further, the company proposes certain revisions to its approved EV cost recovery tariff to incorporate a description of its Phase III EV program, the additional categories of incremental costs in its Phase III EV program, and its proposed PIMs (D.P.U. 21-91, Exhs. NG-CRP-1, at 8-10; NG-CRP-2).

Additionally, the company developed an illustrative bill impact analysis of the Phase III EV program costs for residential customers (D.P.U. 21-91, Exh. AG 5-5). The company estimates that, over the course of the Phase III EV program, a residential customer using an average of 600 kWh of electricity per month would experience a monthly bill increase of $0.85 in year one, $0.59 in year two, $0.79 in year three, and $1.03 in year four (D.P.U. 21-91, Exhs. AG 5-5, Att. 3, at 2; AG 5-5, Att. 4, at 2; AG 5-5, Att. 5, at 2; AG 5-5, Att. 6, at 2).

3. Unitil

Unitil proposes to recover utility-side make-ready infrastructure investments through its annual reconciling Capital Cost Adjustment Mechanism ("CCAM") and to defer remaining costs to a regulatory asset, with carrying costs accrued at the weighted average cost of capital, for recovery in its next base distribution rate proceeding (D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 56-57).

Unitil submitted bill impact analyses showing estimated increases from its proposed EV program (D.P.U. 21-92, Exhs. DPU 5-2, Att. 1; DPU 5-3, Att. 1; RR-DPU-4, Att. 1). Assuming all charging sites were installed in year one, the bill impact of the company's proposed EV program results in an estimated monthly bill increase for a typical residential customer of approximately $0.16 per month for EV costs recovered through the CCAM and an estimated monthly bill increase of approximately $0.23 per month for EV costs deferred as a regulatory asset to be collected through base distribution rates (D.P.U. 21-92, Exh. DPU 5-3, Att. 1; RR-DPU-4, Att. 1).

B. Positions of the Parties

1. Attorney General

The Attorney General recommends that the Department deny the Companies' request to defer recovery of certain EV program expenditures and to amortize them with a carrying charge because: (1) the proposed approach is inconsistent with the Department's Uniform System of Accounts; (2) deferral of program costs is inconsistent with the mechanism utilized for energy efficiency expenditures; and (3) the carrying charges that would accrue on the deferred costs would outweigh the benefits to ratepayers of deferring those costs (D.P.U. 21-90, Attorney General Track 1 Brief at 79-80; D.P.U. 21-91, Attorney General Track 1 Brief at 94-95; D.P.U. 21-92, Attorney General Track 1 Brief at 31-32).

2. NSTAR Electric and National Grid

NSTAR Electric and National Grid urge the Department to approve their proposed EV program cost recovery proposals because: (1) the deferral of make-ready infrastructure costs behind the customer meter for a period of five years will moderate customer bill impacts; (2) the Department approved a similar deferral proposal for the companies' pension adjustment mechanism ("PAM"); and (3) extending the period of recovery for certain program expenses provides an opportunity for EV program costs to be recovered along a timeline in which favorable impacts from EV adoption could grow in parallel and offset customer bill impacts (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 1 Brief at 86-88).

3. Unitil

Unitil argues that the Department should approve its cost recovery proposal because: (1) deferral of customer-side EV program expenses would enable these expenditures to be

recovered around the same time that EV program revenues will become available, which would minimize customer bill impacts, and (2) Unitil must file its next base distribution rate case with the Department by no later than the end of 2024 (D.P.U. 21-92, Unitil Track 1 Brief at 48-49).

C. Analysis and Findings

1. Cost Recovery Proposals

The Companies each propose to defer certain EV program costs to regulatory assets to be recovered at a later time with carrying costs at the weighted average cost of capital approved in their last base distribution rate cases (D.P.U. 21-90, Exh. ES-RWF-1, at 6-8; D.P.U. 21-91, Exhs. NG-JG at 4-6; NG-CRP-1, at 8; D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 57). Department precedent does not allow for the deferral of prospective expenses. Aquarion Water Company of Massachusetts, D.P.U. 12-26, Letter from General Counsel (April 25, 2012); Bay State Gas Company, D.P.U. 12-25, at 339-342 (2012); Aquarion Water Company of Massachusetts, D.T.E. 04-77, at 7 (2005); Aquarion Water Company of Massachusetts, D.T.E. 03-127, at 11 (2004). Thus, the Department will not typically preapprove a deferral request prior to a company incurring the expense it seeks to defer.

In response to the companies' assertion that the Department approved similar deferral requests for the companies' respective PAMs, the Department approved the companies' pension and post-retirement benefits other than pensions ("PBOP") proposals for a limited period (i.e., a three-year recovery period) pursuant to Statement of Financial Accounting Standards ("SFAS") 71 and based on the specific facts of that proceeding.[65] Commonwealth Electric

[65] In December 1982, the Financial Accounting Standards Board issued SFAS 71, effective 1983, which established standards for accounting for the effects of certain types of

Company, Cambridge Electric Light Company, and Boston Edison Company, D.T.E. 03-47-A at 24 (2003). In that proceeding, the issue before the Department involved the appropriate mechanism for recovery of recurring pension and PBOP costs in a manner that would minimize harm from the application of accounting rules under unusual economic circumstances. D.T.E. 03-47-A at 25. The Department stated that a failure to adopt a pension and PBOP reconciling mechanism would inevitably trigger an equity write-down entailing significant and impairing financial consequences for the companies. D.T.E. 03-47-A at 25, 26. In the instant matters, the Department determines that the Companies would not suffer from any impairing financial consequences if the Department does not grant the deferral proposals and that the same exigent circumstances do not exist. Therefore, the Department's approval of the deferral proposals in D.T.E. 03-47-A do not support the Companies' deferral proposals in these proceedings.

In addition, the Department has reviewed the bill impact analyses provided by the Companies with the estimated customer bill impacts from approval of the Companies' proposed EV programs under a scenario in which the Companies defer some EV program costs and a scenario in which they do not (D.P.U. 21-90, Exh. DPU 4-1, Att. (a) & (f); D.P.U. 21-91, Exhs. AG 5-5; DPU 5-2; D.P.U. 21-92, Exhs. DPU 5-3, Att. 1; DPU 7-2, Atts. 2-6). Based on

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regulation. D.T.E. 03-47-A at 3. SFAS 71 sets forth the specific criteria that must be met for a regulated company to establish a regulatory asset. D.T.E. 03-47-A at 3. A regulatory asset is an incurred cost for which a regulatory agency, such as the Department, allows a regulated company to record a deferral to be considered for recovery in the future. D.T.E. 03-47-A at 3 n.2. Recognition of a regulatory asset, preserved for later decision as to future recovery, is a common feature of utility regulation at both state and federal level. D.T.E. 03-47-A at 3 n.2.

our review, the Department finds that the Companies' deferral proposals do not yield sufficient benefits to ratepayers to justify approval of the long-term carrying costs associated with the deferral proposals. Additionally, in Sections III.C.8, above, the Department has denied certain aspects of NSTAR Electric's and National Grid's proposed Phase II and Phase III EV programs, respectively, which reduces the overall EV program budgets and assists in moderating the customer bill impacts associated with the companies' proposed EV programs. For these reasons, the Department denies the Companies' request to defer recovery of certain EV program expenditures and amortize them with carrying charges.

Additionally, in D.P.U. 17-05, at 500-501, the Department approved a $45 million budget for NSTAR Electric's Phase I EV program. Here, NSTAR Electric proposes a $191.9 million Phase II EV program budget, a more than four-fold program budget increase (D.P.U. 21-90, Exh. ES-KB-2). Given the substantial increase in the size and scope of the company's Phase II EV program as compared to its Phase I EV program, the Department finds that increased transparency and a focused review of the company's Phase II EV program costs are necessary. Therefore, the Department establishes a separate reconciling cost recovery mechanism for targeted recovery of EV program costs and directs NSTAR Electric to recover its Phase II EV program expenditures through an EV program factor rather than through the GMF. NSTAR Electric shall submit a proposed EV program factor tariff for Department review and approval no later than January 15, 2023. NSTAR Electric shall also file a revised GMF tariff to remove all references to its EV program no later than January 15, 2023. The Department further directs NSTAR Electric to create a separate line item on customers' bills to reflect EV program-related charges. The EV program factor shall not be included in the following kWh charges: (1) basic

service; (2) distribution; (3) transmission; (4) transition; (5) energy efficiency; or (6) renewable energy. For the majority of net metering facilities, the charges that constitute a customer's net metering credit include some or all of the following kWh charges: (1) basic service; (2) distribution; (3) transmission; and (4) transition. 220 CMR 18.04. Accordingly, for the purposes of the net metering credit calculation, net metering credits shall exclude the EV program factor line item. See D.P.U. 17-13, at 61. The company may seek recovery for the costs necessary to create this new line item on customers' bills in its next annual EV program cost recovery filing.[66]

Turning to National Grid, the company currently recovers its Phase I and Phase II EV program expenditures through its approved EV program factor. D.P.U. 17-13, 56-60. The Department directs the company to continue recovery of its EV program costs, including the costs associated with the Phase III EV program approved herein, through its annual reconciling EV program factor. National Grid shall submit compliance tariff revisions for the Department's review no later than January 15, 2023.

Regarding Unitil, to promote transparency and reduce the administrative burden on the Department, we find it appropriate for the company to recover all EV program expenditures through a single reconciling mechanism. The total budget of Unitil's proposed five-year EV program is $1.02 million (D.P.U 21-92, Exh. CSVG-1 (Rev.) at 32-33, 40, 56). Given the relative size and scope of Unitil's proposed EV program, the Department finds that it is not

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66 NSTAR Electric estimates that it will incur $524,000 in costs to modify its billing and back-office systems to create a new EV program reconciling mechanism (D.P.U. 21-90, Exh. DPU 9-1).

administratively efficient or economical for Unitil and its customers[67] to direct the company to establish a separate EV cost recovery factor at this time. Therefore, the Department directs Unitil to recover its EV program costs through its GMF.[68] We note that recovery of Unitil's EV program costs through the GMF aligns with the Department's decision to require Unitil to recover its AMI implementation plan costs in its GMF. 2022-2025 Grid Modernization Plans, D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B at 282-285 (November 30, 2022) ("Grid Mod Track 2 Order").

Consistent with these findings, Unitil shall submit a revised GMF tariff for Department review and approval no later than January 15, 2023. The revised GMF tariff shall clearly distinguish between grid modernization investments and costs and EV program investments and costs.

As noted above, the Department held a joint public hearing in these proceedings on September 14, 2021. Unitil, however, did not meet the prescribed deadline for publication of the Notice of Public Hearing. To correct this defect, the Department issued a second Order of Notice in D.P.U. 21-92, to which Unitil made return of service and proof of publication on October 5, 2021, and the Department held a second public hearing on October 12, 2021.

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67 Unitil estimates that it would cost $7,500 and take approximately 125 labor hours to update its billing and back-office systems to create a new EV program reconciling mechanism and $2,000 and ten labor hours to create a separate line item on customers' bills reflecting EV program-related charges (D.P.U. 21-92, Exh. DPU 6-5(d)).

68 Cost recovery through the GMF is consistent with the cost recovery mechanism the Department approved for NSTAR Electric's Phase I EV program. D.P.U. 15-120/ D.P.U. 15-121/D.P.U. 15-122, at 187.

Because the second public hearing was necessitated by Unitil's omission, the Department disallows recovery from ratepayers for any costs associated with the second public hearing.

2. Bill Impacts

a. NSTAR Electric

According to the bill impact analyses provided by NSTAR Electric under the scenario in which no Phase II EV program expenditures are deferred, a typical Eastern Massachusetts residential customer with an average monthly electric usage of 516 kWh would experience an average annual bill increase of $0.82 in 2025 and a typical Western Massachusetts residential customer with an average monthly electric usage of 516 kWh would experience an average annual bill increase of $0.81 in 2025 (D.P.U. 21-90, Exh. DPU 4-1, Att. (a)). Based on our review, the Department finds that the bill impacts without deferral are reasonable and will result in just and reasonable rates.

b. National Grid

Without deferral, a typical Massachusetts Electric Company residential customer with an average monthly electric usage of 600 kWh would experience an average annual bill increase of $3.52 in 2026 (D.P.U. 21-91, Exh. DPU 5-2, Att. 7, at 2). After review, the Department finds that the bill impacts without deferral are reasonable and will result in just and reasonable rates.

c. Unitil

With no deferral of EV program costs, a typical Unitil residential customer with an average monthly electric usage of 600 kWh would experience an average annual bill increase of $3.96 in 2026 (D.P.U. 21-92, Exh. DPU 7-2, Atts. 2-6). The Department finds that the bill impacts are reasonable and will result in just and reasonable rates.

3. Annual Factor Filings

Above, the Department establishes the method by which each company shall recover its EV program expenditures. The Companies shall file annual rate adjustment and reconciliation filings.[69] Such filings shall be submitted to the Department as follows: (1) for NSTAR Electric, on or before by May 15 with rates effective July 1; (2) for National Grid, on or before May 15, with rates effective July 1; and (3) for Unitil, on or before April 15, with rates effective June 1.

To be eligible for recovery, the Companies must demonstrate that all EV program expenditures are incremental, reasonable, prudently incurred, and used and useful (where applicable). D.P.U. 17-13, at 61. The Companies must also describe any cost variances, as defined in the Companies' respective capital authorization policies, demonstrate that the proposed EV program costs sought for recovery are calculated appropriately, and provide bill impacts. D.P.U. 17-13, at 61. Consistent with Section III.C.6.b, above, the Companies must describe any offsets from alternative government or outside funding received for the EV program investments. The Department will review the Companies' actual EV program expenditures annually to determine if they are reasonable and prudently incurred.[70]

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69 The Companies may request to defer the annual prudence review in a given year if their EV program expenses for the program year are too small to generate an EV program factor for NSTAR Electric and National Grid or a GMF for Unitil. Grid Modernization, D.P.U. 15-120-B/D.P.U. 15-121-B/D.P.U. 15-122-B/D.P.U. 19-23/ D.P.U. 19-36, at 2, 30 (2019).

70 With each annual EV program or GMF factor filing, the Companies shall provide testimony and supporting exhibits, including full project documentation of all EV program capital projects placed into service during the plan investment year and documentation of O&M expenses, describing in detail how the proposed costs meet the eligibility requirements set forth in the present filing.

In addition, all O&M expenses proposed for recovery must be: (1) incremental to the representative level of O&M expenses recovered through base distribution rates, and (2) solely attributable to EV program expenses. D.P.U. 17-13, at 57. A failure to provide clear, cohesive, and reviewable evidence demonstrating eligibility will result in disallowance of targeted cost recovery. D.P.U. 17-13, at 58.

In D.P.U. 12-76-B at 23 and D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, at 218, the Department found that a representative level of O&M costs is already recovered through base distribution rates and, therefore, allowing recovery of costs through a targeted cost recovery mechanism increases the risk that a company could recover a portion of these costs more than once. Accordingly, the Department directs the Companies to develop a rigorous method to demonstrate that only incremental EV program-related costs are proposed for targeted cost recovery. Each company shall make an annual EV program adjustment and reconciliation filing comprised of: (1) actual, eligible expenditures from the prior EV program year, and (2) a reconciliation component in the following year and beyond. Interest on over- or under-recovery of the revenue requirement shall be calculated on the average monthly balance using the customer deposit rate.

D. Conclusion

In Section V.C.2, above, the Department found that the bill impacts from the proposed EV programs are reasonable and will result in just and reasonable rates. Consistent with our findings and directives, above, in Section V.C.1, NSTAR Electric shall recover its Phase II EV program expenses through a new EV program factor, National Grid shall recover its Phase III EV program expenses through its existing EV program factor, and Unitil shall recover its EV

program expenses through its existing GMF. The Companies shall file by January 15, 2023 revised tariffs consistent with the directives contained herein. Additionally, as discussed in Section V.C.1, the Department disallows recovery from ratepayers for any costs associated with the second public hearing on Unitil's EV proposal.

VI. ELECTRIC SECTOR GRID MODERNIZATION PLANS

As discussed above, on January 15, 2021, Governor Baker signed into law the Transportation Act that required each electric distribution company to file by July 14, 2021 at least one proposed commercial tariff or program for Department review using alternatives to traditional demand-based rate structures to facilitate faster charging for light-duty, heavier-duty, and fleet electric vehicles. St. 2021, c. 383, § 29. Then, on March 26, 2021, Governor Baker signed into law the 2021 Climate Act which established new interim goals for emission reductions and a commitment to achieve net zero GHG emissions by 2050. St. 2021, c. 8, § 8.

Consistent with the new legislation, in D.P.U. 20-69-A at 40-41, 49, the Department directed each company to file an EV proposal consisting of: (1) any new or expanded EV charging infrastructure proposal, and (2) a commercial EV rate design proposal addressing alternatives to demand charges. In the instant proceedings, on July 14, 2021, the Companies filed new EV charging infrastructure program proposals and demand charge alternative proposals to support EV adoption in the Commonwealth. On August 11, 2022, during the course of these proceedings, Governor Baker signed into law the 2022 Clean Energy Act. The Clean Energy Act requires the Companies to submit proposals to the Department on or before August 11, 2023 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. St. 2022, c. 179, § 90.

Additionally, the 2022 Clean Energy Act establishes an EV Coordinating Council to implement an EV charging infrastructure deployment plan. St. 2022, c. 179, § 81(a). The EV Coordinating Council is required to assess and report on strategies and plans necessary to deploy EV charging infrastructure to establish an equitable, interconnected, accessible, and reliable EV charging network. St. 2022, c. 179, § 81(a). The deployment plan will facilitate: (1) compliance with the GHG emissions limits and sub-limits set pursuant to G.L. c. 21N, § 3, 3A, with emphasis on compliance with the emissions limits and sub-limits set for 2025 and 2030; (2) attainment of the numerical benchmarks for EVs and EV charging stations set pursuant to G.L. c. 21N, § 5; (3) cessation, by December 31, 2035, of in-state sales of non-zero-emission vehicles; and (4) advancement of access to, and affordability of, EV charging and fueling. St. 2022, c. 179, § 81(a). The EV Coordinating Council is also required to seek data and input related to EV charging stations, fueling stations and related infrastructure, equipment, equipment maintenance, and technology, from stakeholders, including investor-owned electric utilities. St. 2022, c. 179, § 81(a). Finally, the EV Coordinating Council is required to issue an initial assessment to the senate and house committees on ways and means and the joint committee on telecommunications, utilities, and energy not later than August 11, 2023 and shall consider and revise its assessment at least once every two years. St. 2022, c. 179, § 81(d).

The 2022 Clean Energy Act also established a new regulatory construct regarding electric sector grid modernization that incorporates, among other thing, considerations of transportation electrification. Specifically, each electric company must develop an electric sector

modernization plan to proactively upgrade its distribution system and where applicable the transmission system to: (1) improve grid reliability, communications and resiliency; (2) enable increased, timely adoption of renewable energy and DERs; (3) promote energy storage and electrification technologies necessary to decarbonize the environment and economy; (4) prepare for future climate-driven impacts on the transmission and distribution systems; (5) accommodate increased transportation electrification, increased building electrification and other potential future demands on distribution and, where applicable, transmission systems; and (6) minimize or mitigate impacts 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: (1) improvements to the electric distribution system to increase reliability and strengthen system resiliency to address potential weather- and disaster-related risks; (2) the availability and suitability of new technologies including, but not limited to, smart inverters, advanced metering and telemetry, and energy storage technology for meeting forecasted reliability and resiliency needs, as applicable; (3) patterns and forecasts of DER adoption in the company's territory and upgrades that might facilitate or inhibit increased adoption of such technologies; (4) improvements to the distribution system that will enable customers to express preferences for access to renewable energy resources; (5) improvements to the distribution system that will facilitate transportation or building electrification; (6) improvements to the transmission or distribution system to facilitate achievement of the statewide GHG emissions limits under G.L. c. 21N; (7) opportunities to deploy energy storage technologies to improve renewable

energy utilization and avoid curtailment; (8) alternatives to proposed investments, including changes in rate design, load management and other methods for reducing demand, enabling flexible demand, and supporting dispatchable demand response; and (9) alternative approaches to financing proposed investments, including, but not limited to, cost allocation arrangements between developers and ratepayers and, with respect to any proposed investments in transmission systems, cost allocation arrangements and methods that allow for the equitable allocation of costs to, and the equitable sharing of costs with, other states and populations and interests within other states that are likely to benefit from said investments. G.L. c. 164, § 92B(b). 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 submit its first plan for review to the Grid Modernization Advisory 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 Grid Modernization Advisory 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 Grid Modernization Advisory Council's recommendations 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).

Pursuant to the 2022 Clean Energy Act, the Department is required to direct each electric company to develop an electric sector modernization plan within 30 days of the Act's effective date. St. 2022, c. 179, § 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 Grid Modernization Advisory Council by September 1, 2023, an electric sector modernization plan consistent with the 2022 Clean Energy Act for the Grid Modernization Advisory 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 Grid Modernization Advisory 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.

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. Distributed Energy Resource Planning and Assignment and Recovery of Costs for the Interconnection of Distributed Generation, D.P.U. 20-75-C at 3 (2021). 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 performance metrics discussed in Section IV.A.3.a, the contents of the annual report discussed in Section IV.C.3, and any specifics for the evaluation plan discussed in Section IV.B.3, the Department's review of investments in EV charging infrastructure and related transportation electrification proposals that would have been investigated pursuant to our existing regulatory construct will instead be filed pursuant to the requirements established in the 2022 Clean Energy Act.[71]

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[71] The Department notes that the budgets approved in this Order are capped, and, based on the content and timing of any future proposals made pursuant to G.L. c. 164, § 92B, a transition process may or may not need to be developed to maintain continuity of the EV programs, similar to the transition process for the energy efficiency programs subject to Chapter 169 of the Acts of 2008, An Act Relative to Green Communities. See, e.g.,

VII. DEMAND CHARGE ALTERNATIVE PROPOSALS

A. Description of the Proposals

NSTAR Electric proposes to offer for a ten-year period two new rate schedules, Rates EV-1 and EV-2, to all separately-metered EV charging sites (D.P.U. 21-90, Exh. ES-RDC-1, at 5, 10-11). Rate EV-1 consists of a customer charge and per kWh base distribution rate and would be available to EV charging sites with a billing demand of no more than 200 kW for twelve consecutive billing months (D.P.U. 21-90, Exh. ES-RDC-1, at 5, 10, 18, 20). Rate EV-2 consists of a customer charge, per kWh base distribution rate, and a demand charge and would be made available to EV charging sites with a billing demand above 200 kW for twelve consecutive billing months (D.P.U. 21-90, Exh. ES-RDC-1, at 5, 10, 18, 20-21).

National Grid proposes revisions to two general service tariffs, Rates G-2 and G-3, to offer for a ten-year period DCA pricing schedules to all separately-metered EV charging sites (D.P.U. 21-91, Exh. NG-DCA-1, at 9-10, 14-15). Rate G-2 consists of a customer charge, demand charge, and per kWh base distribution rate and would be available to EV charging sites with a billing demand of no more than 200 kW for twelve consecutive billing months and monthly kWh usage greater than 10,000 (D.P.U. 21-91, Exhs. NG-DCA-1, at 13; NG-DCA-2, at 1-3). Rate G-3 consists of a customer charge, demand charge, and per kWh base distribution rate and would be available to EV charging sites with a billing demand in excess of 200 kW for twelve consecutive billing months (D.P.U. 21-91, Exh. NG-DCA-1, at 13).

Boston Gas Company, Colonial Gas Company, and Essex Gas Company, D.P.U. 08-109, at 10 (2009).

Unitil proposes revisions to two general service tariffs, Rates GD-2 and GD-3, to offer for a ten-year period tiered DCA rates to separately-metered general delivery service customers (D.P.U. 21-92, Exh. JDT-1, at 6, 9). Rate GD-2 consists of a customer charge, demand charge, and per kWh base distribution rate and would be available to EV charging sites with a monthly usage between 850 kWh and 120,000 kWh and at least 4 kW of demand (D.P.U. 21-92, Exhs. JDT-1, at 6; JDT-3). Rate GD-3 consists of a customer charge, demand charge, and a base distribution rate with an on-peak per kWh charge and an off-peak per kWh charge and would be available to EV charging sites with at least 120,000 kWh of monthly usage (D.P.U. 21-92, Exhs. JDT-1, at 6; JDT-2).

Under all of the DCA rate proposals, the base distribution demand and energy charges would operate on a sliding scale (i.e., as load factor increases, the demand charge increases and the energy charge decreases) (D.P.U. 21-90, Exh. ES-RDC-1, at 5, 18-19; D.P.U. 21-91, Exh. NG-DCA-1, at 10, 23-24; D.P.U. 21-92, Exhs. JDT-1, at 6; JDT-2).

The Companies initially proposed to limit enrollment in the DCA rates to customers whose metered account was limited exclusively to EV charging load (D.P.U. 21-90, Exh. ES-RDC-1, at 10, 20-21; D.P.U. 21-91, Exh. NG-DCA-1, at 13-14; D.P.U. 21-92, Exh. JDT-1, at 9). During the course of these proceeding, the Companies amended their proposals to permit the ancillary load needed for the direct operation of the EV charging station to qualify for the DCA rates (D.P.U. 21-90, Exh. ES-RDC-Reb-1, at 14; D.P.U. 21-91, Exh. NG-DCA-Reb-1, at 16; D.P.U. 21-92, Exh. JDT-Rebuttal-2, at 20).

The Companies propose to structure their DCA rates by load factor bracket as follows: (1) a 100 percent demand charge discount for customers with load factors between zero percent

and five percent; (2) a 75 percent demand charge discount for customers with load factors between five percent and ten percent; and (3) a 50 percent demand charge discount for customers with load factors between ten percent and 15 percent (D.P.U. 21-90, Exh. ES-RDC-1, at 18-19; D.P.U. 21-91, Exh. NG-DCA-1, at 22-23; D.P.U. 21-92, Exhs. JDT-1, at 7; JDT-2). Customers with a 15 percent or greater average load factor over a twelve-month period would not be eligible to receive a demand charge discount for that year (D.P.U. 21-90, Exhs. ES-RDC-1, at 14; ES-RDC-2, at 2; D.P.U. 21-91, Exhs. NG-DCA-1, at 16, 18; NG-DCA-2, at 1-3; D.P.U. 21-92, Exhs. JDT-1, at 7; JDT-2).

New EV charging sites with no prior account history with the Companies would initially be assigned to the price schedule associated with the lowest load factors (i.e., load factor between zero percent and five percent) (D.P.U. 21-90, Exh. ES-RDC-1, at 12; D.P.U. 21-91, Exh. NG-DCA-1, at 15; D.P.U. 21-92, Exh. JDT-1, at 9-10). Existing EV charging sites with account history with the Companies would be assigned to the price schedule reflecting their twelve-month average load factor (D.P.U. 21-90, Exh. ES-RDC-1, at 12; D.P.U. 21-91, Exh. NG-DCA-1, at 14; D.P.U. 21-92, Exh. JDT-1, at 9-10). NSTAR Electric and National Grid propose to assess each customer's average monthly load factor over the preceding twelve months on or before June 1 of each year to determine whether the customer account should be reassigned to a different price schedule (D.P.U. 21-90, Exh. ES-RDC-1, at 12, 15; D.P.U. 21-91, Exh. NG-DCA-1, at 10, 16, 19). Unitil proposes to review each customer's average monthly load factor over the preceding twelve months on or before May 1 of each year to determine whether the customer account should be reassigned to a different price schedule (D.P.U. 21-92, Exh. JDT-1, at 9-10).

Eligible customers would be permitted to enroll in the DCA rates during the first nine years the rates are in operation, after which enrollment would be closed to new customers (D.P.U. 21-90, Exh. ES-RDC-1, at 11; D.P.U. 21-91, Exh. NG-DCA-1, at 14-15; D.P.U. 21-92, Exh. JDT-1, at 9). At the conclusion of the ten-year DCA rate terms, customers enrolled in the DCA rates would be returned to the otherwise applicable general service rates (D.P.U. 21-90, Exh. ES-RDC-1, at 11; D.P.U. 21-91, Exh. NG-DCA-1, at 15; D.P.U. 21-92, Exh. JDT-1, at 9).

NSTAR Electric and National Grid estimate that it would take six months following Department approval of the DCA rates to accurately program their billing systems to set up the required functionality to implement the DCA rates and train their customer service representatives on the new rates (D.P.U. 21-90, Exh. RDC-1, at 17-18; D.P.U. 21-91, Exh. NG-DCA-1, at 22). Unitil anticipates that it would take three months following Department approval to update its billing system to implement the DCA rates and train its customer service representatives on the new rates (D.P.U. 21-92, Exh. JDT-1, at 21). The Companies' state that incremental revenue generated under the DCA rates will offset revenue shortfalls in the Companies' revenue decoupling mechanisms (D.P.U. 21-90, Exh. ES-RDC-1, at 17; D.P.U. 21-91, Exh. NG-DCA-1, at 21; D.P.U. 21-92, Exh. JDT-1, at 8). The Companies state that, to the extent feasible, they coordinated on the development of their DCA rate proposals (D.P.U. 21-90, Exh. ES-RDC-3; D.P.U. 21-91, Exh. NG-DCA-4; D.P.U. 21-92, Exh. JDT-3).

B. Positions of the Parties

1. Rate Design Issues

a. Load Factors

i. Attorney General

The Attorney General urges the Department to direct the Companies to maintain a small, substantially reduced demand charge for customers with load factors between zero percent and five percent (e.g., a 75 percent demand charge discount) because it would: (1) incentivize the development of EV charging stations while sending appropriate price signals to customers regarding their share of the unit cost of local distribution facilities, and (2) reduce the cross-subsidization between customers enrolled in the DCA rates and those who are not (D.P.U. 21-90, Attorney General Track 2 Brief at 9-12; D.P.U. 21-91, Attorney General Track 2 Brief at 13-16; D.P.U. 21-92, Attorney General Track 2 Brief at 19-21; D.P.U. 21-92, Attorney General Track 2 Reply Brief at 9).

ii. CLF

CLF recommends that the Department direct the Companies to expand the load factor brackets such that a full demand charge would not be imposed until the customer's utilization rate or load factor exceeds 30 percent because: (1) it would accelerate EV charging deployment and enable the Commonwealth to reach its GHG emissions reduction mandates; (2) it is consistent with the recommendations in the Rocky Mountain Institute ("RMI") report; (3) a 30 percent utilization rate represents a mature EV market, which is a more appropriate usage level by which to spread higher or full demand charges across customers; and (4) other intervenors agree that the Companies should expand the proposed load factor brackets

(D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 2 Brief at 8-15, 24). CLF also asserts that the Department should direct the Companies to use utilization rates rather than load factors to determine demand charge thresholds because load factors may not reflect the actual use of that location and the ability of that location to recover demand charges (D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, CLF Track 2 Brief at 8 n.11).

Additionally, CLF contends that the Department should reject the Attorney General's recommendation to impose a 25 percent demand charge on customers with a load factor under five percent because: (1) demand charges present a substantial barrier to EV charging station viability at low load factors; (2) it could discourage EV charging station investments and imperil the Commonwealth's ability to achieve its 2025 and 2030 transportation electrification goals and climate mandates; (3) other intervenors and the Companies oppose the Attorney General's recommendation; and (4) at low EV adoption levels, any cross-subsidization between customers is likely to be minimal (D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, CLF Track 2 Brief at 15-19, 24; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 2 Reply Brief at 4-7).

iii. Tesla and EVgo

Tesla and EVgo recommend that the Department direct the Companies to expand the DCA rates to offer the same demand discount rate to customers with a load factor between 16 percent to 25 percent as those with load factors between ten percent and fifteen percent (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tesla Track 2 Brief at 5, 12; D.P.U. 21-90/ D.P.U. 21-91, EVgo Track 2 Brief at 4, 10; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tesla Track 2 Reply Brief at 2, 6; D.P.U. 21-90/D.P.U. 21-91, EVgo Track 2 Reply Brief at 4-5). Telsa argues that its proposal would ensure that customers have a smoother transition from the

DCA rates to rates with a demand charge component (D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, Tesla Track 2 Brief at 5, 8, 16). EVgo adds that the proposal comports with best practices from other jurisdictions that have approved EV charging rates and would accelerate the achievement of the Commonwealth's ambition GHG emissions reductions and transportation electrification targets (D.P.U. 21-90/D.P.U. 21-91, EVgo Track 2 Brief at 4, 6; D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, Tesla Track 2 Reply Brief at 6; D.P.U. 21-90/D.P.U. 21-91, EVgo Track 2 Reply Brief at 5).

iv. ChargePoint

ChargePoint requests that the Department direct the Companies to modify their DCA rates as follows: (1) an EV charging site with load factors between zero percent and five percent would not incur a demand charge; (2) an EV charging site with load factors between five percent and ten percent would receive a demand charge discount rate of 75 percent; (3) an EV charging site with load factors between ten percent and 20 percent would receive a demand charge discount rate of 50 percent; and (4) an EV charging site with load factors between 20 percent to 30 percent would receive a demand charge discount rate of 25 percent (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, ChargePoint Track 2 Brief at 3-4, 9-10). According to ChargePoint, its proposal is consistent with RMI's report, which recommends phasing-in demand charges over time and finds that 30 percent utilization is an appropriate usage level at which to impose a full demand charge (D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, ChargePoint Track 2 Brief at 18). Further, ChargePoint contends that its proposal will foster EV growth and EVSE deployment in the Commonwealth and lower investment barriers to EV adoption (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, ChargePoint Track 2 Brief at 19).

v. Electrify America

Electrify America asserts that the Department should direct the Companies to calculate customers' load factors over a twelve-month period rather than on a month-to-month basis because an annual load factor calculation would mitigate the risk of year-to-year cost volatility (D.P.U. 21-90, Electrify America Track 2 Brief at 6-7, 16; D.P.U. 21-91, Electrify America Track 2 Brief at 6-7, 15). If the Department declines to adopt its proposal, Electrify America recommends that the Department expand the load factor brackets in a manner consistent with that proposed by Tesla, EVgo, and ChargePoint (D.P.U. 21-90, Electrify America Track 2 Brief at 7; D.P.U. 21-91, Electrify America Track 2 Brief at 7; D.P.U. 21-90, Electrify America Track 2 Reply Brief at 2; D.P.U. 21-91, Electrify America Track 2 Reply Brief at 3).

Electrify America also urges the Department to require NSTAR Electric and National Grid to change the proportion of demand charges relative to usage charges in the end-state EV-2 rate for NSTAR Electric and G-2 and G-3 rates for National Grid for customers with load factors that exceed 15 percent to less than $8.00 per kW with an increase in volumetric charges (D.P.U. 21-90, Electrify America Track 2 Brief at 9, 16; D.P.U. 21-91, Electrify America Track 2 Brief at 8-9, 15).

vi. FreeWire

FreeWire argues that the DCA rates should, at a minimum, collect the cost of the customer's impact on the Companies' distribution systems at all load factor brackets because reducing or eliminating the demand charges for some EV charging customers will unfairly shift potentially significant costs onto all other distribution customers (D.P.U. 21-90, FreeWire Track 2 Brief at 4-5; D.P.U. 21-91, FreeWire Track 2 Brief at 4-5). Further, according to

FreeWire, the record does not sufficiently detail the costs of the DCA proposals or the magnitude of the effect that the demand charge discount rates will have on EVSE deployment (D.P.U. 21-90, FreeWire Track 2 Brief at 5-6; D.P.U. 21-91, FreeWire Track 2 Brief at 5-6). Accordingly, FreeWire recommends that the Department find that the DCA rate proposals are not just and reasonable and deny them (D.P.U. 21-90, FreeWire Track 2 Brief at 5, 13; D.P.U. 21-91, FreeWire Track 2 Brief at 12; D.P.U. 21-90/D.P.U. 21-91, FreeWire Track 2 Reply Brief at 5). FreeWire also contends that the Department should reject the recommendation from other intervenors to expand the availability of demand charge discounts to customers with higher load factors because: (1) the RMI report relied on outdated information; (2) it is improper to design utility rates based on an assumption of how an EVSE station operator will price EV charging; and (3) it would further exacerbate the cross-subsidization of EV charging rates by non-participating customers (D.P.U. 21-90/ D.P.U. 21-91, FreeWire Track 2 Reply Brief at 2-3).

vii. NSTAR Electric and National Grid

NSTAR Electric and National Grid oppose the Attorney General's recommendation to revise the zero percent to five percent load bracket to include a demand charge because: (1) demand charges for the lowest load factor bracket are a significant barrier to EV charger deployment; (2) it would impede progress in the deployment of faster EV charging stations; and (3) a demand charge is unnecessary for customers in this load factor bracket because they are contributing to distribution system costs through the energy charge (D.P.U. 21-90/ D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 7-8).

NSTAR Electric and National Grid also disagree with the intervenor recommendations to expand the load factor brackets beyond 15 percent because: (1) it would send the wrong signal

to customers about the demand exerted by these charging stations on their distribution systems; (2) a 15 percent cutoff for demand charge discount eligibility would result in more price continuity for EV charging station operators; and (3) the RMI report used to support the intervenors' position is not persuasive in this matter because it relies on rates from other jurisdictions with significant differences in customer chargers, demand charges, and other volumetric charges from those offered in the Commonwealth (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 5-6). NSTAR Electric and National Grid also oppose Electrify America's recommendation to calculate customers' load factors on an annual basis because it is not representative of the actual billing and customer monthly usage (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 7). Additionally, NSTAR Electric and National Grid contend that the Department should reject Electrify America's assertion that the end-state demand charge for customers with load factors greater than 15 percent is excessive and should be lowered because Electrify America did not present persuasive evidence to support its recommended end-state unit prices (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 7).

viii. Unitil

Unitil disagrees with the Attorney General's assertion that the DCA rates should maintain a substantially reduced demand charge for customers with load factors between zero percent and five percent because: (1) the DCA rates were designed to be revenue neutral and shift cost recovery from the demand charge to the energy charge and, therefore, DCA rate customers will contribute to the costs of local distribution facilities through the volumetric component of the

DCA rate, and (2) it would hinder the development of new EV charging sites with initially low utilization rates (D.P.U. 21-92, Unitil Track 2 Brief at 17-18).

In addition, Unitil urges the Department to reject CLF's, Tesla's, and ChargePoint's recommendation to expand the load factor brackets to provide demand charge discounts to customers with load factors of up to 30 percent because: (1) the RMI report that the intervenors relied on to support their positions was specific to the rate structure examined in that study, which significantly differs from the company's proposed DCA rates, and (2) the company's DCA rate proposal allows for price continuity as load factor improves (D.P.U. 21-92, Unitil Track 2 Brief at 43-45).

Regarding CLF's argument that utilization rate is a more appropriate method to measure EV charging usage than load factor, Unitil disagrees because load factor is: (1) commonly used in the utility industry; (2) measured by the utility with its existing meters; (3) related to the relationship between the utilization of facilities and the demand placed on the system; and (4) measured using the same demand that is used to apply the demand charges (D.P.U. 21-92, Unitil Track 2 Brief at 45). Moreover, Unitil notes that the Department's Order in D.P.U. 20-69-A directed the Companies to design DCA rates "based on the load factor of the EV charging site," and its proposal is consistent with that directive (D.P.U. 21-92, Unitil Track 2 Brief at 46).

b. DCA Rate Term

i. Attorney General

The Attorney General recommends that the Department reduce the term of the proposed DCA rates from ten years to five years, with the opportunity for an extension if the initial rates

have not yet accomplished their intended purpose by the end of the five-year term, because a ten-year DCA rate term: (1) is too lengthy given the evolving changes in the EV market; (2) would disincentivize customers from transitioning to future rate designs with greater benefits for load management initiatives; (3) would create excessive cost shifting, particularly to non-EV owners; (4) if terminated early, would be complicated, costly, and confusing to customers whereas a five-year DCA rate term could be easily extended if necessary upon a petition by the Companies; (5) is not necessarily more likely to accomplish its intended purpose than a five-year term; and (6) does not protect ratepayers from potentially excessive cost shifting, including cross-subsidization by non-participants (D.P.U. 21-90, Attorney General Track 2 Brief at 12-16; D.P.U. 21-91, Attorney General Track 2 Brief at 16-20; D.P.U. 21-92, Attorney General Brief at 21-24; D.P.U. 21-90/ D.P.U. 21-91, Attorney General Track 2 Reply Brief at 11; D.P.U. 21-92, Attorney General Track 2 Reply Brief at 2-4, 7). The Attorney General also recommends that the Department direct the Companies to incorporate into the DCA rates cost thresholds, at which time the Companies would close the DCA rates to new participants (D.P.U. 21-90, Attorney General Track 2 Brief at 16; D.P.U. 21-91, Attorney General Track 2 Brief at 19-20; D.P.U. 21-92, Attorney General Track 2 Brief at 24; D.P.U. 21-92, Attorney General Track 2 Reply Brief at 4).[72]

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[72] For NSTAR Electric, the Attorney General recommends a cost threshold of $28 million (D.P.U. 21-90, Attorney General Track 2 Brief at 16). For National Grid, the Attorney General recommends a cost threshold of $10 million (D.P.U. 21-91, Attorney General Track 2 Brief at 20). For Unitil, the Attorney General recommends a cost threshold of $135,000 (D.P.U. 21-92, Attorney General Track 2 Brief at 24).

ii. FreeWire

If the Department approves the DCA rate proposals, FreeWire requests that the Department set a program cost cap and limit the term of the DCA rates to five years, consistent with the Attorney General's recommendations (D.P.U. 21-90, FreeWire Track 2 Brief at 6-7; D.P.U. 21-91, FreeWire Track 2 Brief at 6).

iii. CEP

CEP recommends that the Department approve the DCA rate proposals for a ten-year term with a review of the DCA rates every three years to allow for continued evaluation and potential refinements where necessary (D.P.U. 21-90/D.P.U. 21-91, CEP Track 2 Brief at 2, 6, 7). According to CEP, the three-year review should include: (1) an assessment of the success of the DCA rates in supporting transportation electrification, particularly with respect to the development of new DCFC; (2) an analysis of EV adoption trends in the Commonwealth and DCFC load factors; (3) a comparison of gasoline prices relative to average electricity costs for EV charging stations; and (4) an evaluation of potential changes to the design of the DCA rates, including whether to add a time-varying component or adjust the load factor thresholds (D.P.U. 21-90/D.P.U. 21-91, CEP Track 2 Brief at 8). CEP contends that this approach would provide longer-term price certainty to EV station developers and EV drivers while also allowing for flexibility to adjust the DCA rates as market conditions evolve and new data is collected (D.P.U. 21-90/D.P.U. 21-91, CEP Track 2 Brief at 8).

iv. CLF

CLF opposes the Attorney General's recommendation to limit the term of the DCA rates from ten years to five years and to impose a cost threshold after which the DCA rates would be

closed to new participants because: (1) it could hinder the development of a robust EV charging station market in the Commonwealth and the attainment of the Commonwealth's climate goals; (2) other intervenors agree that a ten-year duration for the DCA rates is appropriate; (3) the cost threshold would arbitrarily cut off participation in the DCA rates regardless of whether the Commonwealth is on track to meet its electrification transportation and climate goals; (4) limiting participation in the DCA rates would create winners and losers and negatively impact the EV charging market; and (5) it could drive investments in public EV charging into communities where EV adoption is already rapidly growing, creating charging deserts in communities most in need of assistance (D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, CLF Track 2 Brief at 19-22, 24; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 2 Reply Brief at 2-4). Therefore, CLF requests that the Department reject the Attorney General's recommendations regarding both the duration of the DCA rates and the implementation of a cost threshold by which customers would no longer be permitted to enroll in the DCA rates (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 2 Reply Brief at 4).

v. Tesla and EVgo

Telsa and EVgo request that the Department reject the Attorney General's recommendation to limit the DCA term from ten years to five years because: (1) more price certainty would encourage developers to invest in EV charging infrastructure; (2) many other jurisdictions have approved EV charging rates for a ten-year period; (3) the Attorney General's recommendation is not supported by the record; (4) a shorter DCA rate term could make the Commonwealth a less attractive location for EV charging station developers to invest in EV charging infrastructure, which would impede progress in achieving the Commonwealth's

transportation electrification targets; (5) a ten-year DCA rate term will not disincentivize customers from shifting to a TOU rate; and (6) a ten-year DCA rate term better aligns with the anticipated timeline for investments in public DCFCs (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tesla Track 2 Brief at 12-15, 16; D.P.U. 21-90/D.P.U. 21-91, EVgo Track 2 Brief at 6-8, 10; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tesla Track 2 Reply Brief at 6-7; D.P.U. 21-90/ D.P.U. 21-91, EVgo Track 2 Reply Brief at 2-3). EVgo also supports National Grid's proposal to conduct a review of the DCA rates at the mid-point of the offering to allow the Department and stakeholders an opportunity to review the efficacy and necessity of the DCA rates (D.P.U. 21-90/D.P.U. 21-91, EVgo Track 2 Reply Brief at 3-4).

vi. ChargePoint

ChargePoint asserts that it may be necessary for the Companies and the Department to make the DCA rate offerings permanently available to a subset of EV charging stations based on their unique charging patterns because DCFC utilization rates in less-traveled areas will likely be consistently lower than DCFC utilization rates in high-trafficked areas regardless of EV adoption rates (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, ChargePoint Track 2 Brief at 14-15).

vii. Electrify America

Electrify America disagrees with the Attorney General's recommendation to reduce the term of the DCA rates from ten years to five years because a ten-year term is necessary to provide EV charging station developers the requisite level of price certainty to make large capital investments to build out the public EV charging infrastructure network needed to meet the Commonwealth's transportation electrification goals (D.P.U. 21-90, Electrify America Track 2 Brief at 3-4, 16; D.P.U. 21-91, Electrify America Track 2 Brief at 3-4, 15; D.P.U. 21-90,

Electrify America Track 2 Reply Brief at 2; D.P.U. 21-91, Electrify America Track 2 Reply Brief at 3). Electrify America also requests that the Department clarify in its Order that it will not approve unilateral changes to the program term or material changes to the DCA rate structures during the program term (D.P.U. 21-90, Electrify America Track 2 Brief at 5, 16; D.P.U. 21-91, Electrify America Track 2 Brief at 5, 15).

viii. NSTAR Electric and National Grid

NSTAR Electric and National Grid oppose the Attorney General's recommendation to reduce the term of the DCA rates from ten years to five years because: (1) EV charging station operators need price certainty to evaluate the economic viability of their investments in EV charging stations; (2) the term of the proposed DCA rates was carefully considered by the Companies with feedback from stakeholders, including EV charging station developers; (3) it is inconsistent with the Commonwealth's transportation electrification targets for 2030; (4) the DCA rates may be re-assessed by the Department or Companies as necessary; (5) other intervenors support a ten-year term for the DCA rates; and (6) other jurisdictions have approved EV-specific rates for a ten-year period (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 10-12).

ix. Unitil

Unitil encourages the Department to reject the Attorney General's recommendation to reduce the term of the DCA rates from ten years to five years because: (1) the Attorney General's position is based on unsupported speculation and vague generalizations; (2) only customers with a load factor of 15 percent or below would be eligible to remain on the DCA rates; (3) to the extent that other rate offerings become available, customers would have the

ability to opt into those rates so long as they meet the applicable eligibility requirements; (4) the Attorney General misrepresents the extent to which cross-subsidization could occur under the DCA rates; (5) it would create price uncertainty for EV station developers; and (6) it could drive DCFC investments to only communities where EV adoption is likely to progress at a faster pace (D.P.U. 21-92, Unitil Track 2 Brief at 14-17).

c. Ancillary Load

i. Electrify America

Electrify America requests that the Department direct the Companies to include specific language in their EV tariffs.[73] According to Electrify America, its proposed tariff language should be adopted because: (1) it is broad enough to include ancillary equipment that EV charging station operators may need at their respective sites while ensuring that all equipment is directly supporting EV charging station operation; (2) it resolves ambiguity in the Companies' proposed tariff language by removing a case-by-case analysis of ancillary load eligibility; and (3) it would allow solar canopies to qualify as ancillary load (D.P.U. 21-90, Electrify America Track 2 Brief at 13-15, 17; D.P.U. 21-91, Electrify America Track 2 Brief at 13-15).

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73 Specifically, Electrify American proposes the following tariff language:

> Rate EV-1 [EV-2] is an optional schedule that is applicable only to EV charging stations and supporting equipment. Ancillary equipment in support of station operation includes, but is not limited to, equipment needed for site safety, immediate site lighting, security, customer interface and transaction processing, networking, equipment heating and cooling, and co-located energy storage and solar systems.

(D.P.U. 21-90, Electrify America Track 2 Brief at 13; D.P.U. 21-91, Electrify America Track 2 Brief at 13).

ii. Attorney General

The Attorney General opposes Electrify America's proposed tariff language, which characterizes energy storage and solar canopies as ancillary loads, arguing that energy storage and solar canopies are not related to EV charging and that that it would be inappropriate to permit load from energy storage and solar canopies to qualify as ancillary load for purposes of the DCA rates (D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 2 Reply Brief at 6-7). Moreover, the Attorney General argues that energy storage and export tariffs should be developed through the Attorney General's recommended load management process (see Section III.B.4.b) to ensure that the electric grid costs caused by energy storage are reflected in rates and that the rates incentivize load flexibility (D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 2 Reply Brief at 7).

iii. ChargePoint

ChargePoint recommends that the Department direct the Companies to limit participation in the DCA rates to customers whose EV charging load makes up at least 90 percent of their total individually metered load (D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, ChargePoint Track 2 Brief at 3, 9, 17-18).

iv. NSTAR Electric and National Grid

NSTAR Electric and National Grid disagree with Electrify America's recommendation to classify solar canopies and battery storage as ancillary load for purposes of the DCA rates because: (1) solar canopies and battery storage are not related to EV-load; (2) the companies do not want customers to predicate their decisions on solar or battery storage installation on a temporary rate; and (3) the companies can separately meter the load from solar canopies and

battery storage to the extent that customers want to install those technologies at EV charging sites (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 13). Accordingly, NSTAR Electric and National Grid urge the Department to reject Electrify America's recommendation to include solar canopies and battery storage as ancillary load for purposes of the DCA rates (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 13).

d. DCA Rate Implementation

i. Intervenors

DOER, Tesla, and EVgo urge the Department to direct the Companies to make the DCA rate offerings effective immediately following Department approval in these proceedings and to provide bill credits to customers who enroll in the DCA rates retroactively to the date of the Department's Order in the instant proceedings regardless of how long it takes for the Companies to update their billing systems (D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, DOER Track 2 Brief at 7-8, 14; D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, Tesla Track 2 Reply Brief at 7; D.P.U. 21-90/D.P.U. 21-91, EVgo Track 2 Reply Brief at 4).

Electrify America contends that the Department should direct the Companies to make the DCA rate offerings available to customers within two months following the issuance of the Department's Order in these proceedings (D.P.U. 21-90, Electrify America Track 2 Brief at 16). Electrify America adds that a delay in implementation of the DCA rates of more than two months must include retroactive rebilling of the DCA rates (D.P.U. 21-90, Electrify America Track 2 Brief at 16).

ii. NSTAR Electric and National Grid

NSTAR Electric and National Grid urge the Department to reject the intervenor recommendations to direct the Companies to implement the DCA rates immediately following the Department's Order in this matter and to issue bill credits back to the date of the Department's Order because: (1) it will likely take six months for the Companies to implement the necessary billing system updates and train their customer service representatives on the DCA rates; (2) it would introduce an additional layer of complexity by adding back-billing into the implementation of the DCA rates; and (3) bill credits would be confusing to customers and send inconsistent price signals (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 14, 15). For these reasons, NSTAR Electric and National Grid request that the Department approve the Companies' proposal to implement the DCA rates within six months of the Department's Order in this matter with no bill credits to customers during that period (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 15).

iii. Unitil

Unitil opposes intervenor recommendations to make the DCA and residential EV TOU rates available immediately following the Department's approval of the rates in this matter because billing system updates and customer service training are necessary for implementation (D.P.U. 21-92, Unitil Track 2 Reply Brief at 4). Unitil states that it will take approximately three months for the company to accurately program its billing system to set up the required functionality for the new EV rates (D.P.U. 21-92, Unitil Track 2 Reply Brief at 4). Unitil also opposes DOER's recommendation for the Department to direct the Companies to provide

customers retroactive bill credits to the date of the Department's Order in these proceedings because it would: (1) introduce an additional layer of complexity into the implementation of a new program without providing meaningful benefits for EV market development, and (2) likely delay implementation of the program (D.P.U. 21-92, Unitil Track 2 Reply Brief at 4). Accordingly, Unitil requests that the Department approve its implementation proposal without modification (D.P.U. 21-92, Unitil Track 2 Reply Brief at 4).

e. Metering Options

i. Attorney General

The Attorney General asserts that the Department should direct the Companies to explore the metering capabilities of networked EVSE because the Companies' proposal to install a separate utility-owned meter to implement the DCA rates could underutilize the networked chargers' functionality, add duplicative technologies, and increase costs to ratepayers for use cases where the embedded meters in networked EVSE are an appropriate metering solution (D.P.U. 21-90, Attorney General Track 2 Brief at 20-21; D.P.U. 21-91, Attorney General Track 2 Brief at 24; D.P.U. 21-92, Attorney General Track 2 Brief at 28). Specifically, the Attorney General recommends that the Department direct the Companies to: (1) evaluate the metering capabilities of networked EVSE and vehicle telematics for billing purposes; (2) use the results from the first step to develop a plan to ensure integration and interoperability of networked chargers and EVs with the Companies' billing systems and future grid modernization investments; (3) propose milestones and timelines for conducting the evaluation and developing the plan described in the first two steps in a compliance filing to be submitted within 30 days following the Department's Order in this matter; (4) submit bi-annual reports, which may be

consolidated with any compliance filings associated with EV load management, to the Department that include the latest findings and progress on the evaluation and plan; and (5) coordinate to establish uniformity and minimize the costs of the evaluation (D.P.U. 21-90, Attorney General Track 2 Brief at 27-28; D.P.U. 21-91, Attorney General Track 2 Brief at 31-32; D.P.U. 21-92, Attorney General Track 2 Brief at 34; D.P.U. 21-92, Attorney General Track 2 Reply Brief at 11, 14-15). The Attorney General further recommends that the Department: (1) establish a process for stakeholder input on the evaluation and results, and (2) adopt standards for the use of EVSE and vehicle telematics submetering for billing purposes within two years following the Department's issuance of an Order in these matters based on the evaluation and stakeholder input (D.P.U. 21-90, Attorney General Track 2 Brief at 28; D.P.U. 21-91, Attorney General Track 2 Brief at 32; D.P.U. 21-92, Attorney General Track 2 Brief at 34-35; D.P.U. 21-92, Attorney General Track 2 Reply Brief at 15).

ii. Shell

Shell supports the Attorney General's recommendation for the Department to direct the Companies to evaluate the metering capabilities of networked EVSE and vehicle telematics for billing purposes and develop a plan to integrate these technologies into the Companies' billing systems (D.P.U. 21-90/D.P.U. 21-91, Shell Track 2 Reply Brief at 7). As part of the evaluation process, Shell recommends that the Department establish a technical standards working group to create standards, methodologies for accuracy, and communication protocols for networked EVSE following the Department's approval of the DCA rate proposals in these proceedings (D.P.U. 21-90/D.P.U. 21-91, Shell Track 2 Brief at 3, 8, 10, 11; D.P.U. 21-90/D.P.U. 21-91, Shell Track 2 Reply Brief at 3, 6-8). According to Shell, a comprehensive technology strategy

will allow the Companies to provide advanced load management functionalities while evaluating networked EVSE functionalities (D.P.U. 21-90/D.P.U. 21-91, Shell Track 2 Brief at 6; D.P.U. 21-90/D.P.U. 21-91, Shell Track 2 Reply Brief at 3). Shell also notes that other jurisdictions have adopted networked EVSE embedded metering, submetering, and managed charging to enhance the deployment of EVs (D.P.U. 21-90/D.P.U. 21-91, Shell Track 2 Brief at 6-8; D.P.U. 21-90/D.P.U. 21-91, Shell Track 2 Reply Brief at 5-6). Shell further recommends that the Department direct the Companies to analyze data from both AMI and networked EVSE in their billing systems to reduce redundancies in the regulatory process, avoid the need for multiple billing system upgrades, and reduce ratepayers' costs (D.P.U. 21-90/D.P.U. 21-91, Shell Track 2 Brief at 9; D.P.U. 21-90/D.P.U. 21-91, Shell Track 2 Reply Brief at 3).

iii. FreeWire

FreeWire argues that the metering capabilities of networked EVSE are accurate and secure enough to be used as the default metering option for EV-specific rates without the need for a costly additional utility meter and service upgrade (D.P.U. 21-90, FreeWire Track 2 Brief at 11; D.P.U. 21-91, FreeWire Track 2 Brief at 10, 12). Therefore, FreeWire recommends that the Department direct the Companies to immediately begin a process for evaluating whether embedded metering in networked EVSE can be used to implement EV-specific rates (D.P.U. 21-90, FreeWire Track 2 Brief at 11, 13; D.P.U. 21-91, FreeWire Track 2 Brief at 10-11, 12). FreeWire also supports the Attorney General's recommendation to require the Companies to: (1) establish a standard for data quality requirements for networked charger and vehicle telematics data; (2) evaluate whether networked chargers and vehicle telematics can serve as alternative metering approaches for future metering implementations; and (3) propose clear

timelines and milestones for addressing these recommendations (D.P.U. 21-90, FreeWire Track 2 Brief at 11; D.P.U. 21-91, FreeWire Track 2 Brief at 12). Additionally, FreeWire agrees with Shell that the Department should establish a technical standards working group and further argues that the Department should allow managed charging and battery storage to serve as an alternative to the DCA rates (D.P.U. 21-90/D.P.U. 21-91, FreeWire Track 2 Reply Brief at 4).

iv. ChargePoint

ChargePoint contends that the Department should deny Unitil's proposal to make company-owned AMI meters the default metering option for residential program participants because: (1) the smart, managed Level 2 EV charging stations required for enrollment in the EV program contain the requisite embedded metering capabilities to enable EV charging at a lower cost, and (2) other jurisdictions have developed or piloted EV-specific TOU rates with embedded metering (D.P.U. 21-92, ChargePoint Track 1 Brief at 1, 5, 7-10).[74]

v. Tesla and EVgo

Tesla and EVgo contend that the Department should approve the Companies' proposal to implement the DCA rates using company-owned interval meters because: (1) alternative metering options have not yet been adequately tested; (2) alternative metering options are not yet widely available in the Commonwealth; (3) embedded meters in networked EVSE do not currently produce billing quality or consistent data; (4) the Companies may have difficulty obtaining data from third-party owned meters; (5) the Department lacks jurisdiction over

[74] ChargePoint also recommends that Unitil require EV chargers to be ENERGY STAR-certified and tested for safety by a nationally recognized laboratory (D.P.U. 21-92, ChargePoint Brief at 9).

third-party owned meters; and (6) in California, it took ten years to develop alternative metering options for EV charging rates (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tesla Track 2 Brief at 15-16; D.P.U. 21-90/D.P.U. 21-91, EVgo Track 2 Brief at 9, 10; D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, Tesla Track 2 Reply Brief at 8; D.P.U. 21-90/ D.P.U. 21-91, EVgo Track 2 Reply Brief at 5).

vi. Electrify America

Electrify America urges the Department to reject the Attorney General's recommendation to require the Companies to use embedded meters in networked EVSE as the default metering option for the DCA rates because doing so would increase EV station operator costs without any tangible benefit (D.P.U. 21-90, Electrify America Track 2 Brief at 12; D.P.U. 21-91, Electrify America Track 2 Brief at 12; D.P.U. 21-90, Electrify America Track 2 Reply Brief at 4; D.P.U. 21-91, Electrify America Track 2 Reply Brief at 4). Instead, Electrify America requests that the Department approve the Companies' proposal to make utility meters the default metering option to implement the DCA rates (D.P.U. 21-90, Electrify America Track 2 Brief at 12, 17; D.P.U. 21-91, Electrify America Track 2 Brief at 12, 15; D.P.U. 21-90, Electrify America Track 2 Reply Brief at 4; D.P.U. 21-91, Electrify America Track 2 Reply Brief at 4).

vii. NSTAR Electric and National Grid

NSTAR Electric and National Grid request that the Department approve their proposals to implement the DCA rates using separate utility-owned meters because: (1) the Department does not have regulatory authority over third-party owned meters; (2) third-party owned meters do not have the same consumer protections provided under G.L. c. 164, § 1; and (3) there is an

increased risk of malicious cyber activity with third-party owned meters (D.P.U. 21-90/ D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 15-17).

NSTAR Electric and National Grid also disagree with the Attorney General's recommendation for the Department to direct the Companies to evaluate the metering capabilities of networked EVSE and vehicle telematics for billing purposes and to develop a plan to integrate networked chargers into the companies' billing systems because: (1) national standards for metering, testing, and evaluating networked EVSE do not currently exist; (2) the recommendation is beyond the scope of this proceeding; (3) testing of each potential networked charger telematics would require either shipping the charger to the companies' facilities or field testing the charger, which would be onerous, costly, and time-consuming; and (4) it would be administratively burdensome to add EV charging data from these technologies into the companies' billing systems (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 17-18, 22-23). Accordingly, NSTAR Electric and National Grid request that the Department reject the Attorney General's recommendation to require the Companies to evaluate networked EVSE and vehicle telematics and develop a plan to integrate these technologies into their billing systems (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 23).

Additionally, NSTAR Electric and National Grid argue that vehicle telematics are not a viable alternative to utility-owned meters because: (1) not all EVs are equipped with telematics capabilities; (2) EVs do not follow mandatory telematics data standards; (3) even if all EVs were equipped with standardized telematics capabilities, using vehicle telematics to implement the DCA rates would require data collection agreements between the companies and individual

drivers; (4) there are no industry standards for vehicle telematics data as it relates to energy usage; and (5) to determine peak kW demand for a given month, the companies would need to sum all individual charging sessions on an interval basis with locational data from EVs in a billing period and then calculate peak demand and total billed demand based on aggregated vehicle data, and it is unclear whether vehicle telematics could provide the charging information necessary to perform these complex calculations (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 18-19).

viii. Unitil

Unitil contends that the Department should approve its proposal to implement the DCA rates using a separate utility-owned meter because: (1) the use of third-party owned meters for this purpose without the express written consent of the company would violate Unitil's exclusive service territory rights under G.L. c. 164, § 1B; (2) the Department does not have regulatory authority over third-party owned meters; (3) third-party owned meters do not have the same consumer protections provided under G.L. c. 164, § 1; (4) EVSE operators do not have a regulatory obligation to ensure safe and reliable service to customers and are not directly accountable to the Department; (5) the use of third-party owned meters could impede Unitil's ability to respond to customer questions regarding meter information and accuracy, troubleshoot meter issues, resolve potential disputes, or comply with its duty to render timely and accurate current-use bills; (6) the use of third-party owned meters increases complexity and risk, may create the need for multiple processes for retrieving, processing, and storing third-party meter data, and could present compatibility issues with the company's metering, data management, and billing operations; (7) it is unclear whether the Department has the authority to require EVSE

manufacturers to carry cybersecurity insurance; and (8) Unitil would likely need to modify or upgrade its back-office capabilities and business processes to accommodate EVSE meters, which could by costly (D.P.U. 21-92, Unitil Track 1 Brief at 52-53; Unitil Track 1 Reply Brief at 12-13; D.P.U. 21-92, Unitil Track 2 Brief at 31-39; D.P.U. 21-92, Unitil Track 2 Reply Brief at 7-9).

Additionally, Unitil asserts that it would be impractical to use vehicle telematics as a replacement for utility-owned meters for public DCFC stations because: (1) not all EVs are equipped with telematics capabilities, and those that are equipped with such capabilities do not use mandatory data standards; (2) there are no industry standards for vehicle telematics data as it relates to energy usage; (3) even if all EVs were equipped with standardized telematics capabilities, using vehicle telematics to implement the DCA rates would require data collection agreements between the company and individual drivers; and (4) to determine peak kW demand for a given month, Unitil would need to sum all individual charging sessions on an interval basis with locational data from EVs in a billing period and then calculate peak demand and total billed demand based on aggregated vehicle data, and it is unclear whether vehicle telematics could provide the charging information necessary to perform these complex calculations (D.P.U. 21-92, Unitil Track 2 Brief at 41).

Nevertheless, Unitil proposes to collect and analyze EVSE data from participating EVSE vendors and the company's residential EV TOU meters and compare historical embedded EVSE data against the utility metering interval data to assess accuracy, availability, format, interface capabilities, data sharing, load metering, sub-metering, metering data disaggregation, remote control, volt/VAR capability, customer controls, testing, privacy, and cyber and physical security

in conjunction with other considerations that arise during the assessment (D.P.U. 21-92, Unitil Track 1 Brief at 53; Unitil Track 1 Reply Brief at 13-14; D.P.U. 21-92, Unitil Track 2 Brief at 40). Unitil states that it will collaborate with participating EVSE manufacturers to properly test the performance of networked EVSE metering capabilities and share that data with the Department and interested stakeholders as part of its annual reports to the Department (D.P.U. 21-92, Unitil Track 2 Brief at 40, 42). According to Unitil, its proposed approach is prudent and sensible and is consistent with the company's obligation to provide high quality, safe, and reliable service to its customers (D.P.U. 21-92, Unitil Track 1 Brief at 53; D.P.U. 21-92, Unitil Track 1 Reply Brief at 13). As such, Unitil requests approval of its proposal to deploy AMI meters as part of its EV program offerings.

f. Transition Plan

i. DOER

DOER urges the Department to direct the Companies to develop, in consultation with DOER and other stakeholders, a transition plan to replace the DCA rate offerings with AMI-enabled DCA EV rates by 2027, at the latest (D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, DOER Track 2 Brief at 9-11). DOER also recommends that the Department direct the Companies to file tariff revisions eliminating the DCA rates as soon as an implementation schedule for AMI-enabled DCA EV rates is established in a future proceeding by 2030 (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, DOER Track 2 Brief at 13, 14).

ii. Attorney General

The Attorney General argues that the timeline by which the Companies would be required to propose new advanced rate designs under DOER's proposal is too slow because:

(1) planning and stakeholder collaboration take time, so any delay in that process would be detrimental; (2) the Companies plan to deploy AMI meters before 2030, which is likely the earliest the new rates would be made available to customers under DOER's proposal; and (3) the Companies must proactively plan for managed charging to minimize wasteful and unnecessary spending on electric grid expansion to accommodate increased EV load (D.P.U. 21-90/ D.P.U. 21-91, Attorney General Track 2 Reply Brief at 4-6; D.P.U. 21-92, Attorney General Track 2 Reply Brief at 20-21).

iii. FreeWire

FreeWire agrees with DOER that the Department should direct the Companies to develop advanced AMI-enabled EV rates to replace the DCA rates by 2027 (D.P.U. 21-90/ D.P.U. 21-91, FreeWire Track 2 Reply Brief at 3, 5).

iv. Tesla

Tesla disagrees with DOER that the Companies should replace the DCA rates with AMI-enabled DCA EV rates before the end of the ten-year term (D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, Tesla Track 2 Reply Brief at 8). Nevertheless, Tesla supports a transition to AMI-enabled time-varying rates at the conclusion of the ten-year DCA rate term (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tesla Track 2 Reply Brief at 8).

v. NSTAR Electric and National Grid

Given that the Companies do not yet have experience with the DCA rates, there are few DCFC stations currently deployed in the Commonwealth, and the nascent state of the EV charging market, NSTAR Electric and National Grid argue that it is premature for the Companies to identify a timeline and approach to transition the DCA rates to more advanced

AMI-enabled demand charge rate designs (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 24-25).

g. Marginal Cost Analyses

i. CEP

CEP recommends that the Department direct the Companies to conduct marginal cost analyses of EV load on their distribution systems within the next three years to evaluate the design and effectiveness of future EV rates and inform the design and assessment of other programs, such as load management (D.P.U. 21-90/D.P.U. 21-91, CEP Track 2 Brief at 2, 6-7, 9). In the absence of marginal cost studies, CEP argues that it would be difficult to determine the extent of any cost shifting resulting from EV-specific rates or the degree to which EV customers are reducing rates for other customers through spreading fixed costs over greater sales (D.P.U. 21-90/D.P.U. 21-91, CEP Track 2 Brief at 8).

ii. FreeWire

FreeWire supports CEP's recommendation to direct the Companies to conduct marginal cost studies within three years of the Department's Order in these matters because they are essential to developing future rates to replace the DCA rates proposed in this proceeding (D.P.U. 21-90/D.P.U. 21-91, FreeWire Track 2 Reply Brief at 4-5).

2. Other Issues

a. Attorney General

The Attorney General recommends that the Department direct the Companies to incorporate time-differentiated rates, including time-differentiated generation and transmission costs and volumetric distribution costs, into their DCA rates because time-differentiated rates

incentivize EV charging during off-peak periods, thereby encouraging EV adoption and cost-effectively preparing the electric grid for increasing load from renewable energy penetration (D.P.U. 21-90, Attorney General Track 2 Brief at 7-9; D.P.U. 21-91, Attorney General Track 2 Brief at 8-10; D.P.U. 21-92, Attorney General Track 2 Brief at 14, 16-17). The Attorney General also recommends directing the Companies to designate the on-peak period as 3:00pm to 8:00pm because it will incentivize EV charging outside of the hours with the highest distribution system costs and allow customers to realistically and meaningfully shift their electric consumption, which would, in turn, reduce potentially costly and harmful demand on the electric grid (D.P.U. 21-90, Attorney General Track 2 Brief at 8; D.P.U. 21-91, Attorney General Track 2 Brief at 10-11, 13; D.P.U. 21-92, Attorney General Track 2 Brief at 17-19). The Attorney General claims that its recommendations would benefit all ratepayers by: (1) reducing the Companies' power and fuel costs; (2) limiting the need for costly new infrastructure to accommodate peak demand; and (3) encouraging consumption during periods with higher renewable energy production (D.P.U. 21-90, Attorney General Track 2 Brief at 9; D.P.U. 21-91, Attorney General Track 2 Brief at 10; D.P.U. 21-92, Attorney General Track 2 Brief at 17).

b. CEP

CEP asserts that the non-coincident peak demand charge in National Grid's proposed G-2 rate sends a poor price signal, fails to reflect cost causation for most distribution system costs, and may result in higher emissions and inefficient use of the electric grid (D.P.U. 21-90/ D.P.U. 21-91, CEP Track 2 Brief at 9). Accordingly, CEP recommends that the Department direct National Grid to convert the non-coincident demand charge for its proposed G-2 rate to a

time-varying volumetric charge or a demand charge that only applies to peak hours (D.P.U. 21-90/D.P.U. 21-91, CEP Track 2 Brief at 2, 7, 9).

c. FreeWire

FreeWire contends that the DCA rate proposals would distort the competitive EVSE market by providing a significant advantage for site designs that do not incorporate battery storage systems or other approaches to managing energy costs (D.P.U. 21-90, FreeWire Track 2 Brief at 6; D.P.U. 21-91, FreeWire Track 2 Brief at 6). FreeWire also asserts that the DCA rate proposals are not sufficiently advanced enough to address the growing amount of variable and distributed energy resources on the electric grid and would fail to send customers an appropriate price signal to allow for an opportunity to make informed decisions about how much electricity to consume and at what time (D.P.U. 21-90, FreeWire Track 2 Brief at 7-8; D.P.U. 21-91, FreeWire Track 2 Brief at 7). Therefore, FreeWire recommends that the Department deny the DCA rate proposals and open an investigation into advanced rate design (D.P.U. 21-90, FreeWire Track 2 Brief at 8, 13; D.P.U. 21-91, FreeWire Track 2 Brief at 7-8, 12).

d. GECA

GECA asserts that, in developing the DCA rate proposals, the Companies did not fully consider how the DCA rates would impact the co-location of solar, storage, and DCFCs (D.P.U. 21-90/D.P.U. 21-91, GECA Track 2 Brief at 2). Accordingly, GECA recommends that the Department direct the Companies to submit proposals with changes to the DCA rates to incentivize the co-location of DCFC sites with solar generation and energy storage (D.P.U. 21-90/D.P.U. 21-91, GECA Track 2 Brief at 2).

e. Electrify America

Electrify America opposes the Attorney General's recommendation for the Department to direct the Companies to incorporate time-varying components into the proposed DCA rates because they could become misaligned with future TOU rates approved in other proceedings (D.P.U. 21-90, Electrify America Reply Track 2 Brief at 4-5; D.P.U. 21-91, Electrify America Track 2 Reply Brief at 5). Instead, Electrify America argues that the Department should consider TOU rate proposals that apply to all commercial rates, not just EV-specific rates, in a base distribution rate proceeding or a stand-alone rate design proceeding (D.P.U. 21-90, Electrify America Track 2 Reply Brief at 4-5; D.P.U. 21-91, Electrify America Track 2 Reply Brief at 5).

f. NSTAR Electric and National Grid

NSTAR Electric and National Grid urges the Department to reject the Attorney General's recommendation to incorporate time-varying price signals into the proposed DCA rates because: (1) it is beyond the scope of this proceeding; (2) it would require a redesign of the DCA rates, which would delay implementation of the DCA rates; (3) a peak period specific for EVSE has not yet been established and could vary between fleet and public charging sites as well as use-cases within those sites; (4) public DCFC load is largely inelastic because EV drivers are in transit and need to charge in order to complete their journey and, therefore, it is unclear whether time-differentiated rates would benefit public EV charging stations because these charging stations have little control over when their facilities are being utilized; (5) the Department should review proposed TOU rates holistically in a future proceeding; and (6) it would hamper NSTAR Electric's ability to align its legacy rates (D.P.U. 21-90/D.P.U. 21-91, NSTAR Electric and National Grid Joint Track 2 Reply Brief at 9-10, 27-28).

g. Unitil

Unitil contends that the Attorney General's recommendation to incorporate new time-varying price signals into the proposed DCA rates is beyond the scope of this proceeding (D.P.U. 21-92, Unitil Track 2 Brief at 18-19). Additionally, Unitil argues that the Attorney General's recommended modifications to the DCA rates: (1) are not supported by evidence; (2) could hinder the development of EV chargers, particularly for low load factor stations; and (3) are questionable because public charging station owners have little control over when their facilities are being utilized (D.P.U. 21-92, Unitil Track 2 Brief at 19). For these reasons, Unitil requests that the Department reject the Attorney General's proposed modifications to the DCA rate proposals (D.P.U. 21-92, Unitil Track 2 Brief at 19).

C. Analysis and Findings

1. Load Factors

A number of intervenors recommend revisions to the Companies' proposed load factor brackets. The Attorney General and FreeWire recommend that the Department direct the Companies to incorporate a demand charge applicable to the zero percent to five percent load factor bracket (D.P.U. 21-90, Attorney General Track 2 Brief at 9-12; D.P.U. 21-91, Attorney General Track 2 Brief at 13-16; D.P.U. 21-92, Attorney General Track 2 Brief at 19-21; D.P.U. 21-92, Attorney General Track 2 Reply Brief at 9; D.P.U. 21-90, FreeWire Track 2 Brief at 4-5; D.P.U. 21-91, FreeWire Track 2 Brief at 4-5). Additionally, several intervenors recommend an expansion of the load factor brackets to 25 percent or 30 percent (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 2 Brief at 8-15, 24; D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, Tesla Track 2 Brief at 5, 12; D.P.U. 21-90/ D.P.U. 21-91, EVgo

Track 2 Brief at 4, 10; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tesla Track 2 Reply Brief at 2, 6; D.P.U. 21-90/D.P.U. 21-91, EVgo Track 2 Reply Brief at 4-5; D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, ChargePoint Track 2 Brief at 3-4, 9-10). Electrify America urges the Department to require NSTAR Electric and National Grid to reduce their end-state demand charge rates and to assess customer load factor on an average annual basis (D.P.U. 21-90, Electrify America Track 2 Brief at 6-7, 16; D.P.U. 21-91, Electrify America Track 2 Brief at 6-7, 15).

Currently, public EV charging sites are assigned to a general service rate based on the size of their expected load (D.P.U. 21-90, Exh. ES-RDC-1, at 5; D.P.U. 21-91, Exh. NG-DCA-1, at 10). Depending on the particular service territory and EV charging station size, the site may be billed on a rate structure comprised of both demand and energy charges (D.P.U. 21-90, Exh. ES-RDC-1, at 5; D.P.U. 21-91, Exh. NG-DCA-1, at 10). Because EV charging stations in the Companies' service territories typically have load factors averaging less than ten percent, this combination of low energy use and high charging power under a demand charge-based rate structure can result in demand charges comprising the majority of an EV charging station's monthly bill (D.P.U. 21-90, Exh. ES-RDC-1, at 5-6; D.P.U. 21-91, Exh. NG-DCA-1, at 10; D.P.U. 21-92, Exh. JDT-1, at 4).[75] High demand charges have been identified as a significant obstacle to EV charger deployment (D.P.U. 21-90, Exh. ES-RDC-REB-1, at 13; D.P.U. 21-91, Exh. NG-DCA-REB-1, at 15-16; D.P.U. 21-92, Exh. JDT-1, at 4). See also D.P.U. 20-69-A at 42. The legislature sought to address this barrier by enacting Section 29 of the Transportation

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75 EV charging sites in Massachusetts commonly bill EV drivers for use of their station on a per kWh basis, which results in a mismatch between station revenue and operational costs because utilization is low (D.P.U. 21-91, Exh. NG-DCA-1, at 10; D.P.U. 21-92, Exh. JDT-1, at 6).

Act, requiring that each electric distribution company submit a commercial EV rate design tariff or program proposal that includes alternatives to traditional demand charges.

The Companies proposed a 100 percent demand charge discount for the lowest load factor bracket (i.e., a load factor between zero percent and five percent) (D.P.U. 21-90, Exh. ES-RDC-1, at 18-19; D.P.U. 21-91, Exh. NG-DCA-1, at 23-24; D.P.U. 21-92, Exh. JDT-2). In the case of smaller customers with EV charging stations, it is not necessary to apply a demand charge in order to ensure that these customers contribute to the Companies' distribution system costs. For example, residential rates do not incorporate a demand charge; instead, customers served under such rates pay demand-related costs through the incorporation of those costs within the energy-only distribution charge (D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, Tr. 5, at 950).[76] See, e.g., Nantucket Electric Company, D.P.U. 91-106/138, at 142 (1991). In fact, demand charges for EV charging stations with load factors below five percent produce volatile charges that deter developers from deploying fast charging technology (D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, Tr. 5, at 949). Therefore, the Department finds the argument that demand charges are necessary for the lowest load factor bracket to be unpersuasive.

The Attorney General characterizes her proposed 75 percent demand charge discount for the zero percent to five percent load bracket as having a minimal effect on rates (D.P.U. 21-90, Attorney General Track 2 Brief at 11). While the effective unit price may be more acceptable as load factors approach five percent, billing impacts vary widely across the zero percent to

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[76] The absence of a demand charge is also a feature of C&I rates intended for small use customers, such as National Grid's G-1 rate, Unitil's GD-1 rate, and certain customers served on NSTAR Electric's G-1 rate.

five percent load bracket (D.P.U. 21-90, RR-AG-Track 2-1, Att.; D.P.U. 21-91, RR-AG-Track-2-2, Att.). For example, an NSTAR Electric customer with a demand of 500 kW and a load factor of one percent to two percent would experience an effective unit price between $0.41 and $0.63 per kWh (D.P.U. 21-90, RR-AG-Track 2-1, Att.). Similarly, a National Grid customer with the same demand and load factor would experience an effective unit price between $0.35 and $0.52 per kWh (D.P.U. 21-91, RR-AG-Track-2-2, Att.). The Department considers these unit prices to be significant and finds that they will likely result in significant obstacles to the deployment of EV charging stations in the Commonwealth.

The Companies' analysis of anticipated annual load factors and unit prices at DCFC stations over a ten-year period support their proposed load factor brackets (D.P.U. 21-90, Exh. ES-RDC-2, at 5-6; D.P.U. 21-91, Exh. NG-DCA-3, at 3-4; D.P.U. 21-92, Exh. JDT-6, at 2). Under the "High" scenario based on assumptions derived from the Memorandum of Understanding on State Zero-Emission Vehicle Programs, load factors will increase from two percent to eight percent over the next ten years and the projected unit price would decline from $1.21 per kWh to $0.34 per kWh over the same period (D.P.U. 21-90, Exh. ES-RDC-2, at 5; D.P.U. 21-91, Exh. NG-DCA-3, at 3). Under a "Low" scenario based on scaled-back DCFC and medium- and heavy-duty vehicle deployments and load factor projections from those used in the high scenario, load factors will increase from two percent to three percent over the next ten years and the projected unit price would decline from $1.22 per kWh to $0.71 per kWh over that same period (D.P.U. 21-90, Exh. ES-RDC-2, at 5; D.P.U. 21-91, Exhs. NG-DCA-3, at 3; DPU 3-14). NSTAR Electric's and National Grid's high estimate indicates that load factors may be sufficiently high in ten years to yield an economic unit rate for EV charging stations

comparable to the cost of refueling a gasoline-fueled car (D.P.U. 21-90, Exhs. ES-RDC-REB-1, at 8; AG 10-3; D.P.U. 21-91, Exhs. NG-DCA-REB-1, at 10; AG 10-3).

In the case of NSTAR Electric, under a 100 percent demand charge discount scenario where the class revenue requirement is recovered entirely through the energy charge, a one percent load factor produces a unit rate of $0.27 per kWh (D.P.U. 21-90, Exhs. ES-RDC-2, at 4; DPU 3-3). Under a full demand charge scenario, a 16 percent load factor produces a unit rate of $0.25 per kWh (D.P.U. 21-90, Exhs. ES-RDC-2, at 4; DPU 3-3). In the case of National Grid, under a 100 percent demand charge discount where the class revenue requirement is recovered entirely through the energy charge, a one percent load factor for a G-3 customer with 300 kW demand produces a unit rate of $0.30 per kWh (D.P.U. 21-91, Exhs. NG-DCA-3, at 1-2; NG-DCA-REB-1, at 13). Under a full demand charge scenario, a 16 percent load factor produces a unit rate of $0.23 per kWh (D.P.U. 21-91, Exhs. NG-DCA-3, at 1-2; NG-DCA-REB-1, at 13). In the case of Unitil, under a 100 percent demand charge discount where the class revenue requirement is recovered entirely through the energy charge, a one percent load factor for a GD-2 customer with 300 kW demand produces a unit rate of $0.21 per kWh (D.P.U. 21-92, Exh. JDT-6, at 1). Under a full demand charge scenario, a 16 percent load factor produces a unit rate of $0.26 per kWh (D.P.U. 21-92, Exh. JDT-6, at 1). This evidence indicates that the Companies' proposed demand charge discounts allow for price continuity as load factors improve (D.P.U. 21-90, Exh. ES-RDC-REB-1, at 12; D.P.U. 21-91, Exh. NG-DCA-REB-1, at 13-14; D.P.U. 21-92, Exh. JDT-Rebuttal-2, at 17). Additionally, the evidence demonstrates that the Companies' proposed demand charge discounts produce relatively flat load curves as the bill savings percentages decrease within and between the EV

pricing tiers as load factors increase (D.P.U. 21-90, Exhs. ES-RDC-REB-1, at 12; EA-JJS-3; D.P.U. 21-91, Exhs. NG-DCA-1, at 13-14; EA-JJS-3; D.P.U. 21-92, Exh. JDT-Rebuttal-2, at 17).

Several intervenors relied upon the RMI report to support their assertion that the load factor brackets should be expanded beyond the 15 percent load factor bracket proposed by the Companies (see D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Exh. CLF-CV-SUR-2). The RMI report evaluated two EV tariffs of Xcel Energy in Colorado and Pacific Gas and Electric Company in California, as well as a hypothetical tariff prepared by RMI (D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, Exh. CLF-CV-SUR-2, at 8-10). There are some limitations in the applicability of the RMI report. First, the RMI report relies on utilization rates, which is defined as the percentage of time an EV charger is actively charging in a month (D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, Exh. CLF-CV-SUR-2, at 12). In contrast, the Companies' proposals are based on load factors, which the Companies define as the ratio of billed kWh to the product of billed kW and the number of hours in the billing period (D.P.U. 21-90, Exhs. DPU 3-15; CLF-ES 3-1; D.P.U. 21-91, Exhs. DPU 3-18; CLF-NG 3-1; D.P.U. 21-92, Exh. JDT-1, at 7). Because the Companies are unable to measure utilization rates, the Department considers the use of load factors to be more relevant than utilization rates to measure demand (D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, Tr. 5, at 947-948).

More significantly, the EV rate components (i.e., customer charges, demand charges, and volumetric energy charges) in these jurisdictions, as well as those in RMI's hypothetical tariff, are considerably different from those in Massachusetts. For example, because demand charges in Massachusetts are much lower than those used in California and Colorado (D.P.U. 21-90/

D.P.U. 21-91/D.P.U. 21-92, Exh. CLF-CV-SUR-2, at 8-10), load factors and discounts needed to be higher in order to arrive at RMI's recommended dollar-per-mile basis within those jurisdictions (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 5, at 1021). Moreover, RMI's own analysis noted that the relevance of its hypothetical tariff was found in its sliding scale design, a feature that the Companies have proposed to incorporate in their own EV tariffs (D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, Exh. CLF-CV-SUR-2, at 35; Tr. 5, at 1021). The Department finds that the RMI report is more supportive of sliding scale rate designs, with the particular prices and amounts to be determined based on the level of demand charges in each jurisdiction.

Electrify America contends that the end-state demand charges for NSTAR Electric and National Grid customers with load factors greater than 15 percent is too high and should be significantly reduced with commensurate increases in the volumetric charges (D.P.U. 21-90/ D.P.U. 21-91, Exh. EA-JJS-1, at 4-5). The evidence relied on by Electrify America, however, demonstrates that, notwithstanding the decreased price differential that would occur once a customer's load on the EV-2 rate exceeds 15 percent, NSTAR Electric's proposed EV prices remain below the otherwise applicable T-2 rate on which the customer would be assigned and National Grid's proposed EV prices remain below the otherwise applicable G-2 or G-3 rates on which the customer would be assigned (D.P.U. 21-90 Exh. EA-JJS-3; D.P.U. 21-91, Exhs. NG-JJS-3; NG-DCA-3, at 1-4; NG-DCA-Reb-1, at 13-14). Therefore, the Department declines to adopt Electrify America's proposed reduction to NSTAR Electric's and National Grid's end-state demand charges.

The Companies propose to calculate EV charging station load factors annually based on a monthly average of load factors from the twelve months of the prior year (D.P.U. 21-90,

Exh. ES-RDC-1, at 15; D.P.U. 21, Exh. NG-DCA-1, at 16; D.P.U. 21-92, JDT-1, at 9-10). Electrify America recommends that the Department direct the Companies to calculate the annual load factor based on the average demand throughout the program year divided by the peak demand of the program year (D.P.U. 21-90, Exh. EA-JJS-SUR-1, at 12-13). Typically, an annual load factor is calculated based on the maximum demand observed over twelve months (D.P.U. 21-90, Exh. ES-RDC-REB-1, at 16; D.P.U. 21-92, Exh. JDT-1, at 9-10). If the load peaks on an annual basis, then the annual load factor will be lower than the load factor on a monthly basis, where the load factor is calculated based on the usage and the demand within the same month (D.P.U. 21-90, Exh. ES-RDC-REB-1, at 16-17). The lower annual load factor would not be representative of the actual billing and customer usage occurring on a monthly basis (D.P.U. 21-90, Exh. ES-RDC-REB-1, at 17). The use of an average of monthly load factors, however, aligns with how demand and usage is billed monthly. Therefore, the Department accepts the Companies' proposal to rely on annual load factors based on the average monthly load over the previous year.

2. DCA Rate Term

The Companies, CEP, CLF, Electrify America, EVgo, and Tesla support a ten-year term for the DCA rates (see, e.g., D.P.U. 21-90/D.P.U. 21-91, CEP Track 2 Brief at 2, 6, 7; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, CLF Track 2 Reply Brief at 2-4; D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, Tesla Track 2 Brief at 12-15, 16; D.P.U. 21-90/ D.P.U. 21-91, EVgo Track 2 Brief at 6-8, 10; D.P.U. 21-90, Electrify America Track 2 Brief at 3-4, 16). In contrast, the Attorney General and FreeWire support a five-year term for the DCA rates, and ChargePoint opines that future EV developments may warrant making the DCA rates permanently available

to DCFCs in less-traveled areas (D.P.U. 21-90, Attorney General Track 2 Brief at 12-16; D.P.U. 21-91, Attorney General Track 2 Brief at 16-20; D.P.U. 21-92, Attorney General Brief at 21-24; D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 2 Reply Brief at 11; D.P.U. 21-92, Attorney General Track 2 Reply Brief at 2-4, 7; D.P.U. 21-90, FreeWire Track 2 Brief at 6-7; D.P.U. 21-91, FreeWire Track 2 Brief at 6; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, ChargePoint Track 2 Brief at 14-15). The selection of an appropriate term is driven by multiple factors, including those outside of a utility's control (D.P.U. 21-90/D.P.U. 21-91, Exh. AG 10-3). The Companies' proposed ten-year term is based on input from stakeholders, such as EV charging station developers, as well as other considerations, including the Commonwealth's transportation electrification and 2030 decarbonization goals (D.P.U. 21-90, Exhs. ES-RDC-REB-1, at 9; DPU 3-6; D.P.U. 21-91, Exhs. NG-DCA-REB-1, at 10; DPU 3-9; D.P.U. 21-92, Exh. JDT-Rebuttal-2, at 10-11).

Investment horizons are a critical consideration in determining the appropriate term for the proposed DCA rates. EV charging stations are capital-intensive by nature, requiring at least one year for planning and construction (D.P.U. 21-90, Exh. EA-JJS-SUR-1, at 7; D.P.U. 21-91, Exh. EA-JJS-SUR-1, at 6). Consequently, EV charging station developers need price certainty to evaluate the economic viability of their investment decisions (D.P.U. 21-90, Exhs. EA-JJS-SUR-1, at 7; CLF-CV-1, at 18; EVgo-RTB-1; Tesla-WE-1, at 8; D.P.U. 21-91, Exhs. EA-JJS-1, at 6; CLF-CV-1, at 18; EVgo-RTB-1, at 14; Tesla-WE-1, at 8). If the DCA rate term is too short, it could deter investment in public EV charging stations or result in over-investment in public EV charging stations within communities where EV adoption is

rapidly growing at the expense of other communities where investor returns may not be as quickly realized (D.P.U. 21-90, Exh. EA-JJS-SUR-1, at 7).

The Companies' based the term of their DCA rate proposals in part on their analysis of anticipated annual load factors and unit prices at DCFC stations over a ten-year period (D.P.U. 21-90, Exh. ES-RDC-2, at 5-6; D.P.U. 21-91, Exh. NG-DCA-3, at 3-4; D.P.U. 21-92, Exh. JDT-6, at 2). As noted above, under NSTAR Electric's and National Grid's high forecast scenario, load factors may be sufficiently high within ten-years to yield an economic unit rate for EV charging stations comparable to that of gas-fueled vehicles (D.P.U. 21-90, Exh. ES-RDC-REB-1, at 8; D.P.U. 21-91, Exh. NG-DCA-REB-1, at 10). The Department finds that the Companies' reliance on unit price projections to determine the appropriate duration for their proposed DCA tariffs was reasonable and based on substantive evidence.

The Attorney General notes that a number of states, including Florida, Nevada, Pennsylvania, and Rhode Island, have approved EV charging rates for five-year terms or less, and that other states, including California, North Carolina, and South Carolina, have offered similar terms for economic development rates (D.P.U. 21-90/D.P.U. 21-91, Attorney General Track 2 Reply Brief at 9-10 & n.19).[77] It is, however, uncertain whether the development of the EV charging station market will be sufficiently robust to transition to AMI-enabled rates within the next ten years (D.P.U. 21-91, Exh. NG-DCA-REB-1, at 9). Further, as noted by several

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[77] The Department is familiar with the concept of economic development rates. Commonwealth Electric Company, D.P.U. 93-41 (1993). Although EV charging service has been likened to economic development rates, the Department finds that there are significant differences between time-limited rate discounts to promote economic development and the use of such rates to promote the role of EVs as part of the Commonwealth's overall climate strategies.

intervenors, there is credible evidence to suggest that a shorter-term offering (i.e., an offering of three or five years) may not provide DCFC station developers enough price stability to overcome the risk of making the high initial investment in these stations (D.P.U. 21-90, Exhs. ES-RDC-REB-1, at 9; DPU 3-6; D.P.U. 21-91, Exhs. NG-DCA-REB-1, at 10; DPU 3-9; EA-JJS-SUR-1, at 7; D.P.U. 21-92, Exh. JDT-Rebuttal-2, at 10).

The Department notes that other jurisdictions, including Arizona, California, Illinois, and Oregon, have approved the use of ten-year terms for time-limited EV rates (D.P.U. 21-90/ D.P.U. 21-91, Exhs. EVgo-RTB-5; EVgo-RTB-6; EVgo-RTB-9; EVgo-RTB-10; EVgo-RTB-11; TESLA-WE-5). While the EV rates in some of these states incorporate a phase-in of demand charges after an initial period, or restrictions on the number of customers that can enroll in such rates, the Department finds that inclusion of a demand charge phase-in or participation restrictions do not negate the fact that the respective regulatory commission approved ten-year terms for the EV rates.

Based on the foregoing analysis, the Department finds that a ten-year term for the DCA rates strikes an appropriate balance between the need for price certainty and stability for EV charging station developers and the Commonwealth's transportation electrification and 2030 decarbonization goals. Therefore, the Department approves a ten-year term for the proposed DCA rates.[78]

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[78] In doing so, the Department recognizes that future events may warrant reexamination of the DCA rates, including their term.

3. Ancillary Load

The Companies each proposed revisions to their exemplar tariff to include language that certain types of ancillary load qualify for the DCA rates (D.P.U. 21-90, Exhs. ES-RDC-3; ES-RDC-REB-1, at 14; D.P.U. 21-91, Exhs. NG-DCA-1, at 13-14; NG-DCA-REB-1, at 16; D.P.U. 21-92, Exhs. JDT-Rebuttal-2, at 20; DPU 13-7).[79] The Department's tariff construction standards requires that a proposed tariff have sufficient detail to explain the basis for the rate to be charged for the offered service.[80] 220 CMR 5.00; NEES-EUA Merger, D.T.E. 99-47, at 22 (2000). Therefore, the Department finds it is appropriate to examine the Companies' proposed tariff language governing ancillary load.

Certain types of load, such as security lighting, touchpads, and telecommunications equipment, are not directly related to load from EV charging equipment itself, but are essential to the operation of the EV charging station (D.P.U. 21-90, Exh. ES-RDC-REB-1, at 14; D.P.U. 21-91, Exh. NG-DCA-REB-1, at 16; D.P.U. 21-92, Exh. JDT-Rebuttal-2, at 20). While this type of load can potentially be metered in combination with other load at some EV charging stations, such as those co-located with a convenience store, other EV charging stations may operate as stand-alone installations (D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, Exhs. CP-MJD-1, at 15; Tesla-WE-1, at 14-15). In such cases, driver security and convenience would require the

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79 In its initial filings, NSTAR Electric's and Unitil's exemplar DCA tariffs made no provision for ancillary load while National Grid's exemplar tariff required all ancillary load to be separately metered (D.P.U. 21-90, Exh. ES-RDC-3; D.P.U. 21-91, Exh. NG-DCA-1, at 13-14; D.P.U. 21-92, Exh. Unitil-JDT-3).

80 The sufficiency of a tariff must be judged on its face, and testimony is insufficient to cure a defect or supply a missing essential term. Boston Gas Company, D.P.U. 92-259, at 47-48 (1993); Dedham Water Company, D.P.U. 13271, at 10 (1961).

provision of amenities, such as security lighting, that could be provided by the host facility (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Exh. Tesla-WE-1, at 14-15). As acknowledged by the Companies, this type of load may be considered ancillary load and included in the metering for EV charging infrastructure (D.P.U. 21-90, Exh. ES-RDC-REB-1, at 14; D.P.U. 21-91, NG-DCA-REB-1, at 16; D.P.U. 21-92, Exh. JDT-Reb-2, at 20; D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, Tr. 5, at 1056-1058). Further, inclusion of some ancillary load in EV charging station metering is expected to have a minimal effect on the total EV charging load for that station (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 5, at 953-954). Based on these considerations, the Department finds it appropriate to permit ancillary load of this type to be metered with EV charging equipment for purposes of the DCA rates.

In addition to this type of ancillary load, EV charging station developers may choose to install solar canopies and energy storage (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 5, at 1066-1068). This type of co-located infrastructure offers potential benefits to the owner of an EV charging station, such as reduced reliance on the utility's electric grid and lower demand charges, resulting in potential cost savings (D.P.U. 21-90/D.P.U. 21-91, Exh. GECA-JRC-1, at 14-16). Nevertheless, this type of co-located infrastructure is not essential to the operation of the EV charging facility (D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, Tr. 5, at 1066-1068). While the inclusion of some ancillary load in EV charging station metering is expected to have a minimal effect on the total EV charging load for that station, combining more extensive infrastructure, such as solar canopies and energy storage, with EV charging equipment for metering purposes would skew load data results away from EV charging equipment in favor of ancillary load (D.P.U. 21-90, Exh. ES-RDC-Reb-1, at 14; D.P.U. 21-91, Exh. DPU 13-8;

D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, Tr. 5, at 1066-1068; Tr. 6, at 1207-1209). Given the need to reliably determine load patterns associated with EV charging stations, the Department is persuaded that the definition of ancillary load for purposes of the DCA rates needs to be narrowly defined. Moreover, given that the proposed DCA rates are intended to be temporary, the Department is persuaded that it would be inappropriate for customers enrolled in the DCA rates to base their non-EV charging infrastructure investment decisions, such as those related to net metering credits or solar payment, on the characteristics of a temporary rate (D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, Tr. 5, at 1067-1068). To the extent that a DCA rate customer wishes to install solar canopies or battery storage equipment at their EV charging sites, the Companies are capable of separately metering the load associated with those technologies (D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, Tr. 5, at 1068-1069).[81] On this basis, the Department declines to include solar canopies or energy storage facilities as ancillary load for purposes of the DCA rates.

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[81] GECA recommends that the co-location of renewables and energy storage be incorporated into the Companies' DCA rate proposals; while FreeWire asserts that the Department should deny the DCA rate proposals because they do not sufficiently incentivize the co-location of battery storage systems (D.P.U. 21-90/D.P.U. 21-91, Exh. GECA-JRC-1, at 31; D.P.U. 21-90, FreeWire Track 2 Brief at 6; D.P.U. 21-91, FreeWire Track 2 Brief at 6). The Department declines to consider co-location of renewables, such as battery energy storage systems, in the present proceedings. These proceedings are limited to a review of the Companies' EV charging infrastructure and DCA rate proposals, and Unitil's residential EV TOU rate proposal. Nonetheless, while we determine that the co-location of renewables, including energy storage systems, is outside the scope of this proceeding, the Department expects the Companies to work cooperatively with EV charging station developers considering co-location of these types of technologies. The Department may consider whether future EV rates should include a component to incentivize such co-location in a future proceeding and encourages the Companies to evaluate the benefits of co-locating EV charging stations and renewables prospectively.

Additionally, ChargePoint recommends that the Department direct the Companies to limit the amount of ancillary load that can qualify for the DCA rates to no more than ten percent of an EV charging station's total load (D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, ChargePoint Track 2 Brief at 3, 9, 17-18). As determined above, the Department has found it appropriate to narrowly define ancillary load to non-EV charging load that is nonetheless essential to the operation of an EV charging station. The Department finds that, given this narrow definition of ancillary load, it is unnecessary for the Companies to set a cap on the percentage of ancillary load eligible for inclusion in the DCA rates.

Based on the foregoing analysis, the Department directs NSTAR Electric to include the following language in its EV tariffs (see D.P.U. 21-90, Exh. ES-RDC-REB-1, at 14).

> [Rate] is an optional schedule that is applicable only to EV charging station equipment which includes security lighting, networking, touch screens, component heating, charger fans and cooling equipment, of which the aggregate load must be metered separately. Any non-EV general service use must be separately metered and assigned the applicable rate.

The Department directs National Grid to delete the following EV pricing language from its G-2 and G-3 tariffs: "Any non-EV charging usage at the site's service location must be separately metered and receive delivery service at the applicable general service rate" (D.P.U. 21-91, Exh. NG-DCA-4). National Grid shall replace this language with the following:

> EV charging station usage includes security lighting, networking, touch screens, component heating, charger fans and cooling equipment, of which the aggregate load must be metered separately. Any non-EV general service use must be separately metered.

(D.P.U. 21-91, Exh. DPU 13-8).

The Department directs Unitil to delete the first paragraph under "EV Demand Charge Alternative" as proposed in Exhibit JDT-3 and include the language, which identifies specific categories of ancillary load that would be permitted on the same meter as an EV charger, in its GD-2 and GD-3 tariffs as provided in response to information request Exhibit DPU 13-7 (see D.P.U. 21-92, Exhs. JDT-3, at 3, 12; JDT-Rebuttal-2, at 20; DPU 13-7).

4. DCA Rate Implementation

A number of intervenors recommend that the Companies implement the proposed DCA rates immediately following the Department's Order in these matters, and to issue bill credits retroactively to the date of the Department's Order (D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, DOER Track 2 Brief at 7-8, 14; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tesla Track 2 Reply Brief at 7; D.P.U. 21-90/D.P.U. 21-91, EVgo Track 2 Reply Brief at 4). There is credible evidence in the record that it will likely take six months for NSTAR Electric and National Grid and three months for Unitil to implement the necessary billing system updates and train their customer service representatives on the DCA rates (D.P.U. 21-90, Exh. ES-RDC-1, at 17-18; D.P.U. 21-91, Exh. NG-DCA-1, at 22; D.P.U. 21-92, Exh. JDT-1, at 21). Incorporating back-billing into the implementation of the DCA rates would create an additional layer of complexity and could result in customer confusion and inconsistent price signals.

Moreover, requiring the Companies to issue billing credits raises issues relative to retroactive ratemaking. The rule against retroactive ratemaking is implicated when the Department requires refunds of charges previously fixed by a formal finding that had become final. Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 6 (1978); Metropolitan District Commission v. Department of Public Utilities, 352 Mass. 18, 26-27 (1967).

The Department may not generally order adjustments of a company's base distribution rates.[82] See Boston Edison Co. v. Department of Public Utilities, 375 Mass. 1, 6 (1978); Lowell Gas Co. v. Attorney General, 377 Mass. 37, 44-45 (1979); Fryer v. Department of Public Utilities, 374 Mass. 685, 689-690 (1978).

Based on these considerations, the Department declines to require implementation of the proposed DCA rates immediately upon approval. Instead, the Department directs the Companies to implement the DCA rates within six months of the Department's Order and disposition of any relevant post-Order motions or appeals in this matter with no provision for billing credits.

5. Metering Options

In D.P.U. 20-69-A at 42-43, the Department stated that the proposed DCA rates should be based on EV charging data collected through one of the following means: (1) smart chargers or networked chargers; (2) EV telematics; or (3) interval meters installed at the request of the customer. The Department also encouraged the Companies to solicit input from EV charging companies and other stakeholders to standardize the data quality requirements for smart charger and EV telematics data. D.P.U. 20-69-A at 43 n.21.

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82 The rule against retroactive ratemaking is not without exception. For example, exceptions to retroactive ratemaking have been recognized for the recovery of extraordinary past losses that otherwise would not be recoverable in future rates. See, e.g., Attorney General v. Department of Public Utilities, 453 Mass. 191, 201-202 (2009); Attorney General v. Department of Public Utilities, 390 Mass. 208, 228-229 (1983); Electric Industry Restructuring, D.P.U. 95-30, at 29, 37-39 (1995). Further, rate adjustments associated with reconciling mechanisms do not constitute retroactive ratemaking. Fitchburg Gas and Electric Light Company v. Department of Telecommunications and Energy, 440 Mass. 625, 627-628 (2004). None of these exceptions apply to the Companies' exemplar DCA tariffs.

In these proceedings, the Companies state that the DCA rates were evaluated using EV charging data collected from separately metered EV charging sites in compliance with the Department's directives in D.P.U. 20-69-A (D.P.U. 21-90, Exh. ES-RDC-1, at 13; D.P.U. 21-91, Exh. NG-DCA-1, at 17; D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 10). The Companies also state that, in analyzing the capabilities of embedded EVSE meters and EV telematics, they determined that there would be a host of challenges to using these technologies for data collection and billing purposes, including technical, cybersecurity, and consumer protection concerns, and that there are no national standards for metering, testing, and evaluating embedded EVSE meters (D.P.U. 21-90, Exh. ES-RDC-Reb-1, at 17, 20; RR-DPU-Track 2-1; D.P.U. 21-91, Exh. NG-DCA-Reb-1, at 20, 23; RR-DPU-Track 2-2; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 6, at 1141-1143, 1257). Therefore, the Companies propose to install utility-owned meters to implement the DCA rates and collect EV charging data.

Shell and FreeWire, however, support the use of embedded metering for billing purposes, with Shell recommending that the Department convene a working group to establish technical standards for embedded EVSE metering (D.P.U. 21-90, FreeWire Track 2 Brief at 11; D.P.U. 21-91, FreeWire Track 2 Brief at 10, 12; D.P.U. 21-90/D.P.U. 21-91, Shell Track 2 Reply Brief at 7). The Attorney General recommends that the Companies evaluate the metering capabilities of networked EVSE and EV telematics for billing purposes and develop a plan to integrate networked chargers into their billing system (D.P.U. 21-90, Attorney General Track 2 Brief at 20-21; D.P.U. 21-91, Attorney General Track 2 Brief at 24; D.P.U. 21-92, Attorney General Track 2 Brief at 28).

On November 30, 2022, the Department issued an Order approving full deployment of AMI meters and preauthorizing the Companies' core AMI investments. Grid Mod Track 2 Order at 238, 258, 277. Additionally, the Department determined that the Companies' proposed meter replacement plans struck an appropriate balance between maximizing customer benefits and minimizing stranded costs. Grid Mod Track 2 Order at 204-205. Further, the Department stated that AMI meters should be capable of load disaggregation, which would eliminate the need for a company to install more than one meter at a customer's location. Grid Mod Track 2 Order at 234. With full AMI deployment on the horizon, the Department is concerned that the Companies' proposal to separately meter customers' EV load using soon-to-be obsolete traditional utility meters will result in unnecessary stranded costs for ratepayers.

The Department acknowledges the Companies' concerns with these technologies. Indeed, the Department notes that, in addition to potential data compatibility and cybersecurity issues, there may be implementation issues involving the ability of utilities to obtain data sharing agreements with EV drivers, particularly in the case of non-customers. Nevertheless, the Department recognizes that networked chargers and EV telematics may provide benefits, including eliminating the need for a second utility-owned meter, new managed charging opportunities, and V2G capabilities (D.P.U. 21-90, Exh. AG-REN-2, at 29-32). Accordingly, the Department directs the Companies to work with EVSE providers, the Attorney General, and other stakeholders to explore the metering capabilities of networked EVSE and vehicle telematics for data collection and billing purposes in an effort to reach consensus on EVSE data quality standards. Further, the Companies shall coordinate efforts to the extent feasible to

establish uniform statewide EVSE data quality standards. The Companies shall report on their progress in their annual reports.

Despite our concerns regarding the stranded costs associated with the Companies' metering proposal, the evidentiary record in this proceeding demonstrates that there are still significant hurdles to overcome before embedded EVSE meters and EV telematics can be used for data collection and billing purposes (D.P.U. 21-90, Exh. ES-RDC-REB-1, at 17, 19-20; D.P.U. 21-91, Exh. NG-DCA-REB-1, at 20, 22-23; D.P.U. 21-92, Exh. CG-Rebuttal-2, at 10-11; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tr. 6, at 1141-1143, 1244-1245; RR-DPU-Track 2-1; RR-DPU-Track 2-2). Therefore, the Department finds that the Companies' proposal to deploy utility-owned meters for data collection and billing purposes, before establishing EVSE data quality standards, is reasonable and based on credible evidence. In doing so, we recognize that advances in technology may eventually provide some role for other metering technologies in EV data collection and billing. Grid Modernization, DPU 12-76-A at 27 n.35 (2014); D.P.U. 12-76-B at 1. Depending upon future technological advances, the Department may reexamine the appropriateness of continued use and deployment of utility-owned meters for EV data collection and billing purposes.

6. Transition Plan

A number of intervenors recommend that the Department direct the Companies to develop a transition plan to replace the DCA rates with AMI-enabled rates (D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, DOER Track 2 Brief at 9-11; D.P.U. 21-90/D.P.U. 21-91, FreeWire Track 2 Reply Brief at 3, 5; D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, Tesla Track 2 Reply Brief at 8). Transition plans require consideration of multiple factors, including those outside of a

utility's control (D.P.U. 21-90/D.P.U. 21-91, Exh. AG 10-3). With the approval of the Companies' AMI investments, the Department finds that it is appropriate for the Companies to begin planning for AMI-enabled demand charge rates. Grid Mod Track 2 Order at 238, 258, 277. The Department also recognizes that the Companies need to collect data and information related to the implementation of the DCA rates to inform any transition plans (D.P.U. 21-90, Exh. FW-ES 3-4; D.P.U. 21-91, Exh. FW-NG 3-4; D.P.U. 21-90/ D.P.U. 21-91/D.P.U. 21-92, Tr. 6, at 1231-1235). Therefore, the Department declines at this time to require the submission of any transition plans. However, the Department expects the Companies to identify a timeline and approach to transition all proposed DCA rates to future demand charge rate designs that will be enabled through the full deployment of AMI. Accordingly, the Department directs the Companies, as an initial step toward the development of a transition plan, to report on the implementation of the DCA rates in their annual reports, including relevant data and lessons learned on DCA rate implementation, and the status of all transition plan development activities undertaken.

7. Time-Varying Rates

The Attorney General and CEP urge the Department to direct the Companies to incorporate time-varying rate components into their DCA rate proposals (D.P.U. 21-90, Attorney General Track 2 Brief at 7-9; D.P.U. 21-91, Attorney General Track 2 Brief at 8-10; D.P.U. 21-92, Attorney General Track 2 Brief at 14, 16-17; D.P.U. 21-90/ D.P.U. 21-91, CEP Track 2 Brief at 9). The Department finds that the evaluation of time-varying rates is beyond the scope of this proceeding. Neither the Transportation Act nor the Department's directives in D.P.U. 20-69-A required the distribution companies to propose time-varying DCA rates.

Additionally, the Attorney General's recommendation would require a complete redesign of the Companies' proposed DCA rates, including transmission and basic service rates,[83] significantly delaying the implementation of the proposed DCA rates and frustrating the intent of both the Transportation Act and our directives in D.P.U. 20-69-A.

Further, on August 11, 2022, during the course of these proceedings, Governor Baker signed into law the 2022 Clean Energy Act. Pursuant to Section 90 of the 2022 Clean Energy Act, the Companies must submit proposals to the Department on or before August 11, 2023 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. Accordingly, on or before August 11, 2023, each company shall file EV TOU rate designs with the Department. The Department encourages the Companies to consider including time-varying DCA rates as part of their EV TOU rate designs. To the extent feasible, the Companies shall coordinate the development of their EV TOU rate proposals. Any proposed tariff included as part of the Companies' EV TOU rate proposals must be filed as an exemplar tariff. The Department will review company-specific tariffs at the conclusion of our investigation of the EV TOU rates.

8. Customer Outreach

NSTAR Electric and National Grid propose to inform existing and prospective customers about the DCA rate offerings through multiple outlets, including EVSE vendors with relationships with customers, direct outreach to EV charging station developers, and project

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83 A peak period specific for EVSE has not yet been established and could vary between fleet and public charging sites as well as among individual sites (D.P.U. 21-91, Exh. NG-DCA-Reb-1, at 17).

commitment letters and the make-ready application process (D.P.U. 21-90, Exh. DOER-ES 4-1; D.P.U. 21-91, Exhs. DPU 3-7; DOER-NG 4-1, at 1). Unitil proposes to inform existing and prospective customers about the DCA rate offerings through multiple outlets, including customer newsletters, bill inserts, social media, earned media, and the company's website (D.P.U. 21-92, Exh. DOER-FGE 3-1). Unitil also proposes to engage in outreach to EVSE customers on its GD-2 and GD-3 rates as part of its project commitment letters and the make ready application process (D.P.U. 21-92, Exhs. CVSG-1 (Rev.), at 35-38); DOER-FGE 3-1). DOER suggests expanding the Companies' customer outreach efforts to include direct mail, bill inserts, emails, website postings, and communication with municipal officials (D.P.U. 21-90/D.P.U. 21-91/ D.P.U. 21-92, DOER Track 2 Brief at 8).

The Department recognizes the importance of a robust customer outreach program to engage customers and to provide simple, clear information about the availability of new rate offerings. Time Varying Rates, D.P.U. 14-04-C at 19 (2014); NSTAR Electric Company, D.P.U. 12-95, at 17 (2014). The Department finds DOER's additional recommended outreach methods to be reasonable and appropriate given the importance of the DCA rates in achieving the Commonwealth's transportation electrification goals. Therefore, the Department directs the Companies to include direct mail, bill inserts, emails, website postings, and communication with municipal officials as part of their overall customer outreach efforts.

9. Marginal Cost Studies

CEP and FreeWire recommend that the Companies be directed to conduct marginal cost analyses of EV load on their distribution systems within the next three years to evaluate the design and effectiveness of future EV rates and inform the design and assessment of other

programs, such as load management (D.P.U. 21-90/D.P.U. 21-91, CEP Track 2 Brief at 2, 6-7, 9; D.P.U. 21-90/D.P.U. 21-91, FreeWire Track 2 Reply Brief at 4-5). While the Department has long required electric and gas distribution companies to provide a marginal cost study as part of a base distribution rate case filing, as a practical matter, the Department does not rely on the results of a marginal cost study in designing tariffed rates for electric and gas distribution companies.[84] D.P.U. 18-150, at 516. Rather, in evaluating a petitioning company's rate design proposals, the Department considers its rate design goals of efficiency and simplicity as well as ensuring the continuity of rates, fairness between rate classes, and corporate earnings stability. See, e.g., Fitchburg Gas and Electric Light Company, D.P.U. 15-80/D.P.U. 15-81, at 294 (2015); Bay State Gas Company, D.P.U. 13-75, at 330 (2014); Bay State Gas Company, D.P.U. 12-25, at 444 (2012); New England Gas Company, D.P.U. 10-114, at 341 (2011); Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 09-39, at 401 (2009). We also consider relevant statutory requirements in determining appropriate rate design and allocation. See, e.g., G.L. c. 164, § 94I (cost-allocation method based on equalized rates of return for each customer class with specific parameters).

NSTAR Electric's proposed DCA rates are based on a revenue-neutral shift in demand billing units associated with its then-existing C&I rates (D.P.U. 21-90, Exhs. ES-RDC-1, at 18-19; ES-RDC-2, at 2). National Grid's proposed DCA rates are based on a revenue-neutral

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84 Marginal cost studies are still submitted by gas distribution companies. Boston Gas Company, D.P.U. 20-120, at 451-468 (2021); NSTAR Gas Company, D.P.U. 19-120, at 423-427 (2020). These studies are intended to ensure that special contracts are priced above marginal distribution cost. See D.P.U. 18-150, at 516. Marginal cost studies have also been used to determine voltage splits for electric distribution companies. NSTAR Electric Company, D.P.U. 22-22, at 410 (November 30, 2022).

shift in demand billing units associated with its G-2 and G-3 rates (D.P.U. 21-91, Exhs. NG-DCA-1, at 18-19; NG-CRP-2, at 2; AG 13-2). Unitil's proposed DCA rates are based on a revenue-neutral shift in demand billing units associated with its GD-2 and GD-3 rates (D.P.U. 21-92, Exh. JDT-1, at 7). The Companies' C&I rates that serve as the basis for the Companies' proposed DCA rates were not based on marginal cost pricing. NSTAR Electric Company/Western Massachusetts Electric Company, D.P.U. 17-05-B at 281-309 (2017); D.P.U. 18-150, at 516-517; Fitchburg Gas and Electric Light Company, D.P.U. 19-130 (2020); Fitchburg Gas and Electric Light Company, D.P.U. 15-80, at 314-325 (2016). Insofar as the Companies' underlying commercial rates were not derived from the results of marginal cost studies, the Department finds it unnecessary to require the use of marginal cost studies to design DCA rates.[85] Therefore, the Department declines to direct the Companies to prepare a marginal cost study.

10. NSTAR Electric DCA Rate Proposal

On November 30, 2022, the Department issued an Order in NSTAR Electric's base distribution rate proceeding, D.P.U. 22-22, approving, among other things, the Company's proposed rate design alignment and consolidation plan. To establish consistency and simplicity, the company proposed and the Department allowed the company to establish: (1) Rate G-1 as its rate class for customers with annual demand equal to or less than 100 kW; (2) Rate G-2 for customers with annual demand greater than 100 kW; (3) Rate G-3 for customers with large loads

[85] The Department further recognizes that a marginal cost study may suggest the need for a demand-based DCA rate, which would be contrary to the requirements of Section 29 of the Transportation Act that electric distribution companies develop a non-demand-based EV rate.

who frequently receive service at the primary voltage level; and (4) WMA Rate T-5, which is unique to WMA and which serves a small number of customers. D.P.U. 22-22, at 421, 432. Moreover, the Department allowed the Company's proposed non-demand offering for small C&I customers under the G-1 rate class. D.P.U. 22-22, at 422.

NSTAR Electric stated that it would align its EV-1 and EV-2 proposals with the revised rate structure consistent with its proposals in D.P.U. 22-22 (D.P.U. 21-90, Exh. DPU 13-1). For example, the Company would propose to alter the availability breakpoint at 100 kW rather than 200 kW as originally proposed in the instant proceeding (D.P.U. 21-90, Exh. DPU 13-1). The Company calculated an alternative Rate EV-1 based on its D.P.U. 22-22 proposals, which showed a higher rate (except for in the former Boston Edison service area) than the rates the Company proposed for its newly expanded Rate G-1 (D.P.U. 21-90, Exh. DPU 13-1). Therefore, the Company stated that it would not propose a Rate EV-1, and, instead, EV charging stations would take service on the otherwise applicable proposed Rate G-1 (D.P.U. 21-90, Exh. DPU 13-1). Rate EV-2 would be introduced starting at demand greater than 100 kW (D.P.U. 21-90, Exh. DPU 13-1). Accordingly, the Department approves the company's modified DCA rates as provided in its response to information request DPU 13-1 and disallows Rate EV-1. In compliance with this Order, the Department directs NSTAR Electric to file a revised Rate EV-2 with updated pricing consistent with the rate design approved in D.P.U. 22-22.

11. Conclusion

Based on the considerations discussed above, as well as after review and consideration of the issues raised by intervenors, the Department approves the Companies' proposed DCA rate

proposals, with the exception of NSTAR Electric's proposal as discussed and modified above. Accordingly, the Companies are directed to submit tariffs in compliance with this Order.

VIII. UNITIL RESIDENTIAL EV TOU RATE

A. Description of the Proposal

Unitil proposes a separately metered EV TOU rate for residential customers to incentivize off-peak charging (D.P.U. 21-92, Exhs. JDT-1, at 11; CSVG-1 (Rev.) at 21-22). Unitil's proposed residential EV TOU consists of three main rate components, differentiated by season: (1) a generation component, which is provided through basic service; (2) a transmission component that is separately charged to all customers and adjusted annually; and (3) a distribution component that is established in base distribution rate proceedings (D.P.U. 21-92, Exh. JDT-1, at 11).

The company determined the generation component by differentiating basic service seasonal energy purchases by time period (i.e., summer on-peak, winter off-peak, etc.), using seasonal load profiles and ISO-NE locational marginal prices to determine time-differentiated projected basic service revenues (D.P.U. 21-92, Exh. JDT-1, at 12). Then, Unitil calculated a time-differentiated marginal rate by dividing the projected basic service revenues by the differentiated seasonal basic service energy purchases for each time period (D.P.U. 21-92, Exh. JDT-1, at 12). The company used the share for each time period and time-differentiated marginal rates to calculate TOU ratios (D.P.U. 21-92, Exh. JDT-1, at 12). Finally, Unitil applied these ratios to the seasonal basic service total costs for each time period to determine the time-differentiated basic service rates (D.P.U. 21-92, Exh. JDT-1, at 12).

For the transmission component, the company time-differentiated its annual system

transmission cost by season and time period, and then divided those costs by time-differentiated system transmission kWh (D.P.U. 21-92, Exh. JDT-1, at 13). To develop the distribution component, the company calculated a time-varied distribution rate in order to produce an overall TOU rate for all components such that the on-peak to off-peak ratio is three to one (D.P.U. 21-92, Exh. JDT-1, at 14).

In its initial filing, Unitil proposed a residential EV TOU consisting of two time periods, an on-peak period of 10 a.m. to 10 p.m. for non-holiday weekdays and an off-peak period for all other times (D.P.U. 21-92, Exh. JDT-1, at 16, 18). During the course of this proceeding, Unitil amended its residential EV TOU proposal, with an on-peak period of 3 p.m. to 8 p.m. and a mid-peak period of 6 a.m. to 3 p.m. for non-holiday weekdays, and an off-peak period for all other times, with rates calculated in a manner consistent with its original proposal (D.P.U. 21-92, Exhs. JDT-1, at 16-17; JDT-Rebuttal-2, at 7).[86] The company states that its amended proposal mirrors the EV TOU rate approved for its New Hampshire affiliate, Unitil Energy Systems, Inc., and is consistent with the Attorney General's recommendations in this proceeding (D.P.U. 21-92, Exh. JDT-Rebuttal-2, at 7).

Unitil's residential EV TOU proposal includes an incremental customer charge of $6.39 per billing cycle, which represents the carrying cost associated with a separate meter required to meter the EV charging port (D.P.U. 21-92, Exh. JDT-1, at 16, 19). Unitil estimates that it would take three months following Department approval to update its billing system to implement the

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86 The company maintained the on-peak to off-peak ratio at three to one, while the summer mid-peak to off-peak ratio is 1.89 to one and the winter mid-peak to off-peak ratio is 1.57 to one (D.P.U. 21-92, Exh. JDT-1, at 18).

residential EV TOU and train its customer service representatives on the new rate (D.P.U. 21-92, Exh. JDT-1, at 21).

B. Positions of the Parties

1. Attorney General

The Attorney General recommends that Unitil expand the residential EV TOU rate offering to include an opt-in whole house TOU rate option because it would reduce ratepayer costs and provide additional load management benefits by including more customer load (D.P.U. 21-92, Attorney General Track 2 Brief at 7, 10). The Attorney General also urges the Department to establish a mechanism by which the Department and stakeholders would reevaluate the TOU rate every two or three years or as part of the Attorney General's recommended load management process (see Section III.B.4.b, below) (D.P.U. 21-92, Attorney General Track 2 Brief at 7, 10, 12).

2. Unitil

Unitil opposes the Attorney General's recommendation to expand the residential EV TOU rate offering to include an opt-in whole house TOU rate option as beyond the scope of this proceeding and not relevant to the Department's review of the company's proposed residential EV TOU rate (D.P.U. 21-92, Unitil Track 2 Brief at 13, 20-22). Further, Unitil argues that this issue was not properly noticed for this proceeding nor was the record sufficiently developed to support approval of the Attorney General's recommended whole house TOU rate (D.P.U. 21-92, Unitil Track 2 Brief at 13, 20-22).

C. Analysis and Findings

The Attorney General recommends that the Department direct Unitil to expand the residential EV TOU rate offering to include an opt-in whole house TOU rate option (D.P.U. 21-92, Attorney General Track 2 Brief at 7, 10). In D.P.U. 20-69-A, at 44, the Department encouraged, but did not require, Unitil to propose an EV-specific TOU rate for residential customers. Consistent with the Department's request, Unitil proposed a residential EV TOU rate, which we examine, below. The Department, however, does not require an expansion of Unitil's residential EV TOU rate proposal to include an opt-in whole house TOU rate option at this time. As previously stated, pursuant to Section 90 of the 2022 Clean Energy Act, the Companies must submit proposals to the Department on or before August 11, 2023 for approval to offer an opt-in residential TOU rate for EV owners or lessees, designed to reflect the cost of providing electricity to a consumer charging an EV at different times of the day. The Department will further explore EV TOU rate options in that proceeding.[87]

The Department reviewed Unitil's three-part residential EV TOU rate proposal and finds it to be reasonable and consistent with the Department's request in D.P.U. 20-69-A. Additionally, the Department determines that Unitil's proposal for an on-peak non-holiday weekdays, mid-peak non-holiday weekdays, and off-peak for all other times, will assist in incentivizing off-peak charging and support the Commonwealth's public policy goals and the Department's grid modernization objective to optimize system demand by facilitating consumer price responsiveness (D.P.U. 21-92, Exh. JDT-1, at 12-14). D.P.U. 15-120/D.P.U. 15-121/

87 The Department also intends to explore TOU rates for non-EV customers in a separate proceeding.

D.P.U. 15-122, at 101-102. Accordingly, we approve Unitil's proposed three-part residential EV TOU rate.

The Department directs the company to file a residential EV TOU tariff for Department review and approval no later than January 15, 2023. The Department expects that the compliance tariff will be identical to the exemplar tariff in all respects other than the inclusion of effective dates.

In Section III.C.4.c.i, above, the Department approved the company's proposal to offer EVSE rebates to low-income residential customers in one to four-unit properties enrolled in the residential EV TOU rate (D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 34). The company proposes to collect the data from participating residential EV TOU rate meters and analyze and compare historical embedded EVSE data against the utility metering interval data (D.P.U. 21-92, Exh. CSVG-1 (Rev.) at 34-45). As discussed in Section VII.C.5, above, the Department urges the company to complete its assessment of EVSE metering capabilities in a timely manner and provide EV program customers the option to participate in the program using embedded EVSE meters instead of a second utility-owned meter (D.P.U. 21-92, Exhs. CSVG-4, at 1; JDT-1, at 19).

The Department also directs Unitil to report on the implementation of the residential EV TOU rate in its annual reports, including data on customer enrollment and other relevant data and lessons learned. The Department expects Unitil to use its experience implementing the residential EV TOU rate to inform the design and implementation of any future TOU rate proposal.

IX. ORDER

Accordingly, after due notice, hearing, and consideration, it is

ORDERED: That the electric vehicle charging infrastructure proposal plans filed by NSTAR Electric Company, Massachusetts Electric Company and Nantucket Electric Company, and Fitchburg Gas and Electric Light Company are APPROVED in part and DENIED in part, consistent with the directives contained herein; and it is

FURTHER ORDERED: That the demand charge alternative rates proposed by NSTAR Electric Company are APPROVED in part and DENIED in part, consistent with directives contained herein; and it is

FURTHER ORDERED: That the demand charge alternative rates proposed by Massachusetts Electric Company and Nantucket Electric Company and Fitchburg Gas and Electric Light Company are APPROVED; and it is

FURTHER ORDERED: That the residential electric vehicle time-of-use rate proposed by Fitchburg Gas and Electric Light Company is APPROVED; and it is

FURTHER ORDERED: That NSTAR Electric Company shall file by January 15, 2023 revised grid modernization factor and electric vehicle program factor tariffs consistent with the directives contained herein; and it is

FURTHER ORDERED: That Massachusetts Electric Company and Nantucket Electric Company shall file by January 15, 2023 revised electric vehicle program factor and General Service – Small Commercial and Industrial G-1 tariffs consistent with the directives contained herein; and it is

FURTHER ORDERED: That Fitchburg Gas and Electric Light Company shall file by January 15, 2023 revised grid modernization factor and residential electric vehicle time-of-use tariffs consistent with the directives contained herein; and it is

FURTHER ORDERED: That NSTAR Electric Company, Massachusetts Electric Company and Nantucket Electric Company, and Fitchburg Gas and Electric Light Company shall comply with all other orders and 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.

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Dan Lipschultz	Commissioner
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John A. Tuma	Commissioner

In the Matter of Xcel Energy's Petition for Approval of Electric Vehicle Pilot Programs

ISSUE DATE: July 17, 2019

DOCKET NO. E-002/M-18-643

ORDER APPROVING PILOTS WITH MODIFICATIONS, AUTHORIZING DEFERRED ACCOUNTING, AND SETTING REPORTING REQUIREMENTS

PROCEDURAL HISTORY

On October 12, 2018, Xcel Energy (Xcel) filed a petition requesting approval of two electric vehicle (EV) pilot programs, a Fleet EV Service Pilot and a Public Charging Pilot.

By February 1, 2019, the Commission received comments on the proposals from the following:

- City of Hastings
- SemaConnect, Inc
- Alliance of Automobile Manufacturers; the Association of Global Automakers; American Honda Motor Co., Inc.; Audi of America; Ford Motor Company; General Motors LLC; Hyundai Motor Company; Kia Motor Corporation; and Mitsubishi Motors R&D of America, jointly
- Alliance for Transportation Electrification
- Siemens
- Institute for Local Self-Reliance (ILSR)
- Greenlots
- the Department of Commerce, Division of Energy Resources (the Department)
- City of Minneapolis
- the Office of Attorney General, Residential Utilities and Antitrust Division (OAG)
- Citizens Utility Board of Minnesota (CUB)
- Tesla, Inc. (Tesla)
- Minnesota Sierra Club Supporters
- Department of Administration
- Xcel Large Industrials (XLI)

- Fresh Energy, Minnesota Center for Environmental Advocacy, Natural Resources Defense Council, the Sierra Club, and the Union of Concerned Scientists, jointly (Clean Energy Organizations)
- Pollution Control Agency (PCA) and Department of Transportation (MnDOT), jointly
- ChargePoint, Inc. (ChargePoint)
- approximately 64 public commenters

By February 15, 2019, the Commission received reply comments from the following:

- Greenlots
- Xcel
- the Department
- CUB
- the OAG
- Tesla
- the Clean Energy Organizations
- ChargePoint
- Pollution Control Agency
- XLI
- Siemens

On April 11, 2019, the Pilot proposals came before the Commission.

FINDINGS AND CONCLUSIONS

I. Introduction

In 2014, the Legislature adopted Minn. Stat. § 216B.1614, which establishes requirements for engaging public utilities in the electrification of the transportation sector. Under the statute, "each public utility selling electricity at retail must file with the commission a tariff that allows a customer to purchase electricity solely for the purpose of recharging an electric vehicle."[1] The tariff must be available to the residential class.[2] The statute also authorizes a cost-recovery mechanism to allow a utility to recover costs "reasonably necessary to comply" with the statute, as well as costs related to informing and educating "customers about the financial, energy conservation, and environmental benefits of electric vehicles."[3]

In response to this directive, Xcel filed, and subsequently received Commission approval of its EV charging tariff, which established the rates to be charged to residential customers, consistent

[1] Minn. Stat. § 216B.1614, subd. 2.

[2] *Id*. at subd. 2 (a) (3).

[3] *Id*. at subd. 2 (c) (2).

with the Legislature's directive.[4] Since the development and implementation of its tariff, Xcel has taken additional steps to further advance the Legislature's policy objective to increase EV usage and ownership, including its proposal of two EV pilot programs in this docket.

The first pilot is a Fleet EV Service Pilot, which would authorize Xcel's investment in installing and maintaining EV infrastructure for fleet operators (entities using groups of EVs). Xcel estimated that over 700 charging ports would be installed as part of this pilot program, and the Company expects to initially serve three customers: Metro Transit; the Department of Administration; and the City of Minneapolis.

The second pilot is a Public Charging Pilot, which would authorize Xcel's investment in installing and maintaining EV infrastructure for site hosts and developers of public fast-charging stations[5] along corridors within Xcel's service territory, as well as for a network of EV community mobility hubs.

II. The General EV Docket

A number of stakeholders cited the Commission's recent decisions in the General EV Docket[6] as a basis for requiring specific action of Xcel in this proceeding, including the filing of a cost-benefit analysis. The purpose of the General EV Order is to shape and guide utility proposals, considering the importance of transportation electrification and its potential benefits to ratepayers. Utilities are specifically encouraged to make filings aimed at expanding charging infrastructure, facilitating fleet vehicle electrification, and enhancing consumer awareness.

The General EV Order, which was issued more than one year after Xcel's initial filing in this case and on the cusp of the Commission's consideration of this petition, also established filing requirements for utilities. By June 30, 2019, Xcel, as well as Minnesota Power and Otter Tail Power, must file a Transportation Electrification Plan identifying EV-related initiatives the utility is contemplating and an analysis of how those initiatives would achieve EV-related objectives.

The Commission encouraged utilities to include in their individual proposals a cost-benefit analysis to examine long-term ratepayer and societal benefits, as well as potential costs, but the Commission did not adopt a particular cost-benefit methodology. Further, the Commission determined that cost recovery should be decided on a case-by-case basis considering various factors, such as the purpose, nature, magnitude, and potential benefits of the investments.

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[4] *In the Matter of Northern States Power Company d/b/a Xcel Energy's Petition for Approval of a Residential Electric Vehicle Charging Tariff*, Docket No. E-002/15-111, Order Approving Tariffs and Requiring Filings (June 22, 2015).

[5] Fast charging stations use direct current chargers that offer a faster charging timeline of typically between 10 and 30 minutes.

[6] *In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure*, Docket No. E-999/CI-17-879, Order Making Findings and Requiring Filings (February 1, 2019) (the General EV Order).

III. Xcel's Petition

In its petition in this case, Xcel stated that its overarching objective is to reduce greenhouse gas emissions and air pollution, while making efficient use of the electric grid and maintaining low bills for ratepayers. Xcel explained that use of pilot programs reasonably limits each program's scope and potential ratepayer impacts, and enables the Company to test, measure, and verify key assumptions before making the programs available on a larger scale.

Xcel developed its pilot proposals following a stakeholder process involving various non-profit organizations, state agencies, corporations, and utility companies. Great Plains Institute helped facilitate five workshops, which were aimed at understanding transportation electrification; identifying proposed solutions; and developing metrics to evaluate pilot success.

The petition includes each pilot program's objectives and budgets, as well as the Company's rate design proposal, proposed annual reporting metrics, and deferred accounting request. Further, Xcel stated that in developing the proposed pilots, the Company also took into consideration the comments filed in the EV General Docket, the experience of other utilities around the country, and the input of customers and stakeholders.

Ultimately, the majority of parties supported Xcel's petition; several offered recommended modifications to improve the pilot programs. The OAG and XLI recommended that the Commission deny the petition.

A. Fleet Electric Vehicle Service Pilot

The EV Fleet Service pilot would be available to non-residential customers operating fleets of light-, medium-, or heavy-duty EVs. Initially, Xcel expects three entities – Metro Transit; the Department of Administration; and the City of Minneapolis – to participate.

Xcel stated that the Company proposed this pilot because the fleet market has a diversity of vehicles; is focused on economic value; is motivated to reduce greenhouse gas emissions and improve air quality; and has the volume of vehicles to make larger strides toward transportation electrification. Xcel stated that although the Company has existing residential EV service offerings, adding the Fleet EV Service pilot would, as EV expansion evolves, deepen the understanding of EV system benefits and how to best socialize costs. Under this pilot, Xcel would own install, own, and maintain infrastructure, and if requested by a participant, would also install, own, and maintain charging equipment.

This pilot's proposed budget is $14.4 million over a three-year term. Details of the proposed budget are shown in the table below.

TABLE 1			
Estimated Fleet EV Service Pilot Budget			
Cost Item	Capital	O&M	Total
EV Service Connection	$1,864,000	$30,000	$1,894,000
EV Supply Infrastructure and Charging Equipment	$9,396,000	$457,000	$9,853,000
Installation Management (includes construction management, design engineering, and legal agreement review)	-	$575,000	$575,000
Advisory Services and Outreach, including Analytics Services	-	$1,163,000	$1,163,000
Program Management	-	$735,000	$735,000
IT	-	$175,000	$175,000
TOTAL	**$11,260,000**	**$3,135,000**	**$14,395,000**

B. Public Charging Pilot

Under Xcel's proposed Public Charging pilot, the Company would install EV infrastructure for site hosts and developers of public charging stations along corridors and at community mobility hubs. Under this pilot, Xcel would own install, own, and maintain infrastructure but would not own or maintain any charging equipment. Xcel stated that public charging is a critical element of expanding the EV market because it supports longer distance driving and makes charging available to those who do not charge EVs at home.

This pilot's offerings are twofold. The first is the development of community mobility hubs; Xcel has partnered with the Cities of St. Paul and Minneapolis for the development of community mobility hubs, with HOURCAR providing a car-sharing service at charging locations in the area. These hubs would make charging available to the public and to transportation network companies, such as Lyft and Uber.

The second offering of this pilot is aimed at, but not limited to, applicants seeking funds from Minnesota's Diesel Replacement Program, which is funded by the Volkswagen Environmental Mitigation Settlement and administered by the PCA. These funds will be used to develop fast-charging stations at corridors within Xcel's service territory, with the goal of expanding the EV market by broadening access to charging stations, which would in turn alleviate impediments to long-range driving.

Under this pilot, Xcel expects to facilitate installation of approximately 350 publicly accessible charging ports.

This pilot's proposed budget is $9.2 million over a three-year term. Details of the proposed budget are shown in the table below.

TABLE 2			
Estimated Public Charging Pilot Budget			
Cost Item	Capital	O&M	Total
EV Service Connection	$2,019,000	$29,000	$2,048,000
EV Supply Infrastructure	$5,781,000	$87,000	$5,868,000
Installation Management (includes construction management, design engineering, and legal agreement review)	$0	$575,000	$575,000
Marketing and Outreach	$0	$60,000	$60,000
Program Management	$0	$555,000	$555,000
IT	$0	$95,000	$95,000
TOTAL	**$7,800,000**	**$1,401,000**	**$9,201,000**

C. Pilot Similarities

Although the two pilots are fundamentally different, they do share certain characteristics.

First, Xcel proposed to waive its tariff provisions governing Contributions In Aid of Construction (CIAC).[7] Generally, CIAC governs the cost of service connection installation, of which customers pay a portion. CIAC provisions apply to the general provision of service, for which costs and revenues are known.[8] In this case, the CIAC waiver would apply to make-ready infrastructure.[9] The Company stated that it does not have accurate estimates of costs and revenues related to EV charging and usage and is therefore unable to determine an accurate customer contribution amount for make-ready infrastructure under the pilots, which are intended to study this and other issues related to EV expansion.

Second, Xcel proposed to treat its capital investments in make-ready equipment as utility plant cost items in its Federal Energy Regulatory Commission (FERC) distribution plant accounts (FERC account 182.3). FERC authorizes a utility to include in that account the cost of installed equipment on the customer's side of the meter when the utility incurs such cost and retains title to, and is responsible for, the maintenance and replacement of such property. The proposed

[7] Xcel Energy Minnesota Electric Rate Book, Section 6, Sheets 22 et. seq.

[8] The CIAC formula is used to determine the customer contribution amount, which is not collected by the utility through revenues.

[9] Xcel defines "make-ready" infrastructure to include: a dedicated service connection for EV charging, along with necessary transformer upgrades, service conductors, and meters. It also includes EV supply infrastructure, such as new service panels, conduits, and wiring up to the charger. In this order, the Commission uses the term with the meaning given by Xcel. Under the Fleet EV Service pilot, customers may request that Xcel provide, install, and maintain chargers, and Xcel has accordingly proposed to recover these costs through either a monthly EV Charger Service charge, or, at the election of the customer, an up-front payment.

classification would allow Xcel to include the investments in rate base in its next general rate case filing.[10]

Third, customers under either pilot would be charged for electric usage according to Xcel's existing general service time-of-day (TOD) rates, which are based on a 12-hour on-peak period between 9:00 a.m. and 9:00 p.m. (also known as a 2:1 energy rate differential ratio). Under the Public Charging Pilot, customers, i.e., site hosts, would not, however, required to pass the TOD rates onto drivers who use the EV charging stations. In addition to the TOD rates, customers in both pilots would be charged a minimum monthly bill based on the number of ports installed.

Fourth, Xcel's petition requests deferred accounting treatment of costs related to Operations and Maintenance (O&M) expenses and depreciation expense related to capital investments in the make-ready infrastructure.

IV. Pilot Approval

There is widespread support for Xcel's petition from parties and from members of the public who commented. The OAG and XLI opposed the petition. The Department and CUB took no position on whether the pilots should be approved but made recommendations on specific aspects of the proposals, which are discussed separately below.

A. Comments in Support of the Proposed Pilots

1. The Clean Energy Organizations

The Clean Energy Organizations recommended Commission approval of both pilot programs, stating that transportation electrification would significantly reduce greenhouse gas emissions and help achieve state targets for emissions reductions (citing a report by the Pollution Control Agency and Department of Commerce that states that transportation is the largest source of greenhouse gas emissions in Minnesota).

They also maintained that EVs would have enormous health benefits by reducing pollution-related health issues (citing Department of Health estimates that particulate matter and ozone pollution contribute to 2,000 deaths annually in the Twin Cities metropolitan area). Both pilots, they stated, would advance these goals while reasonably protecting ratepayers, as the proposals are modest in size with limited budgets.

Further, they stated that the proposed pilots promote effective grid utilization by incentivizing charging during off-peak periods. They also stated that any opposition to the budgets is unfounded, and that the budgets, if anything, are too small to sufficiently bolster EV expansion.

In particular, they highlighted the need for public support and utility intervention in the development of public charging stations, which are not economically viable without decisive action to approve EV programs, such as Xcel's proposed Public Charging pilot. They asserted that expanding the EV charging network is critical to making EVs a favored alternative to gasoline- and diesel-fueled vehicles.

[10] Xcel's proposed classification would include charging equipment provided by Xcel under the Fleet EV Service pilot, although pilot participants would pay their portion of those costs.

They were equally supportive of the proposed Fleet EV pilot program, stating that a fleet EV transit system, such as Metro Transit, will increase the visibility of EVs, enticing riders to purchase EVs for individual use as well. Further, transit buses travel an average of 34,000 miles per year, compared to 11,000 for light-duty vehicles, resulting in more substantial environmental benefits. They noted that any unanticipated complications under either pilot would be a valuable learning tool as EV expansion continues.

2. EV Industry Proponents

The Alliance of Automobile Manufacturers, Tesla, Greenlots, ChargePoint, SemaConnect, Siemens, and the Alliance for Transportation Electrification are variously involved in the manufacturing of EVs or the development of related equipment, products, and services, and they voiced overwhelming support for Xcel's proposed pilot programs.

These stakeholders endorsed the pilot programs' objectives outlined in Xcel's petition and recommended that the Commission approve the proposals. They emphasized the role of utilities in expanding the EV market by developing EV programs that increase grid efficiency and provide ratepayer benefits. They stated that EV load is generally flexible (meaning that charging can occur at optimal times because batteries store the electricity rather than immediately use it). Moreover, adding EV load to the system has the potential to reduce system-wide energy costs if coupled with effective rate structures. They also asserted that because the proposals will explore the central role of utilities in deployment of EV infrastructure at scale, the outcomes will provide valuable information on how utility infrastructure investments affect the EV market and how to increase the effectiveness of the utility's role.

3. Pilot Participants

The Department of Administration, the City of Minneapolis, and Metro Transit, prospective participants in the Fleet EV Service pilot, supported Commission approval of the petition. They stated that the pilot programs would create a sustainable path toward lowering electricity costs for ratepayers, meeting climate goals, and improving health impacts associated with transportation.

4. PCA and MnDOT

The PCA and MnDOT recommended Commission approval of the pilot programs, stating that utility investment in advancing electric vehicles is critical to achieving the agencies' goals of developing a multimodal transportation system that maximizes the health of people, the environment, and the state economy. They also stated that utility infrastructure investments would likely help stretch the VW funding to increase the number of public charging stations.

B. Comments in Opposition to the Proposed Pilots

1. The OAG

The OAG recommended that the Commission deny the petition and direct Xcel to refile its proposed pilots at the time of its June 2019 Transportation Electrification Plan.[11] The OAG

[11] The Plan must be filed by June 30, as directed by the Commission in the EV General Docket.

recommended several changes to the current proposal, including a rate design with more effective price signals. The OAG also recommended that a modified proposal should remove the request to waive CIAC provisions, remove the deferred accounting request, and remove the proposal for utility ownership of make-ready infrastructure beyond the meter. The OAG stated that these changes would shift the cost risk of the pilots away from ratepayers.

The OAG disputed that the proposed budgets are acceptable, stating that the proposed capital budget of $19.1 million for both pilots is unreasonably high due to the Company's CIAC waiver request.

2. XLI

XLI recommended that the Commission deny the petition because the pilot proposals would require ratepayers to subsidize investments that are more appropriately made by private businesses, and because the proposals exceed the Legislature's policy objectives. XLI argued that the structure of the pilot proposals requires ratepayer funding with little return on the investment.

XLI also claimed that Xcel has not demonstrated that the proposed pilots would produce environmental benefits as intended and that investing ratepayer dollars to generate increases in EVs is speculative. XLI recommended that Xcel take steps to support transportation electrification through customer education and advanced rate design to address increases in demand caused by more EVs.

C. Commission Action

The Commission concurs with parties supporting Xcel's petition. The two proposed pilots advance the legislative goal of increasing transportation electrification in a manner that reasonably limits potential rate impacts, while presenting an opportunity for ratepayers and the public to benefit. The Commission is not persuaded that requiring Xcel to file a new petition would do more than delay implementation of these pilots.

Xcel engaged in a meaningful stakeholder process in which a wide range of input was provided, and the Company then took that input into serious consideration when developing its proposals. As a result, the proposals are limited in duration – three years each, and are limited in budget size as needed to achieve the projected increases in fleet EVs and public charging. Together, both pilots are estimated to facilitate the installation of approximately 1,000 charging ports, of which approximately 350 will be publicly accessible. These parameters reasonably balance the commitment to EV expansion and the ratepayer cost of those efforts. Furthermore, any future cost recovery-related filings will be separately scrutinized and considered by the Commission. Additionally, Xcel intends to take the following steps if the pilots are approved: host semi-annual advisory committee meetings with a facilitator; provide data on key metrics in an annual filing; and engage third-party evaluators to conduct an interim and final evaluation. These steps provide helpful continuity between the implementation and subsequent review of the programs.

Further, Xcel's proposal is for two limited-duration pilot programs. As discussed in greater detail below, the Commission will require Xcel to file reports on pilot performance, which the Commission will review before making a decision on whether to continue or expand the programs.

For all these reasons, the Commission will approve the proposed pilots, with modifications as discussed in further detail below.

V. Key Pilot Features

Parties differed on key aspects of the pilot proposals, including the following: wavier of CIAC provisions; the classification of make-ready infrastructure costs; and the pilots' TOD rate structure. These issues are addressed below.

A. Contribution in Aid of Construction

Xcel's proposal included a request to waive its applicable CIAC provisions for both pilots because the Company stated that it could not determine the expected usage of participating customers and corresponding revenue needed to accurately calculate the amount of the customer contribution. Without the waiver, Xcel stated that pilot participants would be required to finance the make-ready infrastructure costs independently, potentially upending pilot participation.

1. Positions of the Parties

The Department recommended that the CIAC waiver request be granted for certain infrastructure. Other parties either supported or opposed the CIAC wavier as proposed.

a. The Department

The Department appeared to take the nuanced approach that infrastructure that is not ordinarily owned by the utility is not subject to the Company's CIAC provisions and therefore no waiver is required for the installation costs of that infrastructure. The Department did, however, support waiver of CIAC provisions for infrastructure that *is* ordinarily utility-owned.

The Department reasoned that the line of demarcation between utility– and customer–owned infrastructure is the point of service connection and that under the pilot, Xcel's proposal to include make-ready infrastructure in that designation is beyond what is traditionally included in determining cost allocation. The Department stated that although the CIAC provisions do not apply to equipment beyond the utility's point of service connection, the waiver request should otherwise be approved.

b. Clean Energy Organizations, ChargePoint, Greenlots, Tesla, and the Alliance for Transportation Electrification

The Clean Energy Organizations, ChargePoint, Greenlots, Tesla, and the Alliance for Transportation Electrification all voiced support for Xcel's proposal to waive the applicable CIAC provisions, asserting that under these circumstances, the request is warranted. They stated that the CIAC formula is not designed with EV usage in mind, and that the smaller volumetric load per EV is therefore not reflected in the calculation.

They also stated that a CIAC waiver would be, in effect, moderated by the limited duration and budget of each pilot, thereby minimizing the impact on ratepayers. Further, they contended that reducing up-front costs through utility investments is essential to fulfilling program objectives and encouraging participation.

c. The OAG, CUB, and XLI

The OAG, CUB, and XLI opposed waiver of the CIAC provisions, stating that granting the request would weaken ratepayer protections by over-subsidizing participating customers. They claimed that waiving the provision is not offset by clear and obvious benefits to ratepayers through system improvements.

They described the pilot investments as large-scale with no clear estimation of expected revenues. They argued in favor of applying traditional cost causation principles in which customers incurring upfront infrastructure costs pay the portion of those costs that the utility would not otherwise recover through its revenues. XLI further contended that a utility's ownership of EV charging infrastructure behind the meter is not within the scope of utility service because it is different from what is ordinarily associated with providing electric service to customers. XLI claimed that Xcel's proposal is an expansion of the utility's role beyond what the Legislature either authorized or envisioned.

d. Xcel

In response to issues raised, Xcel stated that based on its initial observations, potential pilot participants are cost-sensitive and that the Company's proposed investments are a factor affecting participation levels. Xcel also emphasized that ratepayers are expected to benefit from the pilots, both through increased revenues, as well as environmental benefits, and that the data gleaned from the pilots will inform future programs and proposals.

Contrary to claims that the provision of service using make-ready infrastructure is outside the range of what a utility ordinarily provides, Xcel stated that the test for determining whether equipment qualifies as utility distribution plant, i.e., utility equipment, is not its location in relation to the meter, but whether it is "used and useful in rendering service to the public."[12] Xcel also asserted that some degree of departure from ordinary practices is warranted as a means of furthering the goals of electrification of the transportation sector.

2. Commission Action

The Commission concurs with parties who support Xcel's request to waive the CIAC provisions. While the issues raised by those opposing the waiver are relevant considerations, it is important to view the request within the context of each pilot, its duration, and its budget.

The limited terms of the pilots and their reasonable budgets ultimately limit the impact to ratepayers. In the event pilot budgets are reached prior to the end of the three-year term, Xcel will not accept additional participants; the Company has committed to staying within the budgets proposed. Further, Xcel has made a persuasive argument that the customer's CIAC contribution cannot be accurately calculated without knowledge of EV charging and revenues.

The Commission recognizes that the existing CIAC policies were developed to protect ratepayers from excessive and unreasonable costs. But to foster growth of EVs for the purpose of transportation electrification requires a forward-thinking approach. Utilities are at the forefront of this effort. Although the pilots could ultimately lead to an understanding that advancing EVs

[12] Minn. Stat. § 216B.16, subd. 6.

requires no refinement of the traditional cost-causation approach, such an outcome is merely one possibility and is an issue the pilots are intended to study. Facilitating expansion of EVs necessarily requires the installation of equipment not typically installed. This is a new arena, and as Xcel aptly pointed out, it warrants a limited departure from ordinary practices.

Furthermore, as pilots, they are intended to be instructive on the propriety of cost allocation and cost recovery for this infrastructure, and they will provide data that will aid subsequent evaluation of the pilots' costs and effectiveness.

For all these reasons, the Commission will authorize a waiver of CIAC service policy provisions, and other customer contributions, for the three-year term of the pilots. The Commission will also direct Xcel to use its current CIAC formula to determine the amount of subsidy a participant would receive and then track and report these costs for each pilot, including revenues.

B. Classification of Make-Ready Infrastructure Costs

Xcel proposed to treat its capital investments in make-ready infrastructure for both pilots as cost items in its FERC distribution plant accounts. This accounting treatment would enable Xcel to include the amounts in base rates in the Company's next general rate case.

1. Positions of the Parties

Parties differed on this issue for reasons similar to those discussed above.

a. The Department

The Department recommended that if the Commission authorizes classification of equipment that Xcel does not ordinarily own as utility distribution plant, the Commission should limit pilot participation to public entities.

b. The Alliance for Transportation Electrification, Greenlots, Tesla, ChargePoint, PCA and MnDOT,

These parties supported Xcel's proposal, stating that the pilots are modest in scope and that the proposal would foster regulatory certainty and help spur economic innovation in the transportation sector.

They also stated that utility ownership of EV charging infrastructure is likely necessary to make financing possible for pilot participants, particularly fleet participants and that the proposed structure would accelerate EV market growth by alleviating financial barriers to EV expansion. Without utility ownership of make-ready infrastructure, they asserted that the likely pool of eligible participants would be scaled back. They also asserted that utility infrastructure investments would likely help stretch VW funding to increase the number of public charging stations.

c. The OAG and XLI

The OAG and XLI opposed treating make-ready infrastructure as utility distribution plant, stating that the existing utility-customer demarcation point balances the system benefits of each new customer with that customer's cost responsibility for new service.

They also stated that because Xcel intends to contract with third-parties to conduct engineering and maintenance of that equipment, the Company is outside its area of expertise. Instead, they maintained that a competitive EV market ~~that supports a competitive market~~ for the provision of such services is a better option. Further, they argued that Xcel should rely on revenues from pilot participants to recover its make-ready infrastructure costs, rather than impose those costs on ratepayers.

XLI also argued that allowing Xcel to own infrastructure beyond the meter would be an expansion of the utility's traditional role, and that it would be more reasonable for Xcel to conduct such business through an unregulated affiliate.

d. Xcel

Xcel stated that the make-ready infrastructure, including service panels, conduit, and wiring, is not likely to change over time and is not different in kind from the infrastructure installed up to the charging stubs. The Company stated that there is no basis for imposing a location-based test for determining whether the equipment is utility equipment, particularly in light of the fact that there is no law prohibiting such ownership and that the applicable legal standard is whether the equipment is used and useful in rendering service to the public.

2. Commission Action

The Commission will approve Xcel's proposed classification of its make-ready infrastructure as utility distribution plant in this case. One key purpose of the pilots is to investigate the extent to which socializing the costs of this EV-related infrastructure will encourage EV adoption, and to measure the benefit that increased EV adoption provides to ratepayers. This purpose would be unattainable if Xcel were not allowed to classify these infrastructure investments as utility distribution plant. Therefore, Xcel's proposal to install, maintain, and own infrastructure is an essential and necessary part of these pilots. As a result, it is therefore reasonable under these circumstance to authorize Xcel to classify its make-ready infrastructure as requested. More specifically, these proposed infrastructure investments in the context of these pilots will help the Commission and stakeholders evaluate the extent to which these investments will benefit the public.

The Commission will therefore approve Xcel's request to classify its make-ready EV infrastructure investments as utility distribution plant for both pilots, and will approve Xcel's request to own charging equipment provided under the bundled service option in the Fleet EV Service Pilot. This classification is limited to EV infrastructure investments and charging equipment installed during the pilots.

The Commission is also acutely aware, however, of the importance of approving programs that are as sound as possible and do as much as possible to advance the broad public interest. While the Commission does not adopt the Department's specific recommendation, the Commission will direct Xcel to consider geographic and customer diversity in its selection of additional participants in the Fleet EV Service pilot. Of the additional participants, one must be a public entity with a primary location outside Ramsey and Hennepin Counties. Further, no more than one of the additional participants may be a private or non-profit entity.

C. The TOD Rate Structure

Xcel's petition applies a TOD rate structure to participants in both pilots that includes an off-peak period between 9:00 p.m. and 9:00 a.m. Customers would also incur a demand charge applied to the highest 15-minute peak kilowatt (kW) load during a month. Total demand charges are limited according to the kWh energy used during the month, using a calculation that divides the amount of kilowatt hours (kWh) energy used during the month by 100 hours.

Under the Public Charging pilot, public charging stations would be billed according to this rate structure, but Xcel's proposal does not condition their participation in the pilot on their agreement to pass the TOD rates onto to EV customers using the charging stations.

The Clean Energy Organizations recommended two related pilot modifications. First, they recommended that the Commission direct Xcel to require that charging stations in the Public Charging pilot pass the TOD rates onto their customers, EV drivers. Second, in response to disagreement over Xcel's proposed TOD rate structure, they recommended that the Commission initiate a separate proceeding to examine rate structures of Xcel's Commercial and Industrial customer class to better understand whether permanent changes to the existing rate structure are warranted. These two issues are discussed below.

1. Public Charging Stations

a. Positions of the Parties

i. Clean Energy Organizations

In recommending that public charging stations be required to pass the TOD rates through to their customers, the Clean Energy Organizations emphasized the need to encourage efficient grid management by incentivizing drivers to charge their EVs during off-peak periods. This, they said, consequently maximizes cost savings. They stated that unless drivers are incentivized by price, they are much more likely to charge their EVs when it is convenient, rather than when it is most effective in terms of grid utilization. They recommended that Xcel make the TOD rate the default arrangement with public charging stations.

ii. ChargePoint and Tesla

ChargePoint and Tesla adamantly recommended that site hosts retain the flexibility to set pricing that reflects cost components other than the energy cost. They said that such flexibility spurs market competition and ensures that charging stations are able to recover their costs, including the cost of operating a charging station, as well as the fixed costs of charging equipment. This, in turn, helps develop a more innovative and cost-effective market.

They also stated that the recommendation of the Clean Energy Organizations is problematic for several other reasons. They maintained that pricing will vary based on incentives established by charging stations to entice customers, depending on the station's location and business hours, among other factors. Charging behavior also depends, they claimed, on the needs of individual drivers and their accessibility to charging stations commercially or at home. They further stated that pricing restrictions do not achieve better grid utilization if, for example, drivers are not incentivized to leave when the charge is finished. In such a case, charging availability is reduced, preventing other drivers from using the service.

They also disputed that there is a clearly demonstrated effectiveness of price signals, stating that there is insufficient data available to conclusively show that driving behavior is affected by pricing alone. Charging station operators, they asserted, are sophisticated market participants and are in the best position to know how to set prices.

iii. CUB

CUB made the general comment that it is reasonable for the Commission to establish certain contingencies that would be set forth in Xcel's agreements with pilot participants who benefit from ratepayer funds. Those contingencies could address important program features, such as rate structures that are likely to affect the successful use of ratepayer funds. CUB stated that the advantages of price signals are lost if not passed onto drivers.

iv. Xcel

Xcel did not propose to require charging stations to charge their customers TOD rates, stating that maintaining pricing flexibility is important. Xcel also concurred, however, on the importance of using TOD rates, acknowledging that charging during off-peak hours increases sales while reducing the need for additional resources to support peak demand. To address this issue, Xcel proposed to include a provision in its agreements with public charging stations suggesting that TOD rates be passed through to drivers. Xcel also recommended requiring public charging stations to provide data on their rates and fees to enable further examination of this issue. Xcel would include this data in its annual report on the pilot.

b. Commission Action

The Commission concurs with parties on the importance of minimizing ratepayer costs while incentivizing participation in these programs that were developed with the understanding that effective grid utilization will help keep costs down in the near-term and that reducing greenhouse gas emissions will produce both environmental and economic benefits in the long-term. With this in mind, protecting ratepayer interests requires a modified approach to strongly encourage charging stations to effectively incentivize their customers in a way that aligns with the pilot's objectives.

The Commission will therefore modify the Public Charging pilot by directing Xcel to condition participation on agreement by site hosts to have a default time-differentiated rate structure that reflects the on-peak and off-peak time periods of Xcel's pilot tariff and an energy rate differential ratio of at least 2:1. Site hosts may opt out of the default arrangement at their discretion to set pricing that reflects other considerations or needs, provided that such prices are reported to the utility for purposes of Xcel's annual reporting. In its next rate case, Xcel must develop and propose a revised general service TOD rate that is more reflective of hourly system costs with a price signal designed to reduce peak demand. These requirements are consistent with the Commission's directive in the General EV Docket.

2. TOD Rate Design

a. Positions of the Parties

Some parties recommended that the Commission require Xcel to implement a more sophisticated rate design in lieu of the proposed off-peak period of between 9:00 p.m. and 9:00 a.m., which is applicable to participants in both pilots.

The Department had reservations about the 2:1 rate design, stating that without effective price signals to induce charging during off-peak periods, subsidization of EV infrastructure is not fully compatible with the public interest. The Department emphasized the importance of establishing effective price signals at the outset of these pilots to facilitate the success in meeting pilot objectives.

The OAG opposed Xcel's proposed TOD rate structure, arguing that a better rate design would send more accurate price signals by setting rates using an on-peak, a mid-peak, and an-off peak period, similar to Xcel's newly established residential TOD Rate Design Pilot program, which is applicable to residential general service customers, unless those customers opt out of the program.[13]

CUB emphasized that support for transportation electrification is predicated on related system benefits and corresponding savings. CUB echoed the comments of the Department and OAG, stating that a pricing system with critical peak pricing, super off-peak pricing, or real-time pricing would be more effective.

Xcel maintained that its proposed rate structure is reasonable, stating that there is no cost basis to apply the residential TOD rate design to a class of customers with distinct load characteristics. The commercial TOD rates include a demand charge, whereas the residential TOD rates do not. This is an important distinction that encourages efficient use of resources. Further, Xcel stated that the impact of the demand charge is balanced by the provision that limits the billed quantity of peak demand to the amount of kWh energy used in a month, divided by 100 hours.

b. Commission Action

Notably, Xcel's TOD rate proposal was designed with commercial customers in mind. Requiring the Company to implement a three-tiered rate structure similar to what the Commission approved in Xcel's residential TOD Rate Design Pilot program would be premature. That pilot program is ongoing and will study that rate structure's effectiveness within two communities in the Twin Cities metropolitan area.

Recognizing, however, that the Company's proposed rate design with a twelve-hour on- and off-peak period, as applied to commercial customers, is reasonable but is perhaps not optimal for public EV charging, the Commission will require Xcel to file, within six months, a commercial EV charging tariff that is more reflective of hourly system costs with price signals to reduce peak demand. More generally, in its next rate case, Xcel must develop and propose a revised general

[13] *In the Matter of Xcel's Residential Time of Use Rate Design Pilot Program*, Docket No. E-002/M-17-775, Order Approving Pilot Program, Setting Reporting Requirements, and Denying Certification Request (August 7, 2018).

service TOD rate that is more reflective of hourly system costs with price signals designed to reduce peak demand. These requirements are consistent with the Commission's directive in the General EV Docket.

VI. Smart Charging Capabilities of Charging Equipment

A. The Issue

Xcel has committed to using smart charging equipment for chargers the Company would install at the request of participants in the Fleet EV Service pilot. Xcel's petition does not, however, require all pilot participants to install smart-charging equipment with their chargers. A number of parties recommended that the Commission establish such a requirement.

Smart charging uses technology that is capable of sending data to Xcel to enable more effective load management. In some form, Xcel would have remote capabilities to incentivize charging during off-peak hours, to reduce the coincidence between EV charging and system peak, and to avoid charging during emergencies or other high-peak times.

The Department, Greenlots, ChargePoint, the Clean Energy Organizations, Seimens, and the City of Minneapolis supported requiring smart charging capabilities of all pilot participants. They stated that requiring smart charging capabilities is fundamentally reasonable because even if the Company does not currently have plans to use the technology, it is important to have the capability for future use by ensuring that participants install it at the outset. This, in turn, helps the programs achieve the potential benefits of EVs.

Tesla opposed requiring participants to install smart charging capabilities, stating that it is not clear that the technology will be put to use and that imposing unnecessary requirements does not facilitate pilot participation and is inefficient. Tesla also claimed that such requirements can have unintended consequences to market participants by creating an advantage for some, such as charging stations with certain technology. Instead, Tesla recommended that the issue, along with other standards for interoperability, be evaluated as part of the pilot programs.

Xcel stated that while the Company did not propose a smart-charging requirement as recommended by some parties herein, the Company did not object to doing so, noting that the Company intends to install chargers with such capabilities in its Fleet EV Service pilot to any participants who request that Xcel provide the chargers.

B. Commission Action

The Commission concurs on the reasonableness of requiring pilot participants to install chargers with smart charging capabilities. Remote load management and maintenance is aimed at achieving efficient grid utilization, ultimately benefitting ratepayers. The Commission will therefore require that all chargers installed as part of the pilots have smart charging capabilities.

VII. Deferred Accounting Request

Xcel's petition included a request for deferred accounting of O&M expenses and depreciation expenses related to capital investments in the pilots. Xcel stated that it intends to include these

costs for recovery in the Company's next general rate case and requested authorization to track the costs in the EV tracker account established in a separate docket.[14]

A. Introduction

Deferred accounting is a regulatory tool used primarily to hold utilities harmless when they incur out-of-test-year expenses that, because they are unforeseen, unusual, and large enough to have a significant impact on the utility's financial condition, should be eligible for possible rate recovery in the next rate case. Deferred accounting has also been permitted when utilities have incurred sizeable expenses to meet important public policy mandates.

Under Minn. R. 7825.0300, subp. 4, the Commission retains the authority to approve a public utility's request for an exception to a provision of the applicable uniform system of accounts for good cause shown. Xcel has petitioned the Commission for an exception to the standard accounting treatment of certain costs that would otherwise be ineligible for cost recovery because they are incurred between rate cases.

B. Positions of the Parties

Parties disagreed about Xcel's request for deferred accounting. Their positions are discussed below.

1. Comments in Support of the Request

The Alliance for Transportation Electrification supported Xcel's request, stating that deferred accounting provides necessary regulatory certainty in an emerging technology area. Because these proposals will further state goals for emissions reductions and will spur innovation in the transportation sector, the Alliance recommended that the Commission approve the request.

ChargePoint emphasized the strong public policy mandate that the proposals are aimed at fulfilling; the pilots reflect emerging trends and opportunities in electrification of the transportation sector. ChargePoint also stated that the costs were unforeseen at the time of the Company's last general rate case and that it was reasonable for Xcel to pursue the proposals, in spite of the lack of assurance that the associated costs would be eligible for recovery. As a result, ChargePoint recommended that the Commission grant Xcel's request.

2. Comments in Opposition to the Request

The Department, the OAG, and XLI opposed the Company's deferred accounting request.

The Department claimed that costs for equipment beyond the service connection are not suitable for recovery because doing so would potentially stifle competition by giving Xcel an upper hand in the marketplace. The Department also emphasized that Xcel would have the opportunity to recover costs for capital investments in the Company's next rate case after demonstrating that the investments are used and useful in rendering service to customers. Further, the Department stated that these pilots are expected to increase volumetric sales, negating the need for cost recovery and that the Company bears the responsibility to manage its costs between rate cases.

[14] Xcel's tracker account was established in Docket No. E-002/M-15-111.

The OAG argued that the costs for which Xcel seeks deferred accounting are not significantly sizeable, as they are approximately one-quarter of one percent of the Company's total revenue for the time period of the pilot programs. The OAG also stated that the costs are not associated with important policy mandates because the Commission has not mandated the pilot programs. Finally, the OAG stated that the costs are not unforeseen, unusual, or extraordinary because they relate to the addition of new customers and new load, which are to be expected.

XLI echoed these comments, stating that there is no justification for deferred accounting. XLI stated that granting the request would allow Xcel to avoid scrutiny of its expenditures and that the Company could have planned for such investments in its last rate case. XLI dismissed Xcel's contention that without deferred accounting the Company would not likely pursue such initiatives, claiming that private businesses would be more likely to invest in developing EV-related infrastructure in a competitive environment that excluded a regulated public utility.

3. Xcel's Response

Xcel took issue with characterizations that its request is over-reaching. Xcel stated that deferred accounting is a critical tool affecting the Company's decisions to take on innovative projects between rate cases. Xcel also stated that the Commission has granted deferred accounting requests when important public policy issues are involved.

C. Commission Action

After careful consideration of the record, the Commission will approve Xcel's request for deferred accounting under Minn. R. 7825.0300, subp. 4 for the following reasons.

First, investments for which deferred accounting is sought in this case are clearly intended to serve important public policy objectives. Both the Legislature and the Commission have indicated that transportation electrification is an important public policy goal. The Legislature highlighted this objective by enacting Minn. Stat. § 216B.1614. The Commission has further encouraged utilities in this effort by applying its expertise to direct them to file such proposals, and Xcel's proposed pilots move deliberately and promptly in this direction. The record demonstrates that these two pilots are targeted to explore the potential public benefits of EV adoption and have the potential to be transformative. Supporting the growth of two markets – one for EV public charging stations and the other for Fleet EVs – has the potential to broadly expand access to environmentally beneficial transportation, including to lower-income communities through use of public transit EVs. The Commission's decisions to limit portions of the Fleet EV Pilot to public entities further targets the potential public benefits of the program.

Furthermore, these two pilots will be the first window into evaluating the utility's growing role in transportation electrification—through infrastructure investments in public charging and Fleet EVs and the potential ratepayer benefits derived from that role—the results of which will ultimately guide the Commission's future decisions on other EV programs. Ultimately, they are targeted to produce maximum public and ratepayer benefit, while having a limited rate impact.

Second, the request for deferred accounting in this instance is confined to two proposed pilot programs, both of which are limited in scope and duration. As a result, the potential ratepayer impact of deferred accounting here is constrained by the fact the costs are associated with pilots and not more typical utility investments.

Third, the Commission will further limit the potential cost to ratepayers by restricting the timeframe during which these which these costs will qualify for deferred accounting. Specifically, deferred accounting will apply to costs incurred only after the date of this order up to January 1, 2020, which would be the beginning of the test year for Xcel's next anticipated rate case filing. This protects ratepayers by limiting the total amount of expenses eligible for cost recovery.

Finally and importantly, allowing some costs to qualify for deferred accounting does not guarantee the recovery of those costs. To the contrary, any subsequent request to recover those costs will be separately scrutinized and considered by the Commission in the Company's next general rate case. They will not be recoverable unless shown by the utility to be reasonable and prudent.

For these reasons, the Commission will grant Xcel's request for deferred accounting without requiring the Company to demonstrate that the costs are unforeseen, unusual, and significant in size. This decision is based upon the specific facts of this case, and the Commission will continue to evaluate deferred accounting requests on their own merits in the future.

The Commission will therefore authorize Xcel to defer O&M and depreciation pilot expenses, associated with capital assets placed in service for each pilot, incurred during the period between the date of this order and January 1, 2020, the expected onset of the test year in Xcel's anticipated rate case.

Further, the Commission recognizes that there is a particular need to develop a more comprehensive strategy for encouraging utilities to innovate within the regulatory structure. For that reason, the Commission will require Xcel to address in its next rate case filing how it intends to handle and budget for future pilots prior to its following rate case filing.

VIII. Reporting Requirements

Numerous parties recommended additional reporting requirements beyond those proposed by Xcel. Xcel agreed to include most of them, with the exception of three items.

First, CUB requested that Xcel report on whether third-party development and delivery of charging services provides the highest level of customer benefit compared to other possible delivery methods, such as public, or utility ownership. Xcel stated that because the Company is not proposing ownership of charging stations, the data would not be available.

Second, ILSR recommended that Xcel collect and report data on the cost reductions of participants with Fleet EVs. Xcel stated that the Company is disinclined to ask participants to report on their costs and corresponding costs savings.

Third, ChargePoint recommended that Xcel report data on avoided costs as a result of using smart-charging equipment. Xcel stated that the pilots are not focused on the effectiveness of smart-charging technology and that the request goes beyond the scope of these pilots.

The Commission will incorporate parties' recommended reporting requirements, with the exception of the three recommended items listed above. The Commission concurs with Xcel's reasoning for not including them.

The Commission will establish reporting requirements, as set forth in the ordering paragraphs below. The information required must be filed on an annual basis throughout the pilot as part of Xcel's Annual EV Report in Docket 15-111, with a copy filed in this docket.

IX. Other Commission Action

The Commission will require Xcel to take other action and make filings consistent with the decisions herein, as follows.

Xcel must track both the costs and the associated revenues for each pilot.

Xcel must establish a new tracker account for non-promotional and non-educational expenses associated with each pilot.

In its annual report, Xcel must discuss the interoperability of installed charging equipment under both pilots, including which, if any, standards the pilots require. This should include hardware and software standards.

Within 10 days, Xcel must file its Fleet EV Service pilot agreement for Commission approval. The Commission will delegate authority to the Executive Secretary to approve, via notice, the contract if no interested parties or Commission staff object or file an intent to object within 30 days of the filing.

Within 10 days, Xcel must file its Public Charging pilot agreement for Commission approval. The Commission will delegate authority to the Executive Secretary to approve, via notice, the contract if no interested parties or Commission staff object or file an intent to object within 30 days of the filing.

Where not otherwise noted, Xcel must file a compliance filing consistent with the Commission's decisions in this matter no later than 10 days from the date of this order.

ORDER

1. The Commission hereby approves Xcel's proposal for implementing a Fleet EV Service Pilot and associated tariff, as modified.

2. Within 10 days, Xcel must file its Fleet EV Service Pilot service agreement for Commission approval. The Commission hereby delegates authority to the Executive Secretary to approve, via notice, the contract if no interested parties or Commission staff object or file an intent to object within 30 days of the filing.

3. The Commission hereby approves Xcel's proposal for implementing a Public Charging Pilot and the associated tariff, as modified.

4. Within 10 days, Xcel must file its Public Charging Pilot service agreement for Commission approval. The Commission hereby delegates authority to the Executive Secretary to approve, via notice, the contract if no interested parties or Commission staff object or file an intent to object within 30 days of the filing.

5. Within six months, Xcel must file a commercial EV charging tariff that is more reflective of hourly system costs with a price signal designed to reduce peak demand.

6. The Commission hereby modifies the Public Charging tariff to condition participation in the pilot program on agreement by site hosts to have a default time-differentiated rate structure that reflects the on-peak and off-peak time periods of Xcel's Pilot tariff and an energy rate differential ratio of at least 2:1. However, site hosts may opt out of the default arrangement at their discretion to set pricing that reflects other considerations or needs, provided that such prices are reported to the utility for purposes of Xcel's annual reporting.

7. In its next rate case, Xcel must develop and propose a revised general service TOD rate that is more reflective of hourly system costs with a price signal designed to reduce peak demand.

8. Xcel must ensure that all chargers installed as part of the pilots have smart charging capabilities.

9. Xcel must consider geographic and customer diversity in its selection of additional participants in the Fleet EV Service Pilot. Of the additional participants, one must be a public entity with a primary location outside Ramsey and Hennepin Counties. Further, no more than one of the additional participants in the Fleet EV Service Pilot may be a private or non-profit entity.

10. The Commission hereby approves Xcel Energy's request to classify its make-ready EV infrastructure investments as utility distribution plant for both pilots, as well as Xcel's request to own charging equipment provided under the bundled service option in the Fleet EV Service Pilot. This classification is limited to EV infrastructure investments and charging equipment installed during the pilots.

11. The Commission hereby approves a waiver of service policy provisions for contributions in aid of construction and other customer contributions for only the three-year term of the pilots.

12. Xcel must use its current CIAC formula to determine the amount of subsidy a participant would receive and must track these costs, as well as revenues, for each pilot.

13. The Commission hereby grants deferred accounting for Xcel's O&M and depreciation pilot expenses, associated with capital assets placed in service for each pilot, incurred during the period between issuance of the Commission's order approving the pilots and January 1, 2020, the expected onset of the test year in Xcel's forthcoming rate case.

14. In its next general rate case filing, Xcel must address how it intends to handle and budget for future pilots.

15. Xcel must track both the costs and the associated revenues for each pilot.

16. Xcel must establish a new tracker account for non-promotional and non-educational expenses associated with each pilot.

17. The Commission adopts the following reporting requirements, filed on an annual basis throughout the pilot, as part for Xcel's Annual EV Report in Docket 15-111, with a copy filed in the present docket, 18-643.

18. For the Fleet EV Service Pilot, Xcel must report on:

A. Program level:

1. Participation over time on:
    a. the number of fleets;
    b. the number of vehicles; and
    c. the number of ports
2. End-user satisfaction, including surveys of fleet EV drivers and transit users riding electric buses;
3. Publicly accessible information on site host characteristics; and
4. Customer charging behavior in response to rate structure.

B. Site level, annual:

1. Location of the fleet charging site;
2. Number of ports at the site, and individual port capacities;
3. Costs:
    a. program implementation;
    b. installation costs:
        i. EV service connection;
        ii. EV supply infrastructure;
        iii. Optional EV charging equipment;
        iv. Cost of distribution system upgrade investments for the make-ready component of the pilot, including cost per kW.
    c. customer service and technical assistance needs;
    d. dollar estimate of public and private funds being leveraged; and
    e. any other costs not reflected in the list above.
4. Revenues, broken down by:
    a. energy revenues;
    b. demand charge revenues;
    c. fixed costs revenues; and
    d. optional charger cost revenues.
5. Whether the customer elected to charge with renewable energy.

C. Site level, monthly:

1. kWh consumed in the on- and off-peak periods of Xcel's tariff;
2. Coincident peak demand, at the MISO system peak and NSP system peak, including the time of day at which the peak occurred;
3. Non-coincident peak demand, including the time of day the peak occurred;
4. Number of vehicles, reported by the customer, using the charging infrastructure; and

5. Percentage of charging that aligned with any onsite generation, if applicable.

19. For the Public Charging Pilot, Xcel must report on:

A. Program level:

1. Participation over time:
    a. number of site hosts;
    b. number of ports;
2. End-user satisfaction;
3. Publically accessible information on site host characteristics; and
4. Customer charging behavior in response to rate structure.

B. Site level, annual:

1. Location of the site;
2. Number of ports at the site, and individual port capacities;
3. Costs:
    a. program installation;
    b. installation costs:
        i. EV service connection
        ii. EV supply infrastructure
        iii. EV charging equipment
        iv. Cost of distribution system upgrade investments for the make-ready component of the pilot, including cost per kW
    c. Customer service and technical assistance needs;
    d. Dollar estimate of public and private funds being leveraged; and
    e. Any other costs not reflected in the list above.
4. Revenues, broken down by:
    a. energy revenues;
    b. demand charge revenues; and
    c. fixed cost revenues.
5. Whether the site host has elected to charge with renewable energy; and
6. Rates and fees charged to end-user customers, and if those rates changed during the year, what period they were in effect.

C. Site level, monthly:

1. kWh consumed in the on-and off-peak periods of Xcel's tariff;
2. Coincident peak demand, at the MISO system peak and NSP system peak, including the time of day at which the peak occurred;
3. Non-coincident peak demand, including the time of day the peak occurred;
4. Number of charging events, times, and durations, to the extent available; and
5. Percentage of charging that aligned with any onsite generation, if applicable.

20. In its annual report, Xcel must discuss the interoperability of installed charging equipment under both pilots, including which, if any, standards the pilots require. This should include hardware and software standards.

21. Where not otherwise noted, Xcel must file a compliance filing consistent with the Commission's decisions in this matter no later than 10 days from the date of this order.

22. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf
Executive Secretary

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STATE OF MISSOURI
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held at its office in Jefferson City on the 6th day of February, 2019.

In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of Efficient Electrification Program	)))	**File No. ET-2018-0132** Tracking No. YE-2018-0103

ORDER APPROVING SECOND STIPULATION AND AGREEMENT

Issue Date: February 6, 2019 Effective Date: February 16, 2019

On February 22, 2018, Union Electric Company d/b/a Ameren Missouri filed an application and accompanying tariff sheets seeking approval of two new tariffed programs that are collectively referred to as the "Charge Ahead" program. The application also sought approval of modifications to Ameren Missouri's existing distribution system extension procedures, variances from portions of the Commission's regulations regarding promotional practices, and the request for an accounting authority order (AAO) for the Charge Ahead program.

On October 4, 2018, Ameren Missouri, the Staff of the Missouri Public Service Commission, the Office of the Public Counsel, and the Missouri Department of Economic Development – Division of Energy (collectively referred to as the "signatories") filed a *Stipulation and Agreement* resolving all issues between them related to the line extension policy. At the time the agreement was filed, the parties were still developing tariff sheets to implement the agreement. On October 12, 2018, the signatories filed a *Second Stipulation and Agreement* containing the exemplar tariff provisions as Exhibit A and indicating that although not signatories, The Empire District Electric Company, Kansas City Power & Light Company, KCP&L Greater Missouri Operations Company, Sierra

Club, and Natural Resources Defense Council each indicated that they do not oppose this settlement. The terms of the *Second Stipulation and Agreement* were presented to the Commission on December 4, 2018, prior to hearing evidence on the issues regarding the Charge Ahead programs.

Commission rule 4 CSR 240-2.115(2)(B) allows nonsignatory parties seven days to object to a nonunanimous stipulation and agreement. More than seven days have passed and no objections were received.

No evidentiary hearing is necessary to grant unopposed relief.[1] Based on the verified filings, the Commission finds and concludes that the *Second Stipulation and Agreement*'s provisions support safe and adequate service at just and reasonable rates and are in the public interest. The Commission incorporates the provisions of the *Second Stipulation and Agreement* into this order as if fully set forth herein.

In addition, because the parties are in agreement that the exemplar tariffs should become effective and the Commission has determined that they are in the public interest, the Commission will reject the proposed line extension tariff (Tariff Tracking No. YE-2018-0103), direct that compliance tariffs be filed, and make this order effective in less than 30 days.

THE COMMISSION ORDERS THAT:

1. The *Second Stipulation and Agreement* filed on October 12, 2018, and attached hereto is approved. The attached stipulation and agreement is incorporated into this order as if set forth herein.

[1] *State ex rel. Rex Deffenderfer Ent., Inc. v. Public Service Commission,* 776 S.W.2d 494, 496 (Mo. App. 1989).

2. The parties are ordered to comply with the provisions of the stipulation and agreement.

3. The tariff submitted under Tariff Tracking No. YE-2018-0103 is rejected.

4. Union Electric Company d/b/a Ameren Missouri shall file compliance tariffs consistent with the exemplar tariff sheets attached to the *Second Stipulation and Agreement.*

5. This order shall be effective on February 16, 2019.

BY THE COMMISSION

Morris L. Woodruff
Secretary

Silvey, Chm., Kenney, Hall, Rupp, and Coleman, CC., concur.

Dippell, Senior Regulatory Law Judge

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of Efficient Electrification Program.	)))	File No. ET-2018-0132

SECOND STIPULATION AND AGREEMENT

Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or the "Company"), the Missouri Public Service Commission Staff ("Staff"), the Office of the Public Counsel ("OPC"), and the Missouri Division of Energy ("DE") (collectively the "Signatories") present this Second Stipulation and Agreement ("Second Stipulation") to the Missouri Public Service Commission ("Commission") for its approval.

I. BACKGROUND

1. On February 22, 2018, Ameren Missouri requested the Commission approve its Charge Ahead program, consisting of an Efficient Electrification program, an Electric Vehicle Charging Program, and a change to its line extension policy.

2. On October 4, 2018, Ameren Missouri, Staff, OPC, and DE filed a Stipulation and Agreement resolving all issues between them on the line extension policy. However, the associated tariffs were not ready for filing and were to be submitted later.

3. In talking with the rest of the parties in the case, additional parties indicated they should be listed as not opposing the stipulation, resulting in this Second Stipulation.

II. SPECIFIC TERMS AND CONDITIONS

4. As a result of settlement discussions, the Signatories have agreed that the Commission should approve Ameren Missouri's line extension provisions, subject to the terms and conditions set forth below.

5. The Signatories agree that line extension costs are associated with new revenue and so do not meet the definition of "qualifying plant" found in Section 393.1400 RSMo (from Senate Bill 564) and so cannot receive the accounting treatment set forth in that section.

6. The Signatories agree that the cost of service factor and marginal revenue calculations defined in the tariff for purposes of calculating the extension allowance for new or expanding customers shall be based on an average of the first five years of the new or expanding customer's operation.

7. When Ameren Missouri determines that the permanency of a customer's service cannot reasonably be assured or the revenues cannot be projected with sufficient certainty, the Company agrees to document the basis for that determination and shall make that information available to the customer upon request. Ameren Missouri shall notify any such customer that has been required to pay an upfront refundable deposit that it has been categorized that way and explain how that determination causes higher upfront costs.

8. Ameren Missouri agrees to record customer contribution values by voltage and service classification. Prior to beginning to record these values, the Company shall circulate the form for Staff and OPC comment and agreement. This information shall be retained by Ameren Missouri and made available to Staff and OPC in future cases involving class cost of service study and/or rate design issues.

9. Five years after implementation of this program, Ameren Missouri shall compile a report (due in year six) to examine how well the tariff is working to align cost causation. The report shall include the following information, at a minimum:

a. Analysis of a random sample of projects to determine whether extension costs were over- or under-estimated,

b. Number of customers whose revenue projections were uncertain and therefore required upfront refundable deposits that are still active customers in year five, and

c. For the customers that are not still active in year five, an explanation of any under-recovery of costs which is more than 20% of the actual costs, shall be provided by Ameren Missouri to the Signatories.

10. Ameren Missouri shall seek input and comment from Staff, OPC and DE regarding the scope and analysis of the report referenced in paragraph nine above.

11. Ameren Missouri agrees to withdraw the Non-Residential Existing Infrastructure Incentive option from its request.

12. Attached as Exhibit A to this Second Stipulation are exemplar tariffs that Ameren Missouri will file upon Commission approval of the agreement.

13. Empire District Electric Company, Kansas City Power & Light Company, KCP&L Greater Missouri Operations Company, Sierra Club, and Natural Resources Defense Council have each indicated that they do not oppose this settlement.

III. GENERAL PROVISIONS

14. This Stipulation is being entered into for the purpose of disposing of the issues that are specifically addressed herein. In presenting this Stipulation, none of the Signatories shall be deemed to have approved, accepted, agreed, consented, or acquiesced to any ratemaking principle or procedural principle, including, without limitation, any method of cost or revenue determination or cost allocation or revenue related methodology, and none of the Signatories shall be prejudiced or bound in any manner by the terms of this Stipulation (whether it is approved

or not) in this or any other proceeding, other than a proceeding limited to enforce the terms of this Stipulation, except as otherwise expressly specified herein.

15. This Stipulation has resulted from extensive negotiations, and the terms hereof are interdependent. If the Commission does not unconditionally approve this Stipulation, or approves it with modifications or conditions to which a party objects, then this Stipulation is considered to be void and no Signatory shall be bound by any of its provisions.

16. If the Commission does not unconditionally approve this Stipulation without modification, or approves it with modifications or conditions to which a party objects, and notwithstanding its provision that it shall become void, neither this Stipulation, nor any matters associated with its consideration by the Commission, shall be considered or argued to be a waiver of the rights any Signatory has for a decision in accordance with Section 536.080, RSMo 2000, or Article V, Section 18, of the Missouri Constitution, and the Signatories retain all procedural and due process rights as fully as though this Stipulation had not been presented for approval, and any suggestions or memoranda, testimony or exhibits that have been offered or received in support of this Stipulation shall become privileged as reflecting the substantive content of settlement discussions and shall be stricken from and not be considered as part of the administrative or evidentiary record before the Commission for any further purpose whatsoever.

17. This Stipulation contains the entire agreement of the Signatories concerning the issues addressed herein.

18. This Stipulation does not constitute a contract with the Commission. Acceptance of this Stipulation by the Commission shall not be deemed as constituting an agreement on the part of the Commission to forego the use of any discovery, investigative or other power which the

Commission presently has. Thus, nothing in this Stipulation is intended to impinge or restrict in any manner the exercise by the Commission of any statutory right, including the right to access information, or any statutory obligation.

WHEREFORE, the Signatories request the Missouri Public Service Commission issue an order approving the terms and conditions of this Stipulation and Agreement.

Respectfully submitted,

/s/ Wendy K. Tatro
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CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of the foregoing was served on the parties of record via electronic mail (e-mail) on this 12th day of October, 2018.

/s/ Wendy K. Tatro
Wendy K. Tatro

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 — 1st Revised — SHEET NO. 59.2

CANCELLING MO.P.S.C. SCHEDULE NO. 6 — Original — SHEET NO. 59.2

APPLYING TO **MISSOURI SERVICE AREA**

SERVICE CLASSIFICATION NO. 6 (M)
STREET AND OUTDOOR AREA LIGHTING – CUSTOMER-OWNED (Cont'd.)

1. RATE APPLICATION

Available for automatically controlled dusk-to-dawn lighting where customer furnishes, installs and owns all street and outdoor area lighting facilities. Lighting service provided under this Service Classification shall consist of metered service with all maintenance of such facilities provided by the customer, or unmetered service as provided for or limited by the rate section of this Classification. The metered service portion of this Classification is not available on an individual premises where all other electric service thereon is provided to an individual customer or entity. Any account billed under the provisions of the metered portion of this Classification on September 1, 1992 may continue to be billed under such provisions until alternative or replacement rates or tariff options are approved by the Commission.

2. CHARACTER OF SERVICE SUPPLIED

Company will specify and provide a standard single- and/or three-phase alternating current secondary service voltage. Where customer requires and Company supplies service at a primary service voltage, customer shall furnish all transformers necessary to transform such service to a secondary service voltage.

3. GENERAL PROVISIONS

a. Customer shall pay all costs incurred by Company in constructing any line extensions required in providing said lighting service to the point or points of delivery designated by Company, in accordance with the provisions of Section III - Special Facilities.

b. Where required, customer shall install suitable switching, protective equipment, meter loop, space and mounting facilities as determined by the Company.

c. All equipment owned and installed by customer shall be of a type acceptable to Company and shall be maintained by customer in a condition satisfactory to and approved by the appropriate electrical inspection authority.

d. Where required for connection to customer's lighting system, customer shall provide, without cost to Company, wire of sufficient length to reach a point specified by Company on Company's secondary distribution system and Company will make the required connection. Such wire may be removed by Company at any time after termination of service hereunder.

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 — 1st Revised — SHEET NO. 77

CANCELLING MO.P.S.C. SCHEDULE NO. 6 — Original — SHEET NO. 77

APPLYING TO **MISSOURI SERVICE AREA**

RIDER D

TEMPORARY SERVICE

Customers desiring service for operations which are not considered permanent in nature, including, but not limited to, construction connections, carnivals, lawn parties, bazaars, fetes, etc., may contract for such service under the applicable rate, subject to all terms and conditions of said rate and applicable rules and regulations except as hereinafter modified:

1. Customer will pay Company in advance or at the option of Company, with the first bill for service rendered, the estimated cost of connection and disconnection of service, installation, reading and removing of meters, and any other cost or expense incurred by Company incident to the connection and disconnection of such service, less the estimated net salvage value of recoverable facilities and materials.

2. Customer may have service disconnected by giving written notice to Company ten (10) days prior to the date when service is to be disconnected.

3. In case of service required for carnivals, lawn parties, bazaars, fetes, etc., which is generally required for only a few days, Company may estimate the service used based upon connected load and hours of use.

4. This service may not be cumulated with any other service for billing purposes. Each connection of temporary service will be billed for separately.

5. Upon request by Company, customer will furnish insurance to protect Company against liability for injury or damage claims incident to the supply of service to temporary installations.

6. If after a customer has entered into a contract for Temporary Service, such service becomes permanent in character and customer receives electric service during the entire term specified in the rate under which service is supplied, Company may refund all or part of the payment made by customer under (1) above.

   Such refund will be made by Company at the end of the first year's use of service, or sooner if full refund is earned prior to that time, under the following provisions:

   a. If a non-residential customer is receiving the class of service designated by Company, the cost of the extension which was made to connect such service to customer's premises shall be determined in accordance with the Extension Cost definition in Section III – Distribution System Extensions.

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 — 1st Revised — SHEET NO. 77.1

CANCELLING MO.P.S.C. SCHEDULE NO. 6 — Original — SHEET NO. 77.1

APPLYING TO **MISSOURI SERVICE AREA**

RIDER D

TEMPORARY SERVICE (Cont'd.)

6. a. (Cont'd.)
Refund in full will be made if the Company's Extension Allowance, as defined in Section III and calculated based on Marginal Revenues for electric service during the one-year period, commencing with the fourth billing period for service, equals or exceeds the Extension Cost as defined in Section III. If the Extension Allowance calculated for the one year period is less than the Extension Cost, Company shall retain the calculated Extension Charge and refund to the customer the remainder, if any, of customer's payment. No refund shall exceed the amount actually paid by customer under (1) above.

b. If a non-residential customer has been supplied a class of service different from that designated by Company, an estimate will be made by Company (in accordance with the definition of Extension Cost in Section III.B) of the excess cost of the extension actually made over the cost of the extension which Company would have had to make to supply the class of service designated by Company. Such estimated excess cost, to be retained by Company, will be deducted from the amount subject to refund and the balance, if any, shall be subject to refund to customer in accordance with the provisions of Section 6(a) above.

DATE OF ISSUE _____ DATE EFFECTIVE _____

ISSUED BY Michael Moehn (NAME OF OFFICER) President (TITLE) St. Louis, Missouri (ADDRESS)

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

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CANCELLING MO.P.S.C. SCHEDULE NO. 6 — Original — SHEET NO. 79

APPLYING TO **MISSOURI SERVICE AREA**

RIDER F

ANNUALLY RECURRING SERVICE WITH EXTENDED PERIODS OF SHUT DOWN

Customers desiring service for other than residential use during recurring portions of successive years, where all service is normally discontinued or curtailed during the remaining portion of the year, have the option of contracting for service under either of the two following plans:

A. Pay for all service used under the applicable service rate subject to the minimum bill provisions of such rate during periods of shut down, or

B. Receive service under provisions stated in the following paragraphs 1 to 8, inclusive.

1. Customer shall pay the total installed cost of all facilities initially utilized for the supply of service, and any subsequent replacements thereof, under the provisions of Section III - Special Facilities. Such installed cost shall include all facilities from the metering point back to the point on the Company's system where adequate capacity exists to provide for the customer's requirements.

2. Facilities supplied by Company will be predicated upon customer's statement of his maximum load requirements.

3. Customer shall give Company reasonable advance notice when service is required or is to be discontinued or curtailed. All provisions of the applicable rate shall apply to service used within each such period of use. The reconnection charge shown on Sheet No. 63, Miscellaneous Charges, will be made for each connection point each time normal use of service is resumed. Minimum monthly charges, as provided for under the applicable rate schedule, will be waived during the period in which service is discontinued or curtailed.

4. Where service is used at the election and option of customer, such as for air conditioning, ball park lighting, driving tees, ice manufacturing, seasonal use by municipal or private sewage and/or water systems, summer refreshment stands, etc., bills will be normally rendered on regular monthly schedules for all service used between regular meter reading dates, provided, however, that customer shall be entitled to not more than two prorated bills for service during each calendar year where service is reconnected or disconnected or curtailed between regular meter reading dates.

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

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CANCELLING MO.P.S.C. SCHEDULE NO. 6 — Original — SHEET NO. 79.1

APPLYING TO **MISSOURI SERVICE AREA**

RIDER F

ANNUALLY RECURRING SERVICE WITH EXTENDED PERIODS OF SHUT DOWN (Cont'd.)

4. (Cont'd.)
Where use of service during emergencies is irregular, indeterminate and not subject to control by customer, such as for pumping of flood water, or pumping of gas during emergencies incident to the acquisition of gas from pipe line operator, Company will prorate all bills rendered based on the respective periods of use requested by customer.

5. Customer who, in lieu of complete disconnection, following periods of normal use of service, requires a small amount of service during the period of shut down, may obtain such service during this period under the Small General Service Rate.

Company reserves the right to require customer to install a separate service entrance for the service required during the period of shut down.

6. This schedule is not available to customers who qualify as Supplementary Service customers under the provisions of Rider E or who qualify as Standby Service customers under the provisions of Rider SSR.

7. Upon completion of payments required of customer in accordance with paragraph (1) above, customer may cancel contract for service at any time thereafter upon 3 days advance written notice to Company.

8. This service may not be cumulated with any other service for billing purposes.

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 — 2nd Revised — SHEET NO. 95

CANCELLING MO.P.S.C. SCHEDULE NO. 6 — 1st Revised — SHEET NO. 95

APPLYING TO **MISSOURI SERVICE AREA**

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APPLYING TO **MISSOURI SERVICE AREA**

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APPLYING TO **MISSOURI SERVICE AREA**

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UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

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APPLYING TO **MISSOURI SERVICE AREA**

GENERAL RULES AND REGULATIONS

II. CHARACTERISTICS OF SERVICE SUPPLIED

A. GENERAL PROVISIONS

Company will designate and supply standard electric service, suitable for customer's electrical requirements, in the form of 60 Hertz alternating current at the various voltages indicated below to all customers within its service area.

B. SECONDARY SERVICE VOLTAGES

Company's standard single phase secondary voltage is 120/240 volts. Standard three phase, four wire, secondary voltages are 120/208 volts and 277/480 volts. Company may designate more than one service connection for engineering and operating reasons. These services will not be cumulated or otherwise combined for billing purposes. Company may, at its sole discretion, make three phase, three wire, secondary voltages of 240 volts or 480 volts available.

C. NUMBER OF SECONDARY VOLTAGES ALLOWED

Company will designate and supply not more than one single phase and/or one three phase secondary voltage to a premises, unless otherwise required to satisfy Company's engineering, operating, or economic considerations. Where large single phase customer loads are to be supplied, Company shall have the right to supply two or more single phase or a three phase, four wire, secondary voltage and to require customer to arrange his wiring so that the load can be divided equally among the two or three phases. Company may designate a three phase secondary service when single phase facilities are not readily or economically available to serve the customer.

D. COMPANY SUBSTATION ON CUSTOMER PREMISES - SECONDARY SERVICE

If in Company's opinion it is impractical or inadvisable to supply customer with the designated secondary service from Company's general distribution system, Company will install the substation or transformation required for such service in a space, area, room or vault. The Customer shall construct such space, area, room or vault in accordance with Company provided specifications. Company may use such transformation or substations for supplying service to other customers where it is technically and economically feasible to do so. Said area for Company's substation equipment shall be constructed by customer in accordance with Company's specifications and at no cost to Company. Only one substation will be installed by Company for such purposes at any premises and Company may utilize said substation for supplying service to other customers where it is technically and economically feasible to do so.

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

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APPLYING TO **MISSOURI SERVICE AREA**

GENERAL RULES AND REGULATIONS

II. CHARACTERISTICS OF SERVICE SUPPLIED (Cont'd.)

E. PRIMARY SERVICE VOLTAGE

The primary voltages designated and supplied by Company will generally be limited to the voltage of Company's distribution lines in the geographic area which encompasses the premises of the customer to be served. Such three phase, four wire, primary voltages will be either 4160Y/2400 or 12470Y/7200 volts. Although not generally available, other primary voltages may be supplied in limited portions of the Company's service area under certain conditions designated by Company.

F. SERVICE AT A PRIMARY VOLTAGE

Company may designate and supply a three phase primary voltage to customer where any of the following conditions, pertaining to customers electrical requirements, exist:

1. The magnitude of the customer's load would require Company to install a primary to secondary voltage transformer which exceeds the rated capacity of the individual transformers normally purchased and installed by Company for such purposes.
2. Customer, at the time of Company's initial line extension for electric service, requests more than one point of delivery of the same three phase secondary voltage for supplying a single customer at the same premises.
3. An existing secondary voltage customer's expansion requires one or more single or three phase secondary voltage connections in addition to the secondary connections presently used for the supply of electric service to the same premises currently being served by Company.
4. Where in the Company's judgement the location of transformation and customer's service equipment are or would be inaccessible, subject to flood, contamination, etc., or potentially result in other anticipated operating difficulties.
5. Where in the Company's judgement the customer's load characteristics make such service advisable.

When Company requires or customer requests primary service to serve a premises and Company agrees to additional connections at primary or secondary voltages for Company's general engineering, operating or economic reasons, such additional connections will be provided under the provisions of the line extension rules in Section III. Company will designate the point of delivery of any connections provided hereunder. The service supplied through such additional connections installed at customer's request on and after May 5, 1990 will not be cumulated or otherwise combined, for billing purposes, with any other service supplied to customer.

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

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APPLYING TO **MISSOURI SERVICE AREA**

GENERAL RULES AND REGULATIONS

II. CHARACTERISTICS OF SERVICE SUPPLIED (Cont'd.)

G. COMPANY SUBSTATION ON CUSTOMER PREMISES - PRIMARY SERVICE

If in Company's opinion it is impractical or inadvisable to supply customer with the designated primary service from Company's general distribution system, Company will install a substation on customer's premises to transform a higher delivery voltage to the designated primary service voltage. For said substation, customer shall provide, without cost to Company, a fenced space, area, room or vault, as required, an easement, access for Company personnel and equipment, transformer pads, grounding grid, secondary circuitry and supports and adequate ventilation in accordance with Company specifications. Only one substation will normally be installed by Company for such purposes at any premise and Company may utilize said substation for supplying service to other customers where it is technically and economically feasible to do so. The configuration of the service to these facilities will take into account Company engineering and operating requirements. The Company and the Customer will enter into appropriate agreements regarding assurances for procurement of equipment.

H. HIGH VOLTAGE NON-STANDARD SERVICE

Where customer requests for its purposes to be supplied at a voltage higher than the Company's standard primary service voltages, or Company specifies same due to operation of converters, electric furnaces or other equipment, customer shall own, operate and maintain its own substation designed in accordance with Company specifications and shall, in return for same, receive a discount from Company's applicable rate schedule as set forth in Rider B.

I. SERVICE TO DOWNTOWN ST. LOUIS UNDERGROUND DISTRICT

The Downtown St. Louis Underground District is the area bounded by Twenty-Second Street, Cole Street, Spruce Street, and the Mississippi River. The preferred form of service within this area is either a 13.8 kV, three phase, four wire primary radial supply, or a three phase, four wire secondary voltage connection in an indoor substation room provided by customer at or one level below grade and constructed in accordance with Company's specifications.

When new or increased load can be supplied from the existing 120/208 volt, three phase, four wire gridded network without major reinforcement required by Company, service will be provided in such limited amounts and subject to the line extension provisions.

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

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APPLYING TO **MISSOURI SERVICE AREA**

GENERAL RULES AND REGULATIONS

II. CHARACTERISTICS OF SERVICE SUPPLIED (Cont'd.)

I. SERVICE TO DOWNTOWN ST. LOUIS UNDERGROUND DISTRICT (Cont'd.)

Where in Company's judgement it is impractical or inadvisable to supply a customer's new or increased load from the gridded or spot networks, customer will be required to provide at no cost to the Company an indoor substation room at or one level below grade, constructed in accordance with Company's specifications, and transfer all electrical load to the new connection point. In such instances requiring an indoor substation, customer may, with the Company's approval, accept responsibility for all excess costs incurred by Company in continuing to provide all or a portion of customer's service from the gridded network solely for customer's benefit.

J. NON-STANDARD SERVICE

Changes in business practices and regulatory and legal requirements will, from time to time, result in the Company serving or billing a limited number of customers in a manner that is currently considered a non-standard form of service. Such non-standard service includes, but is not limited to, voltages, frequencies, metering equipment, metering locations, electrical distribution system supply facilities and configurations, and master and cumulated meter billing situations that are prohibited by current Commission rules and Company tariffs for application to new customers. The continued provision of such non-standard service and billing is limited to the premises presently served by such facilities. These facilities may only be relocated, expanded or enhanced for Company's engineering reasons.

In order to minimize and phase out the number of non-standard service installations and billing applications on its system, Company will, unless otherwise provided for above, discontinue providing any such non-standard service to a premises when a) the premises is remodeled or rehabilitated in any such manner that requires new, modified, enhanced or relocated electrical distribution supply facilities from the Company, or b) the premises become an inactive account for a consecutive period of six (6) months or more. Any premises meeting the conditions of (a), or (b) herein shall be considered to have been constructed after June 1, 1981, for application of 4 CSR 240-20.050 of the Commission's metering requirements and related Sections Rent Inclusion and Resale of Service, which are a part of the Billing Practices Section of Company's General Rules and Regulations.

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 — 1st Revised — SHEET NO. 111

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APPLYING TO **MISSOURI SERVICE AREA**

GENERAL RULES AND REGULATIONS
III. DISTRIBUTION SYSTEM EXTENSIONS

A. APPLICABILITY

Permanent electric service of the form and character described in Section II of these rules will be supplied for permanent year round use to Customers within the Company's authorized service area, by extension and/or modifications or enlargements to Company's electric distribution system, in accordance with the provisions set forth in this Section III. Company's extension shall be considered as completed when said extension is adjacent to the premises to be served and Company is prepared to connect service thereto.

B. DEFINITIONS

Extension Allowance: An economically justifiable investment which may be made by the Company for distribution line extensions, service extensions, or a combination thereof, and uses the following formula:

$$\text{Extension Allowance} = \frac{\text{Marginal Revenue}}{\text{Cost of Service Factor}}$$

Marginal Revenue: The estimated average annual revenue measured over the first 5 years of life associated with the line extension project, less incremental energy, capacity, and marginal network and infrastructure support cost.

Cost of Service Factor: Comprised of the Company's cost of capital, cost of depreciation, property tax, state and federal income tax and insurance. The factor is applied to the Marginal Revenue to determine Ameren Missouri's Extension Allowance, and is determined from Ameren Missouri's most recent rate case proceeding and/or through a periodic review conducted by the Company.

Extension Charge: That portion of the total Extension Cost which is not covered by the Extension Allowance and for which the Customer is responsible.

$$\text{Extension Charge} = \text{Extension Cost} - \text{Extension Allowance}$$

Extension Cost: The estimated installed cost of any line extensions and/or modifications and enlargements of the Company's distribution system, which will include the total cost of all labor and materials, easements, licenses, permits, cleared right-of-way and all other incidental costs, including indirect costs. The indirect costs will include, where applicable, the cost of engineering, supervision, inspection, insurance, payments for injury and damage awards, taxes, AFUDC (Allowance for Funds Used During Construction), legal and administrative and general expenses associated with the extension of the Company's distribution system. The percentage used for indirect costs reflects the Company's historical indirect cost experience. The Company's Extension Cost is based on normal, pre-construction and unobstructed conditions. Cost estimates relative to Extension Allowances or Customer contributions are based on the conditions prevailing at the time the estimate is made. Additional costs due to changes in surface conditions or unanticipated subsurface

GENERAL RULES AND REGULATIONS
III. DISTRIBUTION SYSTEM EXTENSIONS (Cont'd.)

B. DEFINITIONS (Cont'd.)

conditions occurring after the initial Extension Cost estimate, will be covered by the Company to the extent there is available remaining Extension Allowance. Should the unanticipated additional Extension Cost cause the new Extension Cost to exceed the Extension Allowance, the Customer will be responsible for an additional Extension Charge resulting from the updated Extension Cost. Company may install a distribution extension of greater length or capacity than initially required for the Customer requesting service, due to general engineering, economic, operating, or reliability reasons, in which case the additional cost of such increases in distribution system length or capacity shall not be included in the cost of the extension applicable to Customer.

C. DISTRIBUTION EXTENSION LENGTH

The length of the extension of the distribution system will be the distance along the installation route designated and utilized by Company in making said extension. Such distance shall be measured from the Company's designated point of delivery on Customer's premises to the nearest point of connection to Company's existing distribution system having like phase and voltage as that being supplied to Customer's premises.

D. POINT OF DELIVERY OF SERVICE

The point of delivery of service, at which Company's distribution facilities connect to Customer's electrical facilities without regard to meter location, shall normally be at the following electrical connection points:

1. Overhead Service
   a. Secondary Voltage - All Customers - At Customer's service entrance conductors, i.e., weatherhead or bus duct outlet.
   b. Primary and Higher Voltages - At the line-side dead end attachment on Customer's meter pole, or on the bus structure of Customer's substations, or at the low side terminals of a Company substation on Customer's property.
2. Underground Service
   a. Secondary Voltage-Residential - At the line-side meter terminals for Company owned services; on the pole, connecting to Company's overhead distribution system or Company's padmounted transformer or pedestal, in the case of Customer owned cables.
   b. Secondary Voltage-All Other Customers - At the connection of Customer's cable to the low side terminals of Company's padmounted transformer or pedestal or Customer provided junction box.
   c. Primary and Higher Voltages - At the line-side terminals in metal-clad switchgear, or at an agreed upon point on or in a Customer owned substation.

GENERAL RULES AND REGULATIONS

III. DISTRIBUTION SYSTEM EXTENSIONS (Cont'd.)

E. EXTENSIONS TO NON-RESIDENTIAL CUSTOMERS

Company will provide a distribution extension to non-residential premises at no cost to Customer provided the estimated Extension Allowance equals or exceeds the estimated Extension Cost of the portion of required extension applicable to Customer. Where the Extension Cost is greater than the Extension Allowance, the Customer will be required to pay the Extension Charge in advance prior to the commencement of construction by Company.

At the Company's sole discretion, where permanency of service cannot be reasonably assured in order to predict the revenue stream from the Customer or the revenues cannot be projected with sufficient certainty, the Customer may be required to pay to Company in advance of Company's construction all of the estimated Extension Cost as an Extension Charge. Where the entirety of the Extension Cost is required upfront, after a 12 month period beginning with the Customer's fourth billing cycle, the Extension Charge will be recalculated using actual revenues to determine if the customer is eligible for a refund. If applicable, a refund will be issued for the difference between the original Extension Charge and the Extension Charge recalculated on the actual revenue.

1. Non-Residential Underground Extensions

Where underground extensions are requested or required by law the following provisions apply:

a. Point of Delivery of Service

Company will designate to Customer the point of delivery of the required electric service and Customer shall be responsible for the installation, maintenance, replacement, enlargement or relocation of all underground electric service facilities, other than metering, to the Company's designated delivery point.

b. Specifications

Customer will install, maintain, replace, enlarge, or relocate all underground conduit, foundations, manholes, service boxes, transformer pads, switchgear pads, and other surface and sub-surface structures to meet Company specifications which are necessary to contain and/or support Company's electrical primary and secondary cables and equipment within the boundaries of the development. Maintenance, replacement, enlargement, or relocation of such facilities will be done by the Company at the Customer's expense once they contain or support energized cables or equipment. Company will provide standard switchgear pads and transformer pads to Customer for installation in order to maintain uniformity and quality control of these items. Customer is to provide Company open access to said

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

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APPLYING TO **MISSOURI SERVICE AREA**

GENERAL RULES AND REGULATIONS
III. DISTRIBUTION SYSTEM EXTENSIONS (Cont'd.)

E. EXTENSIONS TO NON-RESIDENTIAL CUSTOMERS (Cont'd.)

1. Non-Residential Underground Extensions (Cont'd.)

b. Specifications (Cont'd.)

facilities, and when necessary, remove obstructions, improvements, decorative structures, etc., when Company requires such access for maintenance, replacement, enlargement, etc. When Company requests additional conduits or larger structures for facilities that will serve Customers beyond the boundaries of the development, Company will pay the incremental or extra cost of those additional facilities.

Non-residential line extension agreements executed prior to January 1, 2019 shall remain in effect. Agreements executed after January 1, 2019 shall be in accordance with the terms of this Section III., Distribution System Extensions.

F. OVERHEAD EXTENSIONS TO INDIVIDUAL RESIDENTIAL CUSTOMERS

Company will provide, at no cost, single-phase overhead electric service consisting of a meter, service drop, transformation capacity and up to 1,000 feet of additional distribution facilities, as required, no more than 500 feet of which shall be extended on private property, to the premises of an individual residential Customer not located within a residential subdivision. The portion of any distribution extension applicable to Customer in excess of the aforementioned allowance shall be paid for by Customer, in advance of construction, at the Company's then current standard construction cost per foot of single phase overhead extensions.

G. OVERHEAD EXTENSIONS TO RESIDENTIAL SUBDIVISIONS

1. Single-Family Residences

Company will provide single-phase overhead electric service consisting of meters, services, transformation capacity and all additional facilities required for the distribution of electricity, through and within the boundaries of a residential subdivision for which permanent electric service has been requested by Customer/developer to two or more residential buildings, at no cost to the Customer/developer, excluding subdivisions covered by the Large Lot Subdivision provisions outlined below. Company will also provide additional distribution facilities of up to 150 feet per subdivision lot, as required, to extend its existing distribution system to the boundaries of the subdivision site, at no cost to Customer/developer. For any permanent electric distribution extension facilities to or within the subdivision, in excess of the aforementioned allowances, Customer/developer shall make a deposit in advance of construction, based upon the Company's then current standard construction charges for such facilities, which deposit may be refundable in whole or in part. Semi-annually thereafter, Company will compare its standard

DATE OF ISSUE _____ DATE EFFECTIVE _____

ISSUED BY Michael Moehn (NAME OF OFFICER) President (TITLE) St. Louis, Missouri (ADDRESS)

GENERAL RULES AND REGULATIONS

III. DISTRIBUTION SYSTEM EXTENSIONS (Cont'd.)

G. OVERHEAD EXTENSIONS TO RESIDENTIAL SUBDIVISIONS (Cont'd.)

1. Single-Family Residences (Cont'd)

overhead distribution cost per lot with the annual net revenue per lot estimated to be received from the additional homes within the subdivision having been connected with electric service and permanently occupied for residential dwelling purposes, after receiving notification of such connections from Customer/developer. Any estimated annual net revenue per lot, from homes added during each review period, in excess of Company's standard per lot overhead costs shall be refunded, without interest, to Customer/developer up to the total amount of the advance deposit actually made by Customer/developer. Such refunds will be made at semi-annual intervals from the date the deposit was received by Company, with any amounts remaining unrefunded after five years being retained by Company and credited to the Company's appropriate plant account.

a. Large Lot Subdivisions

In addition to meeting the criteria described in this section F.1. above, in subdivisions where the average lot size exceeds 100,000 square feet, the Company will assess excess per lot footage charges for the amount that the average frontage footage exceeds 500 feet. In addition, for developments where the average lot size exceeds 100,000 square feet, the Company will also assess excess footage charges on individual lots for overhead services of more than a single span or underground services of more than 250 feet. Said charges will be payable in advance of construction and not be subject to refund.

2. Multiple Occupancy Dwellings

Multiple occupancy buildings consist of structures which stand alone, enclosed with exterior walls or are segregated from adjoining structures by fire walls, and are designed for permanent occupancy as two or more single-family residences. Extensions to subdivisions consisting of multiple occupancy dwellings shall be made in accordance with the provisions of this section G, applicable to single-family residences, utilizing an allowance of 50 feet per dwelling unit for distribution facilities beyond the subdivision boundaries, and applying a 0.60 occupancy factor to the annual net revenue estimated to be received from each multiple occupancy dwelling unit.

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 — 1st Revised — SHEET NO. 116

CANCELLING MO.P.S.C. SCHEDULE NO. 6 — Original — SHEET NO. 116

APPLYING TO **MISSOURI SERVICE AREA**

GENERAL RULES AND REGULATIONS
III. DISTRIBUTION SYSTEM EXTENSIONS (Cont'd.)

H. OVERHEAD EXTENSIONS TO INDIVIDUAL MOBILE HOMES AND MOBILE HOME PARKS

1. Individual - Other Than Mobile Home Parks

Where a mobile home is permanently located on real property owned or leased by the mobile home occupant, utilized as a permanent dwelling unit, connected to piped water and sewage facilities, and is in excess of 400 square feet in size, Company shall extend its electrical distribution system to the mobile home service entrance equipment on the same terms and conditions indicated in this Section III for extensions to individual residential or non-residential Customers, as applicable. Extensions to individual mobile homes not meeting the qualifications specified in this paragraph shall be made in accordance with the provisions of Rider D - Temporary Service.

2. Mobile Home Parks

Where a mobile home park owner/operator provides a designated lot with water utility and sanitary facilities for mobile homes in excess of 400 square feet in size intended for use as residential dwelling units, Company will extend its distribution system to each mobile home lot on the same terms and conditions indicated in this Section III for extensions to residential subdivisions. The billing for electric consumption at any common facilities installed within the mobile home park for the benefit of all the mobile home park occupants shall be to the park's owner/operator.

3. Recreational Vehicle Parks

Company will extend its electrical distribution system to a single delivery point to provide service to campgrounds and parks which dedicate at least 80% of their space for recreational vehicle sites. Such extensions will be made under the same terms and conditions indicated in this Section III as applicable to non-residential Customers.

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 — 1st Revised — SHEET NO. 117

CANCELLING MO.P.S.C. SCHEDULE NO. 6 — Original — SHEET NO. 117

APPLYING TO **MISSOURI SERVICE AREA**

GENERAL RULES AND REGULATIONS
III. DISTRIBUTION SYSTEM EXTENSIONS (Cont'd.)

I. EXTENSIONS FOR LIGHTING SERVICE

The Company's lighting tariffs are based upon the required distribution facilities being in place and no additional extension required thereof. Therefore, the cost of any extension of facilities required for lighting service shall be paid by Customer to Company in advance of any construction of distribution facilities installed solely to supply electrical service for lighting.

J. UNDERGROUND EXTENSIONS

1. Individual Residential Extensions

Where an underground extension is requested by an individual residential Customer or required by law, Company will estimate the cost of equivalent overhead and underground extensions, and Customer will pay a non-refundable contribution to Company, in advance of construction, for any excess cost of making the underground extension. The Company's rules for overhead extensions to individual residential Customers shall apply to Company's estimated underground extension costs. Customer, at his option, may install a direct buried service cable to be owned and maintained by Customer, or Company will install, own, operate and maintain the service cable in Customer's conduit, installed by Customer in service trench in accordance with Company specifications to a delivery point designated by Company. Where Company determines that primary and/or secondary voltage facilities are necessary to provide the requested service, the Customer will install the conduit system, consisting of conduit, manholes, pulling boxes, transformer pads, switchgear pads, pedestal bases and other required subsurface structures to a point designated by Company. All such materials will be provided by Company for Customer pick-up at a location designated by the Company and included in the cost for underground service. Company will install, own, operate and maintain the cable in Customer's conduit system. Where applicable, the underground extension may be provided by Company in accordance with the rules applicable to overhead extensions, Section III.F.

2. Residential Subdivision Extensions

Where an underground distribution extension for permanent electric service in a residential subdivision is requested to two or more single-family residential buildings, multiple occupancy units, or mobile homes, by an applicant/developer, or is required by law, applicant shall first satisfy the Company's applicable rules for overhead extensions to residential subdivisions, Section III.G. Thereafter, applicant shall contract for and satisfy the requirements specified in this section for obtaining an underground residential distribution extension.

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 — 1st Revised — SHEET NO. 118

CANCELLING MO.P.S.C. SCHEDULE NO. 6 — Original — SHEET NO. 118

APPLYING TO **MISSOURI SERVICE AREA**

GENERAL RULES AND REGULATIONS
III. DISTRIBUTION SYSTEM EXTENSIONS (Cont'd.)

J. UNDERGROUND EXTENSIONS (Cont'd.)

2. Residential Subdivision Extensions (Cont'd.)

a. Requirements of Applicant/Developer

Applicant will initially provide, at its cost, all trenching and the installation of a complete conduit system as its contribution to the Company's underground distribution system within a residential subdivision. The conduit system installation by applicant will consist of conduit, manholes, pulling boxes, transformer pads, switchgear pads, pedestal bases and other required subsurface structures. All such materials will be provided by Company at no cost to applicant, excluding subdivisions covered by the Large Lot Subdivision provisions below. Applicants for electric service to individual single family homes shall, subsequently, provide and install service trench and service conduit. All installations will be in accordance with Company's design criteria and specifications, the National Electrical Safety Code and any other applicable codes.

b. Requirements of Company

The Company's distribution system within the subdivision will consist of all primary and secondary voltage and service cables installed by Company, including street lighting circuitry and the conduit system initially installed and contributed by applicant, except for service lateral conduit. Street light circuitry and construction temporaries, installed by Company concurrent with other primary and secondary distribution system facilities, shall be provided by Company at no charge to applicant. Thereafter, except for service lateral conduit, Company shall own, operate and maintain the entire distribution system within the subdivision, including both the portion installed by Company and that installed and contributed by applicant.

c. Options of Applicant

At the request of applicant, Company will, on a per lot or per dwelling unit basis, estimate its distribution system extension cost within the subdivision and annual net revenue, exclusive of gross receipts taxes, anticipated to be received from such homes or dwelling units connected within the subdivision.

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 — 1st Revised — SHEET NO. 119

CANCELLING MO.P.S.C. SCHEDULE NO. 6 — Original — SHEET NO. 119

APPLYING TO **MISSOURI SERVICE AREA**

GENERAL RULES AND REGULATIONS
III. DISTRIBUTION SYSTEM EXTENSIONS (Cont'd.)

J. UNDERGROUND EXTENSIONS (Cont'd.)

2. Residential Subdivision Extensions (Cont'd.)

d. Distribution Lines Preserved

When Company requires that an overhead or underground distribution line be installed, or an existing overhead line be relocated to underground on the perimeter of the development, or accepts another alternative route thru the subdivision, for engineering and/or operating reasons, applicant shall install Company supplied conduit per Company specifications in accordance with III.J.2, and Company shall be given a reasonable amount of time to construct such underground or overhead facilities before affected lots are sold.

e. Right-of-Way and Easements

Company shall construct, own, operate and maintain the underground distribution system, within the subdivision, only on or along public streets, roads, alleys and highways which Company has the legal right to occupy, and on or along private property across which rights-of-way and easements satisfactory to Company have been received at no cost to or without condemnation by Company.
Right-of-way and easements within the subdivision which are satisfactory to Company, including those which may be required for street lighting, must be furnished by applicant in reasonable time to meet Company's construction and service requirements. Prior to commencement of construction by Company, such rights-of-way and easements must be cleared of trees, tree stumps, and other obstructions, and graded level, perpendicular to the length of the easement and to within six inches of final grade by applicant, without cost to Company. If the grade is changed subsequent to construction of the distribution system in such a way as to require relocation or reconstruction of any of the underground facilities, the estimated cost of all such work required shall be paid by applicant or by its successor.

f. Joint Utility Construction

Company will endeavor to coordinate its construction work with that of applicant and other utilities whenever possible in an effort to keep the overall cost of providing the underground electric distribution system as low as possible. Company may, to any extent practicable, become a party with applicant and/or other utilities to agreements involving trenching arrangements mutually beneficial to each party and the installation of electric cables in the same trench with the cables and/or pipes of other utilities, care being taken to conform to all applicable codes and utility specifications.

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 — 1st Revised — SHEET NO. 120

CANCELLING MO.P.S.C. SCHEDULE NO. 6 — Original — SHEET NO. 120

APPLYING TO **MISSOURI SERVICE AREA**

GENERAL RULES AND REGULATIONS
III. DISTRIBUTION SYSTEM EXTENSIONS (Cont'd.)

J. UNDERGROUND EXTENSIONS (Cont'd.)

2. Residential Subdivision Extensions (Cont'd.)

g. Designated Service Delivery Points

Feeder lines and service lines shall be installed by Company along the most practical route that will avoid known or anticipated future construction on applicant's property and permit a safe and economical installation. The normal meter location point to a single family building shall be on the side or front of the house proper, within ten (10) feet of the corner of the house proper, nearest the direction from which the service line enters the property to be served. In instances where Company and applicant agree that the extension of service to the normal meter location is impractical due to: a) rock, grade, or other soil limitations; or b) physical circumstances of the home which restrict meter accessibility for reading and testing; or c) physical circumstances of the home requiring meter installation at a height of six (6) feet six (6) inches or greater above final grade on the front of the house proper; or d) service entrance equipment to be installed in a garage, said meter location point shall be at the next nearest location designated by Company which will alleviate said impracticability while minimizing the additional length of service cable required to be installed and avoids areas of the home which may require future relocations of service lines and/or meter equipment. A meter location on the rear will only be permitted in those instances where the designated side of the house proper is not physically available for a meter attachment. A service connection at other than the above designated meter location point is not permitted unless specifically approved by Company for engineering or other reasons. Where practical, the service connection to a multiple occupancy building of two dwelling units shall be a single service line to a two (2) meter location acceptable to Company. The service connection to a multiple occupancy building of three (3) or more dwelling units shall be a service line or lines to a minimum grouping of meters at locations acceptable to Company.

h. Protection of Company Facilities

Applicant shall protect the facilities of Company installed on applicant's premises and shall, unless otherwise authorized by the Company, permit no one but Company's employees or its authorized agents to handle same. In the event of loss or damage to facilities owned by Company arising out of carelessness, negligence, or misuse by applicant or its authorized agent, the cost of such loss of repairing such damages shall be borne by applicant.

GENERAL RULES AND REGULATIONS
III. DISTRIBUTION SYSTEM EXTENSIONS (Cont'd.)

J. UNDERGROUND EXTENSIONS (Cont'd.)

2. Residential Subdivision Extensions (Cont'd.)

i. Access by Company Employees or Agents

Applicant shall permit access to the Company's employees, or other authorized agents, for the purpose of inspecting, modifying, maintaining, or operation of Company's facilities, at all times.

j. Company Rights and Construction Standards

Company shall own, operate and maintain the conduit system initially installed and contributed by applicant, all primary and secondary underground feeder lines, underground service lines installed in Customer owned conduit, and shall have the right to install pad-mounted transformers, above ground cable switching enclosures and service pedestals in the subdivision.

k. Street Lighting Facilities

Street lighting facilities installed in any subdivision shall be contracted for under the appropriate tariff of Company applicable to said installation.

l. Large Lot Subdivisions

The above provisions regarding Residential Subdivision Extensions – Requirements of Applicant/Developer is limited to subdivisions having an average lot size of 100,000 square feet or less. Where average lot size does exceed 100,000 square feet, the Company will assess excess per lot footage charges for the amount that the average frontage footage exceeds 500 feet. In addition, for developments where the average lot size exceeds 100,000 square feet, the Company will also assess excess footage charges on individual lots for overhead services of more than a single span or underground services of more than 250 feet. Said charges will be payable in advance of construction and not be subject to refund.

K. EXTENSIONS REQUESTED IN ADVANCE OF PERMANENT SERVICE

Where Customer requests Company to complete all or a portion of an extension in advance of when said installation is required to provide permanent electric service, and Company agrees to do so, Customer shall pay for such advancement of facilities at the monthly rate of 2.0% of the estimated installed cost of the extension being advanced. Such payments shall be non-refundable and shall continue until the permanent metering for the premises is installed by Company and utilized to provide permanent service thereto.

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 — 1st Revised — SHEET NO. 122

CANCELLING MO.P.S.C. SCHEDULE NO. 6 — Original — SHEET NO. 122

APPLYING TO **MISSOURI SERVICE AREA**

GENERAL RULES AND REGULATIONS
III. DISTRIBUTION SYSTEM EXTENSIONS (Cont'd.)

L. MODIFICATION OR ENLARGEMENT OF DISTRIBUTION SYSTEM

Modifications or enlargements of Company's distribution system associated with additional electrical load of existing non-residential Customers shall be performed at no cost to Customer provided the estimated Extension Allowance exceeds the estimated Extension Cost from the proposed distribution system modifications or enlargements. Where the estimated Extension Allowance is less than Company's estimated Extension Cost from the proposed modification or enlargement costs, an Extension Charge may be required prior to the commencement of construction by Company.

Where modifications or enlargements of Company's distribution system are performed at the request of any existing Customer and no additional Marginal Revenue is anticipated therefrom, Customer shall pay, in advance, the total estimated costs associated with such changes.

M. RELOCATION OF THE DISTRIBUTION SYSTEM

Company may, at its sole discretion, upon Customer's request, relocate any distribution facilities providing service to Customer and/or other parties to a right-of-way acceptable to Company, on or off Customer's premises, following the payment by Customer of the Company's total estimated cost of said relocation. Additionally, at the Company's discretion, it may relocate any distribution facilities based upon safety, reliability, or operational needs at the cost of the Company.

In the presence of physical conflicts associated with any new construction or enlargement of Customer's premises or electrical load, Company may, at its sole discretion, upon Customer's request, relocate any distribution facilities to a right-of-way acceptable to Company on or off Customer's premises, following the payment by Customer of the Company's estimated net cost of relocating its distribution facilities. The net cost of relocation referred to herein excludes any costs estimated by Company to be associated with the supply of any additional electrical requirements of Customer, absent the relocation of any distribution facilities.

When Company agrees to relocate existing overhead facilities with an underground installation, the Customer will be responsible for all costs associated with the undergrounding of facilities including spare conduits, manholes, and other structures or equipment required to replace the to-be-vacated overhead right-of-way considering present and future needs as determined by Company.

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 — 1st Revised — SHEET NO. 123

CANCELLING MO.P.S.C. SCHEDULE NO. 6 — Original — SHEET NO. 123

APPLYING TO **MISSOURI SERVICE AREA**

GENERAL RULES AND REGULATIONS
III. DISTRIBUTION SYSTEM EXTENSIONS (Cont'd.)

N. SPECIAL FACILITIES

1. General

Where Customer requests and Company agrees to install distribution facilities not normally contemplated for installation, or otherwise provided for, under Company's standard rate schedules, Company may at its option provide such facilities under the provisions of this section. Examples of facilities which fall into this category of "special" include, but are not limited to, duplicate or additional service facilities, excess transformer capacity or other distribution facilities, and facilities necessitated by special legal or engineering requirements.

2. Payments by Customer

Where Company agrees to supply distribution facilities under the provisions of this paragraph P in lieu of other alternatives available to Customer, Customer shall pay to Company a one-time contribution equal to the total additional costs incurred by Company in supplying such facilities. Customer shall also pay to Company an additional one-time contribution equal to ninety percent of such total additional costs for the present value of the Company's projected operations, maintenance and subsequent replacement cost of such facilities, which shall be continuously owned and maintained by Company. All charges payable to Company shall be non-refundable and due in advance of construction. Such payments by Customer shall be in addition to any payments required for electric facilities provided under the Company's standard line extension rules or other tariff charges.

3. Supply and Billing Standards

Company will designate the point of delivery of electric service relative to the installation of any additional facilities provided to Customer hereunder and the service supplied through such facilities installed on and after May 5, 1990 will not be cumulated or otherwise combined, for billing purposes, with any other service supplied to Customer. When total or partial replacement of any special facility installation is required, such revision will be made by Company at no cost to Customer. Any enlargement of such previously installed facilities requested by Customer shall be made in accordance with Company's standard line extension rules. Following any such replacement, or enlargement, all separately installed special facility connections shall be billed as provided herein without application of monthly special facility charges, and maintained by Company in the same manner as Company's standard line extension facilities serving other Customers.

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 — 1st Revised — SHEET NO. 124

CANCELLING MO.P.S.C. SCHEDULE NO. 6 — Original — SHEET NO. 124

APPLYING TO **MISSOURI SERVICE AREA**

GENERAL RULES AND REGULATIONS
III. DISTRIBUTION SYSTEM EXTENSIONS (Cont'd.)

N. SPECIAL FACILITIES (Cont'd.)

4. Installations Prior to July 23, 1992

Customers utilizing special facilities installed prior July 23, 1992 shall continue to pay the present charges and form of billing applicable to all special facilities connections until any total or partial replacement or enlargement of such facility is required. Thereafter, such revisions will be made by Company and the subsequent metering and billing of all services provided over such newly installed facilities standardized, as provided in paragraph 3 of this section, Supply and Billing Standards.

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 — 1st Revised — SHEET NO. 125

CANCELLING MO.P.S.C. SCHEDULE NO. 6 — Original — SHEET NO. 125

APPLYING TO **MISSOURI SERVICE AREA**

THIS SHEET RESERVED FOR FUTURE USE

DATE OF ISSUE _____ DATE EFFECTIVE _____

ISSUED BY Michael Moehn (NAME OF OFFICER) President (TITLE) St. Louis, Missouri (ADDRESS)

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 — 1st Revised — SHEET NO. 126

CANCELLING MO.P.S.C. SCHEDULE NO. 6 — Original — SHEET NO. 126

APPLYING TO **MISSOURI SERVICE AREA**

THIS SHEET RESERVED FOR FUTURE USE

DATE OF ISSUE _____ DATE EFFECTIVE _____

ISSUED BY Michael Moehn (NAME OF OFFICER) President (TITLE) St. Louis, Missouri (ADDRESS)

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 — 1st Revised — SHEET NO. 127

CANCELLING MO.P.S.C. SCHEDULE NO. 6 — Original — SHEET NO. 127

APPLYING TO **MISSOURI SERVICE AREA**

THIS SHEET RESERVED FOR FUTURE USE

DATE OF ISSUE _____ DATE EFFECTIVE _____

ISSUED BY Michael Moehn (NAME OF OFFICER) President (TITLE) St. Louis, Missouri (ADDRESS)

STATE OF MISSOURI

OFFICE OF THE PUBLIC SERVICE COMMISSION

I have compared the preceding copy with the original on file in this office and I do hereby certify the same to be a true copy therefrom and the whole thereof.

WITNESS my hand and seal of the Public Service Commission, at Jefferson City, Missouri, this 6th day of February 2019.

Morris L. Woodruff
Secretary

MOPSC Digitally signed by MOPSC
Date: 2019.02.06 13:41:12 -06'00'

MISSOURI PUBLIC SERVICE COMMISSION

February 6, 2019

File/Case No. ET-2018-0132

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Enclosed find a certified copy of an Order or Notice issued in the above-referenced matter(s).

Sincerely,

Morris L Woodruff

Morris L. Woodruff
Secretary

Recipients listed above with a valid e-mail address will receive electronic service. Recipients without a valid e-mail address will receive paper service.

Records, PRC, PRC

From: Sullivan-Leshin, Isaac, PRC
Sent: Friday, November 12, 2021 2:53 PM
To: Records, PRC, PRC
Subject: 20-00237-UT; Filing Submission
Attachments: 20-00237-UT, Final Order Adopting Recommended Decision.pdf

IN THE MATTER OF PUBLIC SERVICE COMPANY OF NEW MEXICO'S APPLICATION FOR APPROVAL OF ITS 2022-2023 TRANSPORTATION ELECTRIFICATION PROGRAM	)))))	**Case No. 20-00237-UT**

Please file the attached FINAL ORDER ADOPTING RECOMMENDED DECISION into the above captioned case.

Thank you.

Isaac Sullivan-Leshin
Paralegal for Office of General Counsel
New Mexico Public Regulation Commission
PO Box 1269
Santa Fe, New Mexico 87504-1269
isaac.sullivan-leshin@state.nm.us
Phone: (505) 670-4830

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE COMPANY OF NEW MEXICO'S APPLICATION FOR APPROVAL OF ITS 2022-2023 TRANSPORTATION ELECTRIFICATION PROGRAM	)))))	**Case No. 20-00237-UT**

FINAL ORDER ADOPTING RECOMMENDED DECISION

THIS MATTER comes before the New Mexico Public Regulation Commission ("Commission") on the December 18, 2020, 2020 application ("Application") filed by Public Service Company of New Mexico ("PNM") for approval of its 2022-2023 Transportation Electrification Plan ("TEP") in accordance with NMSA 1978, 62-8-12 ("EV Statute") and the Recommended Decision issued by Hearing Examiner Elizabeth Hurst on August 30, 2021 (the "RD"). **WHEREUPON**, being duly advised in the premises,

THE COMMISSION FINDS AND CONCLUDES:

1. The Commission has jurisdiction over the parties and the subject matter of this proceeding pursuant to the New Mexico Constitution, the New Mexico Public Utility Act and other applicable law.

2. Due and proper notice of this case has been provided.

3. The Recommended Decision (a copy of which is not attached due to its length), including the statement of the case, discussion, findings of fact, conclusions of law and decretal paragraphs, should be adopted and is incorporated herein by reference except to the extent such are expressly modified or disapproved herein.

4. Exceptions to the RD were filed on September 24, 2021 by PNM, ChargePoint, Inc. ("ChargePoint"), Prosperity Works ("PW"), Western Resource Advocates ("WRA"),

5. Responses to Exceptions were filed on October 4, 2021 by PNM, PW and jointly

by the Coalition for Clean Affordable Energy ("CCAE") and WRA.

6. The TE Statute requires the Commission to consider whether the utility's proposed investments, incentives, programs, and expenditures are:

> (1) reasonably expected to improve the public utility's electrical system efficiency, the integration of variable resources, operational flexibility and system utilization during off-peak hours;
>
> (2) reasonably expected to increase access to the use of electricity as a transportation fuel, with consideration given for increasing such access to low-income users and users in underserved communities;
>
> (3) designed to contribute to the reduction of air pollution and greenhouse gases;
>
> (4) reasonably expected to support increased consumer choices in electric vehicle charging and related infrastructure and services; allow for private capital investments and skilled jobs in related services; and provide customer information and education;
>
> (5) reasonable and prudent, as determined by the commission; and
>
> (6) transparent, incorporating public reporting requirements to inform program design and commission policy.

NMSA 1978, Section 62-8-12(B). (RD, p. 12)

7. PNM proposed two rates specific to the TEP. As originally proposed, the Whole Home Electric Vehicle Charging Rate Pilot ("WHEV rate") would be a time-of use (TOU) rate pilot option for new and current EV drivers under Rate Schedule 1A Residential Service available for up to a cap of 4,000 residential EV drivers. It would apply to all home energy usage, including EV charging, between 10:00 pm and 5:00 am, Monday through Sunday, year-round. The WHEV rate is 50% of PNM's current residential TOU off-peak rate and is intended to send a strong price signal to shift energy use to overnight hours away from peak-load hours. PNM capped the WHEV participation at 4000 to limit the expense of smart meters to $1.8 million. These costs are not included in the TEP because the advanced meter will replace the existing meter for the house and is considered a cost of doing business

8. PNM also proposed Original Rate 3F – Non-Residential Charging Station as the TOU rate pilot available to all non-residential EV charging stations that accept TEP incentives. Charging stations on this rate are required to be separately metered. PNM developed Rate 3F as a two-part rate comprised of a customer charge and an energy charge only, with no demand charge, in order to encourage the installation of non-residential charging stations.

9. PNM's TEP is based upon a "Utility Incentive" model, under which all infrastructure behind the customer meter is installed, owned, and maintained by the customer and funded with the help of utility incentives to offset the initial deployment costs. The type of incentive offered and the requirements to receive that incentive are related to the type of EV charger that will be used. (RD, p. 13)

10. PNM proposed to provide up to 3,000 rebates of up to $500 for the purchase of a residential Level 2 charger. The requirements to claim the residential charger rebate were outlined in Section 7.2.2 of the TEP. To qualify for the charging station rebate, a charger must 1) be a Level 2 charger; 2) be UL 2594 listed; 3) be ENERGY STAR® certified; and 4) have a WIFI or cellular connection. To receive the rebate, the customer must enroll in the Whole-Home EV ("WHEV") pilot rate. 3,000 of the WHEV pilot rate slots will be reserved for customers that receive the residential charger rebate. RD p. 31. PNM also proposed supplemental rebates for customers that self-identify as income-qualified pursuant to Section 5.5 of PNM Exhibit AJB-2. The additional rebate would be up to $1,500 for the installation cost of a qualified residential charger. PNM proposes to make 150 of these supplemental installation rebates available. Customers must also take advantage of the residential charger rebate to qualify for the additional installation incentive. (RD, p. 15, 31)

11. For non-residential customer incentives, PNM proposed i) rebates for the

installation cost of electrical infrastructure behind the meter and up to the base of the charging station ("make-ready infrastructure") for public Direct Current Fast Charging ("DCFC"); ii) rebates for the installation of make-ready infrastructure for public Level 2 charging stations; iii) rebates for the installation cost of make-ready infrastructure for workplace Level 2 charging for non-residential customers; iv) rebates for the installation cost of make-ready infrastructure for Level 2 chargers at multifamily housing (MFH) in LMI communities; and v) rebates for the installation of make-ready infrastructure for mass transit operations that serve LMI communities. (RD, p. 15)

12. To qualify for a rebate, all charging infrastructure must: 1) be listed to conform to the applicable UL standards; 2) be networked to a public charging network; 3) be capable of smart charging capabilities to program charging windows and respond to external signals; and 4) agree to share charging data with PNM. All rebates would only apply to infrastructure installed by customers after the date of implementation of the TEP, and customers may need to provide proof of completed installation, such as a signed statement. (RD, p. 15)

13. In addition, projects that apply for the public DCFC rebates must meet the following qualifications: 1) DC Fast Charger with a minimum 50 kW capacity; 2) accessible to the public; 3) both types of non-proprietary charging plug must be available (SAE Combo, CHAdeMO); and 4) if fees will be charged for use of the charging station, EVSE must have the Europay MasterCard Visa ("EMV") chip reader to allow for point of sale transactions. Other additional point of sale systems such as app-based payment, contactless credit card, and phone payment are permissible but are not required. To receive the DCFC installation rebate, the customer must enroll in the pilot non-residential TOU EV Rate 3F.

14. PNM agreed to certain changes to the original TEP proposed by other parties. For the residential incentives, PNM agreed with: Prosperity Work's request to increasing the Supplemental Incentive for installation to $2000.00; Prosperity Work's recommendation that LMI customer should have instant or point of sale incentives; ChargePoint's recommendation to develop a list of prequalified chargers; and ChargePoint's recommendation to require Energy Star qualified chargers.

15. Certain residential incentives were disputed by parties. These include the RD's recommendation that the number of rebate incentives for residential chargers be increased and that PNM's data sharing requirement be maintained over objections.

16. For non-residential incentives, PNM agreed to include additional budget for forty charging ports for non-LMI MFH customers for a total increase of $100,000 and to increase the MFH incentive amount for LMI customers to $5,000 per port ($10,000 for a dual port charging station) for a total of $200,000 for this subset of customers. Under these changes, the proposed total MFH infrastructure budget would be $300,000. PNM also agreed to reserve 20 percent of the public and workplace Level 2 charging budget for installation of infrastructure in LMI communities.

17. Certain non-residential incentives were also disputed by interveners. The RD recommends that EMV chip reader requirement and a pass through of the TOU rates under Rate 3F to customers be included for non-residential public EV charging station site hosts that accept rebates and incentives under the TEP.

18. PNM's TEP also proposes to allow for 25 percent total budget flexibility, an additional $2.1 million that can be spent in implementation of the program, in case any program category is fully utilized prior to the two-year TEP lifetime. The RD found that this provision was

appropriate to give the flexibility to use and potentially re-deploy the funds in the amounts proposed to respond quickly to the demand patterns it experiences.

PNM EXCEPTION - WHEV RATE

19. The RD accepted WRA's recommendation to increase the number of residential incentives available for Level 2 chargers based on the view that PNM should expect more than half of the expected 6,000 new EV drivers to take the residential charger rebate and be placed on the WHEV rate. The Hearing Examiner found that in order to provide an adequate number of incentives, PNM's proposal of 3,000 customer charging incentives should be increased to 3900, representing 50% of the anticipated 7,800 new EVs in PNM's service area. The RD found that number to be realistic "based upon the evidence PNM has presented and in consideration of the imperative to increase EV adoption and the need to maintain a reasonable budget." The RD found that the proposed budget impact of the increase would be $450,000.00

20. PNM's exception does not object to the RD's recommendation that the number of residential vehicle charger rebates be increased from PNM's proposed 3,000 to 3,900. Rather, PNM argues only that the RD should be further modified because the effect of raising the number of residential rebates would be to potentially reduce the number of WHEV rate slots available to current existing EV drivers from 1,000 to 100.

21. PNM notes that goal of PNM's proposed WHEV pilot rate is to encourage overnight charging of EVs, as well as load-shifting of other household energy use to overnight. The WHEV rate is also required for all drivers receiving a rebate on the purchase of a Level 2 charger. However, PNM's proposed TEP limits the WHEV rate to 4,000 customers. To further the goals of load-shifting to night hours, PNM had contemplated that the WHEV rate would also be available for up to 1,000 current EV drivers who already have a Level 2 charger.

22. To correct for this reduction in current EV drivers eligible for the WHEV rate, PNM argues that the cap on the number of slots for the participating in the WHEV rate should also be expanded by 900 to 4,900 to correspond with the increase in the number of customers receiving the residential rebate. This would avoid a resulting reduction in the number of WHEV rate slots for existing EV drivers.

23. PNM identifies two numerical errors in the RD that should be corrected so that the Commission can correctly assess the potential cost impact of PNM's proposed increase in the participation level to 4,900. PNM notes that while the RD correctly identifies the increase in budget needed to support the 900 additional residential rebates at $500 each as $450K, it elsewhere incorrectly identifies that budget increase as $340K. PNM reiterates that $450K is correct.

24. PNM also notes that RD incorrectly cites PNM's testimony as establishing the cost for 3,000 meters at $1.8M. PNM points out that the testimony actually establishes the $1.8M cost as being for 4000 meters. PNM estimates the expected costs of the advanced meters needed to support the 900 additional WHEV customers will increase to approximately $2.2 million.

25. If the Commission accepts this revision, PNM requests that the increase in the limit on the WHEV rate participation be reflected in the Final Order as a change to the RD. PNM suggests the following language be included in the Final Order: "PNM's proposed limit for participation in the WHEV rate of 4,000 EV owners is increased to 4,900 EV owners. This will allow the potential participation in the WHEV rate of all customers who receive a residential EV charging rebate (3,900) and up to 1,000 customers who drive an electric vehicle and wish to take service under the WHEV rate but do not take advantage of the rebate" and that Decretal Paragraph F of the RD be revised to state: " F. PNM's WHEV Rate Pilot under Rate No. 1A is approved, with the modification that, in the "Rate Qualifications" Section, up to 4,900 EV drivers who take

electric service under Rate Schedule 1A may request the WHEV Pilot Rate."

WRA EXCEPTION - WHEV RATE

26. WRA also takes exception to the RD on this point. WRA makes a similar argument as PNM - that current EV owners could be precluded from participation in the WHEV rate due to the 900 increase in rebate recipients - as well as the converse argument that if more than 100 of the 2,800 current EV owners in PNM's service territory sign up for the WHEV pilot rate, there would not be enough capacity remaining in the WHEV pilot rate program for those receiving the 3,900 rebates.

27. WRA argues that allowing the WHEV rate to be taken up almost completely by rebate recipients with the effect of excluding existing EV owners would be contrary to the statutory objective to "improve the public utility's electrical system efficiency, the integration of variable resources, operational flexibility and system utilization during off-peak hours."

28. WRA argues that to ensure that EV drivers in PNM's service territory have the opportunity to participate in the WHEV rate, the conflict with the rate cap of 4,000 should be cured by increasing the WHEV rate participation by an additional 1,100 from 4,000 to 6,000 rather than 4,900 as accepted by the RD.

29. WRA argues there is insufficient evidence that the budget impact for the cost of time-of-use meters needed for WHEV rate participation outweighs the potential benefit of expanding WHEV rate participation from 4,000 to 6,000 because expanded participation furthers the objectives of the TE statute.

CCAE/WRA Joint Response:

30. CCAE/WRA's Joint Response to PNM's Exception is less a response than a reiteration and expansion of WRA's Exception 1. CCAE/WRA again argue that PNM's proposed

increase in the limit of 4,900 customers eligible for the WHEV rate is still too low to accommodate participation from existing EV drivers. They assert this problem will be compounded if more than 3,900 rebates become available through the 25% budget increase flexibility provision in the TEP. CCAE and WRA argue that increasing the cap to 6000 would accommodate all customers who receive one of the residential rebates plus 2,100 of the 2,800 existing EV owners estimated by PNM.

31. CCAE/WRA further argue that while 6,000 is a reasonable compromise between an unduly restrictive limit and unlimited participation, the Commission should consider removing all limits on WHEV rate participation. CCAE/WRA asserts there is insufficient evidence supporting concerns about the cost impact of the new meters that are required for WHEV participation relative to the benefits of expanded participation.

PNM Response:

32. PNM argues that WRA's suggestion to increase the WHEV rate participation to 6000 should be rejected. PNM argues that the 900 customer increase accepted by the RD appropriately balances the size and cost of the program with the statutory goals of the transportation electrification statute. While PNM acknowledges the goals of improving system efficiency and encouraging off-peak use, PNM argues the primary goal of the TE statute is to incentivize the expansion of transportation electrification by increasing customer adoption of EVs. PNM argues that making the WHEV rate available to customers who already drive an EV would not further the goal of expanding use of EVs, but would have other significant impacts.

33. PNM also points out that increasing the number of WHEV rate participants will increase costs beyond the TEP budget impacts because participants in the WHEV rate require the installation of a new advanced meter and the cost of those advanced meters will be recovered

through rates rather in the TEP budget.

34. PNM also points to testimony that opening the WHEV rate to more existing EV drivers could potentially cause overload on the PNM system if a substantial number of EV drivers were located on the same distribution feeder and offset the benefits of off-peak system utilization. PNM argues that it does not intend to exclude that portion of existing EV drivers not eligible for the WHEV rate indefinitely. PNM argues that limiting WHEV rate participation to 1,000 existing EV drivers will enable PNM to understand the grid impacts of EV charging before PNM opens the rate to all drivers.

COMMISSION DETERMINATION:

35. The Commission finds that PNM's request to approve an increase in the limit for customers eligible to participate in the WHEV rate to 4900 should be approved. However, PNM argues that the potential benefit of expanded WHEV participation does not currently outweigh the cost impact at this time and that the increase to 3900 drivers receiving charger rebates and its requested increase to a total of 4900 customers for WHEV rate subscription currently strikes an appropriate balance in increasing EV use and extending the WHEV rate to EV drivers who are either not eligible for or otherwise do not take the charger rebate. PNM should make a filing with the Commission when the amount of spaces available to customers who to wish to take service under the WHEV rate but do not take the charger rebate reaches 75% of available subscription capacity to enable the Commission to assess whether the WHEV rate should be made available to additional customers.

CHARGEPOINT'S GENERAL EXCEPTION REGARDING COMMISSION JURISDICTION

36. ChargePoint asserts the Commission lacks the authority to require site hosts to offer credit card EMV chip readers on public EV charging stations and to require that site hosts pass on

time-varying prices to drivers. ChargePoint claims that these provisions amount to regulation of EV charging station site hosts and that the Commission lacks jurisdiction to impose such requirements on site hosts because they are not public utilities.

PNM Response:

37. While PNM agrees that the Commission lacks jurisdiction to directly regulate charging station site hosts, it argues the Commission is not exercising jurisdiction over site hosts, but instead is requiring PNM to include certain conditions in its TEP. PNM argues that the Commission can require PNM to impose reasonable conditions on customers who participate in programs with benefits paid for by utility customers and that any effect such conditions may have on the activities of a charging station host result from those site hosts' agreement to participate in those programs.

38. By extension, PNM argues that as a utility, it has a statutory duty to serve its customers and as part of that duty, it can impose reasonable conditions on its customers. PNM asserts it has proposed reasonable program requirements that charging station site hosts must adhere to in exchange for the incentive rebate funded by ratepayers including that site hosts offer specific forms of credit card payments. PNM argues this requirement is supported by substantial evidence in the record that requiring chip-enabled credit cards is the best way, at this stage of transportation electrification in New Mexico, to ensure widespread availability of public charging.

CCAE/WRA Response:

39. CCAE/WRA also agree that the Commission has the authority to set the terms and conditions for utility programs that provide ratepayer funded incentives to ensure that ratepayer money is prudently spent on programs that serve the legislative intent underlying the transportation electrification statute, including the terms and conditions of EV programs and rates offered by

PNM in which customer participation is voluntary.

40. Like PNM, CCAE/WRA agree that NMSA § 62-3-4(A)'s definition of a "public utility" or "utility" when used in the Public Utility Act, shall not include, "any person not otherwise a public utility . . . who engages in the retail distribution of natural gas or electricity for vehicular fuel" and that this excludes electric vehicle charging station site hosts from the definition of public utility. However, CCAE/WRA disagree with ChargePoint's assertion that this provision in NMSA 1978 § 62-3-4A prohibits the Commission from approving TEP participation requirements such as credit card EMV chip readers on public EV charging stations and that site hosts pass on time-varying prices.

41. CCAE/WRA point out that ChargePoint's argument ignores that to participate in an EV-incentivizing expenditure, program, or rate, any customer, including EV charging station site hosts, must voluntarily agree to its terms and thereby receive the ratepayer funded benefits of that program. CCAE/WRA argues that approving the inclusion of such TEP requirements do not constitute regulation of site hosts because a customer's voluntary consent to is not regulation, but a contractual agreement supported by mutual consent and consideration. Without such consent, these requirements are inapplicable to these site hosts.

42. CCAE/WRA further argue that PNM may properly require participants to accept those terms of its TEP and rates that support statutory purposes, including requiring credit card readers to increase access to electricity as a fuel by both the general public and low-income customers, as well as requiring site-hosts to pass through time-variant price signals.

COMMISSION DETERMINATION:

43. The Commission agrees that the conditions established for PNM's proposed TEP are a valid exercise of the Commission's regulatory authority over PNM and do not constitute an

improper exercise of its regulatory authority over ChargePoint or any other customer of PNM that voluntarily seeks to avail itself of the ratepayer funded benefits offered under PNM's TEP.

CHARGEPOINT EXCEPTION – CREDIT CARD EMV CHIP READER REQUIREMENT

44. Under PNM's proposed TEP, public charging stations requiring a fee must at a minimum have an EMV chip reader to allow for point of sale. Other forms of payment are allowed but not required. PNM asserted that this is to ensure EV TEP funds are readily accessible to a greater portion of the public.

45. ChargePoint argues that the TEP requirement that site hosts utilize credit card chip card readers should be rejected because it will increase the cost of hosting EV chargers, decrease the reliability of chargers, create risks for site hosts, and limit the number of charger options available to site hosts through the program. ChargePoint asserts no evidence demonstrates that chip card readers are necessary or ensure EV charging stations are accessible to EV drivers, or provide any other benefits. Alternatively, ChargePoint argues that if the Commission requires charging stations to accept credit cards, "it should simply require that public charging stations have credit card readers, without specifying any particular card-reader technology."

46. ChargePoint argues that the RD erred because PNM failed to provide *prima facie* evidence supporting PNM's assertion that the EMV chip reader requirement would "ensure that at this early juncture, EV charging using TEP funds is readily accessible to a greater portion of the public." ChargePoint asserts PNM does not identify for which "portion of the public" the EMV chip reader would ensure accessibility.

47. ChargePoint disagrees with PNM witness Babej's testimony that EMV chip readers will allow a greater majority of New Mexicans to access payment at charging stations because many New Mexicans do not yet have contactless credit cards and it is not acceptable to rely solely

on charging station manufacturers apps or call centers to process payments. ChargePoint asserts PNM's testimony ignores that ChargePoint and other vendors offer other payment methods such as Google Pay, Apple Pay, free charging network RFID cards, contactless and debit credit cards, and a 1-800 number. ChargePoint further asserts that PNM witness Babej's testimony is unreliable and unsupported by a sufficient sample size because he acknowledged that his conclusion was based on personal experience, including that he does not have a contactless credit card.

48. ChargePoint further argues that PNM did not address "how prevalent contactless credit cards will be in 2022 and future years in New Mexico, how prevalent mobile payments (such as through Google Pay or Apple Pay) are in New Mexico, or the reliability or failure rates of EMV chip readers." ChargePoint therefore argues the "RD erred when it found that there is "sufficient evidence in the record" to support PNM's proposed chip card reader mandate."

49. ChargePoint further argues that the evidence establishes that the **EMV chip reader** requirement is not necessary to promote LMI customer access. ChargePoint asserts testimony establishes that all of ChargePoint's stations designed for public use offer multiple payment options including credit, debit, prepaid cash cards stored on the ChargePoint app; Apple Pay, Google Pay; contactless credit cards, debit cards, ChargePoint RFID cards; apps and RFID cards issued by other major charging networks and used through roaming agreements, and via a 24-hour 1-800 telephone number. It also points to evidence from EVgo, which has installed credit card readers on many of its public DCFCs, that credit card swipes represent less than 1% of transactions on its charging network. ChargePoint asserts this evidence establishes that "it is arguably easier to pay for a charging session at a ChargePoint charger than it is to pay for gasoline because most gasoline stations only offer two payment methods: a chip or stripe reader at the pump and cash at the window."

50. ChargePoint further argues that PNM's EMV chip reader requirement would increase the cost of chargers because adding a credit card EMV chip reader would "increase the lifetime cost of a charging station by approximately $3,000, nearly doubling the cost of a public Level 2 station." ChargePoint argues this will "result in fewer stations being deployed" and harm all customers.

51. ChargePoint also asserts that "certain credit card reader technologies also run the risk of exposing customers to credit card fraud" because "chip and magnetic strip readers are vulnerable to malicious skimming and shimming devices" that expose customers to personal data theft. ChargePoint further argues that "EMV chip readers are also known to have reliability issues when exposed to the elements, which is often the case with charging stations."

52. ChargePoint argues that "many EV chargers do not include EMV chip readers as an available option" and this will limit the choices of chargers available to site hosts that participate in the TEP, contrary to the statutory requirement of considering whether the TEP is "reasonably expected to support increased consumer choices in electric vehicle charging and related infrastructure and services."

53. ChargePoint further argues that no evidence established that EMV chip readers are necessary to reach the low-to-moderate income (LMI) population, rejecting PW's testimony that "[l]ow-income drivers are less likely to have access to alternative payment methods, such as proprietary smartphone apps."

54. ChargePoint further argues there was no evidence presented demonstrating that there are or will be EV drivers who will be unable to use an EV charging station that does not have a EMV chip reader. ChargePoint asserts testimony from PW witness Ona Porter that low-income drivers lack access to smartphone apps was undermined when, at hearing, Ms. Porter described a

successful college savings program run by PW that relies on participants having smartphones in order to make bank deposits. ChargePoint specifically points out that Ms. Porter also acknowledged that LMI communities often rely on prepaid cash cards and that many prepaid cash cards lack EMV chips.

55. ChargePoint instead points out that its app is "free for any EV driver to download and use to link their preferred payment method, including any credit card, debit card, or prepaid cash card. Similarly, anyone with a smartphone can use mobile payment methods like Apple Pay or Google Pay."

56. ChargePoint argues against PW witness Ona Porter's assertion that app-based payments would be impossible "in the large swaths of New Mexico that lack adequate cell phone service" noting that Ms. Porter acknowledged that many charging stations rely on a cell signal to connect to the internet to process payments.

PNM Response:

57. PNM opposes ChargePoint's exception and argues that substantial evidence in the record does establish that many New Mexicans do not yet have contactless credit cards and supports the requirement that charging stations be accessible to customers who use all types of payments in order to increase transportation electrification by making the charging experience accessible to all users of EVs. PNM argues it is unacceptable to rely solely on charging station apps developed by the manufacturers or call centers to process payments. PNM asserts that requiring only specific types of payment sources could constitute a barrier contrary to the statutory mandate to remove barriers to EV adoption.

58. PNM opposes ChargePoint's argument that a EMV chip reader requirement would increase costs, create security risks, and limit choices for site hosts rather than increase

accessibility to charging. PNM also points out that California regulators recently adopted a payment standard for public charging stations that includes chip-enabled card readers.

59. PNM asserts that "charging stations installed with the assistance of customer funds that will charge a fee for charging an EV should meet standards for accessibility that will be the most equitable possible." PNM argues that contactless credit cards do not currently meet these standards and the approach adopted by the RD "will allow a greater number of New Mexicans to access payment at charging stations" with the understanding "that payment method requirements are not a blanket requirement for *all* charging stations in PNM's service area, and not even a requirement for all charging stations for which a customer receives a rebate: the requirement applies *only to public charging stations for which EV drivers must pay a fee*. Therefore, only those PNM customers who receive a rebate to install and operate a public charging station that will require the charging customer to pay a fee must comply with this requirement."

PW Response:

60. In opposition to ChargePoint, PW argues "the record shows that Europay, MasterCard, and Visa ("EMV") chip readers are important to increasing accessibility of electricity as a vehicle fuel, particularly for low-income customers. ChargePoint has not rebutted this evidence."

61. PW argues that common sense supports requiring TEP participant site hosts to utilize EMV chip readers among other payment options as "an important strategy for ensuring that ratepayer-supported chargers are broadly accessible." PW points the testimony of WRA expert Aaron Kressig: "These requirements will ensure that ratepayer funds are being used to support charging stations which can be accessed by all EV drivers, regardless of what EV they drive and what charging network they subscribe to. These open access requirements will help to ensure all

EV drivers can access public charging stations funded by PNM's TEP."

62. PW argues that the broader issue of accessibility to EV charging infrastructure by all drivers is magnified in low-income communities and "people should be able to pay for public charging as easily as they pay for gasoline."

COMMISSION DETERMINATION:

63. The Commission finds that the RD correctly found there was sufficient evidence in the record to approve PNM's TEP requirement that EV charging station site hosts requiring a fee must at a minimum have an EMV chip reader to allow for point of sales in order to ensure non-residential EV charging station site hosts utilizing TEP funds are readily accessible to the greatest portion of the public possible, including LMI users.

64. While ChargePoint focuses its challenges on the conclusions drawn about LMI users, concerns about ensuring all EV drivers will have ready ability to pay for EV charging accord with express statutory purpose of ensuring a TEP promotes consumer choice and consumer use. The Commission finds that the PNM TEP requirement that public charging stations site hosts meet accessibility needs by providing point of service payment through the use of EMV chip readers is reasonable. That ChargePoint offers multiple other payment options should be applauded as also promoting these concerns. However, the availability of such other options does not render PNM's EMV chip reader requirement unreasonable or otherwise invalid. Indeed, while ChargePoint relies on testimony from Prosperity Works that LMI communities often rely on prepaid cash cards and that many prepaid cash cards lack EMV chips, these facts do not support ChargePoint's assertion that the EMV chip reader requirement is invalid. To the contrary, this but instead supports a finding that public charging station site hosts receiving TEP incentives should endeavor to provide the fullest possible range of payment options, but at a minimum should be required to provide EMV

chip readers. Requiring credit card readers will still promote ease of use for many, which will enable EV users to pay for public charging "as easily as they pay for gasoline."

CHARGEPOINT EXCEPTION - REQUIREMENT THAT SITE HOSTS PASS ON TIME-VARYING PRICES TO EV DRIVERS

65. ChargePoint takes exception to the RD's acceptance of CCAE's recommendation that as a default, EV charging station site hosts receiving 'Non-residential Infrastructure Rebates' should be required to pass through the time-variant price signals on the underlying TOU rates to EV drivers."

66. ChargePoint argues that site hosts do not necessarily price charging in a way that accommodates time-varying price signals. As an example, ChargePoint notes that site hosts may offer free or low-cost charging to attract customers or site hosts "may prefer to charge a flat per-session fee or an hourly fee, rather than a per-kWh fee." ChargePoint asserts site hosts should be free to price charging in a manner that best supports their own business goals. ChargePoint asserts that there is no need to require site hosts to pass on time-varying price signals to end users as a default because site hosts will likely be motivated to do so where appropriate to their business model. ChargePoint argues:

> CCAE provided no details about how its proposed "default arrangement" would work or how a site host would comply with such a requirement. Would any pricing scheme that charges EV drivers a higher price during PNM's peak hours meet this requirement? Or would site hosts need to implement the same on-peak/off-peak ratio as the tariffed rate? If site hosts were required to implement a pricing scheme with the same on-peak/off-peak ratio as the tariffed rate, would they need to include or exclude the cost of riders in this calculation? Would site hosts need to adopt the same on-peak time periods as the tariffed rate, or could they create their own on-peak time periods? These are just a few of the implementation questions that would need to be answered for PNM to implement such a requirement, but CCAE provided no details that would answer these questions. Even more problematically, the RD also fails to answer any of these questions.

67. ChargePoint further argues:

> [S]ite hosts need flexibility to implement charging solutions for their customers and believes

> site hosts are in the best position to decide how to price charging. EV charging station site hosts install EV chargers for a wide variety of reasons and to support a wide variety of other goals, such as attracting EV drivers into their business. Site hosts should be free to determine the pricing scheme that will best support their own unique goals. Again, some site hosts will want to implement peak pricing to reflect their own cost of electricity, but since electricity is only one of several costs of hosting EV charging stations, any site host that determines peak pricing is not appropriate for their business model should not be required to implement such a pricing scheme, even as a "default arrangement" as CCAE recommended. As an alternative to a requirement that site host pass along a pricing structure to drivers, PNM should provide guidance and education to site hosts to encourage them to charge time-varying prices and support optimal grid use for EV charging stations.

68. ChargePoint asserts that imposing the default requirement will simply discourage site host participation and the TEP should "support site hosts' unique goals and business models by providing them with as much flexibility as possible, rather than requiring them to opt out of a "default arrangement."

PNM Response:

PNM took no position on this exception.

CCAE/WRA Response:

69. CCAE/WRA argue that requiring EV charging station site hosts that receive non-residential infrastructure rebates to pass through the time-variant price signals on underlying TOU rates to end-user EV drivers as a default is reasonable. They note that "widespread transportation electrification can put downward pressure on electric rates by using the spare capacity on the grid that is available at night" and "a failure to pass on time variant price signals could result in worsening grid conditions."

70. CCAE/WRA cite to CCAE witness Mr. Baumhefner's testimony that "if drivers have no reason to change their behavior, they will just charge their vehicles upon arrival regardless of whether that helps or hurts the grid, thus they need to be incentivized with Time of Use Rates that pass on price signals to drivers." They argue: "Time of use rates optimize the grid and better

inform customers of real time rates, rather than sites setting prices that may or may not reflect the real time rates."

COMMISSION DETERMINATION:

71. The RD recommends approval of CCAE's alternative recommendation, finding that CCAE's "default option for all customers receiving non-residential infrastructure incentives provides encouragement to site hosts to adopt a form of time-variant pricing, but it also provides the flexibility site hosts may need to develop successful business plans that are necessary to encourage the extensive deployment of privately owned charging stations. The requirement will potentially better ensure that the investments made by the Company in residential EV charging can be "reasonably expected to improve the public utility's electrical system efficiency, the integration of variable resources, operational flexibility and system utilization during off-peak hours," as is required by § 62-8-12(B)."

72. The Commission agrees that site hosts will retain sufficient discretion to implement business models and marketing strategies even while passing on the time varying price signals to drivers. The Commission agrees with CCAE that passing those time-varying price signals is important to the desired load shifting "because if price signals are not visible to the EV drivers they will simply charge whenever they arrive at their destination."

CHARGEPOINT EXCEPTION - CHARGING DATA

73. ChargePoint argues that the requirement the charging stations have data connectivity to enable PNM to collect charging data from EV chargers is "needlessly burdensome" and should be eliminated. ChargePoint asserts PNM can instead monitor utilization rates with meter data and confirm that site hosts have connected only chargers to their dedicated EV charging service by requiring installers to certify that chargers are the only load on a new dedicated service

and performing a limited number of audits.

74. ChargePoint argues that site hosts should not have to incur possible additional network service fees to share their charging data and these costs are "likely to discourage program participation." In addition, ChargePoint asserts that "many commercial site hosts consider EV charging data to be competitively sensitive business data."

75. ChargePoint concludes its own interests in the data should control because PNM has failed to prove that its interest in such data is sufficient to support the RD's conclusion that: "Data collected initially can be very important to the foundation of future TEPs" and that "PNM must have sufficient and reliable data from all the various types of participants to be able to validate, change or eliminate programs as necessary, especially when the payment of the TEP expenses is by PNM's customers." ChargePoint asserts that it supports PNM's proposal to require charging infrastructure to be smart and network-capable so that PNM can use that infrastructure for any managed charging programs that it may decide to propose in the future, but it opposes requiring site hosts to share data now because there is no evidence that collecting this data will help PNM "validate, change or eliminate programs as necessary."

76. ChargePoint argues the Commission should modify the RD to reject PNM's proposal to collect any and all charging data from EV charging stations that participate in the TEP and proposes that as an alternative, the Commission could allow PNM to collect data from residential customers, who do not have competitive concerns.

PNM Response:

77. PNM argues that substantial evidence in the record supports its need for charging data to properly evaluate the success of the program. PNM states it needs "granular data" from non-residential stations to understand usage patterns and the actual demand and energy use. PNM

asserts charging data for all customers is required.

78. PNM argues that charging stations must have data connectivity and that the charging data be made available to the utility. "Networked charging infrastructure will be important to implement managed charging programs, such as demand response, in the future. By missing the opportunity to install networked charging infrastructure at the outset of the TEP, PNM would be negatively impacting the future adoption of any proposed managed charging programs." PNM further notes that because it is not requiring submetering for residential charging infrastructure in the WHEV rate, it has no way to identify load from a home residence compared to the EV charging load. PNM maintains that access to the data collected by the networked charger will assist in analyzing the data to better inform rates in the future.

COMMISSION DETERMINATION:

79. The Commission finds that PNM's interest in the charging data is substantial in light of the need to assess the performance and success of the measures under the proposed TEP so that future proposed TEPs will be informed by such data. While ChargePoint asserts its own interest in such data, that interest does not overcome the broader public interest of the EV statute pursuant to which PNM is acting. ChargePoint retains the option to opt out of receiving incentives under the TEP if it feels that its own interests are compromised by the charging data sharing requirement.

CHARGEPOINT EXCEPTION - RATE 3F

80. ChargePoint takes exception to the TEP's requirement that charging site hosts that participate in the DCFC rebate program must take service under the new Rate 3F Non-Residential Charging Station Pilot Rate. The rate structure is intended to encourage the installation of non-residential charging stations through the use of a customer charge and an energy charge only; with

no demand charge. PNM indicates this will avoid the disproportionately large demand charge for charging stations that would result under Rate Schedule 3C-General Power Low Load Factor due to "the short but large spikes in demand when cars are charging." Rate 3F will be available to all non-residential EV charging stations, but is required for charging site hosts participating in the DCFC rebate program.

81. ChargePoint acknowledges that PNM designed Rate 3F to incentivize site hosts to establish charging stations, but argues that does not justify prohibiting site hosts that are choosing to establish charging stations and desiring to participate in the TEP from taking service on another cost-based commercial rate if the site host prefers the other rate and qualifies for it. ChargePoint asserts: "while many DCFC site hosts will likely prefer the rate to another rate with demand charges when station utilization is low, rates with demand charges can actually be advantageous at higher utilization rates because the energy charges are generally lower than they are for rates that do not have demand charges (such as Rate 3F)." ChargePoint asserts: "To put it simply, site hosts should not be forced to take service on a rate that results in higher bills if another applicable rate is available."

PNM Response:

82. PNM opposes removing the requirement that site hosts who take advantage of the DCFC rebate take service under Rate 3F. PNM believes that it is reasonable to require that customers accepting a rebate to take service under proposed Rate 3F because Rate 3F is designed to both correlate to times when energy is less expensive and places the additional DCFC load on the rate that provides the biggest benefit to the system.

CCAE/WRA Response:

83. CCAE/WRA support the RD's finding that Rate 3F should not be optional and is

supported by the HE's finding that time-variant rates are necessary because electric vehicles can "substantially change the load curve when EV's start causing load on the system." (RD, p. 29).

COMMISSION DETERMINATION:

84. The RD correctly finds "PNM's incentive program requirement to take service under proposed Rate 3F was specifically designed as an energy-only rate pilot to incentivize the installation of charging stations and thus comports with the TE Statute." The Commission agrees with CCAE/WRA that time-variant rates are important and notes the RD's further recognition that "If EV drivers are not incentivized and habituated to charge at ideal times, the expected increased load could come at times that exacerbate demands on the system, such as at the end of the work day when many people arrive home and begin using more residential electricity. Therefore, encouraging new EV charging to occur at the times when the PNM system is least utilized is important. By setting pricing windows to encourage customers to charge during off-peak times, EVs can utilize the system when it is underutilized, thereby minimizing the need for further system upgrades. Additionally, setting pricing windows to coincide with variable generation such as wind and solar can help match load with generation."

85. Moreover, the RD found this requirement was reasonable given that the TEP does not require all charging station site hosts to take service under Rate 3F and "customers that do not accept PNM rebates are free to obtain electric service under another appropriate rate for which they qualify." The Commission agrees that requiring DCFC charging stations to take service under 3F is a reasonable requirement of accepting incentive funding under the TEP.

CHARGEPOINT EXCEPTION – THE COMMISSION SHOULD CLARIFY THE RD THAT COMMERCIAL SITE HOSTS THAT INSTALL LEVEL 2 CHARGING STATIONS ARE NOT SUBJECT RATE 3F AND MAY INSTALL THE LEVEL 2 CHARGING STATIONS BEHIND THE METER

86. ChargePoint argues that the RD's discussion concerning PNM's requirement that

DCFC site hosts participating in the DCFC rebate program take service under Rate 3F makes statements that fail to distinguish between DCFC and Level 2 site hosts. Charge Point is concerned that these statements appear to imply that the requirement of taking service under Rate 3F shall apply to all commercial site hosts as it does not distinguish between DCFC and Level 2 charger site hosts. ChargePoint requests clarification that the RD did not intend to alter PNM's original proposal in the TEP that public Level 2 chargers "can either be [on] a dedicated service or behind an existing customer meter" and therefore, Level 2 chargers do not need to be separately metered or to take service on a specific rate such as Rate 3F.

87. ChargePoint requests that the Commission clarify that the RD does not require commercial customers that install only Level 2 charging stations through the TEP to install separate meters and take service on Rate 3F and that commercial customers that only install Level 2 chargers are permitted to install those charges behind their existing meters as PNM proposed.

PNM Response:

88. PNM agrees with this exception and believes the Commission should clarify the Recommended Decision on this point. Level 2 stations should be able to be installed on existing electric services. PNM's proposal did not require customers that install Level 2 charging stations to install separate service and take service on Rate 3F.

COMMISSION DETERMINATION:

89. ChargePoint's exception does not identify the specific language that it asserts raises the ambiguity that is the subject of its exception and merely states that it is on page 67 of the RD. It appears that ChargePoint may be concerned about language stating that Rate 3F was specifically designed as an energy only rate pilot to incentivize the installation of charging stations. Elsewhere in the discussion, it appears clear that the charging stations to which the Rate 3F requirements

apply are DCFC charging stations for which a customer has accepted a TEP rebate. Nonetheless, the Commission will clarify that customers that install Level 2 charging stations are not required to install separate service for those charging stations and take that service under Rate 3F.

PROSPERITY WORKS EXCEPTION NO. 1

90. PW takes exception to the RD's acceptance of PNM's TEP requirement that all residential customers must connect their EV chargers to Wi-Fi or cellular service in order to receive incentives under the TEP. PW argues that this requirement unnecessarily excludes LMI customers who cannot afford Wi-Fi.

91. PW points to evidence in the record it asserts establishes that approximately 25–30% of New Mexicans lack access to Wi-Fi and includes many low-income residences. As evidence, PW points out that during the COVID pandemic many low-income households faced difficulty accessing education due to the lack of internet connections. PW further notes that the PNM's failure to include financial assistance for the required Wi-Fi connection to address this disparity does not justify excluding customers who cannot afford Wi-Fi from the residential charging incentives.

92. PW proposes that PNM should instead either collect data only from those participants who voluntarily connect their chargers to Wi-Fi; require all customers who already have Wi-Fi to connect their chargers to it; or eliminate the internet connection requirement for low-income customers.

93. PW argues that PNM's claimed need for data from "all the various types of participants" improperly assumes that data from customers with Wi-Fi will differ from that of customers who cannot afford Wi-Fi. PW asserts that "data from the "vast majority" of customers who would voluntarily interconnect their smart chargers to the internet would provide the utility a

reasonable opportunity to collect data from their customers without excluding customers who cannot afford Wi-Fi." PW argues that PNM could require only a "sample of participating residential customers to connect their chargers to the internet" and thereby narrow its data collection requirement and "not undermine access to the program for low-income customers."

PNM Response:

94. PNM asserts that access to charging data is necessary in order to properly evaluate the success of the TEP. PNM argues that because the TEP does not require a submeter for customers to participate in the WHEV rate, PNM would have access to charging data and therefore no insight into customer charging behavior. PNM asserts it needs to assess actual demand and energy use and charging data for all charging stations in this pilot TEP is necessary rather than just a sample.

COMMISSION DETERMINATION:

95. The RD accepted PNM's reasoning for the data sharing requirement, noting: "Data collected initially can be very important to the foundation of future TEPs. Further, PNM must have sufficient and reliable data from all the various types of participants to be able to validate, change or eliminate programs as necessary, especially when the payment of the TEP expenses is by PNM's customers." (RD pp. 38–39)

96. The Commission agrees with the RD that at this early stage, the collection of data from all customers is necessary for planning the successful implementation of future TEPs should take priority over attempting to incentive universal participation.

PROSPERITY WORKS EXCEPTION NO. 2

97. PW takes exception to the RD's failure to accept PW's recommendation that PNM be required to "make all information about its residential electric vehicle programs and education

materials about electric vehicles equally available on the English and Spanish versions of its website."

98. PW cites the RD's analysis as stating "the Hearing Examiner believes that …[PNM's] customer service and program customer service and program materials might be more effective for some of its customers if they were in Spanish. However, the Hearing Examiner does not find that this modification to be [sic] required by the TE Statute."

99. PW asserts the RD's analysis is arbitrary and capricious because "The RD improperly rejects the proposed modification without identifying any harms that the Hearing Examiner believes would outweigh these benefits." PW argues that PNM's concern that "it might take an unreasonable amount of program resources to translate a software package into Spanish if they are licensing a web tool from a third-party vendor that does not market the tool in Spanish, the Commission should at a minimum require PNM to license these tools in Spanish *whenever they are available*."

PNM Response:

100. PNM asserts the RD correctly concluded that a requirement to translate all web content into Spanish would therefore not be practical or economical. PNM notes that PNM witness Babej agreed that *PNM-created* content about EVs will be made available in English and Spanish. PNM also testified that it does translate some material into Spanish and PNM agreed that some TEP program information as well as some general EV information should be made available in Spanish. PNM notes in its normal utility operations it does not normally translate all of marketing material into Spanish. PNM asserts a requirement that it translate all material into Spanish would not be realistic to implement because PNM uses third party software packages to provide information, including information about EVs, to customers. PNM asserts a requirement that it

translate all web content would require PNM to significantly increase the budget to translate another company's software package. PNM is not certain this would be feasible. PNM further argues that it has customers with many linguistic backgrounds and while translation into Spanish would serve a subset of these customers, it would not necessarily be feasible to remove the language barriers for all possible customers.

COMMISSION DETERMINATION:

101. The Commission agrees with PNM that the RD did consider harms in the form of the practical barriers faced in providing informational materials to customers with different language needs. The Commission also agrees with both PW and the RD that the ability to provide program informational material in a customer's primary language would always be an effective means to achieve the purposes of disseminating such information. However, the Commission also recognizes that there may be limitations on the ability of PNM to achieve this goal in a cost-effective manner, especially when faced with the reality that the number of languages PNM would likely need to address is significant. The Commission agrees that PNM should be cognizant of and endeavor to utilize software that has multi-language capability when making its choice of which software to utilize. The Commission declines PW's request that PNM be required to make its software choices based solely on criterion that any specific software may have the capability to be licensed in any one specific language. PNM's choices should none-the-less take into consideration whether the software it considers would be effective in reaching the greatest number of customers with language translation needs.

PROSPERITY WORKS EXCEPTION # 3

102. PW similarly takes exception to the RD's failure to accept its suggestion that the Commission require at least one the two TEP staff PNM intends to hire be able to provide customer service in Spanish.

103. PW rejects PNM's stated intention to utilize some of its "over 160 Spanish speakers, many of whom are able to assist with translation services when the need arises" as insufficient substitutes" for the TEP staff members who would have expertise in the TEP.

104. PW asserts the RD's rationale for rejecting PW's proposed modification is legally inadequate for the same reason as its rationale for not modifying the TEP to require PNM to post all web content in Spanish.

PNM Response

105. PNM argues the RD properly considered that requiring PNM to hire at least one of the two full-time employees to be a Spanish speaker would limit the pool of qualified candidates for the positions. PNM notes that it does not have specific language requirements for its employees based on which customer programs those employees may be involved with. PNM notes that it employs over 160 Spanish speakers and those employees are utilized to assist in translation when the need arises.

106. PNM again notes that it serves customers with many different linguistic backgrounds across many customer programs and a requirement that PNM provide a specific Spanish-language hiring criterion would ignore the diverse linguistic needs of PNM's other customers.

COMMISSION DETERMINATION:

107. The Commission finds that the RD's finding that imposing a requirement that PNM hire persons to assist with customer service activities who are proficient in several languages,

including Spanish, would be unnecessarily restrictive given that no similar requirement is imposed for PNM's other customer service employees. Again, the Commission encourages PNM to make efforts to include multiple language proficiency, including Spanish, a consideration in hiring customer service personnel as PNM's response indicates it has numerous multiple language speakers on staff.

IT IS THEREFORE ORDERED:

A. Except as it may be expressly modified or disapproved herein, as stated in the findings and conclusions above, the Hearing Examiner's August 30, 2021 Recommended Decision, including decretal paragraphs, is incorporated herein by reference as if fully set forth herein, and is adopted, approved and accepted as the Order of the Commission.

B. PNM's proposed limit for participation in the WHEV rate of 4,000 EV owners is increased to 4,900 EV owners to permit the potential participation in the WHEV rate of all customers who receive a residential EV charging rebate (3,900) and up to 1,000 customers who drive an electric vehicle and wish to take service under the WHEV rate but do not take advantage of the rebate. Decretal Paragraph F of the RD is revised to state: "F. PNM's WHEV Rate Pilot under Rate No. 1A is approved, with the modification that, in the "Rate Qualifications" Section, up to 4,900 EV drivers who take electric service under Rate Schedule 1A may request the WHEV Pilot Rate."

C. PNM shall make a filing with the Commission when the amount of spaces available to customers who to wish to take service under the WHEV rate but do not take the charger rebate reaches 75% of available subscription capacity to enable the Commission to assess whether the WHEV rate should be made available to additional customers.

D. All exceptions, pending motions, requests and any other matter not specifically

ruled on during the hearing in this matter or in this Final Order are deemed disposed of consistent with this Final Order.

E. This Order is effective immediately.

F. This docket is closed.

G. Copies of this Order shall be e-mailed to all persons on the attached Certificate of Service if their e-mail addresses are known, and otherwise shall be sent via regular mail.

ISSUED under the Seal of the Commission at Santa Fe, New Mexico, this 10th day of November, 2021.

NEW MEXICO PUBLIC REGULATION COMMISSION

/s/ Cynthia B. Hall, electronically signed
CYNTHIA B. HALL, COMMISSIONER DISTRICT 1

/s/ Jefferson L. Byrd, electronically signed
JEFFERSON L. BYRD, COMMISSIONER DISTRICT 2

/s/ Joseph M. Maestas, electronically signed
JOSEPH M. MAESTAS, COMMISSIONER DISTRICT 3

/s/ Theresa Becenti-Aguilar, electronically signed
THERESA BECENTI-AGUILAR, COMMISSIONER DISTRICT 4

/s/ Stephen Fischmann, electronically signed
STEPHEN FISCHMANN, COMMISSIONER DISTRICT 5

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE COMPANY OF NEW MEXICO'S APPLICATION FOR APPROVAL OF ITS 2022-2023 TRANSPORTATION ELECTRIFICATION PROGRAM	))))	**Case No. 20-00237-UT**

CERTIFICATE OF SERVICE

I CERTIFY that on this date I sent, via email only, to the parties listed below a true and correct copy of the **Final Order Adopting Recommended Decision.**

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DATED this November 12th, 2021

NEW MEXICO PUBLIC REGULATION COMMISSION

/s/ Isaac Sullivan-Leshin, electronically signed
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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 18-E-0138 - Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure.

ORDER ESTABLISHING ELECTRIC VEHICLE INFRASTRUCTURE MAKE-READY PROGRAM AND OTHER PROGRAMS

Issued and Effective: July 16, 2020

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on July 16, 2020

COMMISSIONERS PRESENT:

John B. Rhodes, Chair
Diane X. Burman, concurring in part and dissenting in part
James S. Alesi
Tracey A. Edwards
John B. Howard

CASE 18-E-0138 - Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure.

ORDER ESTABLISHING ELECTRIC VEHICLE INFRASTRUCTURE MAKE-READY PROGRAM AND OTHER PROGRAMS

(Issued and Effective July 16, 2020)

BY THE COMMISSION:

INTRODUCTION

On April 24, 2018, the Public Service Commission (Commission) commenced this proceeding to identify cost-effective approaches for electric utilities to support the infrastructure and equipment necessary to accommodate increased electricity demands associated with the deployment of Electric Vehicles (EVs).[1] The EV Instituting Order recognized that EVs provide various potential benefits for the State and that ensuring adequate EV supply equipment and infrastructure (EV Infrastructure) is critical to securing these benefits and achieving the State's environmental and clean energy goals. As the Commission noted at that time, electrification of the

[1] Case 18-E-0138, Order Instituting Proceeding (issued April 24, 2018) (EV Instituting Order).

State's transportation sector is needed to meet the "[New York] State Energy Plan (SEP) targets of reducing greenhouse gas emissions 40 percent below 1990 levels by 2030, and 80 percent below 1990 levels by 2050."[2]

Since then, the State enacted the Climate Leadership and Community Protection Act (the CLCPA), which codified the 2030 target and increased the 2050 objective by establishing a State goal to "reduce greenhouse gas emissions from all anthropogenic sources 100 [percent] over 1990 levels by the year 2050, with an incremental target of at least a 40 percent reduction in climate pollution by the year 2030."[3] The CLCPA also directed the Commission to establish a renewable energy program whereby jurisdictional load serving entities (LSEs) have secured adequate amounts of renewable energy resources to serve at least 70% of load in 2030 and that there are zero emissions in 2040 associated with electrical demand, which the Commission is considering in Case 15-E-0302.

In addition, the CLCPA calls for a newly formed Climate Action Council to make recommendations to promote the beneficial electrification of the transportation sector in order to reduce greenhouse gas emissions.[4] While the Commission expects the Climate Action Council's recommendations will provide a valuable framework for the State to follow, the

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[2] EV Instituting Order, p. 1; see also, The Energy to Lead: New York State Energy Plan Vol. I, p. 30.

[3] Chapter 106 of the Laws of 2019. See also, the Climate Act Fact Sheet, available at: https://climate.ny.gov/-/media/CLCPA/Files/CLCPA-Fact-Sheet.pdf.

[4] The Climate Action Council is a 22-member committee that will prepare a Scoping Plan, oversee sector-specific advisory panels and working groups, and work in consultation with the Climate Justice Working Group and the Environmental Justice Advisory Group.

actions undertaken in this proceeding are intended to meet near-term objectives that are appropriate and necessary to advance the State's clean energy and infrastructure requirements.[5]

Electrifying the transportation sector can reduce harmful carbon dioxide, methane, nitrogen oxides, sulfur dioxide, hydrocarbons, carbon monoxide, and particulate matter emissions. New York's transportation sector is responsible for more of the State's greenhouse gas emissions than any other sector.[6] By reducing the use of diesel and gasoline fuels in vehicles now, New York State can significantly improve air quality. As the mix of energy generation grows cleaner per recent State mandates, the environmental benefits of an electrified transportation sector will grow.

The EV Initiating Order noted that in 2013, Governor Cuomo formalized New York State's commitment to transportation electrification by signing on to the Multi-State Zero Emissions Vehicle Memorandum of Understanding (ZEV MOU).[7] Under the ZEV MOU, New York is one of eight states with a collective target of

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[5] The analysis recently presented to the Climate Action Council suggests that the CLCPA will drive approximately 60 to 70 percent of sales of zero emissions vehicles in the light-duty market, or 1.8 to 2.2 million zero emissions vehicles to be on New York's roads by 2030. See New York State Decarbonization Pathways Analysis: Summary of Draft Findings (June 24, 2020). Available at: file:///C:/Users/l323ps.SVC.000/Downloads/2020-06-24-NYS-Decarbonization-Pathways-CAC-Presentation%20(1).pdf.

[6] See New York State Department of Conservation, Reducing Greenhouse Gas Emissions: Limiting Future Impacts of Climate Change. Available at: https://www.dec.ny.gov/energy/99223.html.

[7] State Zero-Emission Vehicle Programs, Memorandum of Understanding available at: dec.ny.gov/docs/air_pdf/zevmou.pdf.

at least 3.3 million Zero Emissions Vehicles[8] on the road by 2025, and has committed to work together with other signatory states to establish charging and fueling infrastructure that will adequately support this number of vehicles. New York's share of the ZEV MOU is to have approximately 850,000 Zero Emissions Vehicles registered in New York by 2025.

The EV Instituting Order sought to support the State's ZEV MOU targets by removing obstacles to EV adoption and to ensure critical EV supply equipment and infrastructure (EV Infrastructure) is in place. To address these matters, the Commission directed Department of Public Service Staff (Staff) to collaborate with stakeholders to identify and address immediate and long-term actions to best support ZEV market growth, and to issue a whitepaper that addresses these topics.

On January 13, 2020, Staff filed a "Whitepaper Regarding Electric Vehicle Supply Equipment and Infrastructure Deployment" (the Whitepaper), as directed by the Commission. In the Whitepaper, Staff estimates that New York State will need between 20,000 and 50,000 additional public Level 2 chargers,[9] between 35,000 and 80,000 additional Level 2 workplace-sited chargers, and between 1,000 and 4,000 additional direct current fast charger (DC Fast Charger) ports to support the ZEV MOU

[8] Zero Emissions Vehicles include plug-in hybrid electric vehicles, battery electric vehicles, and hydrogen fuel cell vehicles. The actions taken by this Order primarily support a growing battery electric vehicle market and support existing and expected plug-in hybrid electric vehicles.

[9] Level 2 chargers operate at 240 volts, have fixed cables that connect to an EV, and are at least two times faster than Level 1 charging, where power is drawn from a standard 120 volt wall outlet. Level 2 charging speeds vary depending on the size of the EV's battery, but as an example, a Chevy Bolt EV draws approximately 25 miles of range per hour.

goal.[10] To reach these targets, Staff recommends establishing a statewide "Make-Ready Program" that would provide incentives for the installation of light-duty EV Infrastructure for both Level 2 and DC Fast Charger stations. The Make-Ready Program would cover up to 90 percent of the eligible costs needed to prepare a site for EV charging if all eligibility criteria are met, or 50 percent of the costs if the station does not meet the public accessibility or standardized plug eligibility requirements.[11] In addition, the Whitepaper contains many recommendations regarding tools for the utilities to develop to meet the expected increase in EV charging stations, and recommendations for advancing fleet electrification.

In this Order, the Commission adopts Staff's Proposed Make-Ready Program with modifications. Additionally, the Commission directs the utilities to establish a Medium-Duty and Heavy-Duty Make-Ready Pilot Program, and a Fleet Assessment Service. In order to support electrifying public transportation, the Commission directs Con Edison, National Grid, and RG&E to establish the Transit Authority Make-Ready Program to work with specific transit authorities in their efforts to achieve 25 percent electrification by 2025. The

[10] DC Fast Chargers, also known as Level 3 chargers, operate at the highest power levels and are the fastest charging option for battery electric vehicles. DC Fast Chargers operate at between 400 – 1,000 volts and while charging speeds vary based on battery size, state of charge, and other factors, can charge an EV up to 80 percent in 20 - 30 minutes. Plug-in hybrid electric vehicles typically cannot use DC Fast Chargers.

[11] The Whitepaper recommended that Level 2 plugs must use the North American standard for electrical connectors for electric vehicles as maintained by the Society of Automotive Engineers International (SAE) as an eligibility threshold. In the event an alternate standard is adopted plugs of the new standard would be eligible for the incentive.

Commission also directs the New York State Energy Research and Development Authority (NYSERDA) to establish an Environmental Justice Community Clean Vehicles Transformation Prize, a Clean Personal Mobility Prize, and a Clean Medium-Duty and Heavy-Duty Innovation Prize to equitably deliver transportation electrification benefits throughout the State. These actions will encourage the accelerated, forward-thinking development of EV charging infrastructure and promote the State's environmental and clean energy goals.

In sum, electrification is key to decarbonizing the transportation sector, given the powerful progress and trajectory seen decarbonizing the power sector. Initially the focus is on light-duty vehicles, where the prospect for near-term progress is greatest and where existing commitments provide clear direction. This, in turn, requires charging infrastructure. The Whitepaper and this Order propose that appropriate utility investments are powerful, sound, and necessary. Make-ready investments by utilities can support and complement charger investments by private developers to jointly enable the complete charging infrastructure required, and such make-ready investments are aligned with utility strengths and responsibilities. These utility investments can enable the market to deploy at the needed scale, while ensuring that market developers are motivated to deploy their own investments soundly, in locations and configurations that promise best utilization and economics.

The needed quantity and mix of this make-ready infrastructure deployment have been estimated based on the best available vehicle and mileage projections and targets. Program rules for this deployment, as well as certain innovative projects, will ensure best access to charging and to clean transportation for all New Yorkers, including communities that

would otherwise be underserved. This scale of deployment and the requirements for accessibility to the public and to disadvantaged communities, especially with the application of strong cost-effectiveness and cost-containment measures, drive investments that yield compelling benefit-cost results.

The strategy directed in this Order incorporates a midterm review as well as thorough and ongoing tracking and reporting of results and performance, allowing the Commission to quickly react to market conditions while providing a strong signal to EV developers to build New York.

SUMMARY OF THE WHITEPAPER

The Whitepaper focuses on proper and valuable utility roles in the electrification of light-duty vehicles in the State as a first step in establishing the necessary economic, regulatory, and physical infrastructure needed for widescale transportation electrification. Staff does not propose to terminate the existing statewide DC Fast Charger Per-Plug Incentive Program, which aims to support the infrastructure deployment needed to increase EV penetration and to complement existing utility-specific programs.[12] However, Staff recommends establishing a comprehensive, practical, and economically sound statewide Make-Ready Program for light-duty vehicles, so that EV charging infrastructure developers may access incentives using a common statewide framework.

[12] See Case 18-E-0138, Order Establishing Framework for DC Fast Charger Infrastructure Program (issued February 7, 2019) (DC Fast Charger Framework Order); Order Modifying Incentive Program and Granting, In Part, Petition for Rehearing (issued July 12, 2019) (Order Modifying DC Fast Charger Program); Order Providing Clarification and Modifying DC Fast Charger Incentive Program (issued March 19, 2020) (Order Further Modifying DC Fast Charger Incentive Program).

Using the National Renewable Energy Laboratory's (NREL) Electric Vehicle Infrastructure Projection Tool (commonly known as EVI-Pro Lite),[13] Staff concludes that supporting the ZEV MOU goal may require between 20,000 and 50,000 additional public Level 2 charging ports, between 35,000 and 80,000 additional workplace Level 2 charging ports, and between 1,000 and 4,000 additional DC Fast Charger ports. In addition to this publicly accessible charging infrastructure, Staff expects that the majority of Zero Emission Vehicle drivers will have home charging access equipped with a Level 1 or Level 2 charger, which should meet the majority of their charging needs.[14]

Under the Make-Ready Program proposal, certain infrastructure costs required to support a charging station would be eligible for a cost-sharing incentive. The Staff proposal specified that traditional distribution network services on the utility side of the meter needed for a new station would be eligible for an incentive. On the customer side of the meter, equipment such as new service drops,

[13] See, https://afdc.energy.gov/evi-pro-lite. NREL's EVI-Pro Lite tool was developed to simulate the needed level of public and workplace Level 2 and DC Fast Charging infrastructure given a future electric vehicle stock. EVI-Pro Lite factors in the assumed mix of plug-in hybrid and full battery electric vehicle types and the availability of at-home charging. The model simulates driving patterns for the expected future electric vehicle stock using historic data collected from internal combustion engine vehicles, generating daily driving patterns similar to today's driving behavior. The model applies spatial and temporal post processing to calculate the level of EV charging infrastructure deployment needed to maximize the electric vehicle miles traveled, balancing the need for geographic diversity and favorable station utilization.

[14] As previously noted, Level 1 charging is the slowest charging option, at 120 volts, and uses a standard three-prong plug in a typical residential wall outlet.

trenching/boring, and running conduit/cable to the section of the site (e.g., parking lot) would be eligible for an incentive. The Whitepaper recommends that the utility own the equipment on the utility side of the meter, and the customer own the equipment on the customer side of the meter.[15] The Whitepaper also recommends that under limited circumstance, such as an existing demonstration project, utilities should be allowed to continue to own equipment on the customer side of the meter.

Staff proposes a tiered incentive structure based on the new charging station satisfying certain eligibility criteria. Staff notes that the level of public accessibility and the types of charging plugs deployed would be the crucial factors in determining incentive levels. Public accessibility, according to Staff, requires unlimited public access and 24-hour standard payment options, while standardized plug types must be used to access the full incentive. Other proposed program criteria include the number of plugs and capacity per site, and oversizing infrastructure to accommodate future expansion.

Staff proposes that chargers satisfying all the criteria should receive payments for up to 90 percent of eligible costs, although per site cost ceilings may limit this amount. Under Staff's proposal, if the public accessibility or standardized plug type criteria are not satisfied, but all other requirements are met, the site is eligible for up to a 50 percent incentive.

[15] The Whitepaper proposal assumed the meter was the point of demarcation of ownership. The point of demarcation may not be so clear, however, since the meter is owned by the utility but there are some assets between the meter and a utility's transmission and distribution system that are owned by the customer such as primary underground cable running to pad mounted transformer.

Although Staff's proposed program would be statewide within utility service territories, each utility would have a separate budget and cap on the number of incentivized plugs. The Whitepaper proposes using a maximum incentive level for each installation based on utility-specific station development costs estimates. The number of Level 2 and DC Fast Chargers that would be eligible for incentives for each utility territory would be based on the current number of registered light-duty vehicles in the utility service territory. Staff also suggests that program budgets for each utility be determined based on the maximum incentive level for each installation and the number of charging stations allocated to each utility service territory. The Whitepaper proposes that the number of Level 2 plugs eligible for incentives in the first three years of the program be capped at 50 percent of the total number of plugs allocated to each service territory.

The Whitepaper proposes an estimated aggregate EV Make-Ready Program budget of $582 million through 2025, which represents approximately 70 percent of the total anticipated make-ready costs of $828 million. The 70 percent figure represents the anticipated overall program reimbursement when factoring in projects at both the 90 percent level and the 50 percent level.[16] As per Staff's proposal, the utilities would recover program costs through a combination of rate base and surcharges. In addition, Make-Ready Program costs would be allocated to all customer classes based on transmission and distribution revenues.

[16] Staff's proposal assumes that all DC Fast Chargers qualify at the 90 percent incentive level, all public Level 2 qualify at the 90 percent incentive level, and all workplace Level 2 qualify at the 50 percent incentive level.

The Whitepaper proposes a number of design elements intended to constrain costs and provide the necessary Staff oversight to ensure effective program implementation. Staff notes the potential suitability of an Earning Adjustment Mechanism (EAM) to incentivize utilities to contain program costs. A quarterly reporting requirement from site owners and utilities was identified to allow Staff to recommend timely program modifications if needed. Staff suggests coordinating midpoint program review with the DC Fast Charger Per-Plug Incentive Program review, which commences on October 1, 2023. Under Staff's proposal, if each utility has completed applications for 45 percent of the total number of plugs eligible in the DC Fast Charger Per-Plug Incentive Program in their territory prior to that date, then the program review would begin earlier.

Staff also proposes that the utilities collaborate to support the achievement of State and regional EV market objectives. To fulfill this requirement, the utilities would incorporate EV charging scenarios in their annual capital planning process and establish site suitability criteria for site identification. Staff proposes that the utilities identify potential host sites using available load-serving capacity, and work with developers to provide site interconnection capabilities overlaid with local traffic pattern maps to further pinpoint the most useful sites. Staff also proposes that the JU perform education and outreach to developers through a common methodology using a fair and competitive process for the eventual selection of a developer. The Whitepaper proposes that the utilities also provide education outreach to current and potential EV owners regarding rate options.

Staff recommends that the program create even greater EV adoption opportunities for rural and economically

disadvantaged communities. Staff proposes that the seven upstate Regional Economic Development Councils (REDCs) be eligible for limited additional incentives under the program.[17] In each REDC, at least four locations with four 150 kilowatt (kW) DC Fast Charger plugs at each site would be developed through a competitive procurement process during the first year of the program. Staff suggests this minimum DC Fast Charger network statewide to encourage EV adoption and limit EV travel anxiety. Staff also proposes that 20 percent of each utility's DC Fast Charger EV Make-Ready Program budget be deployed within 10 miles of an environmental justice community.

In addition, the Whitepaper proposes that the utilities implement a web-based application process that provides the updated status of applications for developers of EV charging stations. Staff's proposal is for each utility to develop an Interconnection On-Line Application Portal (IOAP) similar to the one used in the Standard Interconnection Requirements (SIR) process for New Distributed Generators and Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems.[18] Staff advises that the utilities

[17] The seven upstate Regional Economic Development Councils are: the Capital Region, Central New York, the Finger Lakes, the Mohawk Valley, the North Country, the Southern Tier, and Western New York.

[18] Case 14-M-0101, In the Matter of Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) (REV Track One Order) (Phase I of REV required the development of a utility-customer engagement web platform, to allow for online interconnection application submittal with automated management and screening). See also, Case 18-E-0018, In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Small Distributed Generators, Order Modifying Standardized Interconnection Requirements (issued April 19, 2018) (by which the Commission adopted the IOAP into the SIR).

could appropriately manage their resources to meet the industry's needs and avoid queueing problems with the anticipation of increased EV charging station applications. Staff suggests that dedicated EV team members would be in place at the outset comprised of interconnection experts, distribution system planners, and other key subject matter experts within each utility.

The Whitepaper proposes that a Staff-led working group be formed with stakeholders to develop protocols and minimum standards for open communications. These stakeholder groups would explore open technical standards related to EV supply equipment, such as the International Electrotechnical Commission (IEC) accepted OpenADR 2.0b, International Organization for Standardization (ISO)/IEC 15118, and the Open Charge Point Protocol (OCPP). Furthermore, Staff proposes adopting baseline standards in engineering and safety, payment, communications, and interoperability.

Staff also proposes that collaborative work be undertaken to assess vehicle-to-grid capabilities and managed charging practices to best enable these potential EV uses. The concept of vehicle-to-grid would be used to align vehicle charging with the system needs of the grid. Staff suggests that actively managed charging could rely on dispatch signals from the utility to influence times for EV charging.

Further, the Whitepaper proposes that each utility should offer new Fleet Assessment services to customers interested in fleet electrification. These services would consist of site feasibility and rate analyses and would be based on the maximum power draw of an electrified fleet to determine if the local distribution system can accommodate the increased load. The site feasibility analysis, as per the Whitepaper, would include all planned utility work on the distribution

system, both nearby and on the infrastructure serving the existing depot, to find cost-saving synergies that may exist. Finally, Staff proposes that a rate analysis should be tailored to each depot location, allowing the fleet manager to understand all rate options available, as well as a reasonably certain range of expected costs based on charging behavior.

PUBLIC NOTICE

Pursuant to the State Administrative Procedures Act (SAPA) §202(1), a Notice of Proposed Rulemaking regarding the Staff Whitepaper was published in the State Register on February 5, 2020 [SAPA No. 18-E-0138SP4]. The time for submission of comments pursuant to the SAPA notice expired on April 6, 2020.

In addition, on February 5, 2020, the Commission issued a Notice Soliciting Comments on the Whitepaper and a list of specific questions. While initial comments on the Whitepaper were originally sought by April 6, 2020, with reply comments due on April 20, 2020, the Commission subsequently extended those deadlines due to the impacts of the novel coronavirus COVID-19. Pursuant to the Notice Clarifying Comment Period and Provision of Meeting Details, issued on March 30, 2020, initial comments on the Whitepaper were due by April 27, 2020, with reply comments due by May 11, 2020. In response to the public notices, the Commission received numerous comments, which are summarized in Appendix A and are addressed in relevant sections below.

LEGAL AUTHORITY

Pursuant to Public Service Law (PSL) §§5, 65, and 66, the Commission has the legal authority to take the actions prescribed in this Order. In carrying out its responsibilities,

the Commission has broad discretion and judgment in choosing the means of achieving statutory mandates and has the authority to adopt different methodologies or combinations of methodologies in balancing ratepayer and investor interests.[19] PSL §5 grants the Commission with authority to direct utilities to "formulate and carry out long-range programs, individually or cooperatively, with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources." The Make-Ready Program, the Medium- and Heavy- Duty Make-Ready Pilot Program, the Transit Authority Make-Ready Program, the Environmental Justice Community Clean Vehicles Transformation Prize, the Clean Personal Mobility Prize, and the Clean Medium-Duty and Heavy-Duty Innovation Prize are all designed to support long-range program goals economically and efficiently to support public health and safety, the preservation of environmental values, and the conservation of natural resources.

PSL §65 authorizes the Commission to ensure that every electric corporation furnishes and provides safe and adequate service, instrumentalities, and facilities at just and reasonable rates. The Make-Ready Program authorized by this Order directs New York's investor-owned electric utilities to provide such service, instrumentalities, and facilities. Further, PSL §66 authorizes the Commission to direct the improvement of utility property whenever the Commission determines existing utility equipment is "inefficient or inadequate." The utility property upgrades authorized by this Order shall replace inefficient equipment with utility fixtures that adequately support New York State's environmental and clean

[19] Multiple Intervenors v. Public Service Commission of the State of New York, 154 A.D.2d 76 (3d Dept. 1991).

energy mandates. The actions undertaken herein are also consistent with the CLCPA mandates.[20]

DISCUSSION

The Commission identified the potential for wide-scale adoption of EVs challenging the capacity of some distribution circuits early in the Reforming the Energy Vision (REV) proceeding.[21] The Commission also recognized that EVs may be used to provide ancillary services on distribution circuits.[22] Throughout the REV proceeding, the Commission recognized that EVs present a great opportunity if coordinated with grid functions.[23] To ensure proper coordination, the Commission required the Joint Utilities (JU or Joint Utilities)[24] to include an EV Readiness Framework in their Distributed System Implementation Plans and directed the JU to "…directly contribute to EV market development and the resulting decreases in carbon emissions."[25] The actions directed by this Order

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[20] L. 2019, Ch. 106.

[21] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Instituting Proceeding (issued April 25, 2014), p. 7.

[22] Id. at 8.

[23] Case 14-M-0101, supra, Order Adopting a Regulatory Policy Framework and Implementation Plan (issued February 26, 2015), p. 27.

[24] The Joint Utilities, or utilities referenced herein are: Central Hudson Gas & Electric Corporation (Central Hudson), Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation (NYSEG), Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), Orange and Rockland Utilities, Inc. (O&R), and Rochester Gas and Electric Corporation (RG&E).

[25] Case 14-M-0101, supra, Order Adopting a Distributed System Implementation Plan Guidance (issued April 20, 2016), p. 4.

advance the Commission's REV goals and re-affirm the Commission's finding that EVs can increase utility sales and reduce rate pressure caused by infrastructure needs.[26]

As part of implementing the Clean Energy Standard, the Commission adopted the State Energy Plan's goal that "50 percent of New York's electricity is to be generated by renewable sources by 2030 as part of a strategy to reduce statewide greenhouse gas emissions by 40 percent by 2030."[27] In order to achieve the State's clean energy and greenhouse gas reduction objectives, contributions will be required from a variety of resources, including the transportation sector. However, decarbonizing the electric generation sector in parallel with electrifying the transportation sector is critical to achieving these ambitious objectives. As the State Energy Plan indicates, decarbonization of the electric sector will increase the emission reduction benefits of Zero Emission Vehicles.[28] The CLCPA codifies such economy-wide decarbonization mandates, including an electric generation sector that serves as least 70 percent of load in 2030 with renewable energy resources, eliminates emissions by 2040, and provides clean electricity as the fuel for a greater proportion of the overall economy.

The Commission recognizes that EVs are a critical component to achieving the emission reductions called for in the State Energy Plan and the CLCPA. In particular, EV charging stations will serve as a key element to support EV adoption and

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[26] REV Track One Order, p. 27.

[27] Case 15-E-0302, et al., Large-Scale Renewable Program and Clean Energy Standard, Order Adopting a Clean Energy Standard, (issued August 1, 2016), p. 2.

[28] NYSERDA The Energy to Lead: Biennial Report to the 2015 State Energy Plan, p. 56. Available at: file:///C:/Users/l323ps.SVC.000/Downloads/2017-BiennialReport%20(1).pdf.

enable the State to meet its emission reduction targets. The directives of this Order will accelerate EV charging station deployment, drive down costs, reduce range anxiety, and speed the adoption of Zero Emission Vehicles. Successful program implementation will also advance a number of New York State's environmental goals.

The Make-Ready Program authorized in this Order is a multi-year approach to develop and deploy the minimum critical infrastructure necessary to support the EV charging market and EV adoption. The program's design requires that station developers locate and invest in sites and coordinate with utilities before the necessary funds are collected from ratepayers. To the extent that EV charging station development does not occur, program funds will not be collected from ratepayers. Moreover, the cost recovery approach adopted in this Order ensures that program funds will be collected over a time period which coincides with the anticipated useful lives of the assets. In most cases, the cost recovery period for these assets is 15 years or greater. The result of this approach is a minimal bill impact on the average residential bill.

The following sections address Staff's recommendations in the Whitepaper along with the relevant public comments received. While the Commission adopts many of these recommendations, certain modifications have been made where appropriate. Given the importance of the Make-Ready Program in supporting New York's goal of deploying 850,000 Zero Emission Vehicles by 2025, the Commission directs Staff and the utilities to move forward expeditiously with the Make-Ready Program. This clean energy infrastructure program is aligned with the resumption of NY Forward's clean energy workforce.

I. Make-Ready Program Goals

Whitepaper Recommendation

The Whitepaper recognizes that, due to the low penetration of EVs on the road to date, it is difficult for station owners to recoup make-ready installation costs from charging revenues due to low station utilization. As Staff notes, a typical DC Fast Charger station in New York is not expected to be profitable over the initial ten-year period of operations, barring utility investment in make-ready EV Infrastructure or another incentive source. Staff proposes the Make-Ready Program to allow charging stations in almost all regions of the State using various site configurations to have a positive 10-year Net Present Value (NPV) in the first year.

Staff's recommendation is based on a benefit-cost analysis (BCA) performed by Energy & Environmental Economics, ICF, and MJ Bradley & Associates,[29] which estimated that EV ownership in New York at the levels targeted in the ZEV MOU will produce net benefits in excess of $2.6 billion for New York alone. The EV BCA evaluates the impacts of EV adoption in three geographic regions across the State (New York City Metropolitan, Long Island, and Upstate). The EV BCA examines a base case, a behavior modification case where EV owners are encouraged to charge off-peak, and a high infrastructure case which assumes increased DC Fast Charger deployment. The BCA model assumes that 100 percent of the make-ready costs (up to the charger) are recovered from ratepayers. From a societal perspective, the EV BCA is positive across all scenarios and regions, as it captures

[29] Benefit-Cost Analysis of Electric Vehicle Deployment in New York State, prepared for NYSERDA by Energy & Environmental Economics, ICF, and MJ Bradley & Associates (February 2019 EV BCA), (February 2019). Available at: https://www.nyserda.ny.gov/.

the benefits of reduced GHG emissions, pollutants, and displaced petroleum.

Comments

All parties are generally supportive of the Whitepaper program proposal, and many offer specific recommendations to improve it. The most common recommendations request greater program flexibility to determine site-specific incentive levels, relaxation of the proposed public accessibility criteria, and requests to address EV charging rate design and for program expansion to include medium- and heavy duty, fleet, and transit EV charging.

Several parties commend the comprehensive scope of the proposal and its anticipated benefits, including reductions of greenhouse gas and other pollutants, improved public health for low- and moderate-income and environmental justice communities, and enhanced grid operations. Parties such as the Advanced Energy Economy Institute, Alliance for Clean Energy New York, the NRDC and Sierra Club, and ChargePoint commend the proposal for its ambition and the time, effort, and care devoted by the Department of Public Service in developing it.

The City of New York is encouraged by and appreciative of Staff efforts to reduce barriers to EV adoption in New York State and notes that the proposal aligns with its own municipal policy goals. The JU recognize that the proposal represents a vital step toward achieving the State's ambitious climate goals.

Determination

As described above, achieving the State's ambitious GHG emissions reduction mandates and satisfying the ZEV MOU goals will require significant transportation electrification in the State. Currently, there are 50,716 EVs registered in New York, supported by 132 publicly accessible DC Fast Charger stations with 569 plugs, and 1,715 Level 2 stations with 4,631

plugs.[30] The DC Fast Charger Per-Plug Incentive Program has 33 plugs enrolled across three utility service territories as of issuance of this Order, far from the target of 1,074 plugs.[31]

Based on the extensive stakeholder input in support of a Make-Ready Program and the February 2019 EV BCA, the Commission approves a Make-Ready Program that includes a number of components to incentivize utilities and EV charging station developers to locate and invest in projects that produce the greatest public benefits, while encouraging development to achieve the State's EV policy goals at the lowest cost to ratepayers.

The program will work in conjunction with the existing DC Fast Charger Per-Plug Incentive Program, which will remain at the 2019 maximum incentive level through 2021, then step down annually from 2022 through 2025. The programs will work in tandem to support both the upfront capital investment and ongoing operations costs to stimulate station development statewide and assuage range anxiety, thereby encouraging drivers to adopt EVs earlier and accelerating achievement of the State's GHG emissions and transportation electrification goals.

II. Program Size

Whitepaper Recommendations

Staff estimated the number of new Level 2 and DC Fast Charger plugs required to support 850,000 EVs statewide through 2025 using the EVI-Pro Lite. In using EVI-Pro Lite to develop estimated charging infrastructure requirements, Staff entered

[30] These figures are according to Staff's June 26, 2020, analysis of the EV HUB EValuateNY data, available at: https://www.atlasevhub.com/powerbi/evaluateny/.

[31] See Joint Utilities of New York, Statewide DC Fast Charger Incentive Program Summary Table. Available at: https://jointutilitiesofny.org/utility-specific-pages/electric-vehicles/.

the following statewide assumptions about a potential statewide electric vehicle mix in 2025: 25 percent plug-in hybrid vehicles with 20-mile range, 20 percent plug-in hybrid vehicles with 50-mile range, 10 percent battery electric vehicles with 100-mile range, and 45 percent battery electric vehicles with 250-mile range. Staff estimates also anticipated full support for plug-in hybrid (assuming most plug-in hybrid drivers would not require gasoline use on a typical day) and assumed 75 percent of vehicle owners possessed home charging capability on a statewide basis.

Under these assumptions, the EVI-Pro Lite tool projected the following statewide EV infrastructure requirements: 79,798 workplace Level 2 plugs, 49,730 public Level 2 plugs, and 3,287 public DC Fast Charger plugs. Staff proposed plug allocations to three geographic regions: NY Metro, Long Island (Nassau and Suffolk Counties), and the remainder of the state on light-duty EV registrations for each region, resulting in the following recommended percentages: 28 percent for the New York City metropolitan area, 21 percent for Long Island, and 51 percent for the remainder of the state.

Staff also developed program cost estimates based on total number of plugs by type, using estimated development costs consistent with those used to inform the February 2019 EV BCA. In its proposal, Staff recommends that the utilities submit station development cost estimates based on historic costs and current trends to develop utility-specific average development costs. Under Staff’s proposal, these estimates would be used to establish incentive caps and maximum budgets for Commission consideration. Utility budgets would be developed by multiplying proposed plug allocations by maximum per-plug incentives for each utility. Staff recommends that maximum

budgets remain fixed for the first three years of the program and would only be revised, if necessary, at the midpoint review.

Comments

Several parties question Staff's assumptions built into the EVI-Pro Lite modeling tool. Alliance for Transportation Electrification, Green Machine Power, New York Power Authority, and Plug In America assert that the forecast of EV mix between plug-in hybrid electric vehicles and battery electric vehicles is obsolete and could result in an underestimated need for DC Fast Chargers that, unless revised, will likely cause a misallocation of funds and incentives.

On the other hand, Green Machine Power contends that EVI-Pro Lite overestimates future use of plug-in hybrid electric vehicles by relying on sales data from prior years and by ignoring current sales trends that indicate a growing consumer preference for battery electric vehicles. Green Machine Power warns that Staff's assumptions would result in as much as a 50 percent overinvestment in Level 2 chargers. Both Green Machine Power and the New York Power Authority (NYPA) recommend a revised forecast that inputs data reflecting market trends and a more realistic future statewide vehicle mix. Alternatively, Green Machine Power proposes using a forecast assuming 100 percent battery electric vehicles with 250-mile ranges on the grounds that this input would likely represent the long-term future of EV deployment.

The Alliance for Automotive Innovation challenges the modeling assumption that 75 percent of drivers would have access to home charging as overly optimistic. For its part, New York Power Authority observed that this capability would vary considerably across urban, suburban, and rural areas, potentially confounding statewide forecasts. The New York Power Authority therefore recommends using home charging rates at the

service territory level on the grounds that it would produce a more realistic ratio of Level 2 and DC Fast Charger plugs needed.

The Alliance for Automotive Innovation asserts that the Staff proposal ignores rideshare fleet charging needs, which exacerbates the underestimation of DC Fast Charger needs. To counter these effects, it recommends increased targets and budgets for DC Fast Chargers. The New York Power Authority also notes that further attention to rideshare and taxi fleets is warranted and recommends that modeling inputs include annual vehicle miles traveled by these sectors to account for increasing reliance on shared mobility and an anticipated dependence on DC Fast Charger charging.

The Alliance for Transportation Electrification takes the position that the EVI-Pro Lite model is an effective tool for estimating public EV infrastructure needs but cautions that its methodology is dependent on assumptions about EV adoption and its results are approximations. Noting its proprietary understanding of distribution grid geography and topology, the Alliance for Transportation Electrification recommends that New York Power Authority and the JU be tasked with developing more accurate, utility-specific estimates. It also recommends comparing statewide estimates to more detailed, service area assessments.

Other parties offer various criticisms and refinements of the Staff approach. The Natural Resources Defense Council and Sierra Club recommend allocation of charging infrastructure between service territories based on EV registrations and in consideration of local variability of other model inputs (e.g., home charging access). The Natural Resources Defense Council and Sierra Club note that EVI-Pro Lite can be run using service territory-specific assumptions and recommends this practice for

determining appropriate plug targets. Tesla advises that program size estimates should assess current and future development by other charging developers such as the New York Power Authority.

Determination

The Commission agrees with the numerous commenters suggesting that the assumptions used in the EVI-Pro Lite model should be refined. It is unquestionable that the battery electric vehicle penetration in the EV market is growing and that trend is expected to continue as battery ranges increase and battery costs decline. The mix of plug-in hybrid electric vehicles and battery electric vehicles used to estimate New York State's charging infrastructure needs should therefore reflect projected growth in battery electric vehicle purchases. As for ranges battery electric vehicles, there are no 2020 battery electric vehicle models with less than 110 miles of range, and most have significantly greater range. For example, 2020 models of the Chevrolet Bolt, Hyundai Kona, Kia Niro, Nissan Leaf, and Tesla Model 3 all have ranges of more than 225 miles. Indeed, data suggests that longer-range battery electric vehicles are much more popular with consumers.

To reflect these considerations, the Commission directs Staff to modify the 2025 vehicle mix input to the EVI-Pro Lite model as follows: 13 percent plug-in hybrid electric vehicles with 20-mile range, 12 percent plug-in hybrid electric vehicles with 50-mile range, 2 percent battery electric vehicles with 100-mile range, and 73 percent battery electric vehicles with 250-mile range. The Commission finds that this composition of the projected EV market is more reflective of the expected vehicle composition over the five-year term of the Make-Ready Program. The assumption that plug-in hybrid electric vehicles would need full support has not been modified.

The Commission agrees with those commenters that suggest that inputs to the EVI-Pro Lite model should be refined to also consider variability among the geographic regions. Accordingly, for purposes of this Order, Staff ran the EVI-Pro Lite model to reflect both statewide patterns, as well as patterns reflecting estimated EV market penetration for the New York City Metro area to more accurately reflect regional infrastructure needs. Staff assumed that 57 percent of EV owners in the New York City Metropolitan area would have access to home charging for the approximately five-year duration of the EV Make-Ready Program. For the rest of the state, excluding Long Island, Staff presumed that 82 percent of EV owners in the rest of the State would have access to home charging systems. These percentages are consistent with information used to develop the EV BCA. The percentage of EV owners with access to home charging on a statewide basis was assumed to be 77 percent, which is an average of the NY Metro and rest of state percentages weighted by light-duty vehicle registrations.

Running these inputs statewide with the vehicle composition mentioned above and full plug-in hybrid electric vehicle supported resulted in 44,280 workplace Level 2 plugs, 29,084 public Level 2 plugs and 2,622 DC Fast Charger plugs needed in the state.

To better determine each utility's portion of the number of plugs needed, Staff allocated the estimated number of plugs needed on a statewide basis to individual service territories based on light-duty vehicle registrations in each utility service territory, including Long Island and municipal service territories. To recognize the unique needs of Con Edison customers related to the disproportionate lack of access to home charging, Staff estimated the number of plugs needed in Con Edison's territory by averaging the number of plugs needed

from the portion of the EVI-Pro Lite NY Metro area run with Con Edison's portion of the statewide total. This resulted in 45,115 workplace Level 2 plugs, 29,256 public Level 2 plugs and 2,567 DC Fast Charge plugs needed in the state.

After Staff determined the number of plugs needed in each service territory under this revised approach, the number of plugs eligible for incentives under the Make-Ready Program was calculated by subtracting public infrastructure already in service as identified in the AFDC Alternative Fueling Station Locator from each utility's service territory total. The Commission adopts the results of this additional Staff analysis, which took into account all Stakeholder comments and extensive outreach to the JU and parties. The number of plugs eligible for incentives in each utilities' service territory are as follows:

	Make-Ready Program	Consolidated Edison	Central Hudson	New York State Electric & Gas	Niagara Mohawk	Orange & Rockland	Rochester Gas and Electric
Workplace Level 2	35,217	12,776	2,091	5,821	10,105	1,765	2,659
Public Level 2	18,556	5,763	1,113	3,458	5,623	1,080	1,519
Total Level 2	53,773	18,539	3,204	9,279	15,728	2,845	4,178
DC Fast Chargers	1,500	457	69	250	504	71	149

A chart further detailing these results is also included in Appendix B of this Order.

III. Eligible Equipment

Whitepaper Recommendations

The Whitepaper recognizes that the electric infrastructure needed to accommodate the load and other operating characteristics of a new EV charging station may require investment in new distribution system infrastructure or upgrades or augmentation of existing infrastructure. Staff recommends that two categories of make-ready EV Infrastructure be eligible for incentives under the program: utility-owned equipment and customer-owned equipment. Utility-owned equipment

includes traditional distribution infrastructure such as step-down transformers, overhead service lines, and the utility meter. This equipment has been and would continue to be owned and operated by the interconnecting utility. The utility would install and own this equipment similar to other traditional utility distribution infrastructure.

The second category of eligible equipment includes make-ready EV supply equipment that would be owned by the EV charging station developer, owner, or manager (collectively, the customer). Examples of this equipment include conductors, trenching, and panels needed for the EV charging station. Equipment such as the EV charging station itself, power blocks, modules, mounting hardware, and co-located distributed generation or energy storage material would not be eligible for an incentive under the proposed program.[32] Utility-approved contractors would build and install the equipment, and the customer would own it.[33] The customer would pay the utility if utility costs exceed the maximum incentive level, or would receive a make-ready incentive from the utility to cover

[32] The Commission has separately authorized various distributed generation and energy storage programs that include incentives for the installation of these technologies. See e.g., Case 19-E-0735, Proceeding on Motion of New York State Energy Research and Development Authority Requesting Additional NY-Sun Program Funding and Extension of Program Through 2025, Order Extending and Expanding Distributed Solar Incentives (issued May 14, 2020); Case 18-E-0130, In the Matter of Energy Storage Deployment Program, Order Establishing Energy Storage Goal and Deployment Policy (issued December 13, 2018).

[33] Utilities would allow contractors to apply at any time for authorization to install this equipment, and would be required to post a contractor application and list of pre-approved contractors to their EV websites.

eligible customer costs if utility make-ready costs were less than the maximum incentive level.

The Whitepaper likens EV supply equipment ownership to distributed energy resource (DER) ownership and proposed that EV supply equipment ownership and incentive eligibility for investor-owned electric utilities and publicly owned entities should only be allowed under very limited circumstances. Staff notes that in the REV Framework Order, the Commission articulated the policy that DER development should occur through competitive markets as opposed to ratepayer funding, and only in limited circumstances would utility ownership of DER be allowed.[34] Under Staff's proposal, the private market would be expected to build, own, and operate the EV charging stations in order to foster a competitive environment and drive down EV customer costs. Staff recommends that there may be a role for utility ownership in areas where the market is not satisfying demand, although it does not see evidence of market failure warranting such a utility role in the broader EV charging industry landscape.

Comments

Tesla asserts that proposed program requirements that are redundant or in conflict with external processes such as electrical and building permit requirements should be removed and recommends that the Commission not require a process to qualify contractors. Tesla notes that local building and electrical permitting requirements already require use of certified contractors to ensure the stations are constructed safely and in compliance with all relevant codes.

[34] Case 14-M-0101, Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) (REV Framework Order), p. 67.

Many commenters agree with the aspect of Staff's proposal recommending a role for utility ownership in certain cases, particularly in areas of market failure or in underserved communities. EVBox argues that utility ownership can provide a valuable complement to private ownership considering the sheer scale of investment required. The JU agrees that utilities should be concerned primarily with the provision of make-ready infrastructure in support of third-party developers. Enel X North America, Inc. (Enel X) recommends allowing utility ownership in lieu of an EAM, but cautions that allowing non-jurisdictional public agencies like the New York Power Authority or municipal and cooperative utilities to access ratepayer funding intended to catalyze the private market is inconsistent with program goals.

Alliance for Automotive Innovation and New Yorkers for Clean Power caution that it is too early in the market development of EV chargers to determine the precise role for utilities. Electrify America warns that allowing utility ownership of EV supply equipment on the customer side of the meter could create challenges to site hosts and their lease terms. ChargePoint, Inc. (ChargePoint) notes that utility ownership would require consistent review standards that consider market competition and additional stakeholder participation.

The New York State Department of Environmental Conservation (DEC) requests eligibility of the Commission-approved programs be extended to its existing and proposed EV infrastructure programs. Drive Electric LI Coalition contends that existing EV programs like the NYSERDA Charge Ready NY program and the DEC ZEV infrastructure program, complement the proposed Make-Ready Program. FreeWire Technologies, Inc. (FreeWire), Greenlots, and the Natural Resources Defense Council

and Sierra Club argue that any future program should supplement and not supersede or replace existing utility programs, and that lower incentives in existing programs should be increased to match current proposals. Enel X North America supports combining existing and new budgets.

The JU recommends a definition of "make-ready" work for the Make-Ready Program that generally reflects current utility practices should be adopted and provides definitions for utility-side and customer-side make-ready costs. Advanced Energy Economy Institute and the Alliance for Clean Energy New York, and EVgo recommend maintaining existing programs until funds are exhausted, particularly to minimize market disruptions during the current public health crisis. The City of New York recommends that any proposed funding should be incremental to approved program funding, while Tesla contends that any existing programs more ambitious that the current proposal should continue and more limited programs should be replaced.

Determination

Staff's proposal regarding eligible EV supply equipment and infrastructure for a make-ready incentive is adopted, with clarifications regarding the definitions of utility-side make-ready costs and customer-side make-ready costs. The infrastructure required to prepare a site for EV charging is a significant upfront investment for customers. As the Whitepaper noted, incentives for the installation of this equipment will produce positive returns in the first year for most use cases. While the estimated costs included in this Order increased from the Whitepaper cost estimates, this still holds true. The Make-Ready Program budget is incremental to existing utility EV programs and will work in tandem with other State EV programs, including the DC Fast Charger Per-Plug

Incentive Program, to improve the economic viability of EV charging stations.

Under Staff's proposal, a utility-approved contractor must construct the customer-sited and customer-owned eligible EV Infrastructure in order for that station developer or owner to receive the Make-Ready Program incentive. The Commission adopts this proposal as it will streamline the construction process and give the utilities an ability to control the quality of work that is being partially funded by ratepayers. While Tesla argues that there are qualified contractors already doing this work without utility certification, the volume of these jobs will increase under the program and therefore increase the risk that unqualified contractors may start performing this work. The utility qualification process will not be onerous, as detailed in Staff's proposal, and the utilities shall allow contractors to apply at any time for authorization to install this equipment.

The utilities are directed to post a contractor approval application and a list of pre-approved contractors to their EV websites. The Commission supplements Staff's proposal by also requiring that the utilities approve or deny a contractor application based on justifiable criteria within one month of the application submittal, so as to ensure that customers have a wide array of contractors to choose from and can benefit from the resulting price competition for their services.

Staff's proposal regarding ownership of this equipment, which excludes utility ownership of the charging station hardware and offers a rebate but not utility ownership of the make-ready infrastructure on the customer side of the meter, is consistent with long-standing Commission policy, and is therefore adopted. The nascent state of the EV industry and

the EV charging business does not necessarily amount to a market failure. The midpoint program review will allow the Commission to reevaluate these assumptions if they prove to be incorrect, and further intervene or modify the Make-Ready Program.

Commission policy on utility ownership of DER is clear and the Commission finds it appropriate to analogize EV supply equipment as the concerns over discouraging potential competitive investment through utility ownership are very similar. The Commission adopts the Whitepaper recommendation that utility ownership of EV supply equipment only be allowed in limited circumstances, such as existing utility-owned EV supply equipment or utility-owned EV supply equipment that exclusively serves utility-owned vehicles or employee vehicles. Public authority and entity participation will be treated differently and require additional discussion.

As a threshold issue, because this is a ratepayer funded program, participating stations must be located within a utility service territory. The Commission acknowledges New York Association of Public Power's comments, but for this reason its members are not eligible for this Make-Ready Program. As New York Association of Public Power states, its members are interested in EV infrastructure and deployment of charging infrastructure. The Commission expects New York Association of Public Power members to benefit from the publicly available data and other lessons learned that will be produced throughout this program, and directs Staff to continue to engage with the New York Association of Public Power and other non-jurisdictional entities throughout New York.

IV. New York Power Authority Eligibility Whitepaper Recommendations

The Whitepaper suggested that NYPA is not a utility subject to competitive market constraints and should therefore

be ineligible to access the incentives funded by ratepayers of the utilities within the JU. In this respect, Staff took the position that, because of the lack of evidence of market failure regarding the EV plug market, NYPA ownership is unjustified.

Comments

NYPA recommends the Commission approve the proposed Program based on certain suggested changes. NYPA asserts that program eligibility criteria should enable participation by NYPA as an EV charging station developer, which it argues is key to promoting market development, development of a statewide network, and ensuring the State's EV targets are achieved. It also asserts other public entities should be eligible to participate as developers.

NYPA's fundamental point is that it would not be participating as a load-serving entity on behalf of its customers but as a developer. NYPA notes that it uses competitive procurements to enlist private companies to build and maintain EV infrastructure, which is consistent with the underlying goals of the proposed program. NYPA also notes that it thus is already participating in the market as an EV charging station developer for the public good and is willing to accept a long-term investment horizon across a statewide portfolio of sites, helping to build out a balanced portfolio of charging sites across the state.

NYPA asserts that conditioning eligibility for the program incentives on a connection to surcharge contributions is not necessary where ratepayer collections are used to develop large scale infrastructure projects for general public use. NYPA believes there is no basis to distinguish it from other EV charging station developers by requiring NYPA customers to pay a surcharge to access Program funds. NYPA comments that some of its customers are governmental entities ultimately supported by

taxpayers that should not pay for the program twice, as a ratepayer and a taxpayer. NYPA thus asserts that the surcharge payments that it would make as a charging station owner should be sufficient. In sum, NYPA believes that its eligibility for the program as a developer is separate and distinct from its actions as a load-serving entity on behalf of its customers.

The Alliance for Transportation Electrification (ATE) believes NYPA should be eligible for make-ready funding. ATE notes that NYPA utilizes in-state vendors and labor, providing an important economic and job-training stimulus to New York. The New York Association of Public Power (NYAPP) also supports expanded eligibility for the program for not only NYAPP municipally and cooperatively owned utility members but also NYPA directly. NYAPP suggests that Staff and Commission should coordinate with NYAPP members, NYPA, NYSERDA, New York State Department of Transportation (NYSDOT), and NYSDEC to ensure holistic approaches to the charging infrastructure. The City of Albany believes that NYPA makes a strong case that it should have access to the bootstrap investment of the Make Ready Program. The City of Albany suggests that Make Ready incentives should extend not just to established market actors but to all public agencies as well.

Clean Communities of Central New York (CCNY) asserts that NYPA's participation in incentive programs is a benefit to all State ratepayers, and is necessary to support the implementation and growth of EV use for the State to meet aggressive GHG reduction goals. CCNY notes that many areas of the state, including Central New York, are underserved by publicly accessible EV charging infrastructure. CCNY argues that NYPA has established a reputation of being a trusted source of information, which would make it the "preferred" brand of DC Fast Chargers. CCNY states that NYPA is uniquely qualified to

continue the growth in EV adoption and would play a necessary role in developing DC Fast Charge sites with transparent pricing practices.

EV Connect strongly supports the inclusion and participation of NYPA and other public entities in the EV Make Ready initiative. EV Connect asserts that a key component of the Program is to ensure state-wide economic and environmental justice for the deployment of EV infrastructure supported by public funds. EV Connect also recommends that public transportation fleet electrification should be eligible for EV Make Ready incentives. NRDC recommends that the Commission should ensure that its approach to charger siting in REDCs complements and is coordinated with NYPA's proposed DC Fast Charger buildout.

Should the Commission approve NYPA's request to participate in the make-ready program, ChargePoint recommends that NYPA's participation in the Make Ready Program be contingent on its adherence to: (i) The Whitepaper's technology-neutral specifications; and (ii) REV Framework Order and Operational Guidance. Enel X asserts that it would be counter to the objectives of Staff's proposal for non-jurisdictional public agencies like NYPA or municipal and cooperative utilities to access funding from investor-owned utility ratepayers that is explicitly intended to catalyze the private market within the utilities' service territories. For this reason, Enel X requests that the Commission deny the recommendation of NYPA to become eligible for Program funding. Enel X alternatively proposes that NYPA be encouraged to bring proposals to that are additive and complementary to the Staff's Make Ready Program proposal.

EVgo states that public power agencies like NYPA should not be allowed to participate in the Make-Ready

Program. EVgo asserts that NYPA use of ratepayer funding to compete with private sector entrants would be against the spirit of the Make-Ready Program and the REV Framework, and would undermine competition in the State. EVgo concludes that NYPA's participation in the Make-Ready Program should only be considered after a public hearing is held on the progress of the EVolve NY program, including Level 2 and DC Fast Charger installed to date, and impacts on the private market.

The JU views NYPA as an important developer of EV charging stations that should be eligible for incentives under the make-ready program. The JU submits that any customers receiving incentives, including NYPA when it acts as a station owner/operator, must be appropriately allocated make-ready program costs through delivery rates. Konrad and Mirabito each filed comments in support of NYPA's participation in the Program, noting that its participation would provide a benefit to ratepayers and is needed for the State to meet its GHG reduction goals.

NYSDOT agrees with and supports NYPA's comments related to expanding eligibility to the program to allow NYPA to participate. NYSDOT points out that NYPA has several on-going programs that support DC Fast Charger availability throughout the State. NYSDOT notes that NYPA has stated that it will not build in areas where the private sector is currently operating or has a commercial commitment to operate. NYSDOT maintains that NYPA's long term goal is to return its network to the private sector when the economics permit. NYSDOT believes that NYPA's inclusion in the Make Ready program is consistent with the goals of the Make Ready Program.

In its reply comments, NYPA asserts that it would not acquire or exercise market power as an owner of DC Fast Charger station or in its selection of vendors. NYPA noted its

intention to own and operate the charging stations it develops for a limited time before selling them to private entities. NYPA also noted that it would assume the market risk of managing EV Infrastructure during periods of low utilization rates as EV ownership increases to meet State policy objectives.

Determination

The Commission has carefully considered whether there is a role in the Make-Ready Program for public entities such as NYPA. Given the current state of the market, the Commission finds that enabling and building the necessary network of EV chargers across New York will require investment in certain areas of the state that otherwise would be overlooked by a private sector provider in the near-term. Such investment is necessary to stimulate usage and continued market development. Indeed, Staff recognized in the Whitepaper that developing additional high-power DC Fast Charger stations that are easily accessible and visible to consumers in the Upstate New York region would help mitigate range anxiety concerns and may, in turn, accelerate EV adoption in areas otherwise underserved. Staff also noted that the economics for high-power DC Fast Charger stations in Upstate New York in the early years of the Make-Ready Program are expected to be challenging because of low EV penetration and lack of density.

While the Commission's objectives of scale and competition means that it looks principally to private companies to provide investment in EV charging equipment, it also finds that developing the charging network in areas where EV demand will not quickly support private charger installations is a task suitable for a public entity like NYPA.

To address Staff's concerns and recognizing that NYPA and NYSERDA have committed to develop a network of DC Fast

Charger sites in the ten REDCs by the end of 2022, the Commission finds that NYPA shall be eligible to access Make-Ready Program incentives. Specifically, NYPA shall be eligible for incentives for two purposes: (i) for the initiative to build 10 fast charging locations in every REDC region by 2022, capped at $15 million; and, (ii) for investments in fast charging locations to help build out a robust network of DC Fast Chargers across the State, under NYPA's Evolve NY program, also capped at $15 million.[35]

Projects developed by NYPA are required to meet the same eligibility criteria and program requirements identified in the Eligibility Criteria section of this Order; however, access to this budget-bounded funding is subject to certain actions intended to stimulate the market and ensure the most effective deployment, collectively by NYPA and private companies. NYPA has agreed to and will provide timely public notice of each site that it has identified for commercial development that will require make ready funds. Such notice will be provided via posting on the Evolve NY program webpage and via monthly submission to the Secretary to enable posting on the Department website. Developers will have an opportunity to inquire about the details of the potential sites identified by NYPA for commercial development, as well as provide NYPA feedback on their plans for commercial development, to ensure the risk of co-location is minimized and private sector development is maximized.

Additionally, and consistent with its comments, NYPA's participation is subject to its eventual divestiture of EV charging stations developed through Program incentives.

[35] $15 million is an appropriate cap, recognizing that Evolve NY is designed to ensure that a robust statewide network of fast chargers is built out in tandem with the private sector.

Accordingly, NYPA will submit, within the first five years of the program start and every year thereafter, an assessment of the feasibility, and plans as appropriate, for divesting all or part of the fast charging stations built under this program. Such assessment and plan shall include a report on the state of the market and identified opportunities for sale, reflecting any applicable requirements of laws, regulations, and financing requirements, such as the Public Authorities Accountability Act and any applicable bond covenants applicable to NYPA that may complicate divestiture. It is the Commission's expectation that all such charging stations will be divested within 10 years.

V. Eligibility Criteria

Whitepaper Recommendations

Staff recommends that certain criteria be satisfied for a customer to receive a full incentive under the program. These criteria include: (i) accessibility; (ii) station maturity; (iii) plug type; (iv) future-proofing; and (v) location capacity. If one or more of these criteria are not satisfied, a partial incentive may be available under certain circumstances.

The chart below summarizes the Whitepaper proposed eligibility criteria, in addition to the standards that should be considered for both Level 2 and DC Fast Chargers and the proposed full and partial support levels. Each of the criteria is then addressed separately below the chart.

Eligibility Criteria		
	Level 2	**DC Fast Charge**
Accessibility	Must be accessible to the public (no access fee or restricted access)	
Station Maturity	Must be a new station, without firm commitment to take service- evidenced by building permit issuance or CIAC payment after Commission ruling on proposed program	
Plug Type	SAE J plug	Standardized, non-proprietary
Standards to be Considered	• International Electrotechnical Commission (IEC) accepted OpenADR 2.0b • International Organization for Standardization (ISO)/IEC 15118 • Open Charge Point Protocol (OCPP)	
Future-proofing	Must oversize all components that can be done with minimal incremental cost to accommodate upgrades to the quantity or charging capacity of the station	
Location Capacity	---	4 to 10 plugs per location; Maximum charging capacity of 2 MW
Support Level	• 90% if all criteria met • 50% if has SAE J plug but does not meet accessibility criteria	• 90% if all criteria met • 50% if does not meet standardized plug type and accessibility requirement

A. Accessibility

Whitepaper Recommendations

In order to satisfy the accessibility criteria in the Whitepaper, a proposed EV charging station would need to be both (i) publicly accessible, and (ii) allow for unrestricted and common forms of payment. Under the publicly accessible prong, the station must be accessible to the public without an access

fee or restricted access.[36] Workplace chargers are considered accessible if they are located in a public venue (e.g., shopping malls, hospitals, hotels) and available to the public without an access fee. Multi-unit dwellings are considered accessible if the public has unlimited access without fees. EV charging stations dedicated to a single owner's personal use (e.g., home charging or dedicated rented parking) do not satisfy the publicly accessible criteria.

Additionally, the Whitepaper would require EV charging stations to use general forms of payment with a kiosk, a card reader, a site business accepting payment, or a phone number that enables 24-hour credit card payments without a fee. This proposed requirement is to ensure that, even in a publicly accessible location, EV charging availability should not be limited by temporal restrictions, membership status, or non-standard or proprietary payment options.

Comments

Most commenters request a relaxation of the public accessibility criteria, particularly due to a lack of areas that meet the Whitepaper definition of publicly accessible in the downstate region, as well as the importance of multi-unit dwellings and workplace charging. The JU recommends that all site types, both public and private, and customer segments, including workplaces, multi-unit dwellings and light-duty fleets, should be eligible for the program on an equal basis. AEEI-ACE Advanced Energy Economy Institute and the ACENY, Alliance for Transportation Electrification, EVBox, NYC, and ChargePoint express concern that complex and rigid public accessibility provisions will undermine program effectiveness.

[36] Under the Staff proposal, waiving an access or parking fee would satisfy the public accessibility criteria. Moreover, charging fees would not be considered access fees.

Several commenters support focusing the program on sectors of need, including highway corridors, workplaces, urban shared spaces, and multi-unit dwellings. Additionally, Alliance for Auto Innovation suggests siting charging stations along travel corridors and in urban areas to mitigate range anxiety and facilitate regional travel. Advanced Energy Economy Institute and the ACENY suggests that carving out budgets for disadvantaged communities can help address concerns about access.

The EV Industry Coalition contends that public access criteria would unnecessarily impede the market and discourage participation for site hosts at semi-public and private locations. EVBox and NYC oppose the public access requirement, claiming that public charging only addresses a small proportion of market needs and that preferential incentive treatment will not yield a maximum return on program investment. NYC recommends that the Commission grant full access to incentives for charging stations located in restricted or paid parking facilities. NYC further warns that public accessibility standards in the present proposal could impede the development of fleet charging infrastructure. For its part, the City of Albany argues that limiting incentives for charger installations based on public accessibility requirements would eliminate many urban areas from program coverage.

AEEI-ACE, Greenlots, and the NRDC and Sierra Club agree that publicly funded or utility-owned nonfleet stations should accept all common payment forms to ensure competition and accessibility. ChargePoint supports open access standards that enable feeless acceptance of commonly used payment forms using kiosks, card readers, on-site acceptance, or phone payments. NYCP recommends that streamlined, easily accessible payment options will foster EV adoption. EVBox warns that requiring

credit card readers would increase installation costs unjustified by their infrequent use. Electrify America supports the near-term flexibility in eligibility requirements for the program, and asserts that overly prescriptive requirements around specific network protocols and payment methods can discourage innovation in charging station design.

Determination

The Commission recognizes the difference in the types of paid parking raised by NYC. As NYC notes, parking fees are an essential revenue stream for municipalities to fund day-to-day operations and it may not be possible or practical for a municipality to waive parking fees in order to capture the higher make-ready incentive amount. The Commission's broad objective is to build the critical infrastructure to support the ZEV MOU EV deployment goals, and particularly to support vehicle electrification in dense urban environments where there are disproportionate air pollution impacts to environmental justice communities.[37] The Commission therefore declines to adopt the Whitepaper's proposed accessibility criteria, and adopts accessibility criteria that include municipal paid parking as "publicly accessible."

While the Commission appreciates Alliance for Transportation Electrification's position that paid parking is ubiquitous and that excluding paid parking may be a deterrent to Multi-Unit welling charging locations participating in the program, the Commission adopts Staff's recommendation that

[37] As discussed in greater detail below, the Commission adopts the DEC Office of Environmental Justice definition of Environmental Justice as: the fair and meaningful treatment of all people, regardless of race, income, national origin or color, with respect to the development, implementation, and enforcement of environmental laws, regulations and policies. Available at: https://www.dec.ny.gov/public/333.html.

privately owned pay-to-park lots shall qualify for a 50 percent make-ready incentive. As noted by NRDC and Sierra Club, there is typically a high concentration of Multi-Unit Dwellings in environmental justice and low- and moderate-income communities where residents don't necessarily own or have access to individual parking spaces. Where there is parking available for residents of Multi-Unit Dwellings in Disadvantaged Communities, Level 2 charging stations sited in them (whether it be pay-to-park or free parking) shall be eligible for incentive levels of up to 100 percent of the eligible make-ready costs. This is consistent with many comments suggesting that higher incentive levels are appropriate to encourage siting charger siting in low- and moderate-income and environmental justice communities.

Where there is no parking available, the Commission is directing a number of actions with DC Fast Charger stations and pilot programs that will deliver benefits to low- and moderate-income and environmental justice areas. For example, the Whitepaper recommendation that 20 percent of each of the utilities' Make-Ready Program budgets shall be directed to publicly accessible DC Fast Charger stations within 10-miles of an environmental justice community is adopted, with the following modifications.

The Commission appreciates NYC's observation that most of the City would be considered an environmental justice area pursuant to a 10-mile radius rule, and such rule would therefore be ineffective at driving benefits to low- and moderate-income and environmental justice communities. This holds true for other service territories as well. The Commission also notes that the recent NYPA and NYSERDA commitments to develop a network of DC Fast Charger sites in the ten REDCs by the end of 2022, referenced in the New York Power Authority Eligibility Section of this Order, will improve access to rural communities

that may have indirectly benefited from a 10-mile radius rule in Upstate NY.

The Commission therefore directs that a DC Fast Charger or Level 2 station must be within a one-mile radius to qualify for the 100 percent incentive in the Con Edison, Central Hudson, O&R, and RG&E service territories. The Commission directs that within NYSEG and National Grid's service territories, a DC Fast Charger or Level 2 station must be within a two-mile radius to qualify for the 100 percent incentive. In some more urban areas within NYSEG and National Grid's territory a two-mile radius will be insufficient to properly target these benefits. Therefore, the Commission directs NYSEG and National Grid to, in consultation with Staff, define areas within their service territories, including metro areas, where a one-mile radius will be required to qualify for the 100 percent incentive in their implementation plan filings.

To further clarify, as discussed in the Eligibility Criteria and Additional Environmental Justice Programs sections of this Order, the 20 percent dedicated environmental justice and low- and moderate- income community budget shall be earmarked for both publicly accessible DC Fast Charger plugs within the specific radii of environmental justice communities and Level 2 plugs sited in multi-unit dwellings within the specific radii At such point that each utility expends the 20 percent budget cap on DC Fast Chargers and Level 2 plugs sited within the specified radius per service territory, the utilities should continue to support development within Disadvantaged Communities at the applicable 90 or 50 percent incentive levels.

B. Station Maturity

Whitepaper Recommendations

Under Staff's proposal, only new sites and sites under construction would be eligible for an incentive. If a customer with a station under development has a "firm commitment" to take utility service before the date of this order, the Whitepaper proposal would disqualify the project from incentives under the Make-Ready Program. Indications of a firm commitment for utility service would include remitting payments for required Contribution in Aid of Construction (CIAC) or Excess Distribution Facilities (EDF) and, for stations not requiring a CIAC or EDF, a signed application for utility service. The Whitepaper also recommended that, if a station under construction in a territory with an existing utility-specific make-ready program is eligible under that program, the customer should continue with the existing program and would not be eligible under this statewide program.

Comments

Electrify America requests that the Commission determine eligibility based on whether physical construction has commenced at a site as of the date of the order approving the program. Electrify America notes that it often issues a payment for a CIAC or EDF well in advance of confirmation that a station will enter construction and has, in the past, not proceeded with construction after a line extension payment has been made. Electrify America asserts that Staff's proposed eligibility requirement would exclude many of its stations in early phases of development, allow competitors who develop stations slightly later to compete with these stations on unequal terms, and encourage developers to walk away from sites that have not yet begun construction.

Determination

The Commission acknowledges Electrify America's experience in New York State and that the Whitepaper proposal on this issue does not necessarily represent the most appropriate marker of station maturity to determine eligibility for the Make-Ready Program. To clarify, in order to be eligible for this Make-Ready Program, a station must be considered "new," which we define as "construction commencing post-issuance of this Order." While the Make-Ready Program shall be considered "live" as of issuance of this Order, and any station not under construction as of issuance of this Order is eligible to apply to the Make-Ready Program, the JU will of course need time to prepare the tools, applications, Implementation Plan, and Make-Ready Program Participant Guide as discussed below. Accordingly, the JU should accept developer interest in the program immediately upon issuance of this Order and process these initial applications as they have been processing EV station service applications while the EV Infrastructure service application portal, described below, is being developed.

C. Plug Type

Whitepaper Recommendations

The Whitepaper proposes requiring that the chargers used at the EV charging station be standardized and non-proprietary in order for the project to be eligible for a full incentive under the program. Under the proposal, Level 2 chargers would need to use the standard Society of Automotive Engineers (SAE) Electric Vehicle Conductive Charge Coupler J1772 (SAE J plug) as a threshold to participate in the Make-Ready Program, while DCFC chargers would need to use standardized, non-proprietary plugs (such as the SAE Combined Charging System) to be eligible for full incentive under the program.

Comments

The JU proposes that all types of plugs, both proprietary and nonproprietary, be eligible for an incentive, which would allow the JU to select projects serving low- and moderate-income and environmental justice communities. ChargePoint recommends allowing plugs capable of simultaneously charging at or above 75 kW, or plugs capable of independently charging at or above 62.5 kW and sharing power to charge one vehicle at or above a combined 125 kW. According to ChargePoint, this modification would reflect that 75 kW-capable EVs do not typically charge at or near 75 kW, and thus would serve as a cost control mechanism for the program. Green Machine Power asserts that the proposed Make-Ready Program fails to achieve technology neutrality and will stifle innovation. For its part, Plug In America suggests that Level 1 charging should be also eligible for a program incentive as it may be suitable in workplace locations and long dwell-time locations. Tesla contends that its proprietary Wall Connectors should be eligible at nonpublic locations.

Determination

The Commission is seeking to deploy the minimum critical infrastructure necessary to support the EV market with imperfect knowledge about how the nascent EV market will evolve. Throughout this proceeding, the Commission has expressed a desire to direct public funds towards the technology types that provide the maximum public benefit, while balancing the need to support the current and projected EV mix and incentivize innovative future technologies and business models. The Commission finds that the Whitepaper's proposed 90 percent make-ready incentive for standardized plug types and 50 percent make-ready incentive for proprietary plug types is a reasonable approach and is adopted with the following clarifications.

Proprietary plug-type DC Fast Charger stations seeking to participate in the DC Fast Charger Per-Plug Incentive program are already encouraged to collocate standardized plugs. Indeed, the current program rules allow a 60 percent per-plug incentive under the "Mixed Tier" approach where two simultaneously accessible standardized plugs can simultaneously provide 62.4 kW – 74 kW speeds, and a full per-plug incentive where the proprietary plug-type is capable of simultaneously charging two vehicles at 75 kW or greater.[38] In order to have a successful Make-Ready Program the Commission must have program rules that recognize that SAE CCS plug types and CHAdeMO plug types are almost always collocated at stations, while Tesla plug types will generally only collocate where practical or in order to access the Mixed Tier DC Fast Charger Per-Plug Incentive.

The Commission rules that, where a proprietary plug type is collocated at a station with an equal number of commonly accepted standardized plug types of equal or greater charging capacity, that station shall receive the 90 percent make-ready incentive. However, where a station with proprietary plug types is not collocated with an equal number of commonly accepted standardized plug types of equal or greater charging capacity, that station shall receive the 50 percent make-ready incentive. The number of plugs eligible for incentives at stations with more than one plug shall be the number of plugs capable of simultaneously charging at 50 kW or greater. For example, a station containing a SAE CCS plug and a CHAdeMO plug type mounted to the same charger (which can only charge either a SAE CCS compatible vehicle or a CHAdeMO compatible vehicle at any given session) shall count only as one plug. By contrast, a

[38] 18-E-0138, supra, Order Further Modifying DC FAST CHARGER Incentive Program, p. 14.

station containing a SAE CCS plug and a CHAdeMO plug type mounted to the same charger (which are capable of simultaneously charging both a SAE CCS compatible vehicle and a CHAdeMO compatible vehicle at greater than 50 kW) shall count as two plugs.

With these program rules the Commission continues to underscore the importance of standardization and the need for collaboration among station developers, while including all technology types as eligible for Make-Ready Program funds. The Commission expects that new plug types and station business models will emerge, and these criteria shall be examined at the midpoint review.

D. Future-Proofing

Whitepaper Recommendations

Staff proposes that eligibility for make-ready incentives would require the specific EV charging station infrastructure to be oversized and infrastructure to accommodate future expansions be put in place if there is minimal incremental cost. For customer-owned equipment, oversizing would be required for the conduit and conductors, and potentially the panel under the Staff proposal. Staff requested comments regarding the specific utility-owned equipment that would need to be oversized, the incremental costs of oversizing, and additional methods to promote future-proofing. Stakeholder comments were also requested on the appropriateness of resiliency requirements for sites receiving incentives under the program. Staff further proposed that the International Council on Clean Transportation (ICCT) “lessons learned” be adopted as well.

Comments

There were a significant number of comments regarding future-proofing. Commenters are broadly supportive of future-

proofing, when necessary and reasonable, but generally caution against strict requirements that could encourage overbuilding and contribute unduly to incremental project costs.

The JU generally agrees that additional connecting points, trenching, and conduits should be encouraged but also note that, depending on plug types and number or plugs per location, more significant system upgrades may be necessary at particular locations, including larger transformers or additional transformer pads. The JU notes that these necessary upgrades would come with additional costs beyond initial plug installations and should be recognized as a separate program budget item. In its reply comments, ChargePoint agreed with JU's proposition.

The JU proposes general criteria for determining acceptable future-proofing efforts, including assessments of developer expansion plans, expansion feasibility, and the cost effectiveness of the requirements. New York Power Authority recommends that future-proofing that can be accomplished at a minimum incremental cost should be required, but suggests limiting capacity to no more than 50 percent greater than is presently necessary, and limiting grid upgrade costs to no more than 10 percent as an additional control on incremental oversizing costs. If future-proofing costs that exceed this cap are warranted, the utility may provide supporting documentation that demonstrates the need for such incremental costs, according to New York Power Authority.

Greenlots encourages future-proofing where feasible but cautions against strict requirements. Alliance for Transportation Electrification and Alliance for Automotive Innovation caution against overbuilding sites without specific justification, and Environmental Defense Fund recommends a comprehensive grid impact study for determining requirements.

The NRDC and Sierra Club note that it is more cost effective to oversize equipment during initial installation and recommend that more expensive components are prudent candidates for future-proofing at this stage. However, these commenters also recommend that the Commission not be over prescriptive in dictating requirements but instead encourage cost-effective future-proofing at sites where likely upgrades are anticipated.

Greenlots, Enel X North America, and EVgo agree that warranted future-proofing efforts can be reasonable and cost-effective but recommend that these activities be optional rather than obligatory, particularly where cost containment is a concern. While initially arguing that future-proofing should be optional, in its reply comments, Tesla acknowledged the reasonableness of the JU's proposed future-proofing criteria on the grounds that they balance costs and feasibility, and recommended their adoption. New York Power Authority, Greenlots, and the NRDC and Sierra Club recommend that future-proofing include open standards and interoperability, and Greenlots further suggests that the Commission investigate other future-proofing solutions not discussed in the proposal. FreeWire warns that future-proofing requirements could limit siting opportunities and delay deployment. EVBox contends that mandated credit card readers hinder public charging business economics and conflict with proposed future-proofing goals.

Drive Electric LI recommends that DC Fast Charger infrastructure on major thoroughfares be built as large as possible to avoid capacity problems that plagued compressed natural gas infrastructure at the turn of the century. ChargePoint argues that the program should require the installation of a minimum of two ports per location and maintain prudent future-proofing requirements. The JU offers similar support and outline a set of criteria to determine the extent of

future-proofing treatment required at each site. The NRDC and Sierra Club support future-proofing and contend the Commission should not be overly prescriptive in setting requirements, but advise that expensive retrenching be avoided. NYC also calls for reasonable restraint in future-proofing EV infrastructure.

Several commenters raise concerns about having grid resiliency as another future-proofing requirement. For example, Advanced Energy Economy Institute and the ACENY warn against expecting charging infrastructure to perform functions for which they are not designed. Alliance for Transportation Electrification believes that an emphasis on resilience will contribute to regulatory barriers already confronting EV supply equipment deployment. Bloom Energy Corporation recommends that resiliency be considered during the earliest stages of EV Infrastructure construction to avoid social and economic risks. Environmental Defense Fund recommends a local approach to EV supply equipment resilience, arguing that communities will best understand pertinent risks and needs.

Greenlots suggests that a comprehensive strategy that complements charging infrastructure with distributed generation and storage can ensure available charging during emergencies and foster EV adoption. Tesla notes that a resiliency review is already included in local planning, building, and electrical code evaluation and permitting. FreeWire notes that battery-integrated charging systems provide inherent resilience during power outages. The JU and NYC suggest that flood vulnerability and other climate-related risks should be considered as a program application criterion.

Vrinda, Inc. (Vrinda) argues that the Commission should make it mandatory for the utilities and developers to pair storage with charging stations as a requirement of future-proofing, to support de-carbonization, address congestion, and

eliminate the need for costly upgrades which may get stranded in the future as EV utilization and ranges change.

Determination

Starting with a budgetary issue, the Commission agrees with the JU comment that future proofing expenditures should be recognized as a separate line item inside the Make-Ready Program budget because such "expenditures represent additional utility costs that are not tied to the quantity or charging capacity of plugs initially installed at a location." Therefore, the cost of future-proofing shall be tracked separately from the other make-ready costs, and for this reason future-proofing costs should not negatively factor into a utility's selection of projects.

The Commission directs that no more than eight percent of each utility's overall Make-Ready Program budget be spent on future-proofing costs. This cap shall be reexamined at the midpoint review as discussed in the Program Review section of this Order. Future-proofing costs for equipment or infrastructure that is not eligible for the Make-Ready Program are not to be included in this budget and shall be the responsibility of the site developer. This modest investment in future-proofing will ensure that future expansion is done at a lower cost with minimal delay.

It will be critical for utilities and EV supply equipment developers to work together to determine which site and equipment should be future-proofed. As the International Council on Clean Transportation explained, future-proofing is an opportunity to increase the growth potential of a site and save money on that future expansion. Developers will understand the potential of a site to be expanded with either more plugs or greater charging capability, as they should also understand customer expectations for charging speeds and plug availability.

The JU has insight into grid impacts and potential costs of additional load enabled through futureproofing. The Commission agrees with commenters that not all make-ready sites will require future-proofing and it thus will be up to the developer to request future-proofing work. The utilities are directed to accommodate such work if it passes the economic analysis.

The developer must explain the future plans for the site at issue, including additional plugs and/or addition power needs. The utility shall work with the developer to determine the feasibility of future-proofing plans from a grid and site perspective, and include for consideration whether the site can accommodate additional make ready infrastructure and a higher level of service, and whether additional parking spots are available or may become available in the future.

For Level 2 charging stations, oversized or additional conduit may need to be installed, panels may need to be oversized to accommodate adequate space associated with expansion, additional conduit and connections points (including trenching and conduit to additional parking spaces for future chargers) may need to be installed, and the service for the station may need to be oversized to accommodate the potential load at the site. Similar future-proofing may be needed at DCFC stations. In recognition of the requests made by the JU and the reports issued by the International Council on Clean Transportation, the Commission thus rules that transformers and transformer pads shall be on the list of approved future-proofing facilities.

The Whitepaper envisioned future-proofing as spending a minimal incremental cost to accommodate upgrades to the number and/or capacity of plugs. The Commission does not interpret this aspect of the Whitepaper as an invitation to over build EV supply equipment stations at rate-payer expense. The Commission

finds that future-proofing of the components described above should be of a reasonable cost to insure future expansion can happen quickly and cost effectively.

New York Power Authority proposed to limit future-proofing per site to no more than 50 percent of the capacity needed to service the installed chargers and no more than ten percent of the make-ready project cost. While the Commission appreciates this proposed cap on capacity of the site, we want to highlight that the purpose of future-proofing must be to allow as much expansion as possible at minimum cost. It could be that the fifty percent capacity cap could restrain cost effective expansion unnecessarily. Instead, capping future-proofing at ten percent of the site specific make-ready cost provides the developer and utility flexibility to determine the appropriate future-proofing at the site to allow for future expansion with a transparent cap on cost. This ten percent station-specific cap is distinct from the cap that no more than eight percent each utility's Make-Ready Program budget shall be spent on Make-Ready. We reject the JU proposal to restrain future-proofing per site by a cost analysis of the incremental cost of expansion per kW at the time of the construction versus the cost of expansion at a future date because the proposal does not appear to be transparent and easily implemented on a large scale.

If a developer opts to future-proof a site, and the cost is greater than ten percent of that site's Make-Ready Program cost, the developer will be required to pay for future-proofing costs in excess of the ten percent limit. In those instances, the utility shall perform the future-proofing work after securing funding from the developer. Thus, the developer can choose to future-proof equipment not eligible for a utility incentive for future-proofing but that developer shall be

responsible for one hundred percent of such future-proofing costs.

E. Location Capacity

Whitepaper Recommendations

Staff's proposal defines the maximum number of chargers and electricity capacity for each eligible EV charging station. For DC Fast Charger stations, the proposal recommends that between four and ten plugs per location be eligible for an incentive, and the aggregate charging capacity per site be limited to 2 MW. For Level 2 plugs, Staff proposed no limitations on the number of plugs eligible for an incentive or on the aggregate charging capacity per location. For the purpose of the Make-Ready Program, the number of eligible plugs per charger would be the number of plugs capable of charging simultaneously. For example, a charger with two types of plugs that can only charge one vehicle at a time would be considered one plug, while a charger with two plugs and load-sharing capability that can charge two vehicles simultaneously would be considered two plugs.

Comments

The JU argues that the minimum and maximum plug requirements could constrain the types of sites that are developed and increase overall program costs. The JU notes that establishing a minimum requirement of two DC Fast Charger plugs at a given location (without a maximum) would better enable multiple kinds of sites with diverse business models to access make-ready incentives. ChargePoint and New York Power Authority request a reduction in the minimum deployment to two ports, with sufficient make-ready for two additional ports in the future at Level 2 and DC Fast Charger deployment sites. New York Power Authority recommends that the Commission rule that charging

sites must be able to serve at least two cars simultaneously to be eligible for Program incentives.

Determination

We find merit in the JU's argument that the minimum and maximum plug requirements could constrain the types of sites that are developed and increase overall program costs. There may be desirable charging locations where developing four DC Fast Charger plugs is unnecessary at the time the site is developed or is cost prohibitive, particularly in NYC. Staff intended the maximum plug and charging capacity limitations to encourage locational diversity of DC Fast Charger charging stations, which and is a particularly important consideration in service territories with relatively small DC Fast Charger plug targets. For example, Central Hudson and O&R could have fewer than ten DC Fast charging locations developed if more stations with more than ten plugs are developed. However, there may be locations that will be heavily utilized that would benefit from having more than ten plugs available.

Based on the JU's comments the locational and capacity sites constraints recommended in the Whitepaper are hereby relaxed, with the following conditions. A limited number of sites with two plugs will be eligible for the incentive for both DC Fast Charger and Level 2 charging stations. For the five boroughs of New York City, the number of plugs at locations with two plugs shall not be more than 50 percent of the target number of plugs included in the program. In the rest of the state no more than 25 percent of the target number of plugs to be developed shall be at locations with two plugs.

Additionally, DC Fast Charger sites with more than ten plugs and/or demands in excess of 2 MW will be allowed to participate in the program conditionally. The Commission will allow incentives for locations with an excess of ten DC Fast

Charger plugs only if developing the site does not cause the utility to incur new business costs greater than those that would have been incurred to develop a site with a maximum demand of 2 MW. Finally, the number of plugs at locations in excess of ten plugs shall not exceed 50 percent of the target number of plugs included in the program the for each utility.

VI. Program Incentive Levels and Cost Containment Whitepaper Recommendations

Under Staff's proposal, an eligible charging station would receive a tiered incentive based on its consistency with certain eligibility criteria. Stations satisfying all the eligibility criteria would receive the lesser of a maximum incentive level based on the average charging station development costs per utility, or 90 percent of the eligible costs for each site. Customers would receive a 50 percent incentive if the accessibility or plug type criteria are not satisfied but all other eligibility criteria are met. The Whitepaper proposes a maximum incentive level for each installation, by utility service territory, using utility station development cost estimates. Under this proposal, customers with above-average development costs would pay for any make-ready costs that exceed the maximum incentive level, requiring them to consider the tradeoffs between the incremental market value and higher cost locations. The maximum incentive level would be reduced as the station economics improve over time.

Staff also proposes that customers developing DC Fast Charger stations be allowed to bundle costs from multiple site locations within a service territory, with all plug installations having to be completed during a developer-chosen 18-month "Bundle Period." The Bundle Period would begin when the incentive application is approved. The Whitepaper proposes

a cap on the total incentive payment at the lesser of 90 percent of eligible costs for all plugs completed during the Bundle Period, or the maximum per plug incentive multiplied by the number of plugs installed during the Bundle Period. Once a bundle application is approved, incentives would be deemed committed.[39]

Comments

Many commenters argue that costs may vary significantly within a utility service territory, and therefore the maximum incentive level proposal needs to be revised or eliminated. Greenlots and ChargePoint note that the per-site cost estimates are too low. Others argue that each utility should have flexibility to determine which sites justify an above-average incentive, including location specific costs and societal benefits. For example, the EV Industry Coalition suggests that the maximum incentive level should be a guideline, not a strict cap. The JU warns that maximum incentive levels may deter implementation of higher-cost and higher-value stations and may perversely encourage less expensive installations to inflate their costs to qualify for greater incentives.

ChargePoint and the EV Industry Coalition argue that the maximum incentive level should not be binding for the first 18 to 24 months of the program to allow the market time to establish more clear cost data, and to enable the development of higher cost and higher value locations. EVBox recommends against adopting maximum incentive levels initially, and instead suggests allowing utilities to evaluate site host applications

[39] A customer would be allowed to submit an addendum to the bundling application to add additional plugs, although approval would be subject to additional incentive payments being available.

based on costs, geography, and the availability of alternative sites. Enel X North America suggests incentivizing a percentage of the eligible costs without a cap or maximum incentive level. NYSDEC, Electrify America, and Plug In America advocate flexibility in setting incentives or in proceeding based on initial market assumptions, particularly in view of the current public health crisis caused by COVID-19 and anticipated disruptions to construction and EV sales. Plug In America recommends that incentives remain stable until at least 2021 due to these considerations. The NRDC and Sierra Club suggest that it may be appropriate to decrease incentives at different times based on EV deployment in various service territories.

New York Power Authority suggests a higher maximum incentive level for chargers less than 150 kW. Electrify America seeks clarification regarding the aspect of the proposal, specifying that maximum incentive levels would be determined based on utility-specific average deployment costs. Advanced Energy Economy Institute and the ACENY request that the Commission make clear that the maximum incentive level is to function as a cost reduction for utility-side costs, rather than a reimbursement to developers. Advanced Energy Economy Institute and the ACENY warn that developers with limited capital may delay pursuing additional projects if funds are tied up in utility-side costs, particularly given the impact of the COVID-19 pandemic on cash flows. Advanced Energy Economy Institute and the ACENY request that the Commission consider alternatives to lessen these effects, including upfront payments from utilities to developers for customer-side work, or utility payment for customer-side work to be reimbursed by the developer.

Several commenters also express concern about the timing and severity of incentive modifications and the effect

these could have on market development. The Alliance for Transportation Electrification and Electrify America note that cost recovery concerns stemming from premature incentive reductions could stifle investment, while Greenlots and NYC express concern that step-downs may occur too frequently to allow project completion of larger or more expensive stations. Enel X North America also argues for infrequent step-downs to ensure program certainty, possibly as few as one in five years. Electrify America recommends the need for further analysis of this issue to allow the Commission to determine whether the proposed Make-Ready Program, when combined with existing incentives, is likely to enable economically sustainable construction and operation of EV charging stations. Electrify America recommends that the Commission conduct a sensitivity analysis around utilization factors and of how possible changes to policies that impact the cost to operate ultra-fast charging stations, such as an expanded Per-Plug Incentive or an EV charging station-specific volumetric rate, would impact the NPV of modelled stations and the projected effectiveness.

The JU states that market certainty should take precedence over a predetermined and premature schedule of incentive decreases and argue that a more flexible incentive structure would increase the likelihood of program success. The JU recommends flexibility in setting and adjusting incentives to increase charger numbers and capability, accommodate customer segment needs, and account for business model diversity. Greenlots warns that the proposed incentive schedule is too optimistic regarding market development and for this reason it currently opposes any step-downs; however, it expects market conditions to improve at some point to allow modifications. Greenlots suggests that financing could take place through a reservation system to avoid depleting funds prematurely for

longer-term projects. The Alliance for Transportation Electrification, Enel X North America, EVgo, the JU, NRDC and the Sierra Club, and Tesla emphasize the importance of waiting for the midterm program review to assess and implement possible incentive decreases. By contrast, Advanced Energy Economy Institute and the ACENY recommend that utilities should be able to adjust payment percentages before a formal program review. New York Power Authority suggests waiting for program milestones, possibly based on number of installed DC Fast Charger ports, before reducing the incentive.

Advanced Energy Economy Institute and the ACENY, the Alliance for Transportation Electrification, NYC, and Tesla argue that any evaluation regarding incentive reductions should be transparent with ample notice given to stakeholders, possibly through a dashboard. The JU argues that regular utility evaluations of applicants could obviate the need for additional notice and process. Tesla requests a minimum 12-month notice be given to stakeholders before any incentive modifications. Advanced Energy Economy Institute and the ACENY, NYC, and Greenlots recommend EV registrations as a metric in determining incentive reductions. On the other hand, the NRDC and Sierra Club contend that station utilization is a more appropriate metric.

The EV Industry Coalition, the JU, and Tesla assert their belief that bundling is administratively inconsistent with typical site development. These commenters are thus particularly concerned that aligning development milestones with bundling periods will be difficult and impede development. Both ChargePoint and EVBox warn that bundling will favor electric vehicle service providers over independent site hosts, citing the ability of the former to spread costs over multiple locations. EVBox and Greenlots propose that utilities encourage

investment at priority sites based on additional criteria, additional incentives or, where appropriate, be allowed to own such sites. Greenlots adds that bundling should remain an option for developing high cost sites but encourages investigation of other methods.

As an alternative to the bundling proposal, Enel X recommends incentives that cover a given percentage of actual costs that would obviate the need to bundle DC Fast Charger costs across an area. FreeWire Technologies supports the bundling proposal but recommends reducing the period to 12 months to encourage faster deployment. Enel X North America believes that the proposal to allow bundling of DC Fast Charger project costs within a single utility service territory would skew program participation to more sophisticated developers who are able to develop multiple sites to increase the coverage of the incentive. ChargePoint further suggests allowing site-specific capital cost variability. The JU proposes that bundling proposals at different locations should include all relevant plugs in a single application to allow comparisons against other applicants.

Determination

The Commission is persuaded by the many commenters calling for greater flexibility regarding setting per-site incentive levels for the Make-Ready Program and thus concludes that a more flexible approach than the maximum incentive level proposal in the Whitepaper is necessary. First, as noted by Enel X North America, EVBox, and Greenlots, setting a prescriptive incentive rate per plug may favor cheaper sites over more expensive sites and sites with higher numbers of plugs over sites with a lower number of plugs, regardless of whether the expensive sites or sites with a lower number of plugs may result in higher benefits in a specific area. Second, as noted

by many commenters, the current set of available information regarding costs per site is relatively limited. We agree that it is unwise to base a prescriptive maximum incentive level on a limited set of data that may not turn out to be representative of the wider charging site development market. The Commission further agrees that the incentive step-downs proposed in the Whitepaper are not appropriate to implement at this time, due to the nascent state of the market and the current uncertainty surrounding the overall representativeness of the EV charging site data presently available in New York State.

The Commission is persuaded by objections made by various parties, including the JU and ChargePoint, regarding the bundling proposal included in the Whitepaper. The Commission agrees that the Whitepaper bundling proposal may result in advantages for larger developers capable of implementing multiple projects simultaneously compared to smaller developers that may only be able to accommodate one project at a time.

In addition, the Commission agrees with the commenters that suggest that the bundling proposal would result in program rules which may not be consistent with, or helpful in easing, the typical site development process. Furthermore, administering the bundling option could be unnecessarily burdensome, increasing costs to implement the program. It is important to emphasize that the Make-Ready Program is intended to create a level playing field for all developers, not to favor certain developers over others due to administrative rules.

Instead of the prescriptive maximum incentive levels recommended in the Whitepaper, the Commission rules that it is reasonable to allow incentives to cover a specified percentage of actual make-ready costs. Accordingly, the JU shall be allowed to provide the following incentive levels depending on whether the site at issue meets certain eligibility criteria:

1) Up to 100 percent of eligible make-ready costs for publicly accessible DC Fast Charger sites within one mile of environmental justice communities in Con Edison's, Central Hudson, O&R, and RG&E's service territories, and within two miles of environmental justice communities in NYSEG and National Grid's service territories.

2) Up to 100 percent of eligible make-ready costs for Level 2 sites in multi-unit dwellings within one mile of environmental justice or low- and medium- income communities in Con Edison's, Central Hudson, O&R, and RG&E's service territories, and within two miles of environmental justice or low-and moderate- income communities in NYSEG and National Grid's service territories.[40]

3) Up to 90 percent of eligible make-ready costs for sites that meet all of the applicable eligibility requirements.

4) Up to 50 percent of eligible make-ready costs for sites that do not meet all of the applicable eligibility requirements.

Further, as recognized by Enel X North America, the increased incentive flexibility from declining to adopt the maximum incentive level obviates the need for site bundling and therefore avoids the problems previously discussed. Refinements to incentive flexibility, whether more prescriptive or site-specific incentives should be implemented, and the appropriateness of implementing incentive level step-downs shall be considered as part of the midpoint review process once additional data is available.

Although the Commission is adopting a more flexible incentive design, containment of program costs remains a specific focus for successful operation of the Make-Ready Program. Instead of containing costs through the application of

[40] The Commission adopts the same definition of low- and moderate- income individuals for this Make-Ready Program as is discussed in the Additional NYSERDA-led Environmental Justice Programs section below.

rigid prescriptive per-plug maximum incentive levels, the Commission is implementing shareholder incentive mechanisms to contain program costs, as described below in greater detail in the Performance-based Regulations section of this Order. These shareholder incentive mechanisms will reward utilities for getting plugs installed at lower make-ready cost than estimated. Further, if the utilities demonstrate through poor program performance that positive shareholder incentives are not sufficient to contain costs, the Commission is committed to consider symmetrical or negative shareholder incentives to refund program costs to customers if the need to do so arises.

VII. Program Budget

Whitepaper Recommendations

Staff proposed in the Whitepaper that an estimated $582 million be allocated to the Statewide Make-Ready Program through 2025. The estimate for incentives available for Level 2 chargers was $431.5 million to support 100,000 chargers and the estimate for the incentives available for DC Fast Chargers was $150.7 million to support 2,600 chargers. Staff's proposal assumed average Level 2 per-plug make-ready costs of $5,000 for Upstate and $9,097 for the NYC metro area. For DC Fast Chargers, Staff's proposal assumed average per-plug make-ready costs of $50,000 for Upstate and $90,970 for the NYC metro area. Staff requested that each utility submit station development cost estimates for the purposes of developing utility-specific budgets.

Under Staff's proposal, each utility's share of plugs would be established using the percent of light-duty vehicle registrations in each service territory. The number of stations that may be incentivized would be capped at this number. Utility program budgets would be capped at the maximum incentive level, which would be the utility-specific average cost to make-

ready on a per plug basis, multiplied by number of plugs needed and remain fixed for 3 years until the program's midpoint program review. The number of incentives for Level 2 chargers would be limited to 50 percent of the total number of plugs per service territory for the first 3 years.

Staff's proposal in the Whitepaper also included a budgetary set-aside for DC Fast Charger stations in and around low- and moderate-income LMI and environmental justice communities. Twenty percent of each utility's DC Fast Charger budget would be directed towards EV charging stations located within 10 miles of a disadvantaged community. Staff did not propose any set-aside for Level 2 chargers, noting that promoting Level 2 charging in low- and moderate-income areas may not be the most effective path to expanding accessibility to clean transportation options in these communities. Staff requested stakeholder feedback on criteria to identify low- and moderate-income and environmental justice communities, as well as criteria for siting and rebate levels to promote EV penetration in environmental justice areas.

Staff also proposed that the seven REDCs be designated as "strategic locations" and eligible for limited additional incentives totaling $5 million, to ensure communities with less access to EV charging stations have a minimum level of DC Fast Charger infrastructure. At least four locations, with four 150 kW DC Faster Charger plugs at each site, would be developed in each upstate REDC through a competitive procurement in the first year of the program. Staff requested stakeholder input on the efficacy of the proposal, administration of the competitive process, site identification and selection, and determination of program size.

Comments

Many commenters suggest revisions to the program budget based on more costly estimate of plug make ready costs. For their part, the JU estimates an average per-plug make-ready costs of $6,000 for Upstate and $16,100 for the New York City metropolitan area. For DC Fast Chargers, the JU estimates average per-plug make-ready costs of $55,000 for Upstate and $130,800 for the New York City metropolitan area. The JU notes that the Whitepaper did not include incremental budgets for implementation or future-proofing costs, which the JU estimate at a 15 to 20 percent addition for implementation and an 8 percent addition for future-proofing.

ChargePoint recommends revising program capital cost projections to reflect greater cost variability. It indicates, for example, that DC Fast Charger installation and make-ready costs average between $34,000 and $211,750 per plug. Electrify America notes that further economic assessment is required and recommends analysis of utilization factors and policy effects on charger installation and operation costs. Green Machine Power believes that an updated forecast will ensure more accurate long-term funding. Plug In America recommends that Staff redo its analysis using a more sophisticated tool. Greenlots agrees with several parties who warned that the overall program budget is likely insufficient.

NYSDEC recommends distributing the proposed $582 million in make-ready investments between investor-owned utilities based on projected Level 2 and DC Fast Charger needs and progress towards goals in five and ten years. NYC notes that authorizing excessive programmatic budgets will have significant effects on ratepayers, especially during uncertain economic conditions. Tesla recommends that other funding sources be investigated before moving ahead with competitive

procurement, such as grants from New York's share of Volkswagen Appendix D funds. The Alliance for Transportation Electrification recommends that a program management budget of ten to fifteen percent of the total budget, ideally in addition to funds already earmarked, is sufficient to accomplish program goals.

There is wide support among parties for Staff's proposal to allow for a set-aside budget for low- and moderate-income and environmental justices communities. Several parties recommend reducing the 10-mile radius for use in urban and suburban locations. NYC suggests using the 10-mile radius in less populated areas. Numerous commenters suggest a smaller 1-mile radius for downstate economic justice areas, while New York Power Authority suggested a four-mile radius. Most commenters suggest leaving the 10-mile radius in place upstate.

The Alliance for Transportation Electrification recommends that Staff and the utilities engage disadvantaged communities directly to learn their needs. The JU supports using existing definitions for low- and moderate-income and environmental justice communities, such as the DEC list of proposed environmental justice communities organized by county. New York Power Authority recommends that the conditions for maximum incentive eligibility be expanded to increase the likelihood of utilization in disadvantaged communities. New York State Department of Transportation and FreeWire Technologies suggest that the program increase its investment goals to align with the CLCPA targets for clean energy investment. NYC recommends that the program also foster workforce development opportunities during the gradual economic recovery from the pandemic.

Commenters generally support the REDC recommendations. The JU states that each utility will work together in each REDC

to structure similar procurements in the program's first year. NYC suggests that the REDC approach is too broad to appropriately incentivize EV supply equipment deployment where it is most needed. NYPA argues that developers should be responsible for siting EV Infrastructure development at strategic locations, coordinating with existing or planned stations to avoid undue clustering. Enel X North America recommends that utilities that serve each REDC should administer the competitive process. Plug In America encourages grants to support installations in more remote locations, noting that actual utilization fails to represent the entirety of the value of installations in these areas. NRDC and Sierra Club believe chargers should be placed based on the types of trips they are likely to support, such as on corridors. Tesla suggests solicitations for discrete areas, whereas Enel X North America supports broad geographic guidelines.

Advanced Energy Economy Institute and the ACENY, Greenlots and the Metropolitan Transportation Authority (MTA) encourage the Commission to address the medium- and heavy-duty sectors expeditiously since environmental justice communities are disproportionately impacted by air pollution from transit and delivery vehicles. New York Public Transit Association, Inc. requested a budget for make-ready in their initial comments, and the EV Industry Coalition and New York Power Authority assert that support for transit authorities is vital.

Determination

The JU proposed average per-plug make-ready costs that were significantly higher than those used by Staff to develop the budget estimate in the Whitepaper. Estimates for Upstate installations were 120 percent higher than those used by Staff for Level 2 and 110 percent higher for DC Fast Chargers. In Con Edison and O&R's service territory, the JU's estimates were 177

percent higher than those used by Staff for Level 2 and 144 percent higher for DC Fast Chargers. Other commenters, including ChargePoint, raised concerns that Staff's estimates were too low, and that make-ready costs for DC Fast Chargers in particular are highly variable.

Staff held several meetings with the Joint Utilities to determine the methodology used by the utilities in calculating average make-ready costs and to identify why the estimates, particularly for Con Edison, were greater than those in the Whitepaper. Staff tested cost component estimates against NYSERDA experience and industry resources. Staff determined that the estimates provided by the JU for Upstate Level 2 and DC Fast Chargers were reasonable. However, Staff determined that estimates for Con Edison's service territory were high. Staff identified the primary drivers of the cost disparity to be assumptions made by Con Edison regarding component costs, plug distribution, site configuration, and variability.

The Commission acknowledges the limited historical data from which to draw, as well as significant variability in site-level costs as indicated by many commenters. In the Cost Containment section above, we determined that a more flexible approach than that proposed in the Whitepaper is necessary and for that reason established alternate cost containment measures. To appropriately balance cost containment with flexibility, the Commission is modifying Staff's proposal to limit the number of incentives for Level 2 chargers to 50 percent in the first three years of the program. At this time the Commission finds that a 50 percent limit could unnecessarily constrain program activity due to the noted variability in site-level costs. However, a 60 percent limit should provide appropriate cost containment while recognizing that site-level costs can vary significantly.

Therefore, we rule that such incentives shall be limited to 60 percent subject to reassessment at the midpoint review.

Based on updated estimates provided by Staff after extensive consultation with the JU and analyzing comments, Make-Ready incentive budgets are set using per-plug average costs of $11,298 for Level 2 chargers in Con Edison's service territory, $6,000 for Level 2 chargers outside of Con Edison's service territory, $100,109 for DC Fast Chargers in Con Edison's service territory, and $55,000 for DC Fast Chargers outside of Con Edison's service territory.

The Commission authorizes a Make-Ready Incentive budget for each utility as follows: Make-Ready Program incentive payouts shall not exceed $233,659,418 for Consolidated Edison, $21,140,800 for Central Hudson, $63,754,000 for New York State Electric & Gas, $112,118,100 for Niagara Mohawk, $19,261,600 for Orange and Rockland, and $30,549,700 for Rochester Gas and Electric. The Commission bases these budgets on the per-plug average costs listed above, each utility's share of Level 2 and DC Fast Chargers as determined in the Program Size section of this order, and in consideration of the varying incentive levels as determined in the Program Incentives and Cost Containment section of this order. These budgets are included in Appendix B to this Order.

In the DC Fast Charger Per-Plug Incentive Program, the Commission directed the Joint Utilities to update program rules so that no single station developer or operator may seek incentives for installation of greater than 50 percent of the plugs per utility service area.[41] The Commission made this modification to mitigate concerns that a single developer or operator could obtain a disproportionate amount of incentive

[41] Order Further Modifying DC Fast Charger Incentive Program.

funds. The Commission has similar concerns in the Make-Ready Program. As noted previously, the Make-Ready Program is intended to create a level playing field for all developers, not to favor certain developers over others. Therefore, the Commission directs that no single station developer or operator may seek incentives for greater than 50 percent of any utility-specific Make-Ready Incentive budget indicated in the preceding paragraph.

The Commission agrees with the JU that a robust program design framework that provides for adequate program implementation focus will help ensure program success. Accordingly, utilities are directed to provide estimated incremental administrative costs for implementation of the Make-Ready Program in their implementation plans. Such incremental costs, inclusive of costs related to the Fleet Assessment Service, shall not exceed 15 percent of each utility's Make-Ready Incentive budget and will be examined at the midpoint review. No utility shall expend more than 60 percent of its budget for administrative and implementation costs prior to the midpoint review.

As discussed in the Future-Proofing section above, an overall budget for incremental future-proofing costs shall not exceed eight percent of each utility's Make-Ready Incentive budget and will be reexamined at the midpoint review.

In the Accessibility section above, the Commission directed each utility to earmark 20 percent of its Make-Ready Incentive budget to support additional incentives for certain charging infrastructure located in or near environmental justice or low- or moderate-income communities. On a statewide basis, this will represent almost $96 million in make-ready incentives earmarked for these communities. Elsewhere in this Order, the Commission directs additional programs and associated budgets

that will further benefit environmental justice and low- or moderate-income communities.

These include: the Environmental Justice Community Clean Vehicles Transformation Prize ($40 million), the Clean Personal Mobility Prize ($25 million), the Clean Medium- and Heavy- Duty Innovation Prize ($20 million), the Medium- and Heavy-Duty Make-Ready Pilot Program ($15 million), and the Transit Authority Make-Ready Program ($10 million). With the Make-Ready Program and these associated programs and pilots, the Commission is authorizing a statewide budget of up to $701 million, $206 million of which will directly benefit environmental justice and low- or moderate-income communities. A chart illustrating each utility's Make-Ready Program budget and the overall statewide budget is included in Appendix B of this Order.

VIII. Cost Recovery

Whitepaper Recommendations

Under Staff's proposal, utilities would recover the make-ready equipment investments and incentive costs, up to the maximum incentive level per plug installed, through a combination of rate base treatment and surcharges. Utility-owned make-ready work would be capitalized and incorporated into the utility's plant in service. Until utility make-ready investments are reflected in base rates, the full pretax return on the average unrecovered investment net of related deferred income taxes, and accrued depreciation expenses, would be deferred as a regulatory asset. At the end of each program year, regulatory assets would be recovered over a subsequent one-year period via an existing surcharge. Utility make-ready investments would be excluded from each utility's plant in service reconciliation.

As proposed in the Whitepaper, if the maximum incentive level is greater than the utility's make-ready costs, the utility would provide the difference between the utility's make-ready costs and the maximum incentive level as a rebate to the customer. Any incentive expenses including carrying charges on the net-of-tax balance, at the pretax cost of capital, would be deferred as a regulatory asset and recovered through an existing surcharge. Collections would begin at the end of the first program year with annual updates thereafter. Incentive costs would be collected and amortized over a period of 15 years. If the maximum incentive level is lower than the utility's make-ready costs, then the customer would pay the balance via an EDF or CIAC. Any EDF or CIAC payments would be used to offset utility plant investment related to make-ready work. Program costs would be allocated based on transmission and distribution revenues to all customer classes. Staff requested proposals from utilities on how best to incorporate existing programs that address similar make-ready costs into the proposed program.

Comments

The Alliance for Transportation Electrification supports the proposal to allocate program costs to all customer classes based on transmission and distribution revenues, although Multiple Intervenors (MI) alleges that the proposed cost allocation is inequitable and should be modified. MI asserts that, if the purpose of the program is to develop publicly accessible and workplace EV charging stations predominantly for the use of mass-market customers, Staff's proposal would force large, nonresidential customers to fund make-ready incentives for which they should not be responsible.

The JU did not opine on Staff's proposed cost recovery method but did note that costs outside of the Make-Ready Program

related to connecting new customers and load to the system would be incurred. These "New Business" costs are typically included in a utility's calculated revenue requirement in rate cases. The JU requests that the Commission "permit utilities to recover the revenue requirement impact of incremental New Business costs on a current basis through a separate recovery mechanism until such time as the costs are placed into base rates." The JU estimated that New Business expenses could be $221 million based on the plug counts envisioned by the Whitepaper.

Determination

As discussed in the Cost Containment section above, plugs developed under the Make-Ready Program will be eligible to receive up to 100 percent, 90 percent, or 50 percent of eligible developer make-ready costs, depending on location and eligibility requirements. There are two categories of make-ready costs associated with plugs developed under the Make-Ready Program: utility-owned make-ready; and customer-owned make-ready.

In future rate filings, utility-owned make-ready work, including work related to future-proofing utility infrastructure, shall be treated as capitalized plant in service with cost allocation and recovery via traditional ratemaking methodologies. However, such costs are not reflected in current rate plans. Therefore, until such time as the utilities' base rates reflects such investments, the utilities will be allowed to recover the associated revenue requirement through an existing surcharge. Such interim recovery of costs shall be from all customers[42] in proportion to each class' transmission and distribution revenues; recovery shall be on a per kilowatt

[42] Excelsior Jobs and Empire Zone economic development sales shall be exempt from the surcharge.

hour basis for energy billed customers and on a per kilowatt basis for demand billed customers. Specifically, until costs are reflected in base rates, at the end of each program year, depreciation expense related to utility-owned make-ready work, and return on the average unrecovered investment net of deferred income taxes, shall be calculated and recovered over a subsequent one-year period. Utility-owned make-ready work shall be excluded from each utility's plant in service reconciliation.

Incentives paid for customer-owned make-ready work, including work related to future-proofing customer facilities, shall be included in base rates as a regulatory asset after the Make-Ready Program terminates and total costs are known. Similar to utility-owned make-ready, such costs are not reflected in current rate plans. Therefore, until such time as the utilities' base rates reflect such incentive payments, the utilities will be allowed to begin recovery through an existing surcharge mechanism. This regulatory asset, inclusive of associated carrying charges (the net-of-tax balances will be allowed to accrue carrying charges at the pretax overall cost of capital) will be collected over a period of 15 years. Surcharge collection shall begin at the end of the first program year, with annual updates thereafter. Such costs shall be allocated to all customers using transmission and distribution revenues and shall be recovered on a per kilowatt hour basis for energy billed customers and on a per kilowatt basis for demand billed customers. Incentives paid for customer-owned make-ready work shall be excluded from each utility's plant in service reconciliation.

With respect to the cost-allocation, the Commission notes the concern raised by MI that Staff's proposal would require large, nonresidential customers to support the deployment of make-ready infrastructure for mass-market electric

vehicles. The Make-Ready Program is being adopted to assist New York State in meeting CLCPA targets of reducing GHG emissions. As noted in Staff's Whitepaper and in MI's reply comments, reduced GHG emissions benefit all customer classes. Further, customers operating demand-billed EV charging facilities will be billed under applicable large, nonresidential rates. As such, revenues received from such customers will inure to the benefit of large, nonresidential customer classes within utilities' embedded cost of service studies, which are used to guide inter-class revenue allocation and for other purposes. Additionally, until such time as utilities' revenue decoupling mechanism targets incorporate revenues from these demand-billed EV charging facilities, such revenues will be credited to large, nonresidential customers through the decoupling mechanism. Therefore, allocating the cost of make-ready incentives to all customer classes is appropriate.

To the extent that the utilities' tariffs require modification to effectuate cost recovery, tariff revisions, to go into effect on January 1, 2021, shall be filed on not less than thirty days' notice. These tariff revisions are to go into effect on a temporary basis until made permanent by the Commission.

Costs related to the Make-Ready Program, Environmental Justice Community Clean Vehicles Transformation Prize, Clean Personal Mobility Prize, Clean Medium- and Heavy- Duty Innovation Prize, Fleet Assessment Service, Medium- and Heavy-Duty Make-Ready Pilot Program, and Transit Authority Make-Ready Program shall be recovered consistent with recovery methods for the Make-Ready Program. To the extent that costs in these programs are for utility make-ready infrastructure, such costs shall be treated as capitalized plant in service with cost allocation and recovery accomplished via traditional ratemaking

methodologies. Other costs resulting from these programs will be deferred as a regulatory asset and, at the end of each program year, be recovered via the surcharges mentioned above over a period of 15 years, with the net-of-tax balances accruing carrying charges at each utility's pretax overall cost of capital.

Make-Ready Program implementation costs inclusive of the Fleet Assessment Service shall be deferred until the end of each program year. At the end of each program year, the deferred costs will be collected over a five-year amortization period, with the net-of-tax balances accruing carrying charges at each utility's pretax overall cost of capital.

The JU's request that the Commission establish a separate recovery mechanism for New Business expenses associated with the Make-Ready Program is denied at this time. As stated by the JU, New Business generally refers to utility budgets designed to cover the socialized expenses of connecting new customers and load to their systems. These costs are included in capital budgets and in utility rate plans. New Business expenses associated with the Make-Ready Program may not have been contemplated at the time existing rate plans were established. However, other developments, like the economic impact of the novel coronavirus COVID-19 pandemic, will likely impact new customer growth and system loads. Therefore, New Business expenses associated with the Make-Ready Program may not be incremental to those provided for in existing rate plans. New Business expenses related to the Make-Ready program are to be included in the net plant true up computation. In the event that actual net plant exceeds the cap, the revenue requirement associated with the lesser of either (a) the New Business expenditure associated with the Make-Ready program, or (b) the

amount by which net plant exceeds the cap, is to be deferred by the affected utility for later recovery.

IX. Performance Based Regulation

Whitepaper Recommendations

The Whitepaper contains a number of recommendations related to overseeing program costs and constraining inefficiencies. Staff proposed that utilities be required to demonstrate that the distribution grid is more resilient as a result of utilities' investment into make-ready upgrades as a basis for performance-based regulation of the Make-Ready Program. In addition, Staff recommended that success of the Make-Ready Program not be measured solely on whether the infrastructure required to meet the State's ZEV goals is built but should also require demonstration of ratepayer benefits and that the investment decisions made in implementing the Make-Ready Program bolster the distribution grid.

Staff posited that successful performance-based regulation of the Make-Ready Program would reward utilities for taking reasonable risks in performing make-ready work at the same time as planned utility construction sites where developers ultimately build an economically rational EV charging station. To that end, Staff requested stakeholder input on whether an EAM focused on facilitating near-term measures to create customer savings and develop market-enabling tools would be appropriate for utilities under the program. Staff also recommended that any additional incentives requested for the Make-Ready Program be aligned with the Beneficial Electrification EAMs currently in place in most of the JU's service territories.

Comments

The JU recommends the development of a set of performance incentives that align the utilities' incentives with those of state policy, including: (i) number of Level 2 plugs;

(ii) number of DC Fast Charger plugs; (iii) cost-effectiveness of Level 2 plugs (on a $/kW installed or $/plug basis); (iv) cost-effectiveness of DC Fast Charger plugs (on a $/kW installed or $/plug basis); (v) kW enabled by Level 2 activities; and (vi) kW enabled by DC Fast Charger activities.

Advanced Energy Economy Institute and the ACENY are broadly supportive of utility incentives, although they warn of unintended consequences. NYC cautions against incentives that fail to strike an appropriate balance between low cost sites and high-value locations. Environmental Defense Fund, Tesla, MTA, and the NRDC and Sierra Club support incentives to encourage utilities to propose alternative rate designs for off-peak charging. Advanced Energy Economy Institute and the ACENY and the NRDC and Sierra Club claim that by aligning utility earnings with the overall success of the charging station, utilities will have an additional incentive to work closely and cooperatively with developers. The Alliance for Transportation Electrification suggests that station utilization is not an appropriate metric for an incentive but recommends that the number of electric vehicles in the market be used instead. Enel X North America and Greenlots oppose an EAM.

NYC warns the Commission to avoid incentives that incent utilities to pursue EV Infrastructure deployment at cost-efficient but otherwise suboptimal locations, noting that electric system capacity is not the only important criterion in siting infrastructure. Tesla recommends utility performance incentives to encourage program cost reductions, customer satisfaction, faster application processing times, greater participation, and greater performance relative to location budgets.

Determination

With the exception of the Alliance for Transportation Electrification, Enel X North America, and Greenlots, comments generally support providing utility shareholder incentives tied to Make-Ready Program performance, and the Commission finds such comments persuasive. Environmental Defense Fund suggests that the incentives related to the Make-Ready Program should be directly tied to program elements that the utilities have control over, and the Commission agrees with this concept. Recent experience with Energy Efficiency EAMs has shown that shareholder incentives tied directly to Energy Efficiency savings achieved by the utility have been very effective at driving greater than anticipated results in these programs.

Instead of the cost containment recommendations included in the Staff whitepaper, the Commission finds that an EAM tied to incentivizing EV charging infrastructure at least cost is the most effective method to ensure customer benefits, at this time as customers will benefit from both the anticipated increase in penetration from EVs themselves, and also benefit by decreasing expenditures below the currently forecasted budget amounts. Further, an EAM tied to decreasing program expenditures provides a counterbalance against a utility's natural business incentive to increase Rate Base by maximizing capital expenditure spending. Therefore, it is reasonable for an incentive intended to maximize Make-Ready Program effectiveness while minimizing cost required to achieve sufficient penetration of EV charging infrastructure to be tied directly to the results of each utility's Make-Ready Program efforts.

Although the Commission agrees that a new programmatic EAM to maximize effectiveness of each of the utilities' Make-Ready Programs is reasonable, the loose set of metrics and

approval process proposed by the JU is neither sufficient nor reasonable. There are several disadvantages to leaving design of a new EAM metric to each individual utility as part of its upcoming rate proceeding. First, while the Make-Ready Programs at each utility would be implemented on the same schedule, the schedules for implementing EAMs at various utilities vary widely based on rate plan filings, providing access to these new EAMs early for some utilities and much later for others.[43] Second, directing that the new EAM to be developed in individual utility proceedings has the potential to result in markedly different EAM metrics at each utility, when the Make-Ready Program EAM should be similarly designed to stimulate effectiveness across each utility. There may be good reason to establish minor variations of the same metric amongst utilities in the context of rate proceedings, and the Commission will consider those proposals in the context of rate plan filings while directing a common EAM by this Order.

The Commission is sensitive to MI's concern regarding the incremental cost of the Make-Ready Program and agrees that careful consideration is necessary when dispensing customer funds. Therefore, the Commission will implement the Make-Ready Program Share the Savings EAM, with certain minimum requirements to ensure that the utilities operate their respective Make-Ready Programs with maximum effectiveness and care for achieving the outcomes that customers are paying for.

[43] For example, Con Edison's most recent Rate Plan provides EAMs through Calendar Year 2022, and NYSEG and RG&E similarly do not have such an EAM metric included in their Joint Proposal. If left to individual utility rate proceedings, these Companies would be locked out from this EAM metric through Calendar Year 2022.

Building on the successes observed with utility Energy Efficiency programs, the Commission will adopt an EAM structure similar to the Energy Efficiency Share the Savings EAM metric that was recently approved for Con Edison,[44] including the requirement that the EAM will be positive-only, at least initially. However, where the Energy Efficiency Share the Savings metric approved for Con Edison was designed to both maximize energy efficiency savings and incentivize achieving the State's energy efficiency goals at less than the budgeted cost, an EAM metric which places greater emphasis on cost savings is appropriate for the Make-Ready Program. Energy Efficiency costs are generally Operations and Maintenance expenses; therefore, absent an EAM, utilities do not earn a return on most of their energy efficiency-related expenditures. Since much of the costs of the Make-Ready Program will be capitalized, and ultimately result in increased utility Rate Base, utilities will have an incentive inherent in their typical business model to maximize expenditures on the Make-Ready Program. Accordingly, the greater emphasis on program cost savings is warranted.

The "Make-Ready Program Share the Savings" EAM will consist of two component metrics, one measuring performance of the Level 2 portion of the Make-Ready Program (Level 2 EAM metric), and the other measuring performance of the DC Fast Charger portion (DC Fast Charger EAM metric). The Level 2 EAM metric will compare each utility's actual Level 2 Make-Ready Program performance to the forecast baseline costs established in this Order on a per-plug basis, whereas the DC Fast Charger Share the Savings metric will compare each utility's actual DC

[44] Case 19-E-0065, Con Edison - Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan (issued January 16, 2020).

Fast Charger Make-Ready performance to the forecast baseline costs on a per-kilowatt (kW) of charging installed basis.[45] Unlike typical EAMs, which are calculated annually, the Commission will establish that this shareholder incentives under this EAM will be calculated on two occasions: once as part of the midpoint review; and, again at the end of the program in 2025.

The Make-Ready Program Share the Savings metrics will only consider the costs of incentives paid to developers and will not include costs related to future proofing or program administration. Further, results from the Transit Authority Make-Ready Program, the Environmental Justice Community Clean Vehicles Transformation Prize, the Clean Personal Mobility Prize, and the Clean Medium- and Heavy- Duty Innovation Prize shall not be included in the EAM metric. The Commission understands that the budgets for future proofing and program administration were developed based on rough estimates and rules of thumb. While maximizing effectiveness and reducing the cost of the utilities' future proofing and program administration efforts is important, it is unreasonable to provide a shareholder incentive for achieving savings in these areas when the basis for the budgets themselves is currently uncertain. Similarly, it is unreasonable to provide a shareholder incentive related to the Transit Authority Make-Ready Program or additional Environmental Justice Programs at this time, given the current lack of anticipated targets and infancy of these pilots. Whether to include future proofing and program administration costs within the EAM metric, and whether the costs and results of the Transit Authority Make-Ready Program

[45] The MWs of charging infrastructure incentivized counts only nameplate MWs of charging capability and does not include any MWs enabled through future-proofing efforts.

and the additional Environmental Justice Programs directed by this Order should be included in the EAM metric would likely be considered as part of the midpoint review.

Expressed simplistically, the Level 2 EAM metric is calculated as 30 percent of the difference between: (1) the baseline incentive cost forecast per plug multiplied by the population of plugs incented as part of the program; and (2) the actual incentives provided by the utility. Similarly, the DC Fast Charger EAM metric is calculated as 30 percent of the difference between: (1) the product of the baseline incentive cost forecast per kW of charging capacity and actual kW charging capability achieved; and (2) the actual program incentive costs provided by the utility. These computations are somewhat more detailed than the simplistic descriptions provided above. Appendix C provides a complete description, mathematical formulae, per-plug and per-kW baseline incentive cost projections, plug and kW targets, example calculations and other relevant details required to implement the Make-Ready Program Share the Savings EAM metrics.

The Level 2 EAM metric and DC Fast Charger EAM metric are computed on a differential basis by design based on the desired outcome for each program type. For Level 2 chargers, the total number of plugs installed is more indicative of program success than wading through the minutiae of whether each plug has a charging capability of five or seven kW. Conversely, for DC Fast Chargers, the total charging capability is a critical indicator of program performance since both charging speed and number of DC Fast Charger plugs are important and per-plug charging capabilities can vary widely for DC Fast Charger plugs. Further, applying the DC Fast Charger EAM metric on a per kW basis provides additional flexibility to implement the Make-Ready Program to right-size the charging capability with

the charging needs of the local area, instead of implementing the metric on a less flexible per-plug basis. The thirty percent sharing amount is reasonable since it is the same percentage share of savings implemented in Con Edison's Energy Efficiency Share the Savings metric, and results in an amount of shareholder incentives that is not too rich that it rewards mediocrity nor too conservative that it fails to motivate performance when applied to example calculations.

While the Make-Ready Program Share the Savings metric will be positive-only to begin with, the Commission will also require the following safeguards to ensure that customer money is used reasonably, and that the charging infrastructure that customers will be paying for actually comes to fruition. First, to be eligible to earn an incentive under the Make-Ready Program Share the Savings metrics, the utility must install a specified minimum number of plugs of the applicable type.[46] This requirement will ensure that the utilities have an incentive to at least meet the minimum number of plugs authorized in this Order.

Second, the utilities shall be allowed to recover only a combined maximum of 15 basis points worth of incentives under the Make-Ready Program Share the Savings metrics[47] each time an

[46] Level 2 and DC Fast Charger plugs will be counted separately and failing to meet the minimum number of plugs for one type will not disqualify a utility from qualifying to earn an incentive based on the other. For example, a utility may still earn an incentive for its DC Fast Charger efforts above the minimum number of plugs even if it does not qualify for an incentive for its Level 2 program efforts.

[47] For example, if a utility demonstrates that it would earn eight basis points of incentives through the Level 2 Share the Savings metric, and ten basis points of incentives through the DC Fast Charger Share the Savings metric, it would only be allowed to collect a total of 15 basis points combined.

EAM is earned.[48] As described in the incentives section above, the amount and quality of EV Infrastructure and charger-specific data available to the Commission is limited. The Commission expects the quality and quantity of data to improve significantly prior to the midpoint review and recognizes that it is imperative to be careful with customer money and ensure that utility shareholder incentives are held to a reasonable maximum level. The maximum combined level of 15 basis points is appropriate, since it roughly approximates the number of basis points currently available for Electric Energy Efficiency EAM metrics, and ensures that the total financial incentives available to utility shareholders through EV-based EAMs does not become excessive.

Finally, the Commission directs Staff to examine the utilities' performance under the Make-Ready Program during the midpoint review, and return to the Commission with a proposal to implement negative revenue adjustment mechanisms to return customer money if, in Staff's view, the utilities are not performing satisfactorily. This review should encompass whether the EAM as directed in this Order is working satisfactorily to spur utilities to maximize program performance at least cost, as well as whether the program results in concert with the EAM incentives are resulting in a satisfactory level of benefits accruing to customers.

Regarding recovery of earned EAM incentives, each utility shall recover earned Make-Ready Program Share the Savings EAM incentives through the same surcharge mechanism that

[48] Up to 15 basis points will be available to each utility based on performance when measured at the mid-point review, and a further 15 basis points will be available to each utility based on performance upon completion of the program.

is currently in place to recover other EAM metric earnings.[49] The utilities shall recover these costs from service classifications using the same allocation factors approved in this Order for recovery of program costs, as discussed in the Cost Recovery section of this Order.

Several commenters request that shareholder incentives related to the Make-Ready Program be tied to broad policy outcomes, such as charging station utilization or electric vehicle penetration. While these broad policy outcomes are critically important, to a large extent they are already included in existing Beneficial Electrification EAMs that are either already in place or currently under consideration by the Commission. Beneficial Electrification EAMs tied to EV penetration are currently in place with respect to Con Edison,[50] Central Hudson,[51] National Grid,[52] and O&R.[53]

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[49] Existing surcharge mechanisms for recovering EAM incentives are in place for Con Edison, Niagara Mohawk, Central Hudson, and O&R. A Joint Proposal containing a proposed Beneficial Electrification was filed in NYSEG and RG&E's ongoing rate proceeding in Cases 19-E-0378 and 19-E-0380 on June 22, 2020. NYSEG and RG&E are directed to recover Make-Ready Program Share the Savings metric incentives through the same surcharge mechanism as is approved by the Commission as part of its rate proceeding.

[50] Case 19-E-0065, Con Edison - Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan (issued January 16, 2020).

[51] Case 17-E-0459, Central Hudson – Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan (issued June 14, 2018).

[52] Case 17-E-0238, National Grid – Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan (issued March 15, 2018).

[53] Case 18-E-0067, O&R – Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued March 14, 2019).

The specific EAM metrics suggested by Tesla and AEEI, based on developer satisfaction with the Make-Ready Program and charging station utilization, respectively, are not reasonable at this time. Tesla's proposal to develop an EAM metric based on participant satisfaction with the Make-Ready Program is similar to the interconnection EAM related to surveying and measuring participant satisfaction with the SIR, which the Commission ultimately concluded was neither reasonable nor efficient.[54] The Commission will thus not adopt a similar customer satisfaction based metric in this proceeding.

The Commission also declines to adopt Advanced Energy Economy Institute and the ACENY's recommended EAM metric based on measuring station utilization because it is strictly outcome-based. Further, this station utilization-based metric could potentially motivate utilities to only incentivize charging stations with the highest anticipated utilization rates, which are arguably the stations that require Make-Ready Program incentive funding the least.

While the Commission declines to implement new EAM metrics tied to these specific outcomes at this time, however, given that the Make-Ready Program is being implemented to help ensure that New York meets its goals in electrifying the transportation sector, future Beneficial Electrification EAMs targets proposed by utilities should be based on meeting and exceeding the penetration of electric vehicles required in their service territories. Combining the programmatic EAM adopted in this Order with the outcome-based Beneficial Electrification EAMs with right-sized targets will ensure that utilities will have the financial incentives to both operate their Make Ready

[54] Case 14-M-0101, et al., Reforming the Energy Vision, Order Eliminating Interconnection Earning Adjustment Mechanisms (issued April 24, 2019).

Programs at maximum efficiency and ensure that customers adopt electric vehicles at the pace required to meet New York's aggressive climate goals.

X. Application Portal

Whitepaper Recommendation

Staff recommends in its Whitepaper that the Joint Utilities: (1) develop a web-based application submittal process; (2) publish load-serving capacity maps and program information; and (3) re-evaluate the organization of EV program content on their websites. Benefits from these steps would include providing project applicants with updated status information and utilizing best practices to safeguard customer information. Utilities would develop a common IOAP for EV chargers, and leverage substantially similar program applications with the below minimum information:

1) The applicant's name, contact information, and project/application identification number.
2) A description of the project, including the project's technology type, size, number of plugs, and location.
3) Project application status, including steps completed and to be completed, along with corresponding completion/deadline dates and the acting party (either the utility or the applicant) associated with each step.
4) Information regarding any outstanding information requests made by the utility to the applicant.
5) The status of all amounts paid and/or due to the utility by the applicant.

Further, utilities would need to manage their resources appropriately to meet the industry's needs and avoid queueing problems, using dedicated EV team members comprised of

interconnection experts, distribution system planners and other key subject matter experts.

Comments

Commenters generally support a cost-effective, streamlined interconnection online application process. Environmental Defense Fund argues for the expeditious availability of an interconnection online application portal. Greenlots contends that an efficient interconnection process can promote cost reductions and urges the Commission to consider other methods for expediting review. The Joint Utilities note that existing procedures should be capable of addressing new load associated with charging infrastructure development, and suggests a new portal is unnecessary.

Electrify America requests that the Commission define and enforce rules with respect to expedited interconnection for EV charging infrastructure and associated energy storage, as the time and cost of interconnection have emerged as barriers to charging station deployment in New York. Electrify America recommends a single nonutility program administrator for any incentive programs with clearly defined requirements that facilitate developer confidence.

Determination

The Commission expects that this Make-Ready Program will spur charging station development in New York State, and thus it is reasonable to anticipate a significant uptick in new load applications. In order for the Joint Utilities to timely review and respond to new applications, and begin construction, each utility must be prepared to scale existing processes and procedures to meet an increased demand. The Joint Utilities observe that EV chargers are not like distributed energy resources, which interconnect via the IOAP, because EV chargers are new load—as compared to new injection or part of the

interconnection queue. The Commission acknowledges the difference between EV stations--handled as new service applications--and DERs that connect to the distribution system via the SIR.

The scope and scale of the Make-Ready Program incentivizes EV Infrastructure and supply equipment development that is orders of magnitude greater than what the Joint Utilities have connected to date. This increase will create a learning curve. The existing processes and procedures for providing service to this sector, treating EV supply equipment as traditional new load, will not be sufficient to meet the goals of this Make-Ready Program. The Joint Utilities are directed to develop an online EV Infrastructure service application portal, which may utilize existing software capability, or may be a new tool.[55] The Commission, leveraging lessons learned from the distributed generation IOAP, directs the Joint Utilities to develop the EV supply equipment service application portal in a phased approach, with Phase One to be complete within three months of issuance of this Order[56] and Phase Two to be completed within six months of issuance of this Order. Phase III, which will be addressed in the future, will require the proposal of EV supply equipment service application portal refinements.

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[55] The Commission expects and requires the Joint Utilities to decide whether to build-out of existing software or develop a new tool based on what is least cost, most useful, and quickest to go live.

[56] The Commission notes that this Make-Ready Program is effective as of issuance of this Order, and it is acceptable for the Joint Utilities to continue processing EV supply equipment interconnection/new service applications as they have been or to immediately implement a more efficient interim process while Phase One work is being completed.

The Joint Utilities must develop Phase One of the EV supply equipment service application portal to capture information needed for both Level 2 and DC Fast Charger EV supply equipment applications, including:

1) The applicant's name, contact information, and project/application identification number.
2) A description of the project, including the number of plugs, charging output and plug type of each, location (and if in an environmental justice community), demand management software or hardware, whether the EV supply equipment will be bi-directional at present or in the future or exclusively load, and any collocated distributed generation or energy storage.
3) Future proofing needs and expansion plans.
4) Project application status, including all the steps completed and to be completed along with corresponding completion/deadline dates and acting party (either the utility or the applicant) associated with each step.
5) Whether there are outstanding utility requests for information and details regarding those outstanding information requests.
6) The status of all amounts paid and/or due to the utility by the applicant.
7) A program assumption that applicants intend to pursue the DC Fast Charger Per-Plug Incentive Program and/or the Make-Ready Program and capture all necessary program information.
8) The inclusion of an opt-out prompt, so that EV supply equipment developers not wishing to pursue the DC Fast Charger Per-Plug Incentive Program and/or the Make-Ready Program may also use the EV supply equipment service application portal.

The EV supply equipment service application portal will allow required documentation to be uploaded, and all payments must be clearly documented.

At this time, the Commission declines to adopt a standardized interconnection procedure and enforceable timelines for EV supply equipment. Quickly scaling this Make-Ready Program will require flexibility, and the Commission intends for the Joint Utilities to have the ability to prioritize some site types over others, such as accelerated application approval and construction commencement for EV supply equipment sited in environmental justice communities. While the Commission acknowledges Electrify America's concern that the time and cost of interconnection has emerged as a barrier to charging station deployment in New York, we do not presently have the necessary data or experience to create enforceable timelines like those in the SIR.

Electrify America highlights the six-month interconnection timeline for a non-export battery storage system at charging stations as burdensome. The Commission seeks to encourage energy storage system deployment and collocation at charging stations and encourages all developers to take advantage of existing NYSERDA Retail Storage Incentives.[57] In order for an energy storage system to receive a NYSERDA incentive, the customer sited system must demonstrate one of four ways it is providing grid support by participating in an non-wires alternative project, participating in demand response, enrolling in the standby tariff or receiving compensation under

[57] See NYSERDA's Retail Storage Incentives, Incentive Dashboards, and Program Manual available at: https://www.nyserda.ny.gov/All-Programs/Programs/Energy-Storage/Developers-Contractors-and-Vendors/Retail-Incentive-Offer.

the Value of Distributed Energy Resources (VDER) tariff. In order for an energy storage system to perform these services, it must interconnect through the SIR. To the extent that Electrify America or any other developer experiences utility non-compliance with the SIR, they should raise that with the utility-specific interconnection ombudsperson and the Staff ombudsperson.[58]

The Commission notes and expects that in those cases where a developer wants to collocate a non-exporting energy storage system that will not impact the distribution grid with the EV supply equipment, such a proposal should not be a barrier to expeditious approval and construction. The Commission directs developers that experience unnecessary or overly burdensome delay to bring those issues to the Interconnection Technical Working Group (ITWG) or the Interconnection Policy Working Group (IPWG) for issue identification and resolution.[59] Furthermore, the Commission directs the Joint Utilities to consider what automated reviews and technical screens may be included in the EV supply equipment service application portal to more efficiently accommodate non-exporting energy storage systems and to propose these additional tools in Phase 2 of the EV supply equipment service application portal development.

The Commission declines to adopt Electrify America's proposal that a single non-utility program administrator be in

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[58] The Interconnection Ombudspersons contacts are available at: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/DAF23BB7AC9AC53A85258050004C17B8?OpenDocument.

[59] EV supply equipment developers may not be familiar with these recurring working groups, but the Commission recommends such develops should begin to engage. See the ITWG and IPWG Information links available at: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/DCF68EFCA391AD6085257687006F396B.

place for the Make-Ready Program incentives. The Joint Utilities of New York are the appropriate program administrators of many incentive programs, including this Make-Ready Program. The Joint Utilities and developers must become partners in building the necessary infrastructure at the least cost to ratepayers, with the least impact to the distribution system, at the sites that drive the most public benefits, and where there is or will be an economic business case. The Commission sees no reason to remove the existing utility core competencies and those that will necessarily be developed while administering this program from the Joint Utilities. As discussed in the Reporting Requirements and Participant Performance section below, there are appropriate roles for third-party entities to play in this Make-Ready Program; however, program administration shall remain the responsibility of the Joint Utilities.

XI. Program Review

Whitepaper Recommendations

Staff recommends in its Whitepaper to reconsider the program design and budgets in parallel with the DC Fast Charger Per-Plug Incentive Program's midpoint review. The Commission would initiate this review the earlier of: (i) October 1, 2023 when the DC Fast Charger Per-Plug Incentive Program interim review begins, or (ii) when each utility has completed applications for 45 percent of the total number of plugs eligible in the DC Fast Charger Per-Plug Incentive Program in their territory. The review would evaluate the following issues:

1) The need for additional phases of the program.
2) Redirecting unused program funding to multi-unit dwellings or redefining the accessibility criteria to include multi-unit dwellings.

3) Revising the accessibility criteria to include metered parking spaces and public pay-to-park lots.
4) Recalibrating the 50 percent utility-funded, make-ready level for private and proprietary technology types.
5) Revisiting future-proofing requirements.

Comments

Several commenters requested that a midpoint review should take place by October 2023 to review metrics, costs and program design for possible adjustments based on participation and other metrics. Some commenters find the proposed advisory council for program review is duplicative and unnecessary given existing Commission and Staff investigative and regulatory powers. Others called for a quarterly meeting, and to brief the Commission biannually. Other commenters agree with Tesla to initiate annual review beginning in January 2022.

Commenters also suggest scheduling review sessions to coincide with quarterly program reports. Some parties stressed that utilities should engage in program design with third-party collaboration, particularly in assessments of project costs and viability. Others requested that utilities be permitted to make program adjustments based on stakeholder response without formal filing requirements to create a more reactive program.

Determination

The Commission appreciates commenters who suggested earlier or more frequent program review than what was proposed in the Whitepaper. However, more time is necessary to collect data and incorporate lessons learned. Staff, due to the nascent EV supply equipment market, proposes to reconsider program design and budgets in parallel with the DC Fast Charger Per-Plug Incentive Program’s midpoint review; however, the Commission finds that Staff’s proposal, while reasonable, would provide the

Commission with information too late for any required Make-Ready Program modification. Instead, the Commission directs Staff to initiate the midpoint review by the earlier of October 1, 2022, or when each utility has completed applications for 45 percent of the total number of plugs eligible in the DC Fast Charger Per-Plug Incentive Program in their territory. Staff shall lead this review, which shall result in recommendations presented to the Commission no later than January 4, 2023 that include a review of data collected during the program, and at a minimum will consider:

1) Program budget and incentive levels.
2) The need for additional phases of the program.
3) Redirecting unused program funding to multi-unit dwellings and workplaces or redefining the accessibility criteria to include multi-unit dwellings and workplaces,
4) Revising the accessibility criteria, to include public pay-to-park lots.
5) Recalibrating the 50 percent utility-funded, make-ready level for private and proprietary technology types.
6) Revisiting future-proofing requirements and budgets.
7) Reviewing implementation requirements and budgets.
8) Utility ownership of charging station hardware.
9) Emerging plug standards.
10) Potential need for residential make-ready.
11) Modifications to performance incentives.

XII. Reporting Requirements and Participant Performance Whitepaper Recommendations

Staff recommends in its Whitepaper that utilities would provide quarterly performance reports to the Commission. The utilities would draft these reports, divided into specific

Level 2 and DC Fast Charger FC program sections, to include for each site:

1) The number of station owners participating.
2) The number of sites to which incentives were issued.
3) The number of plugs installed.
4) EV Infrastructure costs incurred (equipment and installation).
5) The billed usage.
6) Start and stop times of charges.
7) 15-minute interval data.
8) Peak kW per charging session.
9) Number of sessions daily.
10) Amount of time each vehicle is plugged in per session.
11) Amount of time each vehicle is actually charging per session.
12) Whether the station owner is providing charging for free or if there is a usage fee to the EV owner.
13) Operating costs including non-energy related costs.
14) Any technologies being used to manage demand.
15) What percent of service applications mature into operating stations.

Station owners participating in the program would need to provide any customer-specific information above.

Under Staff's proposal, a common third-party data aggregator would be used to help produce these reports, and data would be aggregated and anonymized prior to being published. The station owner would remain the owner of the station-specific data; further, the utility or a third-party data collector could not use these data for any purpose other than to inform Staff and the public through each utility's anonymized and aggregated report.

Comments

The Alliance for Transportation Electrification, Enel X North America, and the Joint Utilities warn that proposed quarterly reports will be too burdensome and provide excessive information at this early stage in development of the industry. The EV Industry Coalition alleges that proposed data collection requirements are administratively burdensome, costly, and may discourage program participation. The EV Industry Coalition further argues that a more abridged dataset could achieve the same results and that much of the recommended information is already available through meter data. It recommends a narrower data collection effort limited to charging sessions counts, unique vehicle connections, power dispensed, average power dispensed per session, and average duration per session.

Alternatives proposed by commenters include full annual reports with abridged semiannual reports, monthly short-form reports, simplified requirements, and annual reports only. Greenlots recommends developing a generic shared report format, and Advanced Energy Economy Institute and the Alliance for Clean Energy New York suggest requiring filing by each utility, rather than by the Joint Utilities collectively. Environmental Defense Fund requests an annual load research report from each utility. Enel X North America, FreeWire Technologies, the City of New York, and the Natural Resources Defense Council and Sierra Club suggest various data categories generally comprising charging session data, technical details on charging stations, participation and financial information. Some parties stress that sufficient data collection is required to address the development of appropriate incentives, adequate and equitable geographic coverage, variety of site types, utilization and pricing.

Determination

Staff and the Commission need periodic program progress reports to continuously update them as the Make-Ready programs are implemented. Staff, under the proposal and as detailed below, would begin a formal midpoint review no later than October 1, 2022. The data provided in the proposed reports would inform and potentially trigger modifications to the program due to changes in technology, station economics, EV charging station consumer experience, and State energy goals.

The EV Industry Coalition's proposed abridged dataset would provide insight into charging sessions for plugs developed under the program. However, such data in isolation is not adequate to guide program modifications. Program participation information is needed to gauge success of the program. Financial information is needed to determine if the incentive amounts remain appropriate. As suggested by Advanced Energy Economy Institute and the Alliance for Clean Energy New York, reports should be provided by each utility, rather than consolidated into one report to be filed by the Joint Utilities. This will provide the greatest insight into EV supply equipment development in each utilities' territory. Reports should be in a relatively standard format as recommended by Greenlots.

As such, the reports will include four categories of information. The first two categories are primarily within the Joint Utilities' reporting responsibility and the second two categories are primarily within the developer or site owner's responsibility, as described below.

1) Reporting period program participation information. This category shall include:
   a) the percent of service applications that have matured into operating stations,
   b) number of station owners participating,

c) the number of sites for which incentives were issued,
d) the number of plugs installed, and
e) infrastructure costs incurred. Infrastructure costs are to be differentiated by equipment and installation costs for customer-owned assets as well as equipment and installation costs for company-owned assets. The cost details for company-owned assets must be broken out into costs that are considered make-ready and costs that are considered new business.

2) Utility system and billing information for each station. This category shall include:
a) 15-minute interval data,
b) load profiles for the stations for the top ten demand days of each year, and
c) utility bills. Utility bills are to be differentiated by delivery service-related costs and energy-related costs.

3) Plug and charging session data. This category shall include:
a) the number of sessions daily,
b) start and stop times of each charge,
c) the amount of time each vehicle is plugged in per session,
d) peak kW per charging session,
e) kWh per charging session, and
f) plug outage information. Plug outage information is to include the number and duration of outages and is to be differentiated by expected outages (for maintenance) and unexpected outages.

4) Financial information. This category shall include:
   a) fee structure (structure of fee to the end-use customer, i.e. cost per minute, cost per kWh, cost per session and whether the station owner is providing charging for free),
   b) charging revenues derived, and
   c) operating costs, which should include energy-related costs and non-energy-related costs separately identified.

The Commission affirms that just as is the case in the DC Fast Charger Per-Plug Incentive Program data reporting requirements, station-specific and session-level data shall not be disseminated publicly or used by the Joint Utilities or their third-party agent(s) for any commercial purposes.[60] Data for categories 3) (Plug and charging session data), and 4) (Financial information) shall be provided by the Make-Ready Program participants (e.g. developers or site hosts/owners) to the Joint Utilities' third-party consultant that is performing the data anonymization and aggregation. The third-party agent will aggregate and anonymize these data for incorporation into the public annual report, which shall be filed by each utility.

The Commission requires Staff to have constant access to the more granular confidential data and directs the Joint Utilities to ensure that their third-party data aggregator will update Staff when requested, without regard to the annual report schedule. To enable this constant monitoring and to provide the Joint Utilities and their third-party aggregator adequate time to compile data, program participants are directed to provide plug and charging session data and financial information

[60] See Case 18-E-0138, supra, Order Further Modifying DC Fast Charger Incentive Program, p. 10.

(category 3) and 4) data) to the third-party vendor on a quarterly basis.

Each utility shall file its report on a calendar year basis. The utility shall combine said report with the report required by the DC Fast Charger Framework Order issued in the present proceeding.[61] The DC Fast Charger Framework Order required the Joint Utilities to file annual reports by March 1 of the following year.

The Commission is not persuaded by comments that claim quarterly reports will be too burdensome, provide excessive information at an early stage in development of the industry or that proposed data collection requirements are administratively burdensome, costly, and may discourage program participation. Any responsible EV charging station developer has this data inventory to inform their day-to-day business operations. Quarterly reporting may prove to be too frequent and may be adjusted at the midpoint review, but in the early stages of program deployment, Staff and the Commission must have frequent and granular data to measure program success. Therefore, program participants that fail to provide the required data will not be eligible for new Make-Ready Program incentives and will either be subject to claw back of the make-ready payments received or revocation of service so that the station can be operated by an alternate market participant.

Further, the Commission finds additional program participant performance requirement are appropriate. The Commission directs program participants to certify to specific uptime requirements, as follows:

- DC Fast Charge Plugs must be operational 95 percent of the time on an annual basis.

[61] Case 18-E-0138, supra, DC Fast Charger Framework Order, p. 42.

- DC Fast Charge stations must be operational 99 percent of the time on an annual basis, with a minimum of half of the plugs operational to be considered "up."

The Commission expects that the plug outage information developers and station owners must report will inform these metrics, and that the 95 and 99 percent annual performance metrics will be revisited at the midpoint review.

The Commission also requires each Make-Ready Program participant to actively operate the charging station site for a minimum of five years; this step will ensure that ratepayer funds are not inappropriately allocated to stations only operate in the near-term. Any program participant may opt to sell or to upgrade a site prior to the five years' time as long as the number of plugs and capacity of the station do not decrease with these actions.

The Commission is requiring program participants to provide data related to station and plug usage, customer complaints, outages, pricing fees and structure, and to make a commitment to ensure that the station is operated and maintained for at least five years in order to ensure that public funds flow to responsible developers that provide the benefits the program is designed to produce.

At this time, the Commission is not modifying the policy determination that EV charging stations are not electric plant per PSL §2(12).[62] The Commission is not requiring any one business model or fee structure in order to participate in the program but is mandating that charging customers at stations participating in the Make-Ready Program have transparent insight

[62] Case 13-E-0199, In the Matter of Electric Vehicle Policies, Declaratory Ruling on Jurisdiction Over Publicly Available Electric Vehicle Charging Stations (issued November 22, 2013)

into the costs they are paying to charge. Pricing transparency is critically important for drivers to understand gas parity and trust that they are receiving the suite of goods (whether they be parking, communication, or payment services) that they are paying for.

Participating developers must report customer complaints to the appropriate utility and to Staff. The details of these customer complaints shall not be public, but will be used by the utilities to develop Make-Ready Program best practices. Staff will monitor customer complaints for egregious behavior, and report any such instance to the Commission for appropriate action. In addition, the Commission directs Staff to convene an "EV Charging Customer Experience Working Group" to explore the customer experience with currently applicable customer protections and price transparency and recommend updates, as discussed in greater detail below.

XIII. Technical Standards Whitepaper Recommendations

Staff recommends in its Whitepaper to encourage open communications protocols and for stakeholders to engage in a working group to develop minimum standards and protocols for EV charging stations. The working group would explore open technical standards such as the International Electrotechnical Commission-accepted (IEC) OpenADR 2.0b, International Organization for Standardization (ISO)/IEC 15118, and the OCPP. Staff recommends that the Commission consider adopting baseline standards in engineering and safety, payment, communications and interoperability.

Comments

Advanced Energy Economy Institute, the Alliance for Clean Energy New York, the Alliance for Transportation Electrification, ChargePoint, Environmental Defense Fund, Enel X North America, EVBox, Greenlots and the Natural Resources Defense Council and Sierra Club recommend open standards, interoperability, and communications protocols to ensure fair and equitable access. Greenlots strongly recommends requiring third-party OCPP certification as a standardized and verifiable mechanism for ensuring the development of a flexible charging statewide system that can be upgraded to accommodate new market participants, evolving user needs and technologies. NYC recommends that the program remain adaptable to accommodate new standards and that program review should assess technology standards for possible inclusion.

Joint Utilities warn of risks in using specific technologies at this early stage and recommend that the EV Technology Standards working group address this issue. Tesla recommends that the Make-Ready Program should focus on establishing electricity service in a nondiscriminatory fashion, instead of imposing interoperability requirements at this time. Natural Resources Defense Council and Sierra Club recommends that the Commission require the use of open-access communication standards, but ChargePoint warns that this requirement would create implementation problems. AEEI-ACE, ChargePoint, and Enel X agree that the proposed working group is appropriate. ATE and Environmental Defense Fund request that this working group include experts from all sectors and be given a defined mission and schedule. However, AEEI-ACE and Environmental Defense Fund recommend that the development of new standards is unnecessary and cite the existence of sufficient standards and experienced industry standards organizations.

Determination

The Commission recognizes the need for more experience before incorporating specific technical standards into the Make-Ready Program eligibility criteria, and, as such, declines to adopt specific standards at this time. The Whitepaper proposal to convene a focused working group, supported by many commenters, is adopted. Within 90 days of issuance of this Order, Staff shall convene a working group focused on discussing how to incorporate emerging technical standards and best practices, such as: IEC-accepted OpenADR 2.0b, ISO/IEC 15118, and the OCPP.

The Commission notes that the California Air Resources Board recently adopted new Electric Vehicle Supply Equipment Standards[63] that will take effect July 1, 2020. These standards are mostly defining terms, labeling requirements, payment method requirements and reporting requirements. As the Whitepaper noted, much of these types of standardization and enforcement measures will be the responsibility of the Department of Agriculture and Market's Bureau of Weights and Measures. The Commission therefore directs Staff to collaborate with the Bureau of Weights and Measures, NYSERDA and other appropriate New York State agencies in convening this "Technical Standards Working Group."

In addition to this Technical Standards Working Group, the Commission expects that issues may arise as EV charging station deployment increases in scales, and anticipates an even greater need for inter-agency collaboration. As mentioned above, the Commission directs Staff to convene an EV Charging Customer Experience Working Group within 120 days of issuance of

[63] See Final Regulation Order, available at: https://ww3.arb.ca.gov/regact/2019/evse2019/fro.pdf.

this Order. This EV Charging Customer Experience Working Group will leverage the anonymized, aggregated data contained in the annual utility reports and the knowledge and experience all stakeholders bring to identify ways to improve the customer experience with consumer protections and more formal complaint procedures, and to improve the customer experience with price transparency.

XIV. System Planning and Mapping Whitepaper Recommendations

Staff recommends in its Whitepaper to use the EV Charging Infrastructure Forecast results to identify sites with adequate load serving capacity, and expected EV charging demand, to proactively educate developers and other stakeholders. Utilities would forecast EV charging infrastructure needs using a common framework (e.g., organization, format, definitions) to identify and characterize existing and potential EV charging scenarios. Utilities would incorporate charging scenarios and screening criteria into their annual capital planning process. Utilities could then identify suitable sites for hosting DC Fast Charger and high densities of Level 2 chargers and where planned work may accommodate infrastructure upgrades and provide enough amenities to justify ratepayer funding. The EV Charging Infrastructure Forecast would use the following information:

1) The type of location (home, apartment complex, store, workplace, public parking site, rest stop, etc.).
2) The number and spatial distribution of existing instances of the scenario.
3) The forecast number and spatial distribution of anticipated instances of the scenario over the next five years.

4) The types of vehicles charged at a typical location (commuter car, bus, delivery truck, taxi, ride-share, etc.).
5) The number of vehicles charged at a typical location, by vehicle type.
6) The charging pattern by vehicle type (frequency, times of day, days of week, energy per charge, duration per charge, demand per charge).
7) The number of charging ports at a typical location, by type.
8) The energy storage capacity (if any) supporting EV charging at a typical location.
9) An hourly profile of a typical location's aggregated charging load over a one-year period.
10) The type and size of the existing utility service at a typical location.
11) The type and size of utility service needed to support the EV charging use case.

Utilities would leverage the most recent EV Charging Infrastructure Forecast to develop common suitability criteria to identify potential EV charging sites, including evaluating load-serving capacity, locations with positive charging business cases and other strategic locations for EV charging. Utilities would publish granular load-serving capacity maps, and sites that already have adequate load-serving capacity would be prioritized.

Utilities would also use insights from the EV Charging Infrastructure Forecast, such as expected utilization and EV adoption levels, to identify locations with positive business cases for EV charging. For locations that pass the Charging Business Case screen and have sufficient hosting capacity, the utility would develop and direct a targeted outreach and

education program for developers and potential site hosts in these locations.

Strategic Locations are the final screen for the Suitability Criteria and include societal benefits that are not considered in the Load Serving Capacity or Charging Business Case criteria. Suitability Criteria include significant environmental justice and public health benefits, or unique network attributes that expand access to rural and hard-to-reach communities.

Staff proposed that the Upstate REDCs be designated as a Strategic Location where up to an additional $5,000,000 in funding would be necessary to develop, through a competitive procurement, a minimum of four locations with four 150 kW DC Fast Charger plugs per site in each REDC referenced.

The Suitability Criteria would be used primarily to direct education and outreach towards locations with the lowest distribution system upgrade costs and highest demand for EV charging. The Suitability Criteria is not a binding eligibility requirement and developers are able to access the make-ready incentive for sites that fail the load serving capacity or business case screen, so long as their proposed site meets the requirements laid out in the Eligibility Criteria section of this Order.

When planned worksites that may also accommodate charging infrastructure are identified, the utilities would prioritize developer and site host education and outreach in these locations. Utilities would propose a common methodology for alerting the developer community and a competitive, fair process for choosing which developer will build at such a site. Utilities would streamline utility core competencies, build out useful tools, and conduct effective outreach and education to developers on site selection, availability and timing with

planned capital upgrades or routine construction. Utilities are also best positioned to educate their customers on the many electric rates available and how EV charging impacts the grid. Staff does not propose that such outreach and education would be ratepayer funded.

Comments

The Joint Utilities state that they will consider load-serving capacity and the strategic location when assessing a proposal but argue it should be up to charging station operators, site hosts and developers to evaluate their own business opportunities and workable business cases. The Alliance for Transportation Electrification agrees that the proposed process to identify suitable locations for charging can serve as useful guidance. New Yorkers for Clean Power agrees that utilities should work with municipalities in siting charging stations, especially ones involved in the Climate Smart and Clean Energy Communities programs.

ChargePoint notes that this proposal risks excluding strategic locations and encumbering utilities with the undertaking of designing a statewide charging network. It also argues that planning and siting should involve greater stakeholder collaboration and argues against eligibility criteria based on load capacity and site host business models.

The Alliance for Transportation Electrification acknowledges that proposed processes for identifying suitable charging locations can guide development, but recommends adopting a more flexible approach, rather than enforcing strict adherence. Enel X North America argues that free-market competition will provide efficient siting but recommends that utilities can implement suitability criteria that promote specific circuits and customers. Environmental Defense Fund recommends that capacity mapping incorporate EV load forecasts

and planned capacity upgrades. The City of Albany requests assessments of capacity in areas considered for DC Fast Charger installations to avoid additional constraints that could inhibit future development. FreeWire Technologies argues that development of load-serving capacity maps by the end of 2020 is reasonable, while the City of New York recommends they be available as soon as possible.

Several parties agree that outreach and education is fundamental to further EV adoption and recommend that utilities are well positioned to serve in this capacity. Green Energy Consumers Alliance (GECA) and ZappyRide note the unsatisfactory progress made by the automobile industry and dealers in customer education. Joint Utilities note that the outreach and education proposal is inconsistent with traditional cost recovery treatments and also existing earnings adjustment mechanisms. AEEI-ACE, ATE, Greenlots, PIA and ZappyRide recommend that utility EV programs include ratepayer-funded customer outreach and education efforts, while GECA recommends that these activities should be funded by ratepayers but administered by a state agency. PIA recommends additional ratepayer-funded education and outreach activities carried out by third parties. NYCP request education and outreach targeted to non-EV-owners to encourage future adoption.

Determination

The Commission anticipates that the Make-Ready Program will accelerate the development of public charging stations throughout New York State, leading to load growth in locations of the grid with significant EV adoption. It is prudent that the Joint Utilities and the developer community have the best available information about expected grid constraints and least costs locations for new charging station development; in this

way, developers are able to balance the benefits of high value locations against the corresponding costs to develop.

ChargePoint and the Joint Utilities both argue that utilities should not be responsible for determining the optimal charging network for the State. Enel X agrees that the free market should determine the most efficient siting; however, they and ATE also suggest that implementing a suitability criterion can be effective at promoting low cost and beneficial locations. The Commission agrees that this Make-Ready Program is designed to have siting driven by the private market. Developers must have flexibility to determine the best locations as ATE recommends.

Several commenters, including the Joint Utilities, pointed out that the developers and site hosts are in the best position to evaluate the business case of locations for EV charging. The Commission agrees with these commenters; however, the Commission also acknowledges that utilities must create an EV Charging Infrastructure Forecast to support their capital planning processes. The EV Charging Infrastructure Forecast may not determine the business case for specific sites but it will identify locations where growth in EV load is expected. This information should be used to prioritize developer and site host education and outreach to promote the development of EV supply equipment, particularly level 2 charging infrastructure at smaller business that may be overlooked by developers or for site hosts who are unfamiliar with the benefit of EV charging and look to the utility as a trusted advisor. The Commission recommends the Charging Business Case criteria, which is defined in the Whitepaper, be modified and to a broader EV Charging Infrastructure Forecast criterion.

The EV Charging Infrastructure forecast methodologies vary by utility today. Given the early stage of the market, the

Commission rejects Staff's proposal to adopt a common framework across the Joint Utilities at this time. The Commission directs the Joint Utilities to produce individual EV Charging Infrastructure forecasts in consultation with Staff and to present their forecast methodologies and results during a Technical Conference in calendar year 2021. Stakeholders will be invited to provide feedback that can inform the forecasting process in the future, including new proposed program requirements to be considered during the midpoint review.

Strategic locations, as recommended in the Whitepaper, shall be a top priority for utility education and outreach efforts and shall be identified in the utility's EV Charing Infrastructure Forecast. Commission approval will be required if funding levels in excess of the standard make-ready incentive are justified and can be introduced in future rate cases or at the midpoint review. The Commission rejects the Staff proposal for a budget of up to $5,000,000 of incremental support for the Upstate REDC Strategic Locations because NYSERDA and New York Power Authority have since committed to develop a network of DC Fast Charger sites in the ten REDCs, avoiding the need for incremental ratepayer funding for these sites. These sites will still be eligible for the standard make-ready incentive, as long as they meet the program's eligibility criteria.

The Commission instructs the Joint Utilities to develop the Suitability Criteria proposed by Staff, modifying the second criteria to be EV Charging Infrastructure Forecast. To summarize, the Suitability Criteria shall be:

1) Load Serving Capacity,
2) EV Charing Infrastructure Forecast, and
3) Strategic Locations.

Several commenters, including AEEI-ACE, ATE, Greenlots, PIA and ZappyRide support ratepayer funded education and outreach programs. GECA and PIA also recommend the education and outreach programs be administered by a State Agency or Third Party, respectively. The Commission agrees that ratepayer funding to support education and outreach programs is appropriate; this funding should be prioritized for developers and potential site hosts in the most beneficial locations identified in the Suitability Criteria, namely locations with adequate load serving capacity and an expectation of high EV supply equipment utilization from the EV Charging Infrastructure Forecast. The utilities shall include education and outreach plans in the required implementation plan filings for the EV Make-Ready Program.

The Joint Utilities shall develop EV Charging Infrastructure Forecasts that align with their capital planning processes. These Forecasts will be used to carry out targeted education and outreach in locations deemed attractive for EV charging and where adequate load service capacity exists. Additionally, the utilities shall publish load serving capacity maps for EV charging by no later than December 31, 2020.

XV. Managed Charging and Vehicle-to-Grid Whitepaper Recommendations

The Staff Whitepaper contemplates two forms of Vehicle Grid Integration: vehicle-to-grid and managed charging. Vehicle-to-grid is a concept that aligns electric vehicle charging and discharging with the needs of the grid. The Whitepaper details two forms of managed charging: active and passive. Active managed charging relies on communication or dispatch signals from a utility or aggregator sent to a vehicle or charging equipment to adjust the time of charge or rate of charge. Passive managed charging relies on customer behavior,

such as by influencing charging times through time-of-use (TOU) rates.

The Whitepaper notes that New York already offers passive managed charging through residential TOU rates and demand charges. Active managed charging initiatives depend on the technology landscape, and more needs to be known before a large-scale program is offered statewide. Staff recommend in the Whitepaper that the Commission wait to require standards regarding vehicle-to-grid until more is known and results of demonstrations are studied. Staff proposes that a collaborative Stakeholder process be established to determine how to enable these potential EV uses.

Comments

Advanced Energy Economy Institute and the Alliance for Clean Energy New York, Enel X North America, Greenlots, and the Natural Resources Defense Council and Sierra Club agree on the many stakeholder and system benefits of managed charging. Several parties note that EV charging represents an opportunity to increase reliance on renewable generation, and the Joint Utilities view it as an especially important solution for concentrated charging situations as with fleets or at workplaces. Greenlots notes that unmanaged EV charging is associated with many potential disadvantages, particularly generation of local grid constraints, amplification of system peaks, greater peak demand and higher operating costs.

Several commenters note that managed charging can be facilitated either through rate design or direct management, including technology-based approaches that can complement or replace rate solutions. Some commenters argue that rate reform will be a key foundational effort in developing vehicle-to-grid capabilities and managed charging, noting that price-responsive forms of vehicle-grid integration such as time-varying rates can

induce smart charging behavior. The Joint Utilities support properly designed cost-reflective standby rates for managed charging to improve system efficiency.

The Joint Utilities and the EV Industry Coalition support the development of utility programs for managed charging or load management at charging infrastructure, possibly coupled with performance incentives for installations that successfully shift EV charging load. The EV Industry Coalition also recommends a working group to develop managed charging solutions. Some commenters recommend investigating technology-based managed charging, either independently or in concert with rate reform. Greenlots argues that managed charging might be optimized according to various factors, including state-of-charge, system load, electricity prices, and greenhouse gas intensity associated with generation. The Alliance for Transportation Electrification recommends maximizing the effectiveness of managed charging with open and interoperable hardware and software. The EV Industry Coalition argues that technology-enabled strategies are especially viable for fleet depots and other longer dwell-time locations that permit greater flexibility in charging schedules and speed.

The Alliance for Transportation Electrification, Bloom Energy Corporation, and FreeWire Technologies propose a number of technical solutions for managed charging. These technical solutions include using EV as virtual power plants for load shifting, and using fuel cells, energy storage systems and distributed generation as ancillary support for charging installations. Advanced Energy Economy Institute and the Alliance for Clean Energy New York and the EV Industry Coalition note potential vehicle-to-grid capabilities that may include: (i) functioning as non-wires alternatives solutions to be incorporated into utility distribution planning, and (ii) the

possible use of large EV fleets as aggregated DERs for load management that could generate additional revenue for operators. Some parties recommend smart network chargers as a requirement at all ratepayer-funded make-ready infrastructure to support load management and managed charging activities. However, the Joint Utilities, while acknowledging that EV technologies may provide significant vehicle-to-grid capabilities, argue that they are not presently scalable.

Determination

Managed charging and vehicle-to-grid integration hold a great deal of promise, as they allow the shifting of charging to moderate impacts on the grid and moderate the cost of charging for consumers. The Whitepaper described the REV Demonstration projects of NYSEG and Con Edison, but the Commission notes that neither project has been completed and both have faced delay due to technical issues; this is a very new market with a lot to learn. Without sufficient learnings or results to guide our policy, the Commission declines to direct specific Statewide actions at-scale related to managed charging and vehicle-to-grid integration.

In terms of managing charging through behavioral methods of incenting charging at off peak times, EV drivers presently have TOU rates that provide incentives for off peak charging.[64] Reviewing the annual reports on participation in voluntary TOU rates, the Commission notes that adoption rates by EV drivers has been minimal and it is clear that more needs to be done to incent off peak charging.

[64] Case 18-E-0206, Tariff filings to Effectuate the Provisions of PSL §66-o, Order Rejecting Tariff Filings and Directing Tariff Revisions (issued November 15, 2018) (directing the Joint Utilities to offer residential customers with EVs that take service under residential TOU rates a traditional customer charge instead and waive incremental meter charges).

The California Public Service Commission (CPUC), in collaboration with fellow California state agencies and stakeholders, has been developing policies that support vehicle-to-grid integration for the last decade. In 2018, CPUC and the vehicle-to-grid integration communication protocol working group members produced a report on Communications Protocols for Vehicle to Grid Integration.[65] On June 30, 2020, the California stakeholders filed a report as directed by the CPUC, to determine: what vehicle-to-grid integration use cases can provide value now, and how that value can be captured; what policies need to be changed or adopted to allow additional use cases to be deployed in the future; and, how does the value of vehicle-to-grid integration use cases compare to other storage or DER?[66]

While New York State has little experience with managed charging and vehicle-to-grid integration, through the REV process the State has worked on some of the fundamental issues of defining the value and process for consumers to participate more actively in the energy market. The Value of Distributed Energy Resources proceeding is already addressing the tariffs that provide the correct incentive for customers to inject power into the distribution system.[67] The Commission must ensure that these forums continue to address the EV use cases. As the impact of EVs, EV chargers and EV drivers on the grid is

[65] VGI Communication Protocol Working Group Energy Division Staff Report, October 2018. Available at: https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442460144.

[66] See, https://www.cpuc.ca.gov/vgi/.

[67] Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources.

better understood, parties should propose plans to implement manage charging solutions.

Staff shall organize a Stakeholder process for interested parties and other State Agencies to discuss managed charging and vehicle-to-grid integration, modeled after the CPUC working group process. This group shall work towards providing the Commission with vehicle-to-grid integration action items for the midterm review.

The Commission directs the utilities to file proposals for active or managed charging programs for mass market customers, in consultation with Staff, within 120 days of the issuance of this Order. The managed charging programs will provide customers with an alternative to the whole home TOU rates already in place. Several utilities already offer managed charging programs, pilots and demonstration projects and these utilities may file existing programs as compliance for this directive; however, the Joint Utilities should consider expanding or filing complimentary programs if the existing program is not available service territory-wide. The managed charging program filings shall be reviewed during the by the managed charging and vehicle-to-grid Stakeholder group.

XVI. Fleet Assessment Service Whitepaper Recommendations

Staff recommends in its Whitepaper that each utility offer new services to customers interested in fleet electrification. This Fleet Assessment Service would consist of a site feasibility analysis and rate analysis. The site feasibility analysis would be based on the maximum power draw of an electrified fleet to determine if the local distribution system can accommodate that increased load. The site feasibility analysis would include all planned utility work on the distribution system both nearby and on the infrastructure

serving the existing depot, to find cost-saving synergies that may exist. The rate analysis would be tailored to each depot location, and the fleet manager would understand all rate options available, as well as a reasonably certain range of costs they may expect based on their charging behavior.

Comments

Several commenters support the proposed fleet advisory services and the Joint Utilities and Metropolitan Transportation Authority suggest that the utilities could fulfill this role. Many commenters request prompt further action on fleet electrification, with Advanced Energy Economy Institute and the Alliance for Clean Energy New York, the Alliance for Transportation Electrification, the Drive Electric Long Island Coalition, EDF, the EV Industry Coalition, Greenlots, Metropolitan Transportation Authority, the City of New York, the Natural Resources Defense Council, the Sierra Club and New York Power Authority requesting the development of Commission guidance on procedures and utility program proposals within the year. Several commenters argue that delaying similar treatment of medium- and heavy-duty EV infrastructure will delay state policy goals. The EV Industry Coalition also charges that this exclusionary approach forces utilities into inefficient system planning efforts that assess these markets separately; the New York State Department of Environmental Conservation stresses that the electrification of the light-duty vehicle market will significantly affect conditions for the development of medium- and heavy-duty EV infrastructure and recommends that these sectors be assessed concurrently.

Several commenters call for complementary rate reform to accompany fleet electrification efforts, and recommend investigation of subscription rates, time-of-use rates and other appropriate price signals that reflect temporal and locational

costs to foster fleet adoption. Metropolitan Transportation Authority calls for the establishment of new service classifications for commercial EV customers. Furthermore, several parties request additional funding and incentives for the development of fleet EV infrastructure. The EV Industry Coalition and Greenlots recommend a $300 million statewide budget incremental to the proposal, so as to avoid competition with existing funds for light-duty EVs. Other various suggested solutions include studies to identify market barriers, performance incentives for the efficient development of fleet charging infrastructure can promote program cost containment and extensive customer outreach for fleet EV customers.

Several commenters detailed environmental, economic and public health benefits associated with increased fleet EV adoption, including greater transportation access for disadvantaged communities, potential grid benefits, lower fuel and maintenance costs for operators and mitigation of air and noise pollution and greenhouse gas emissions. Metropolitan Transportation Authority suggests that all bus depots in environmental justice areas be designated strategic locations. Some parties note that these benefits will accrue to many residents regardless of personal EV ownership, particularly in the case of fleet electrification.

A number of parties providing input at Staff-led stakeholders sessions, including West Harlem Environmental Action, and those providing written comments including the Stakeholder Coalition, the Alliance for Transportation Electrification and the City of New York call attention to the need to expand the Make-Ready Program to include medium-duty and heavy-duty vehicles and trucks.

West Harlem Environmental Coalition points out that diesel emissions from truck traffic continue to burden low-

income families in dense urban communities and exacerbate the already existing negative health conditions, such as asthma and other respiratory afflictions. The Stakeholder Coalition points out that EV options for medium- and heavy-duty vehicles, including cargo vans, box trucks, sanitation trucks and others, are increasing and assisted in electrification by NYSERDA's Truck Voucher Program.

With the increasing presence of medium- and heavy-duty vehicles and trucks, there will be demand for associated charging facilities. The City of New York points out that COVID-19 has disproportionally affected environmental justice communities and that has highlighted the corresponding exposure to particulate matter of 2.5 microns or less (PM 2.5) from medium- and heavy-duty vehicles. NYC requests that the Commission adopt transportation policies within its purview to reduce these emissions.

Determination

The Commission agrees with the statements by New York State Department of Environmental Conservation, the Clean Transportation Coalition, the City of New York and other parties that more work is urgently needed to support the transition to electrified medium- and heavy-duty vehicles. The Make-Ready Program directed by this Order will positively impact conditions for an eventual scalable infrastructure program for medium-duty and heavy-duty vehicles in many ways, including by building utility core competencies. The Commission also agrees that not providing a fleet assessment service to medium- and heavy-duty fleets will delay state policy emission reduction goals. The City of New York notes that clean transportation provides public health benefits to the most at-risk members of our community by reducing the impacts of tailpipe emissions from the trucks and

buses on low-income populations. Driving these benefits to at-risk populations is a crucial measure of program success.

The Commission adopts the Whitepaper Fleet Assessment Service with the modification that the assessment shall be open to light-, medium-, and heavy-duty fleet operators. The Commission expects that the Joint Utilities will be able to expand this new offering over time as lessons are learned but will leverage existing employees and core competencies in the near-term. The Joint Utilities shall post a common intake/application form on the Joint Utilities of New York website and the individual utility EV-specific webpages.[68] This application process shall apply to light-duty as well as medium- and heavy-duty vehicles.

The Fleet Assessment Service shall begin with a site feasibility and rate analysis. The site feasibility analysis should be based on the maximum power draw of the electrified fleet under consideration to determine if the local distribution system can accommodate the increased load. The site feasibility analysis should include all planned utility work on the distribution system both nearby and on the infrastructure serving the existing depot, to find cost-saving synergies that may exist.

If the site feasibility analysis is positive, the utility shall offer the customer a rate analysis, working to understand the maximum costs fleet electrification may incur and how to implement best practices and managed charging to mitigate

[68] Xcel Energy Colorado presently runs a Fleet Advisory Program, which is a good example of the Commission's expectations regarding the application. See https://www.xcelenergy.com/stateselector?stateSelected=true&goto=%2Fprograms_and_rebates%2Fbusiness_programs_and_rebates%2Felectric_vehicles%2Ffleet_electric_vehicles%2Ffleet_electrification_form.

these costs. The rate analysis should be tailored to each depot location, and the fleet manager should be informed of all rate options available, as well as a reasonably certain range of costs they may expect based on the fleets' charging behavior.

The Joint Utilities are directed to design a customer satisfaction survey for those whom participant in the Fleet Assessment Service. The Fleet Assessment Service survey should ask questions to obtain whether participants found the analysis useful, how likely they are to electrify their fleet in the near- and long-term, what the biggest barriers to fleet electrification are, what additional services a utility may provide to support their electrification, and other informative survey questions.

XVII. Medium- and Heavy-Duty Fleet Make-Ready Pilot Program

Many commenters identify exceptional regulatory and market barriers facing the electrification of medium- and heavy-duty fleets that should be addressed through Commission action. Commenters cite significant capital costs and operating costs that are stalling wholesale adoption, as well as growing demand for fleet EVs exceeding the limited supply of commercial options.

In addition to making the Fleet Assessment Service available to the medium- and heavy-duty vehicle fleets, the Commission is persuaded by commenters that additional support is required. The Commission therefore outlines two additional programs aimed at advancing the medium- and heavy-duty vehicle industry in New York. This relatively small-scale Medium- and Heavy-Duty Fleet Make-Ready Pilot Program will inform fleet electrification throughout New York State.

The Medium- and Heavy-Duty Fleet Make-Ready Pilot Program in Con Edison's service territory shall mimic the "Fleet DC Fast Charger Make-Ready Program" approved in their most

recent major rate filing.[69] The currently effective rate plan provides Con Edison with the flexibility to shift funds between the Fleet DC Fast Charger Make-Ready Program and Publicly Accessible DC Fast Charge Program approved in the current rate plan.[70] Since this Order provides additional Light-Duty Make-Ready Infrastructure funds and alters the scope of the rate-plan approved Publicly Accessible DC Fast Charge Program to align with a statewide framework, the budget flexibility to shift funds between the two programs is eliminated. Con Edison shall implement the Fleet DC Fast Charger Make-Ready Program eligibility and program rules and provide $9 million in total budget.[71]

Central Hudson, NYSEG, National Grid, O&R, and RG&E shall develop Medium- and Heavy-Duty Fleet Make-Ready Pilot Program Implementation Plans in consultation with Staff and in accordance with the program elements outlined below, to be filed within 90 days of issuance of this Order. The total budget shall be $15 million and may be unevenly allocated between the utilities based on program interest. In their Implementation Plans, Central Hudson, NYSEG, National Grid, O&R and RG&E shall propose cost recovery and cost allocation. If tariff amendments to effectuate such Medium- and Heavy-Duty Fleet Make-Ready Pilot Program (including by not limited to cost recovery) are needed, Central Hudson, NYSEG, National Grid, O&R and RG&E shall file

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[69] Case 19-E-0065, Case 19-E-0065, Con Edison - Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan (issued January 16, 2020).

[70] Id. at 73.

[71] Con Edison's effective rate plan provides for $3 million per year for each effective rate year, with an incentive of up to $1.2 million per participant.

such tariff amendments to go into effect on January 1, 2021, on a temporary basis on not less than 30 days' notice.

To the extent that the equipment needs overlap with the light-duty Make-Ready Program, the program structure of Central Hudson, NYSEG, National Grid, O&R and RG&E's Medium- and Heavy-Duty Fleet Make-Ready Pilot Program will be based on the light duty Make-Ready Program. The Medium- and Heavy-Duty Fleet Make-Ready Pilot Program must support a direct reduction of diesel emissions located in environmental justice communities through electrification of the medium-duty/heavy-duty vehicles/trucks. In order to qualify for the program participants must also be seeking and receive support through the New York Truck Voucher Incentive Program[72] run by NYSERDA or the New York City Clean Trucks Program administered by the NYC Department of Transportation.[73] Participation in these programs evidences the fact that a fleet owner has replaced an older, heavily polluting diesel truck with a clean vehicle technology that dramatically reduces or eliminates tailpipe pollution.

Participants in the Medium- and Heavy-Duty Fleet Make-Ready Pilot Program that purchase the vehicle through NYSERDA's Truck Voucher Incentive Program will receive up to 90 percent of the utility-side make-ready infrastructure upgrade costs. In addition to the above requirements, charging stations located in environmental justice areas, or that are dedicated for fleets

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[72] The New York Truck Voucher Incentive Program provides funding for between 80 percent and 100 percent of the incremental cost between a new diesel-powered truck and a new battery-powered vehicle of the same type and class. See https://www.nyserda.ny.gov/All%20Programs/Programs/Truck%20Voucher%20Program.

[73] The NYC Clean Trucks Program is administered with similar eligibility criteria, and provides funding from $12,000 up to $185,000 per eligible truck replacement. See, https://www.nycctp.com/.

operating a signification portion of the time in environmental justice areas, as defined in the Accessibility section of the Eligibility Criteria for the Make-Ready Program are of heightened interest.

The Joint Utilities are directed to design a customer satisfaction survey for those whom participant in the Medium- and Heavy-Duty Fleet Make-Ready Pilot Program and Con Edison shall also survey their Fleet DC Fast Charger Make-Ready Program participants. These surveys should ask similar questions to the Fleet Assessment survey, to understand how flexible charging schedules are, future fleet electrification goals, what motivated the electrification, how steep of a learning curve the fleet operator faced, what additional services the utility may provide to support their fleet electrification and other appropriate questions.

XVIII. Additional Transit Authority Make-Ready Support

Additionally, the Commission directs Con Edison, National Grid, and RG&E to partner with Capital District Transportation Authority, Niagara Frontier Transportation Authority, Rochester-Genesee Regional Transit Authority and Westchester County Bee-Line Bus System, to make-ready bus depots for electric vehicle charging.

A number of commenters noted that the GHG emissions reduction and public health benefits of electrifying public transit for disadvantaged communities, who frequently rely on it for mobility, urged the Commission to include make-ready funds for transit authorities in this Order. The Commission recognizes the benefits of transit bus electrification and agrees that action on this subject is merited following the equity mandate outlined in the CLCPA. However, the Commission finds New York Public Transit Association's request of $50

million for make-ready work to be outsized to the initial need and does not adopt it.

The Commission authorizes a budget of $2,960,000 for Con Edison to partner with the Westchester County Bee-Line Bus System, $5,090,000 for National Grid to partner with the Capital District Transportation Authority and the Niagara Frontier Transportation Authority, and $1,950,000 for RG&E to partner with the Rochester-Genesee Regional Transit Authority. These budgets are based on their relative fleet size and alignment with the 2020 State of the State goal to electrify 25 percent of these fleets by 2025; to be used for make-ready work at transit bus depots. Within this budget, the transit authorities shall be eligible for 100 percent make-ready support.

XIX. Additional NYSERDA-Led Environmental Justice Programs

Per the CLCPA, disadvantaged communities are defined as communities that bear burdens of negative public health effects, environmental pollution, impacts of climate change, and possess certain socioeconomic criteria, or comprise high-concentrations of low- and moderate-income households.[74]

The Commission has recognized that the low- and moderate- income segment in New York State is broad and diverse, more than 3.5 million households (40 percent of the State's households) qualifying as low-to moderate-income.[75] Low-income households are defined as those with annual incomes at or below 60 percent of the State Median Income. 2.3 million households meet this criterion. The moderate-income market segment, which encompasses about 1.2 million households, is comprised of households with an annual income between 60 and 80 percent of

[74] NY ECL §75-0101.

[75] 2019 American Community Survey, available at: https://www.census.gov/programs-surveys/acs/.

the State Median Income or the Area Median Income,[76] whichever is greater.

The NYSDEC Office of Environmental Justice defines Environmental Justice as the fair and meaningful treatment of all people, regardless of race, income, national origin or color, with respect to the development, implementation, and enforcement of environmental laws, regulations and policies. The Commission directs these additional Environmental Justice Programs in accordance with the CLCPA's mandate to all State Agencies to prioritize reductions of GHG emissions in disadvantaged communities.[77]

The Commission directs that if the CLCPA mandated Climate Action Council, Climate Justice Working Group and Environmental Justice Advisory Group establish a definition of Disadvantaged Communities that differs from that adopted by this Order, all programs herein shall be modified and updated to adopt the CLCPA established definition going forward.

As stated by numerous commenters, the emissions impacts in urban areas such as NYC are due in large part to pollution from trucks, buses and other vehicles fueled by diesel fuel. In response to the many parties calling for additional, immediate action to electrify this vehicle segment and to take meaningful, significant steps towards mitigating the disproportionate burden of disadvantaged communities as directed by the CLCPA, the Commission directs the following additional programs. These Environmental Justice Programs aim to give Disadvantaged Communities and low- and moderate- income

[76] During Implementation, the JU and NYSERDA are directed to work with Staff to develop streamlined eligibility determinations such as utilizing Housing and Urban Development Census Tracts to identify low- and moderate- income areas.

[77] NY ECL §75-0109.

households the tools and programs to address the disproportionate environmental impact of diesel transit.

In addition to the initiatives to electrify vehicle and truck fleets within Disadvantaged Community areas, the Commission is persuaded by commenters that a number of new approaches are needed to address areas outside of the Make-Ready Program. We therefore direct NYSERDA to propose within 90 days of issuance of this Order, an Environmental Justice Community Clean Vehicles Transformation Prize, the Clean Personal Mobility Prize, and the Clean Medium- and Heavy- Duty Innovation Prize.

The three prize competitions shall be administered by NYSERDA, in accordance with an implementation plan to be developed by NYSERDA in consultation with Staff, and filed within 90 days of the issuance of this Order. Staff and NYSERDA shall work collaboratively to create criteria and other requirements consistent with the goals of the prize pilots: address emissions, equity, and electrification in places where people and transportation intersect. Staff and NYSERDA will work collaboratively to determine appropriate cost allocation for these pilots, under the framework that costs will generally be allocated to all customers within the service territory where the program activity takes place, with the exception that program activities with statewide benefits may be allocated to multiple utilities based on other factors such as utility revenues, number of customers, or other appropriate allocation factors. The definition of environmental justice locations referenced in the Accessibility section of the Eligibility Criteria will apply to these NYSERDA programs.

The full range of activities will be available for support, including planning, community and customer engagement, design, deployment, evaluation, and replication support. Partnerships among public and private entities are encouraged,

with a focus on community involvement. The prize competition is open across the State to all communities served by electric utilities regulated by the Commission, and to all types of organization, including local government, not-for-profit, community-based organizations, and private sector service, equipment, and solution providers.

A. Environmental Justice Community Clean Vehicles Transformation Prize Pilot

In order to ensure that communities burdened by polluting vehicle traffic benefit from new clean vehicle solutions, the State will establish a prize competition. The Environmental Justice Community Clean Vehicles Transformation Prize will drive innovative and high-impact approaches that utilize advances in clean transportation to reduce harmful air pollution in such disadvantaged communities, causing health, economic, and environmental harm. An example solution, provided for illustrative purposes only, could look to the electrification of diesel traffic that specifically burdens these communities. Integrated projects that create “green zones” by taking polluting vehicles off the road and expanding access to clean electric transportation options in disadvantaged communities are of particular interest.

This $40 million prize competition will aim to accelerate the design, development, and deployment of such solutions by supporting pilot or demonstration projects that achieve direct benefits to these communities; allow concrete investigation of opportunities, costs, and benefits; and prove out approaches can be replicated at scale.

In order to accelerate benefits to these disadvantaged communities, and in order to bring forward the most impactful and compelling solutions, the prize competition will be open to providing support for all types of clean electric mobility

solutions; such solutions include, but are not limited to, support for integrated solutions that include medium- and heavy-duty as well as light-duty vehicles, charging infrastructure, managed charging and other resources.

B. Clean Personal Mobility Prize

In order to ensure that New Yorkers who do not readily have access to clean personal transportation options also benefit from new clean vehicle solutions, the State will establish a prize competition. The Clean Personal Mobility Prize will drive innovative and high-impact approaches that enable access to and delivery of clean transportation services, including “last-mile” solutions, to environmental justice, low- and moderate- income and underserved communities. Example solutions, provided for illustrative purposes only, could look to EV carsharing, EV carpooling or vanpooling, microtransit, and other ride-on-demand services using EVs, and other innovative transit services that incorporate electric modes. Integrated projects that both take polluting vehicles off the road and expand electric transportation options in disadvantaged communities are of particular interest.

This $25 million prize competition will aim to accelerate the design, development, and deployment of such solutions by supporting pilot or demonstration projects that achieve direct benefits to these communities; allow concrete investigation of opportunities, costs, and benefits; and prove out approaches can be replicated at scale.

In order to accelerate benefits to these disadvantaged communities, and in order to bring forward the most impactful and compelling solutions, the prize competition will be open to providing support for all types of clean electric mobility solutions, including support for integrated solutions that

include vehicles, charging infrastructure, managed charging solutions and other resources.

C. Clean Medium- and Heavy- Duty Vehicle Innovation Prize

In order to ensure that New York positions itself to make swift and effective progress in electrifying medium and heavy-duty vehicles, beyond light duty vehicle types that are the principal focus of this Order, the State will establish a prize competition. The Clean Medium- and Heavy-Duty Vehicle Innovation Prize will drive innovative and high-impact approaches that demonstrate the viability of the most compelling opportunities for medium- and heavy- duty vehicle electrification.

Projects that demonstrate commercially available technologies or strategies that reduce the cost of electric medium- and heavy- duty vehicle charging and associated electric upgrades, increase the ability to rapidly scale electric medium- and heavy- duty vehicle adoption, and expand viable markets for medium- and heavy- duty vehicle electrification to new applications/vocations, weight classes, and/or duty cycles are of particular interest. Projects involving medium- and heavy-duty vehicles domiciled in or operating a significant portion of the time, including but not limited to those providing last mile movement of goods and people in disadvantaged communities are of heightened interest.

This $20 million prize competition will aim to accelerate the design, development, and deployment of such solutions by supporting pilot or demonstration projects that achieve direct benefits; allow concrete investigation of opportunities, costs, and benefits; and prove out approaches can be replicated at scale.

In order to bring forward the most impactful and compelling solutions, the prize competition will be open to providing support for all types of clean transportation solutions, including support for integrated solutions that include medium- and heavy- duty vehicles, charging infrastructure, managed charging solutions and other resources.

XX. Rate Design

Whitepaper Recommendations

Staff did not propose in its Whitepaper any rate design reforms as part of the package of programs to incentivize EV deployment. In the Residential EV Tariff Order, the Commission addressed new rates for residential customers with EV chargers.

Comments

Advanced Energy Economy Institute, the Alliance for Clean Energy New York and the EV Industry Coalition support Commission action to address rate designs for EV charging. The EV Industry Coalition, Environmental Defense Fund and EVgo contend that EV charging costs must be easily understood by customers to foster adoption. The Natural Resources Defense Council, the Sierra Club and Plug In America all note that off-peak charging encouraged by rate design contributes to downward pressure on rates. The EV Industry Coalition, Environmental Defense Fund and Greenlots argue that rate reform can also increase effective utilization of the grid and minimize grid impacts of EV charging to create value. EDF and Enel X North America contend that EV rate design can be reconciled with conventional cost-of-service ratemaking, and the EV Industry Coalition further recommends that stakeholders develop new rate options that reflect the cost-causation profile of EV charging.

The Joint Utilities acknowledge the importance of developing cost-reflective rate design for EVs to encourage

optimal charging and improving system efficiency, adding that cost-based rates will encourage future software system development, technology improvements and allow managed charging. However, the Joint Utilities stress that discounted rate designs are not an efficient method for scaling transportation electrification and contend that structuring rates to promote specific technologies is inconsistent with fundamental rate design principles.

Advanced Energy Economy Institute and the Alliance for Clean Energy New York call on the Commission to address rate design in a separate track within the year. Similarly, the Natural Resources Defense Council, the Sierra Club and Tesla recommend that the Commission address rate design sooner, rather than waiting for the midpoint program review. The Alliance for Transportation Electrification contends that ratemaking is best accomplished on a case-by-case basis by individual utilities and alleges that market conditions are premature to begin new ratemaking. EDF and Tesla recommend time-varying price signals as the most efficient way to encourage beneficial off-peak charging. The Natural Resources Defense Council and the Sierra Club recommend both specific EV or “whole-house” TOU rates to complement managed charging and demand response programs.

Greenlots adds that ratepayer-funded infrastructure should be capable of supporting time-varying rate but acknowledges that technology-based managed charging is an alternative to TOU rates, noting that this option would support Commission preferences for limiting technology-specific rates. Similarly, FreeWire Technologies suggests that rate reform can be complemented by technological solutions. Advanced Energy Economy Institute and the Alliance for Clean Energy New York note that demand charges constitute a significant portion of EV operating costs, especially at DC Fast Charger sites, and

contend that demand charges provide insufficient price signals to modify charging behavior.

Enel X North America and the Joint Utilities suggest that standby designs could provide viable options for EV charging to provide relief from noncoincident demand charges and encourage managed charging. The EV Industry Coalition proposes that general service rates could be modified to provide appropriate price signals for EV charging and suggests that subscription rates also be investigated. ChargePoint, the EV Industry Coalition, Environmental Defense Fund, Enel X North America, EVgo and Tesla request that utilities develop commercial rates, with Tesla specifically recommending specific commercial EV accounts or general TOU rates applicable to all commercial customers.

The City of New York recommends examining fleet load profiles for purpose of developing commercial EV rates. Advanced Energy Economy Institute and the Alliance for Clean Energy New York argue that commercial rate reform will be foundational to future vehicle-to-grid capabilities. Electrify America urges the Commission to analyze the impact of utilities minimizing demand charges and fixed service costs, while allowing recovery of only the marginal cost to serve without riders or other non-bypassable surcharges associated with historical infrastructure costs and unrelated programs.

Determination

Staff stated in its Whitepaper that it is premature to change rate design and recommended the issue be re-visited at the DC Fast Charger Per-Plug Incentive program’s midpoint review. Due to the market conditions ATE seconded Staff’s statement. There is no doubt that the EV supply equipment market in New York is in its infancy. There were fewer than two dozen DC Fast Charger FC plugs in service under the per plug

incentive program at the time of the Joint Utilities' detailed annual report filings required by the DC Fast Charger Framework Order.

This Order aligns incentives and reporting under the DC Fast Charger Per-Plug Incentive Program and the Make-Ready Program. The data included in the reports will provide information to guide future decisions on whether programmatic and/or rate designs are needed to promote development of EV supply equipment in New York. For example, the utilities will provide load profiles for the DC Fast Charger stations in their annual reports. Such data will help demonstrate if the load characteristics of DC Fast Charger stations warrant a unique rate design. Additionally, DC Fast Charger station Make-Ready Program participants will be required to provide charging revenues and operating costs. This data will provide a deeper understanding of station economics for stations developed under the programs in place in New York. Station owners will also be required to provide their charging structure and such information will provide insight into the impact on station load characteristics.

Demand charges constitute a significant portion of operating costs for DC Fast Charger stations owners, as noted by many parties, including Advanced Energy Economy Institute and the Alliance for Clean Energy New York. However, the Commission has stated, and still finds, that demand charges send the appropriate price signal to consumers to influence behavior and reduce distribution grid impacts.

The Alliance for Transportation Electrification opined that rate design modifications should be make on a case-by-case basis. However, as properly noted by the Joint Utilities, structuring rates to promote a specific technology is inconsistent with fundamental rate design principles. The

Commission declines to modify effective rate design principles by this Order; the need to make rate design modifications will be re-visited as part of the midpoint review.

XXI. Implementation Issues

A. Utility Programs

The Commission recognizes that the scope and scale of this Make-Ready Program and other activities directed by this Order are unmatched. In some areas, the Commission has directed a phased approach to developing the tools directed in this Order, taking lessons learned from our DER deployment experiences in New York. In other areas, the Commission expects that the utilities' core competencies and existing EV subject matter experts will immediately inform program roll-out. The Commission directs the Joint Utilities to work with Staff in drafting Make-Ready Program Implementation Plans and a common Make-Ready Program Participant Guide.

The Implementation Plans shall be utility-specific and include project timelines, administrative cost estimates, third-party support needs and vendors identified, and education and outreach plans. Staff and the Joint Utilities shall work to enable project and tool timelines as expeditiously as possible, and the Joint Utilities shall file the Implementation Plans within 60 days of issuance of this Order.

The common Make-Ready Program Participant Guide shall be a comprehensive guide that will inform the developer, owner, and/or site-host community. This Participant Guide should provide all the information necessary to enable a developer that is unfamiliar with New York's landscape to confidently apply to the Make-Ready Program. The Joint Utilities are directed to work with Staff in developing this Participant Guide. The Make-Ready Program Participant Guide shall be filed in DMM and posted to the Joint Utilities of New York website and each utility's

individual EV website within thirty days of issuance of this Order.

B. NYSERDA Programs

NYSERDA shall file the Implementation Plans outlining an Environmental Justice Community Clean Vehicle Transformation Prize, the Expanded Access to Clean Vehicle Prize, and the Clean Medium- and Heavy- Duty Innovation Prize within 60 days of the issuance of this Order. Staff and NYSERDA shall work collaboratively to create criteria and other requirements consistent with the prize goals, and to determine appropriate cost allocation.

The three prize competitions shall be administered by NYSERDA, in accordance with the Implementation Plans. Staff and NYSERDA will work collaboratively to determine appropriate cost allocation for these pilots, under the framework that costs will generally be allocated to all customers within the service territory where the program activity takes place, with the exception that program activities with statewide benefits may be allocated to multiple utilities based on other factors such as utility revenues, number of customers, or other appropriate allocation factors. NYSERDA shall work with Staff and the utilities to update the Bill-As-You Go (BAYG) process to facilitate the tracking, requisition and transfer of funds between NYSERDA and the utilities.[78] Any necessary changes to the existing BAYG process shall be detailed in a revised BAYG Summary document and filed concurrently with the aforementioned Implementation Plan, within 60 days of this Order.

[78] Case 14-M-0094, et al., Order Authorizing the Clean Energy Fund Framework (issued January 21, 2016), p. 98. (Authorizing the BAYG approach to better match collections with expenditures, where collections are retained in utility accounts an transferred to NYSERDA at a specified frequency based on actual program expenditures).

CONCLUSION

The Commission recognizes the significant efforts by interested stakeholders over the last two years to identify and consider various matters related to increasing ZEV and EV adoption and advancing the State's objectives. The Make-Ready Program, Environmental Justice Community Clean Vehicles Transformation Prize, Clean Personal Mobility Prize, Clean Medium- and Heavy- Duty Innovation Prize, Fleet Assessment Service, Medium- and Heavy-Duty Make-Ready Pilot Program, and Transit Authority Make-Ready Program adopted herein will all support transportation electrification in New York State while attracting private market investment.

The Make-Ready Program, Fleet Assessment Service, Medium- and Heavy-Duty Make-Ready Pilot Program, and the Transit Authority Make-Ready Program will best position the Joint Utilities to serve an appropriate role as collaborator and administrator, and will result in useful and actionable data to modify program elements as needed at the mid-point review and from which the following phases of these pilots and procurements will flow.

The Environmental Justice Community Clean Vehicles Transformation Prize, Clean Personal Mobility Prize, and Clean Medium- and Heavy- Duty Innovation Prize well position NYSERDA to leverage its expertise and experience and procure innovative solutions that meaningfully benefit Disadvantaged Communities.

Collectively, the actions in this Order will promote the public interest by furthering the State's environmental and clean energy goals.

The Commission orders:

1. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., and Rochester Gas and Electric Corporation are directed to implement light-duty Make-Ready Programs not to exceed the amounts specified in the body of this Order. Each Make-Ready Program shall fund 100 percent of eligible make-ready costs for publicly accessible direct current fast charging sites within one-mile of environmental justice communities; 100 percent of eligible make-ready costs for Level 2 sites in multi-unit dwellings located in low-to-moderate income or environmental justice communities; 90 percent of eligible make-ready costs for sites that meet all of the applicable eligibility requirements; and up to 50 percent of eligible make-ready costs for sites that do not meet all of the applicable eligibility requirements. Furthermore, the Public Service Commission directs that where a proprietary plug type is collocated with an equal number of commonly accepted standardized plug types of equal or greater charging capacity, that station shall receive the 90 percent make-ready incentive. Where a station with proprietary plug types is not collocated with an equal number of commonly accepted standardized plug types of equal or greater charging capacity, that station shall receive the 50 percent make-ready incentive.

2. New York State Electric & Gas Corporation and Niagara Mohawk Power Corporation d/b/a National Grid are directed to implement light-duty Make-Ready Programs not to exceed the amounts specified in the body of this Order. Each Make-Ready Program shall fund 100 percent of eligible make-ready costs for publicly accessible direct current fast charging sites within two miles of environmental justice communities; 100 percent of eligible make-ready costs for Level 2 sites in multi-unit dwellings located in low-to-moderate income or

environmental justice communities; 90 percent of eligible make-ready costs for sites that meet all of the applicable eligibility requirements; and up to 50 percent of eligible make-ready costs for sites that do not meet all of the applicable eligibility requirements. Furthermore, the Public Service Commission directs that where a proprietary plug type is collocated with an equal number of commonly accepted standardized plug types of equal or greater charging capacity, that station shall receive the 90 percent make-ready incentive. Where a station with proprietary plug types is not collocated with an equal number of commonly accepted standardized plug types of equal or greater charging capacity, that station shall receive the 50 percent make-ready incentive.

3. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation are directed to establish a Medium- and Heavy- Duty Make-Ready Pilot Program as discussed in the body of this Order.

4. Consolidated Edison Company of New York, Inc., Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation are directed to establish a Transit Authority Make-Ready Program as discussed in the body of this Order.

5. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation are directed to treat rebates paid to customers for customer-sited make-ready work and future-proofing as a regulatory asset, inclusive of associated

carrying charges, to be collected via existing surcharge mechanisms over a period of 15 years. If tariff revisions are needed to effectuate this recovery, such tariff revisions are to be filed to go into effect to go into effect January 1, 2021, on not less than thirty days' notice, on a temporary basis.

6. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation are directed to develop an online EV supply equipment service application portal in a phased approach, with Phase One to be complete within three months of issuance of this Order and Phase Two to be completed within six months of issuance of this Order.

7. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall develop the Suitability Criteria as described in the body of this Order.

8. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall publish load serving capacity maps tailored to support electric vehicle charging station siting by no later than December 31, 2020.

9. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation are directed to work with

developers to determine the feasibility of future-proofing plans from a grid and site perspective at each participating station.

10. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall post a contractor approval application and a list of pre-approved contractors to their EV websites. Furthermore, contractor applications shall be approved or denied within one month of the application submittal.

11. Central Hudson Gas & Electric Corporation, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall work in collaboration with Department of Public Service Staff to develop Medium- and Heavy-Duty Fleet Make-Ready Pilot Program Implementation Plans and file such plans within 90 days of issuance of this Order.

12. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall work with the Department of Public Service Staff to develop utility-specific Make-Ready Program Implementation Plans and a common Make-Ready Program Participant Guide and are directed to post the Make-Ready Program Implementation Plans within 60 days of issuance of this Order and the Make-Ready Program Participant Guide within thirty days of issuance of this Order.

13. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State

Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall file proposals for active or managed charging programs for mass market customers, in consultation with Staff, within 120 days of the issuance of this Order.

14. The New York State Energy Research and Development Authority is directed to work with Department of Public Service Staff to propose, within 90 days of issuance of this Order, implementation plans to establish an Environmental Justice Community Clean Vehicles Transformation Prize, an Clean Personal Mobility Prize, and a Clean Medium- and Heavy- Duty Innovation Prize.

15. To the extent that the New York Power Authority participates in the Make-Ready Program it shall be subject to the program rules established by the Public Service Commission and enforced by the appropriate investor-owned electric utility. The New York Power Authority shall work with Department of Public Service Staff to file an Implementation Plan within 60 days of issuance of this Order.

16. Within 90 days of issuance of this Order, Department of Public Service Staff shall convene a working group focused on discussing how to incorporate emerging technical standards and best practices, such as: the International Electrotechnical Commission (IEC) accepted OpenADR 2.0b, International Organization for Standardization (ISO)/IEC 15118, and the OCPP. In convening this technical working group Department of Public Service Staff shall send invitations to the New York State Department of Agriculture and Market's Bureau of Weights and Measures staff, the New York State Energy Research and Development Authority staff, other appropriate New York State and local government agencies, and industry stakeholders.

Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall engage with this Technical Working Group.

17. The Public Service Commission directs Department of Public Service Staff to convene a Customer Experience Working Group within 120 days of issuance of this Order. In convening this technical working group Department of Public Service Staff shall send invitations to the New York State Department of Agriculture and Market's Bureau of Weights and Measures staff, the New York State Energy Research and Development Authority staff, the New York State Department of Financial Services, other appropriate New York State and local government agencies, and industry stakeholders. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall engage with this Customer Experience Working Group.

18. Department of Public Service Staff shall lead a mid-point review to begin no later than October 1, 2022, with recommendations made to the Public Service Commission by January 4, 2023.

19. In the Secretary's sole discretion, the deadlines set forth in this order may be extended. Any request for an extension must be in writing, must include a justification for the extension, and must be filed at least one day prior to the affected deadline.

20. This proceeding is continued.

By the Commission,

(SIGNED) MICHELLE L. PHILLIPS
Secretary

APPENDIX A

SUMMARY OF COMMENTS

Commenters

Advanced Energy Economy Institute and the Alliance for Clean Energy New York (AEEI-ACE)
Alliance for Automotive Innovation (Auto Innovators)
Alliance for Transportation Electrification (ATE)
Bloom Energy Corporation (Bloom Energy)
ChargePoint, Inc. (ChargePoint)
City of Albany (City of Albany)
City of New York (NYC)
Clean Communities of Central New York (CCCNY)
Clean Transportation Coalition[1]
Drive Electric Long Island Coalition (Drive Electric LI)
Electrify America, LLC (Electrify America)
Enel X North America, Inc. (Enel X)
Environmental Defense Fund (EDF)
Estates NY Real Estates Services (Estates NY)
EVBox
EV Connect, Inc. (EV Connect)
EV Industry Coalition[2]
EVgo
EVSE LLC
FreeWire Technologies, Inc. (FreeWire)
Green Energy Consumers Alliance (GECA)
Green Machine Power (GMP)
Greenlots

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[1] The Clean Transportation Coalition includes CALSTART, Central Hudson Gas & Electric Corporation, ChargePoint, Inc., Consolidated Edison Company of New York, Inc. (Con Edison), Enel X North America, Inc., EVgo, Natural Resources Defense Council, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), Orange and Rockland Utilities, Inc. (Orange and Rockland Utilities), Rochester Gas and Electric Corporation, and Sierra Club.

[2] The EV Industry Coalition includes CALSTART, BYD Motors LLC, Chanje Energy, ChargePoint, Inc., ClipperCreek, Inc., Environmental Defense Fund, EV-Box, EVgo, Greenlots, Green Power Motor Company, IKEA North America, Lion Electric Company, Motiv Power Systems, Nikola Motors, Port Authority of New York and New Jersey, Siemens eMobility, Tesla, Tri-State Transportation Campaign, and Xos Trucks.

APPENDIX A

Joint Utilities[3]
Konrad Advising, LLC and AltEnergyStocks.com (Konrad)
Metropolitan Transportation Authority (MTA)
Mirabito Holdings Inc. (Mirabito)
Multiple Intervenors
Natural Resources Defense Council and Sierra Club (NRDC-SC)
New York Association of Public Power (NYAPP)
New York Power Authority (NYPA)
New York Public Transit Association, Inc. (NYPTA)
New York State Department of Environmental Conservation (DEC)
New York State Department of State, Office of Planning, Development and Community Infrastructure (DOS)
New York State Department of Transportation (DOT)
New York Thruway Authority (NYTA)
New Yorkers for Clean Power (NYCP)
Nikola Corp.
Plug In America (PIA)
Tesla, Inc. (Tesla)
Vrinda Inc. (Vrinda)
ZappyRide

[3] The Joint Utilities are Central Hudson Gas & Electric Corporation, Con Edison, New York State Electric & Gas Corporation, National Grid, Orange and Rockland Utilities, and Rochester Gas and Electric Corporation.

APPENDIX A

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I. Eligible Project Costs and Technologies

ChargePoint

ChargePoint recommends including plugs capable of simultaneously charging at or above 75 kilowatts (kW) or plugs capable of independently charging at or above 62.5 kW, and sharing power to charge one vehicle at or above a combined 125 kW. According to ChargePoint, this modification would reflect the fact that 75 kW-capable electric vehicles (EVs) do not typically charge at or near 75 kW, and it would serve as a cost-control mechanism for the program.

EVSE LLC

EVSE LLC endorses a “solar to wheels” proposal in which utilities integrate EV charging with solar projects where possible. It proposes consideration of garage ceiling-mounted chargers to achieve faster installations, lower costs, reduced risks, and less property disruption. EVSE LLC also suggests that light pole-mounted charging stations offer fewer pedestrian disruptions, greater access, lower costs, and shorter installations than conventional installations, and recommends that utilities evaluate pole inventories as siting assets.

GMP

GMP alleges that the proposed Make-Ready Program fails to achieve technology neutrality and will stifle innovation by invalidating the use of technologies that avoid costly utility line extensions with mobile and other forms of energy storage. GMP requests that these technologies should be eligible for per-plug incentives.

Joint Utilities

The Joint Utilities recommend that all plug types, (proprietary and non-proprietary), site types (public and private), and customer segments (including workplaces, multi-unit dwelling, and light-duty EV fleets) should be eligible for the Make-Ready Program on an equal basis.

PIA

PIA advises that Level 1 charging should be eligible under the program, as it may be suitable in workplace locations and other longer dwell-times facilities, such as commuter rail stations where the expectation of extended parking prevents more rapid charging turnover.

Tesla

Tesla contends that site hosts should be able to choose equipment that best fits their needs, and its proprietary wall connectors should at a minimum be eligible under the program.

II. Eligibility Criteria

AEEI-ACE

AEEI-ACE strongly recommends that the Commission move away from the proposed public accessibility criteria, and instead focus on sectors of need including highway corridors, workplaces, urban-shared, and multi-unit dwellings. AEEI-ACE notes that charging a reasonable fee at time-limited parking spaces is meant to promote turnover that makes these spaces an attractive option for EV infrastructure siting. AEEI-ACE stresses that multi-unit dwelling and workplace chargers are critical to meeting state goals and are ideal candidates for 90 percent cost coverage given the apparent hesitancy of some property managers to install EV supply equipment (EVSE) at these sites. AEEI-ACE agrees that publicly-funded or utility-owned nonfleet stations should accept all common payment forms to ensure competition and accessibility.

AEEI-ACE notes that workplace chargers offer an attractive use of ratepayer funds because their long dwell times allow for managed charging. AEEI-ACE also observes that no party expressed support for the public accessibility provision, and reiterates comments by the Joint Utilities and NYC highlighting the importance of parking fees in funding essential services. AEEI-ACE asserts that the proposed program requirements are overly complex and may inhibit participation, and warns that the list of new methodologies required of utilities is too extensive and requires the development of new

expertise which will cause delays. AEEI-ACE proposes that utilities should provide support, but not dictate charger development.

ATE

ATE expresses concern about the complex and rigid public accessibility provisions, and adds that the Whitepaper disregards the reality of parking in many areas and unduly discriminates against locations that both deserve and need the higher levels of funding.

Auto Innovators

Auto Innovators recommends that Level 2 installations at multi-unit dwellings should be eligible for the same incentives as public charging facilities. It recommends siting DC Fast Chargers along travel corridors and in urban areas to mitigate range anxiety and facilitate regional travel

ChargePoint

ChargePoint suggests that eliminating public accessibility restrictions will provide parity between use cases, better align incentives with program goals, and help create widespread grid benefits. ChargePoint endorses open-access standards adopted in other jurisdictions that enable feeless acceptance of commonly-used payment forms using kiosks, card readers, on-site acceptance, or phone payments. ChargePoint proposes revising the minimum number of ports per site to two EVSE ports per location deployed up front, with sufficient make-ready installation funding to support the eventual deployment of four ports installed at Level 2 and DC Fast Charger deployments. ChargePoint asserts that allowing site hosts to choose multiple networks is essential, regardless of which parties hold title to a station. It also insists that site host control over EV infrastructure is similarly important, as site hosts are in the best position to consider both charging and parking needs in setting prices.

City of Albany

The City of Albany argues that limiting incentives for charger installations based on public accessibility requirements will eliminate many urban areas from program coverage.

Electrify America

Electrify America supports near-term flexibility in eligibility requirements for the program. However, it maintains that overly prescriptive requirements around specific network protocols and payment methods can discourage innovation in charging station design. It is especially concerned that eligibility requirements could prohibit issuance of payments for Contribution in Aid of Construction (CIAC) or Excess Distribution Facilities before construction is confirmed, thereby disqualifying projects in early, more uncertain stages of development. Electrify America warns that this would create an unfair competitive advantage for developers who delay construction and could encourage developers to abandon projects. It recommends that eligibility be based on construction having commenced by the date of the order approving the program.

Estates NY

Estates NY urges the Commission to adopt a flexible approach to make-ready program implementation in line with recommendations by the Joint Utilities, including making both public and nonpublic locations eligible for make-ready incentives. Estates NY predicts that a disproportionate number of large EV fleets will be operated from nonpublic facilities, and will therefore be ineligible for funding under the current proposal.

EVBox

EVBox opposes the public access requirement, claiming that public charging only addresses a small proportion of market needs, and that preferential incentive treatment will not yield a maximum return on program investment. It recommends greater support for workplace and multi-unit dwelling infrastructure instead, noting that public access in the latter is often impossible and that making workplace chargers publicly-accessible removes access assurance for its intended users.

EVBox warns that requiring credit card readers would increase installation costs that would be unjustified by their infrequent use.

EV Industry Coalition

The EV Industry Coalition contends that public access criteria unnecessarily fragment the market and do not reflect customer needs for alternatives to home-charging. It foresees high demand for chargers from multi-unit dwelling residents and transportation network company (TNC) drivers, and warns that lower incentives may be insufficient to overcome the significant capital costs of installations at these locations. According to the EV Industry Coalition, the development of DC Fast Charger stations to support electrification of TNC, taxi, and other light-duty vehicle fleets should be a priority for New York.

The EV Industry Coalition advocates collaboration with state and local agencies to ensure that chargers are installed at multi-unit dwellings greater than four units where parking is included in the development plans. Customers who live in multi-unit dwellings will have a high barrier to purchasing, or sharing, an EV without charging infrastructure installed in parking structures at or near their buildings. None of this parking would likely meet the Whitepaper's definition of "public" and therefore would be reimbursed at a lower rate that may fail to overcome significant capital cost barriers that are characteristic of EV supply equipment deployment at multi-unit dwelling locations. It also urges the Commission to investigate incentivizing neighborhood charging hubs with both Level 2 and DC Fast Charger facilities, and adds that DC Fast Charger stations for light-duty fleets should be prioritized.

The EV Industry Coalition explains its criticism of the current DC Fast Charger-per-plug incentive, citing low participation and what it alleges is a burdensome and complex program design. It notes that credits are not paid out until 13 months after a participating station begins service, and that market participants must bear all near-term risks and wait 20 to 24 months for payment after first incurring costs. The EV Industry Coalition advises that avoiding these drawbacks of the DC Fast Charger per-plug incentive is essential in developing new EV programs.

Greenlots

Charging stations leveraging public funds should not charge a membership fee, and that point-of-sale payment options for charging services be made available, according to Greenlots. While Greenlots agrees with Staff that a majority of stations should serve the public, they argue that tying accessibility to pay-to-park requirements is inconsistent with the way New Yorkers drive and park, and would considerably limit opportunities for charging station deployment. Asking businesses and localities to forgo parking revenues in order to install EV charging is an unreasonable request, as these funds are built into business models and budgets.

Greenlots further encourages parity for incentives that are not publicly accessible, as these stations nonetheless deliver benefits, for example by managing charging in such a way that contributes to downward pressure on rates and reducing transportation emissions. In particular, both commercial and government fleets represent significant opportunities for electrification and any program focused on rapidly transforming the transportation sector should provide strong support for meeting the needs of these market segments. Fleet managers are uniquely focused on operating costs, and for this reason are more likely to develop predictable charging patterns that can align with grid realities.

Greenlots notes that, in certain cases, non-public stations also address market segments that will be harder to reach and therefore need maximum support. Charging opportunities for residents of multi-unit dwellings are also likely to be constrained under the current model. In Greenlots' experience, multi-unit dwellings are one of the most challenging sectors to serve, due to split incentives between landlords and tenants and the often-limited capital and attention of building owners. In many cases, residents of multi-unit dwellings pay to park at their homes and workplaces. Ensuring that charging station deployment is adequately incented, even in pay-to-park lots, will offer meaningful access to a large group of drivers who would not otherwise be served by the proposed program. Downstate investment in strategically-located fast charging hubs can also be an effective strategy.

Joint Utilities

The Joint Utilities request modification of the public access requirement to allow incentives for infrastructure at multi-unit dwellings, workplaces, and paid parking facilities, particularly in the New York metropolitan area where free public parking is scarce and development costs are greater. The Joint Utilities recommend that all plug types, (proprietary and non-proprietary), site types (public and private), and customer segments (including workplaces, multi-unit dwelling, and light-duty fleets) should be eligible for the incentives on an equal basis.

NYC

NYC cites low participation in the existing DC Fast Charger Per-Plug Incentive Program as a warning that overly prescriptive policies may inhibit charger development and EV adoption. NYC opposes the public access requirement, arguing that it would create unnecessary obstacles for deployment in NYC. NYC cites its sustainable transportation goals that call for 80 percent of trips to be made by walking, biking, or mass transit by 2050, and notes that parking fees collected by the New York City Department of Transportation are required to meet revenue targets to fund these initiatives. It requests that the Commission recognize NYC’s power to establish its own parking policy. It also recommends the Commission grant full access to incentives for charging stations located in restricted or paid parking facilities, and notes this position is supported by several other parties.

NYCP

NYCP recommends that streamlined, easily accessible payment at stations will foster EV adoption.

NRDC-SC

NRDC-SC argues that the Commission should expand the definition of public accessibility to include pay-to-park parking garages, and that publicly-funded or utility-owned non-fleet charging stations should accept forms of payment commonly used today by drivers of all vehicle types, regardless of membership to a particular charging network.

Tesla

Tesla advocates that its proprietary wall connectors should at a minimum be eligible under the program at nonpublic locations, including workplaces, multi-unit dwellings, and fleet depots.

III. Eligibility Criteria – Future-Proofing

Auto Innovators

Auto Innovators cautions against prematurely overbuilding sites through encouragement of future-proofing without specific justifications, especially at sites unlikely to require upgrades. It also encourages the State to consider existing vehicle grid integration efforts developed in other states to inform policies and pilot programs.

ATE

ATE agrees with Auto Innovators' concerns about overbuilding, and recommends that the Joint Utilities work together with stakeholders to establish best practices.

ChargePoint

ChargePoint urges adoption of the Joint Utilities recommendation that future-proofing costs constitute a separate budget item, which will allow more effective cost tracking and evaluation.

Drive Electric LI

Drive Electric LI acknowledges that while DC Fast Chargers are not part of utility distribution systems, it is important to develop infrastructure to manage anticipated future use by medium- and heavy-duty EVs. It recommends that DC Fast Charger infrastructure on major thoroughfares be built as large as possible (preferably a 350 kW systems) to accommodate future use by trucks and buses and to minimize charging times. Drive Electric LI argues that this would avoid comparable capacity problems that emerged in the compressed natural gas infrastructure deployment of the late 1990s and early 2000s.

EDF

EDF argues that an imminent and comprehensive utility grid impact study conducted in collaboration with industry partners is necessary for determining futureproofing requirements, adding that all utilities should pilot and evaluate non-wires solutions to obviate the need for some oversizing.

Enel X

Enel X agrees that oversizing customer-side, make-ready components can be a cost-effective method to future-proof sites, but should be an option rather than a requirement.

EVgo

EVgo argues that future-proofing should be optional, noting that while it may be warranted in some cases, requiring it in all cases compromises cost-effectiveness.

FreeWire

FreeWire alleges that the oversizing requirements limit EV supply equipment siting opportunities and could delay deployment. It recommends the use of infrastructure-light technology instead.

Greenlots

Greenlots agrees that the Commission should encourage oversizing where reasonable. It opposes strict requirements and prefers upfront cost containment. Greenlots points out that future-proofing can entail many solutions that the Commission should consider. Greenlots encourages the Commission to require Open Charge Point Protocol (OCPP) certification for any project receiving full incentives.

Joint Utilities

The Joint Utilities support future-proofing and recommend that it include additional connection point installations, trenching, and conduit for future station expansions, as well as system upgrades including larger transformers or additional transformer pads. The Joint Utilities argue that future-proofing expenditures are

incremental and not tied to initial location capacity, and that they should be recognized separately in the program budget. The Joint Utilities propose consideration of the following criteria to determine the extent of future-proofing necessary at each site: expansion plans specifying plug numbers or increased power; feasibility of additional installations; increased power and parking capacity; and costs of increased service power.

NYC

NYC agrees with recommendations by the International Council on Clean Transportation (ICCT), cited by Staff in the Whitepaper, to oversize connection points for future fast chargers and anticipate transformer upgrades. NYC recommends that any future-proofing be done in a measured manner to accommodate changes in EV supply equipment technology.

NRDC-SC

NRDC-SC argues that the Commission should not be overly prescriptive in over-sizing requirements, but should encourage cost-effective future-proofing when site upgrades are expected. NRDC-SC argues that expensive retrenching should be avoided, and DC Fast Charger stations should plan for higher power chargers entering the market by future-proofing electric panels and transformers. NRDC-SC agrees with Greenlots that future-proofing should also include open standards and interoperability. It also concurs with the Joint Utilities that site characteristics should be considered in assessing the extent of future-proofing necessary.

NYPA

NYPA agrees with Staff on its future-proofing proposal, and supports reasonable constraints to prevent overbuilding, such as limiting station capacity to no more than 50 percent over current needs (absent a signed agreement to expand by a greater percentage within two years). NYPA also maintains that the Commission should limit grid upgrade costs to a maximum of 10 percent, and consider providing developers an incremental incentive to install higher-power chargers.

Tesla

While initially arguing that future-proofing should be optional, Tesla acknowledges that the Joint Utilities outline a reasonable approach to determine necessary future-proofing that balances costs and feasibility. Originally, Tesla contended that future-proofing should not be a requirement of the program given the potential added costs, and site host and location considerations. Recommendations for future-proofing, however, could be made, including building larger transformer pads or space for additional panels or switchgears in case of future expansion. It argues that this is particularly relevant for new construction, or sites and fleets with clear future expansion plans, where it may make sense to plan for future EV charging needs upfront in order to save significant costs.

Vrinda

Vrinda states that the Commission should make it mandatory for the utilities and developers to pair storage with charging stations as a requirement of future-proofing. This will support de-carbonization and address congestion in the network. This will also eliminate the need for costly upgrades which may get stranded in the future as EV utilization and ranges change.

IV. Incentives

AEEI-ACE

AEEI-ACE requests that the Commission clearly specify that the maximum incentive level functions as a cost reduction for utility-side costs, rather than a reimbursement to developers. This is important because developers have a limited amount of capital that they can devote to projects, especially given the impact of COVID-19 on business cash flows. If their capital is tied up in utility-side make-ready costs, some developers may need to wait for reimbursement before they can pursue additional projects. If there is a significant lag time for reimbursement, this will create financing costs for developers that will only add to the soft costs of charging stations.

AEEI-ACE recommends that the Commission consider other alternatives that would lessen the impacts of reimbursements on developer balance sheets. Some options could include an upfront payment from the utility to the developer of the available incentive (or a portion of it) for the customer-side make-ready infrastructure, or for the utility to pay for the customer-side work directly and then receive a reimbursement from the developer for the portion not covered by available incentive. These options could provide a boost to the speed and cost-efficiency of development, while preserving cash flow during the challenges created by COVID-19.

AEEI-ACE argues that existing programs should be allowed to continue as currently structured as they do not fully address the charging infrastructure gap. AEEI-ACE also notes that it is important to minimize market disruptions during the current public health crisis.

ATE

ATE argues that utilities should have the flexibility to fund the appropriate number of Level 2 and DC Fast Chargers per site, stating that a preferable approach would be based on broad criteria such as availability, geographic diversity, and equity.

Auto Innovators

Auto Innovators recommends greater program funding for DC Fast Chargers, and requests clarification that the program will provide 90 percent of funding to all DC Fast Charger ownership models.

ChargePoint

ChargePoint does not support setting maximum incentive levels now, and recommends that this be delayed until the first biannual review when the Program Advisory Council can provide appropriate recommendations. ChargePoint supports the Joint Utilities recommendation to replace the proposed maximum incentive level with a less restrictive framework comprised of a total budget and performance incentives, which it predicts would permit greater utility and developer flexibility in selecting locations to best meet user, site host, and system needs.

Clean Transportation Coalition

Clean Transportation Coalition recommends program flexibility to better match incentives with costs, and contends that additional incentives for EV developers (e.g., the DC Fast Charger per-plug incentive currently offered by utilities) will be important for program success. The Clean Transportation Coalition recommends eliminating the difference in incentives available to public and nonpublic locations, particularly downstate where free charging is an unreasonable constraint. It also argues that the program should allow EV service providers and utilities to offer locations and independent sites hosts to directly participate.

DEC

DEC asserts that the existing DC Fast Charger per-plug incentive and proposed Level 2 and DC Fast Charger make-ready incentives should complement current and proposed DEC efforts to promote light-duty EV adoption through EV supply equipment development.

Drive Electric LI

Drive Electric LI submits that existing EV programs like the New York State Energy Research and Development Authority (NYSERDA) Charge Ready NY program and the DEC ZEV infrastructure program complement the proposed program, and should continue to combat range anxiety and other EV adoption impediments.

Electrify America

Electrify America notes that the proposal states that maximum incentive levels will be determined based on utility-specific average deployments costs, and seeks clarification on how these costs would be derived. Electrify America observes that the incentive levels considered in the whitepaper, approximately $45,000 per plug for Upstate and $82,000 per plug for New York metropolitan sites, may be insufficient to cover make-ready costs particularly for high-power stations. Electrify America agrees with ChargePoint that a more effective design would be to establish a range of make-ready development costs that better reflect the current industry, and cites an

observation by the Joint Utilities that actual costs could significantly exceed Whitepaper estimates.

Electrify America suggests that utilization assumptions in the Whitepaper be revisited in view of existing rates at ultra-fast charging stations and COVID-19 effects on utilization, noting that investor concerns about cost recovery may inhibit ultra-fast charger installations. Electrify America cautions that the public health crisis is expected to limit new vehicles sales, with EV sales particularly affected by lower gasoline prices. It also notes that the Commission analysis assumed higher projected utilization rates than were recorded by any Electrify America public station in 2019. Furthermore, Electrify America points out that when utilization is measured as a percentage of time, ultra-fast chargers exhibit lower utilization rates than 50kW DC Fast Chargers due to shorter charging times.

Enel X

Enel X states that allowing projects to claim a specified percentage of their actual costs rather than calculating a set incentive, would provide a much more simplified and streamlined program design that would result in greater program uptake. Enel X points out that fixed incentive amounts applied across an entire charging level based on average historical costs raises questions regarding the cost data used to set the incentive, and masks the many variables that contribute to an individual project's overall costs at a given charging level. Enel X argues that without differentiating incentive levels to account for any of these differences, developers would be incentivized to seek out relatively low cost, low-capacity projects at the expense of seeking to maximize station utilization.

The proposal to allow bundling of DC Fast Charger project costs within a single utility service territory may address this issue, but would skew program participation to more sophisticated developers who are able to develop multiple sites to increase the coverage of the incentive. Enel X argues that developers installing a reduced number of charging ports per project could be penalized because per plug costs for such projects typically run higher than projects with a greater

number of ports. Enel X also suggests that cost containment could be encouraged through alternative methods such as determining a reasonable percentage of increased ratepayer costs by netting societal costs and increased revenue, and by promoting advanced rates and smart charging options that incentivize the cost-effective grid integration of EV charging.

Estates NY

Estates NY supports the initial comments by the Joint Utilities alleging that proposed make-ready incentives do not reflect market conditions, and should be increased to support EV charging development. Estates NY expresses concerns that the proposed incentives will be insufficient to foster development, noting that make-ready costs and other project economic considerations are a significant deterrent to residential and commercial charging installation development.

EVBox

EVBox submits that maximum incentive levels set according to the currently limited number of EV supply equipment installations in the State could prove inaccurate, with detrimental effects. EVBox acknowledges the importance of cost containment, but cautions against overemphasizing it in program design. It notes the immaturity of the EV charging market, and warns that standards applicable to more established distributed energy resources (DER) should not be applied.

EV Industry Coalition

The EV Industry Coalition argues that the maximum incentive level would unnecessarily constrain development of valuable but higher cost stations, and argues that other cost containment measures should be investigated. It suggests that sites developed under the proposed maximum incentive level could qualify for a higher percentage of eligible costs (e.g., 100 percent), than those that are developed at actual greater costs than the maximum incentive level (e.g., 80 percent of eligible costs).

Joint Utilities

The Joint Utilities contend that flexible incentives are necessary to address evolving market needs, customer preferences, and demand, especially in the first years of implementation when appropriate levels should be determined according to these factors. Incentives should also be sufficient to support a variety of EV charger business models, as well as stations with variable levels of use. Concerning incentive funding, the Joint Utilities propose that NYSERDA could expand incentive availability with other funding sources, using collected and unallocated funds.

The Joint Utilities raise several concerns about the proposed maximum incentive levels, and argue that these may be incompatible with the wide range of possible make-ready infrastructure costs, deter implementation of higher cost (and value) stations, and may inadvertently encourage less expensive installations to inflate their costs to qualify for greater incentives. The Joint Utilities suggest instead that a more flexible framework be adopted, with overall budgets and performance incentives. They propose an incentive covering 90 to 100 percent of make-ready costs for Level 2 and DC Fast Charger stations, on average. The Joint Utilities recommend that all plug types, (proprietary and non-proprietary), site types (public and private), and customer segments (including workplaces, multi-unit dwelling, and light-duty fleets) should be eligible for the Make-Ready Program on an equal basis.

The Joint Utilities allege that Staff's proposed prescriptive incentive structure is premature, and suggests that a more flexible incentive structure would increase the likelihood of success for the Make-Ready Program. The Joint Utilities recommend flexibility in setting and adjusting incentives to increase charger numbers and capability, accommodating customer segment needs, and accounting for business model diversity. The Joint Utilities also recommend determining Level 2 and DC Fast Charger station distribution, setting a trajectory through 2025 to evolve and respond to market needs and trends, and setting and adjusting customer acquisition and go-to market strategies.

The Joint Utilities propose three criteria for assessing installation applications: cost per plug, the number

of drivers each site would serve (and associated education and marketing reach of each installation), and the equitable distribution of plugs across each service territory. The Joint Utilities also recommend additional consideration be given for sites that serve low- and moderate-income communities, workplaces where employers provide incentives for employee EV purchases, and workplaces where charging installations can support both fleet and personal vehicles.

Mirabito

Mirabito recommends that incentives should be biased toward DC Fast Charger installations, which it argues will be most needed to foster customer adoption of EVs.

NRDC-SC

NRDC-SC argues that the Make-Ready Program should complement existing programs, arguing that if lower incentive levels were in place previously (i.e., under a REV paradigm), those incentive levels should be increased to align with levels prescribed in this Make-Ready Program. Stations supported by existing programs should count toward the overall goals.

NYPTA

NYPTA supports providing financial incentives covering up to 90 percent of make-ready costs to accelerate EV charging infrastructure development.

Vrinda

Vrinda proposes an incentive sharing structure in which a station whose utilization exceeds ten percent of the projected assumptions would redeposit an amount equivalent to the difference between assumption and projection in a fund after the cost recovery period. This could be used to support future station develop and avoid the difficult prediction of utilization rates. Vrinda also argues that this solution would mitigate the possibility of windfall profits to stations that achieve utilization exceeding projections.

V. Incentive Adjustments

AEEI-ACE

AEEI-ACE recommends that utilities be able to adjust the payment percentages and other program requirements prior to program review. AEEI-ACE also maintains that EV registrations and EV supply equipment deployments should be central to any examination of incentive step-downs, and cautions that, if the nascent EV charging market has not responded, a stepdown may not be warranted. AEEI-ACE advises that the Commission promote transparency in the evaluation process and timing of any potential step-downs to the developer community through a regularly updated dashboard or similar measure.

ATE

ATE does not oppose the concept of reviewing incentive levels later, but explains that market development is too premature to debate the process and nature of a step-down process. ATE contends that debating future incentives at this point could have a dampening effect on EV infrastructure investment. ATE notes that when it becomes appropriate to reduce incentive levels, there should be ample notice with perhaps several alternatives put forth, supported by data and experience from other forward-leaning jurisdictions.

DEC

DEC recommends that the Commission remain flexible to account for the effects of COVID-19, and if necessary, consider further modification of the per-plug incentive and Make-Ready Programs if EV market development is insufficient under the current schedule.

Enel X

Enel X recommends that incentive decreases should be infrequent, ideally occurring once at most during the five-year budget cycle to provide program certainty. Enel X does not anticipate sufficient changes in key indices over the five-year budget to justify more than one step-down. Enel X argues that the midpoint review of the program should include a review of

incentive levels that considers current empirical economic factors.

EVgo

EVgo advocates deferring incentive step-downs until program review takes place.

FreeWire

FreeWire urges a cautious approach to incentive decreases, noting that the Make-Ready Program should complement rather than replace current utility incentives. FreeWire argues that existing EV supply equipment incentive programs should integrate with the Whitepaper proposal to constitute a total cost of deployment comprising equipment, installations, and upgrades. FreeWire suggests the proportion of these constituent costs would vary between each project, allowing caps on total funding based on tiers (i.e., Level 2, 50 – 74 kW, 75 – 150 kW, etc.). It recommends that this approach would yield a greater EV supply equipment deployment across strategic locations. Rather than stepping down incentives, FreeWire encourages the Commission to consider mechanisms within the Make-Ready Program that could provide a portion of avoided infrastructure costs for deployments of advanced systems, like its “Boost Charger.”

Greenlots

Greenlots asserts that the aggressive stepdown schedule and program model proposed is based on a perilously optimistic view of current market conditions and the associated need for utility investment. Greenlots remarks that the current Joint Utilities per-plug incentive offer for DC Fast Charger serves as a warning of the risks in designing stepdown mechanisms for nascent markets. It notes that DC Fast Charger deployment is extremely limited statewide and the current per-plug incentive step-down schedule outpaces the market, and warns that designing a new schedule with scant current evidence would harm the market. Greenlots currently opposes implementing stepdown mechanisms of any type, but expects that as EV deployment increases charging station economics will improve in line with policy expectations.

Greenlots observes that a stepdown mechanism could facilitate market transformation necessary for greater private sector economic confidence in charging station investment. It recommends using criteria of utilization data, EV ownership trends, and station availability, and notes that some installations may still require significant public support even when conditions at other sites indicate stepdown measures should be taken. Greenlots notes that more expensive stations will require more capital investment from site hosts, and cautions that decreasing incentives prematurely could threaten their development. Noting that charging stations (particularly DC Fast Charger) require lengthy project schedules, Greenlots recommends utilities finance projects through a reservation system to avoid depleting or altering fund availability prematurely. This could involve partial payments on an intermittent schedule, which might be helpful in the current economic environment in which many developers have limited liquidity.

Joint Utilities

The Joint Utilities state that a program that provides certainty is critical to fostering a positive business environment for EV market stakeholders, rather than a predetermined, regularly scheduled incentive step-down. The Joint Utilities claim that it would be appropriate to review the effectiveness of the Make-Ready Program incentives during the mid-term review. Such a review could lead to recommendations to decrease, increase, or make no changes to incentive levels. Furthermore, the Joint Utilities recommend that each utility should conduct regular and transparent evaluations of applicants, thereby obviating the need to provide additional notice of incentive reductions.

NYAPP

NYAPP asserts that incentive levels should only decline as penetration rates achieve milestones, and not be linked to specific dates due to the recent pandemic.

NYC

NYC observes that the rate of EV adoption is a key variable in determining a proper incentive level. NYC advises that any potential phase-down should consider the time it takes for a program of this magnitude to ramp up, and should also avoid stepping down levels at such a rapid pace that developers are unable to complete their projects within an allowed timeframe to be eligible for such incentives. NYC requests that stakeholders receive adequate notice of impending step-downs, and that the process should be fully transparent.

NRDC-SC

NRDC-SC cautions that initial assumptions concerning the rate of change in charging station economics may be misleading, and that it may be appropriate to decrease incentives at various times in different service territories based on the rate of EV deployment. NRDC-SC observes that several parties opine against a premature and prescriptive incentive reduction schedule, and agree with these other parties in deferring these actions until midterm review. However, NRDC-SC opposes use of EV deployment as a metric for devising a step-down schedule, recommending instead that station utilization is a more appropriate measure, particularly when assessed against the ratio of EV registrations to charging stations.

NYPA

NYPA argues that incentives should be reduced over time when specific milestones are met, specifically a utility-specific number of DC Fast Charger ports installed based on the National Renewable Energy Laboratory (NREL) Electric Vehicle Infrastructure Projection Tool Lite.

PIA

PIA states that considering the disruption to both EV sales and construction projects caused by the COVID-19 pandemic, the per-plug incentive level of 2019 should be maintained until at least mid-2021.

Tesla

Tesla argues that any potential step-downs in incentive levels should arise from the review process, and stakeholders should have an opportunity to comment. Further, Tesla states that if a step-down occurs, program applicants and charging developers should be provided at least 12 months' notice because of long lead times involved in developing charging locations.

VI. Bundling

ChargePoint

ChargePoint is concerned that bundling would inadvertently favor EV service providers over independent site hosts, who are generally unable to spread costs across multiple locations. ChargePoint suggests allowing site-specific capital cost variability that would alleviate these concerns.

EV Industry Coalition

The EV Industry Coalition insists that the bundling proposal is inconsistent with typical site development, and is concerned that its applicability and usefulness will be limited. It warns that aligning all milestones with bundling periods will be difficult, in part, due to varying funding streams.

Enel X

Enel X recommends that the Commission adopt an incentive for the Make-Ready Program that covers a given percentage of actual project costs, which would obviate the need to bundle DC Fast Charger project costs across a utility territory. The proposal to allow bundling of DC Fast Charger project costs could skew program participation to more sophisticated developers who are able to develop multiple sites to increase the coverage of the incentive. Enel X argues that developers installing a reduced number of charging ports per project could be penalized because per plug costs for such projects typically run higher than projects with a greater number of ports. Enel X also advises that cost containment could be encouraged through alternative methods such as determining a reasonable percentage of increased ratepayer costs

by netting societal costs and increased revenue, and by promoting advanced rates and smart charging options that incentivize the cost-effective grid integration of EV charging.

EVBox

EVBox cautions that Staff's bundling proposal favors owners and operators who own a network of multiple chargers across the State, and penalizes single site installers in high cost areas. EVBox recommends that utilities evaluate applications from site hosts for specific DC Fast Charger sites based on complete information including costs, geography, and availability of alternative sites, and potential customer traffic/site visibility.

FreeWire

FreeWire supports the bundling proposal, but recommends reducing the period in which all of the bundled chargers must be completed from 18 months to 12 months to encourage faster deployment.

Greenlots

Greenlots recommends that bundling remain an option for encouraging development of higher cost sites, but should not be the only mechanism for spurring build-out of these locations.

Joint Utilities

The Joint Utilities predict that the proposed bundling approach will be difficult to implement due to diverse locational and temporal eligibility requirements that could create administrative complexities that may impede infrastructure development. They recommend that projects that propose bundling at different locations include all relevant plugs in a single, filed application to allow comparisons against other applicants.

Tesla

Tesla appreciates the Whitepaper's novel design for developers to bundle project costs as part of the program. However, it acknowledges that administrative burdens may impede

implementation, and notes that the concept may not work for all charging business models.

VII. Program Budgets

ATE

ATE advocates the use of both the Electric Vehicle Infrastructure Projection Tool Lite from NREL, as well as estimates by NYPA and the Joint Utilities, which both have a thorough understanding of the distribution grid and other local needs and conditions. ATE recommends that a program management budget of 10 to 15 percent of the total budget, ideally in addition to funds already earmarked, is sufficient to accomplish program goals.

ChargePoint

ChargePoint advocates revising program capital cost projections to reflect greater cost variability and inclusion in utility rate base. It states that indirect costs like overhead and allowance for funds used during construction are not included in the program's projected costs. ChargePoint contends that the assumptions on direct capital costs are significantly below market expectations. Regarding operating costs, ChargePoint warns against basing program requirements on station utilization assumptions because they may ignore direct and indirect revenue streams and value propositions of successful deployments. Noting that the Whitepaper assumes that a 4 x 50 kW DC Fast Charger configuration will average two to three sessions per port a day in the first year of the program, ChargePoint proposes a more conservative assumption of 0.5 to 1.5 sessions per day.

ChargePoint notes its agreement with other parties in favor of including a greater range of capital program costs. It reiterates its request that more conservative budget estimates be used (between 125 percent and 200 percent of the average capital cost per site), and adds that this is consistent with the Joint Utilities proposal.

DEC

DEC recommends distributing the proposed $582 million in make-ready investments between investor-owned electric utilities based on projected Level 2 and DC Fast Charger needs, and progress toward overall goals in five and ten years.

Enel X

Enel X does not oppose combining existing make-ready utility budgets with the make-ready infrastructure budgets considered presently, assuming such budgets target the same market segments at issue.

EVgo

EVgo supports maintaining existing programs until allocated funds are exhausted.

EV Industry Coalition

The EV Industry Coalition is concerned about the validity of cost assumptions used to size program incentives on a per-site and overall basis, noting that development costs can be heterogeneous but are on average significantly higher, particularly downstate. The EV Industry Coalition warns that greater utility investment than proposed in the Whitepaper will be necessary to increase EV adoption.

Electrify America

Electrify America suggests that further economic assessment is required, and recommends sensitivity analysis modeling of utilization factors and policy effects on charger installation and operation costs. In particular, it urges an evaluation of the effects of utilities minimizing demand charges and fixed service costs, while allowing recovery of only marginal costs to serve without riders or other non-bypassable surcharges associated with historical infrastructure costs and unrelated programs. Doing so would help to determine if the Make-Ready Program combined with other EV incentive programs would result in an economically-sustainable construction and operation of EV stations in New York.

FreeWire

FreeWire requests that the Whitepaper proposal complement existing program budgets, and that EV supply equipment funding and permitting efforts be streamlined to accelerate deployment.

GMP

GMP contends that the forecast ratio between battery EVs and plug-in hybrid EVs overstates the percentage of plug-in hybrid EVs, and will result in misallocated ratepayer funds. An updated forecast will ensure more accurate long-term funding. GMP criticizes the Make-Ready Program for failing to determine which charger types most effectively foster EV adoption, and recommends a proposal to study the merits of Level 2 versus DC Fast Charger installations to accelerate market development. This would allow more cost-efficient program design, especially if a mechanism is developed to incorporate changing market conditions and forecasts, as GMP recommends.

Greenlots

Greenlots argues that EV make-ready investment is an obligatory utility service rather than a discretionary program model, stating that utilities have a requirement to serve new EV load as they would accommodate new residential or commercial customers. It urges the Commission to adopt mechanisms to offer reliable support for the deployment and hosting of this infrastructure. Greenlots recommends that as a fundamental utility service, the provision of make-ready EV infrastructure should be funded in utility rate cases rather than separate program filings, and suggests that coupling this regulatory strategy with programs that focus on managed charging would reduce a major barrier to widespread transportation electrification. This structure will provide assurance to developers that necessary funding will not be subject to regulatory delays or program budget constraints, as well as making programs more equitable and improving market certainty.

Greenlots submits that any approved program should supplement established programs, and that the Commission should encourage utilities to introduce new programs to better serve customers and all market segments. Rather than placing all

utility investments under a single program, Greenlots advocates a range of program designs to best facilitate private market competition and meet the various needs of all customers.

Greenlots concurs with several parties warning that the overall program budget is likely insufficient, adding that the total investment required to meet the State's transportation electrification goals exceeds the Whitepaper estimates. Greenlots advises that this deficiency requires Commission attention, and recommends additional utility programs to address these concerns by the end of 2020.

Joint Utilities

The Joint Utilities recommend establishing incentives and budgets necessary to achieve state EV goals, and urges the Commission to consider the integration of demand-based delivery rate and time-varying supply charges to provide accurate price signals to EV customers. The Joint Utilities plan to integrate their existing make-ready programs with this new Make-Ready Program. For Con Edison, program funds authorized in its current rate plan will continue to be used incrementally or in combination with the Make-Ready Program to offset utility-side interconnections and EDF costs for both publicly-accessible and fleet DC Fast Chargers. The Joint Utilities recommend continuing the NYSERDA Charge Ready program for Level 2 plugs and the DC Fast Charger Per-Plug Incentive Program through the Make-Ready Program midpoint review.

NYC

NYC recommends that utilities design make-ready programs based on existing programs and that any funding should be in addition to any funds already approved. However, NYC notes that authorizing excessive programmatic budgets will have significant effects on ratepayers, especially during uncertain economic conditions.

NYPA

NYPA argues that the assumption that 75 percent of EV owners have sufficient home charging capability is misleading because of significant differences in charging conditions between urban, suburban, and rural residential areas. NYPA

contends that this creates problems for NREL's Electric Vehicle Infrastructure Projection Tool Lite, which is especially sensitive to data inputs, and using simple statewide averages can result in inaccurate estimates of necessary charging infrastructure. NYPA proposes that more refined, regional demographic information on residential charging be used in generating infrastructure estimates. NYPA also contends that estimates of the proportion of battery EVs to plug-in hybrid EVs are similarly inaccurate and suggests that the battery EV numbers should be increased. NYPA adds that modeling inputs should include vehicle miles traveled categorized by private vehicles versus ridesharing and taxi services.

PIA

PIA observes that Staff's estimates using the Electric Vehicle Infrastructure Projection Tool Lite from NREL may not accurately reflect a likely future vehicle mix that should determine charging investment. PIA suggests that Staff's allocation of $431 million to make-ready for public Level 2 and $151 million to public DC Fast Chargers are roughly the reverse of what would be an appropriate mix. PIA recommends that Staff redo this analysis using a more sophisticated tool, reflecting the geographic heterogeneity of EVs that cannot charge at home and reflecting a forward-looking vehicle mix. PIA supports plug-in hybrid EVs, but notes they require a significant investment of resources to enable them to operate entirely in all-electric mode. Therefore, forecast models using a small number of 100-mile battery EVs significantly increases the Direct Current Fast Charger estimate. PIA observes that changing the battery EV assumption to model all battery EVs with 250-mile ranges reduces by 55 percent the number of DC Fast Charger chargers required.

Tesla

Tesla contends that existing utility make-ready or line extension programs are more ambitious than the proposed Make-Ready Program, and should remain in place until fully subscribed or funds are exhausted before implementing a new program. However, Tesla argues that existing utility programs that provide less support than the proposed program should be

replaced by it. Tesla also recommends that other funding sources be investigated before moving ahead with a competitive procurement, such as grants from New York's share of the Volkswagen Appendix D funds.

VIII. Cost Recovery and Allocation

ATE

ATE supports the proposal to allocate program costs to all customer classes based on transmission and distribution revenues.

Electrify America

Electrify America supports allowing utilities to cover the cost of make-ready investments, and recover the costs of these necessary investments to support new DC Fast Charger infrastructure.

Enel X

Enel X agrees with a conventional cost-of-service ratemaking approach based on allocating program costs to customer classes according to transmission and distribution revenues.

EV Industry Coalition

The EV Industry Coalition encourages the Commission to provide guidance on transportation electrification policy for rate cases for the next three-to-five-year rate periods.

Clean Transportation Coalition

The Clean Transportation Coalition contends that a statewide program should be a foundation for all utilities to follow, with the option to extend further assistance according to the terms agreed upon in their own negotiated settlements in rate cases.

Multiple Intervenors

Multiple Intervenors allege that the proposed cost allocation is inequitable and should be modified. Multiple Intervenors claim that if the purpose of the program is to

develop publicly-accessible EV charging stations for mass-market customers, incentives for nonpublic chargers (e.g., employee charging stations) force large, nonresidential customers to subsidize benefits for which they should not be responsible.

Multiple Intervenors warn that most commenting parties accept the premise that electricity customers should fund not only the decarbonization of the generation sector, but also residential heating and transportation. They oppose the imposition of additional costs on customers to fund these initiatives and recommend that the Commission and Staff explore alternative funding sources (e.g., the transportation sector).

IX. Performance-Based Regulation

AEEI-ACE

AEEI-ACE is concerned with the proposal that utilities be expected to demonstrate enhanced resilience to receive performance incentives. AEEI-ACE is not confident that embedded cost-of-service incentives (i.e., bias toward capital) will work as effectively for EV charging infrastructure as compared to their use in energy efficiency and demand response programs, and recommends a cautious approach to performance incentive use. It suggests that it may be possible to promote both utility cost efficiency and individual charging station success through a single metric based on overall megawatt hour use for all stations supported through the program. Additionally, AEEI-ACE claims that by aligning utility earnings with the overall success of the charging station (as measured by customer usage), utilities will have an additional incentive to work closely and cooperatively with developers.

ATE

ATE suggests that station utilization is not an appropriate metric for performance incentives, as many consumers do not rely heavily on public station charging, and recommends instead using the number of electric vehicles in the market.

EDF

EDF contends that utilities should be encouraged with incentives to provide customer benefits through actions they

might not otherwise pursue. These could include greater reliance on energy storage and renewable generation, decreasing infrastructure investments, and other cost reductions.

Enel X

Enel X opposes a Make-Ready Program earnings adjustment mechanism (EAM), but suggests the Commission could forbid utility ownership of customer-side make-ready infrastructure to encourage rapid and efficient EV supply equipment deployment.

EVgo

EVgo supports performance incentives for utilities based on metrics like customer satisfaction, application processing, and program participation.

FreeWire

FreeWire advocates shared performance incentives for utilities and technology providers for cost reductions achieved through use of novel technology products, if the comparative capital costs of the traditional charging equipment are higher. It also recommends that utility make-ready and equipment incentive expenses (total deployment costs) should be divided by the number of chargers to derive a cost-per-charger metric.

Greenlots

Greenlots argues against applying performance incentives to utilities for program features they do not control. Rather, if implemented, incentives should align with broad portfolio goals, as well as encourage programs most beneficial for their respective utility service territories. Any incentives should encourage broader EV supply equipment program effects including equitable access, and environmental, ratepayer, and system benefits. Greenlots also endorses consideration of program costs within the broader context of utility portfolios, arguing that an emphasis on reducing individual station costs could come at the expense of optimal siting. Instead, utilities should be encouraged to maximize deployment within established budgets using strategies to reduce infrastructure development.

Joint Utilities

The Joint Utilities recommend developing performance incentives that align utility incentives with State policy in a way that fosters EV infrastructure deployment cost effectively and under budget. The Joint Utilities recommend that the Commission recognize differing conditions in utility service territories, and suggests six performance metric options that could be used to assess program implementation: number of Level 2 plugs, number of DC Fast Charger plugs, cost effectiveness of Level 2 plugs (either based on cost per installed power or cost per plug), cost-effectiveness of DC Fast Charger plugs (on a cost per installed power or cost per plug basis), total power enabled by Level 2 installations, and total power enabled by DC Fast Charger installations.

The Joint Utilities contend that these metrics would encourage cost-effective deployment while considering local market needs, demographics, vehicle mix, jurisdictional policies, and other factors that affect development. The Joint Utilities contend that past EAM development should inform the design of EV make-ready deployment incentives, incorporating program ramp-ups, actual installation costs, and market conditions like EV adoption rate and vehicle mix. The Joint Utilities cite support by several parties for their recommendation that performance incentives be used as an effective cost containment mechanism.

The City of New York

The City of New York warns the Commission to avoid incentives that encourage utilities to pursue EV infrastructure deployment at cost-efficient but otherwise suboptimal locations, noting that electric system capacity is not the only important criterion in siting infrastructure.

NYCP

NYCP agrees that utilities should be rewarded for implementing rate designs that encourage charging during off-peak times and provide sufficient customer education on time-of-use rates.

NRDC-SC

NRDC-SC proposes rewards for several utility actions, including station cost reductions, beneficial siting at locations avoided by the private market, off-peak charging motivated through price signals, EV rate design development for commercial and industrial customers, and low- and moderate-income and Environmental Justice community assistance. It argues that performance should be assessed according to the extent it supports the achievement of State policy goals.

Tesla

Tesla recommends utility performance incentives for program cost reductions, customer satisfaction, application processing times, participation, and performance relative to location budgets. Tesla also notes that utility involvement in siting can involve additional costs related to station redesign, permitting, and contract and easement renegotiation that can lead to project delay or abandonment.

X. Reporting

AEEI-ACE

AEEI-ACE concurs with the proposal to require the quarterly and annual submission of reports and program overviews, but argues that that these should be filed by individual utilities and not the Joint Utilities. AEEI-ACE suggests that the individual utilities should develop a generic shared format for these documents.

ATE

ATE cautions that quarterly reporting may impose undue administrative burdens, and recommends full annual reports complemented by abridged semiannual reports in the first years of the program. Key criteria could include project milestones, charging session totals, power per session, and participation.

ChargePoint

ChargePoint argues that data reporting should support meaningful program evaluation, and recommends that the Commission amend proposed requirements to align with the dataset

proposed by the EV Industry Coalition, which it contends would provide detailed analysis, minimize compliance burdens, and ensure personal security protections.

EDF

EDF recommends annual load research reports from each investor-owned utility, encompassing total load, program investment, load coverage by rate, charging data by station type, as well as relevant pilot program descriptions and results.

Enel X

Enel X warns that data reporting requirements could constitute a significant administrative burden if undertaken at the proposed quarterly frequency, adding that a profusion of reporting would exceed the level of information needed to inform program design changes. Instead, it proposes limited quarterly reports that convey utilization statistics, charging session totals, total power dispensed, average power and duration per session, charger inactivity (as a percentage), and operating costs.

EVgo

EVgo supports simplified reporting requirements.

EV Industry Coalition

The EV Industry Coalition alleges that proposed data collection requirements are administratively burdensome, costly, and may discourage program participation. It argues that a more abridged dataset could achieve the same results and that much of the recommended information is already available through meter data. It recommends a narrower data collection effort limited to charging session counts, unique vehicle connections, power dispensed, average power dispensed per session, and average duration per session.

FreeWire

FreeWire recommends billed usage detail and operational costs (including demand charges) by station type and model.

Greenlots

Greenlots supports quarterly reporting by individual utilities using a shared general format, while acknowledging that new project information may be limited at this frequency because of extensive implementation times. It advocates greater detail in annual reports, requesting narrative accounts regarding process and experience that could inform policy changes before the midpoint review. Greenlots speculates that assessments by market segment would be especially valuable, and suggests that utilities could also report on rate and bill impacts of managed charging.

Joint Utilities

The Joint Utilities recommend detailed annual reporting instead of the quarterly requirements proposed by Staff, insisting that more frequent filings will impose significant burdens on utilities and stakeholder, especially at the beginning of the program. However, they propose monthly short-form reports as submitted now for community distributed generation projects, as well as filed letters to mark program achievement or spending highlights. The Joint Utilities also recommend developing a program website, and ratepayer funded third-party support in collecting and processing data, and requests use of program data for planning, assuming adequate privacy is ensured.

City of New York

The City of New York requests that quarterly and annual reports include charging station and plug locations to assess program performance regarding the equitable geographic siting of these facilities. It also recommends that added charging capacity per station be reported.

NRDC-SC

NRDC-SC supports data collection as a precondition for participation in transportation electrification programs, and making nonpriority data publicly available. It recommends collecting information regarding installation costs by site type, usage rates by site type and by charger type, charging load profiles, site host EV pricing plans (updated quarterly),

and installations costs (assuming site availability). NRDC-SC requests that the Commission ensure that sufficient data are collected to address key concerns such as the development of appropriate incentives, adequate geographic coverage, variety of site types, utilization, and pricing.

Tesla

Tesla is satisfied that the proposed data categories are adequate for utility reporting purposes, and supports the proposal by the Joint Utilities to adopt an annual reporting schedule. It also argues that utilities should justify the need for charging session data for distribution planning purposes before gaining access to this information. Tesla recommends that the Commission limit the data sharing requirements to categories that inform grid planning and general usage trends.

XI. Program Review

ATE

ATE contends that creating an advisory council for program review will be duplicative and unnecessary in view of extensive reporting and performance assessment requirements proposed in the Whitepaper. It also notes that Staff and the Commission can request additional information if necessary, using powers of oversight and investigation.

ChargePoint

ChargePoint supports regular program review with stakeholder participation, as well as a midpoint review that should take place before October 2023. It also recommends establishing a Program Advisory Council comprising all relevant stakeholders, that would meet quarterly to evaluate the program and its metrics and inform the Commission biannually. ChargePoint proposes delaying implementation of budgetary and programmatic controls until an initial biannual review.

Enel X North America

Enel X North America declares that the program would benefit from additional procedural discussions on relevant program design elements not discussed in the Whitepaper,

particularly the processing and distribution of incentives, use of budget allocations through 2025, allocation of developer caps, and electric vehicle service provider qualifications as eligible program vendors. It also seeks confirmation from the Commission that the midpoint review of the per-plug DC Fast Charger incentive program will be conducted as a holistic assessment.

EVgo

EVgo supports the annual review process proposed by Tesla to begin in January 2022.

EV Industry Coalition

The EV Industry Coalition suggests scheduling a programmatic review after 18 months of implementation, which should be focused on evaluating aggregate costs and program design elements that may require adjustments based on participation and other metrics.

Greenlots

Greenlots recommends quarterly stakeholder sessions to solicit developer opinions and review program progress. According to Greenlots, utilities should be able to make program adjustments based on stakeholder reactions without formal refiling requirements to facilitate more responsive implementation. Utilities should also be engaged in program design and deployment in collaboration with third parties, particularly in assessments or project costs and viability.

Joint Utilities

The Joint Utilities argue that creating an advisory council for program review will be duplicative and unnecessary in view of extensive reporting and performance assessment requirements proposed in the Whitepaper, and notes that Staff and the Commission can request additional information if necessary using powers of oversight and investigation.

Tesla

Tesla supports holding an annual program review process beginning in January 2022, and suggests it may be

beneficial for the Commission and utilities to host review sessions for interested stakeholders that coincide with quarterly program reports.

XII. Capital Planning Process

AEEI-ACE

AEEI-ACE endorses active stakeholder engagement, and recommends that each utility host sessions in development of distributed system implementation plans (DSIPs) to gather information and responses on handling the effects of EV adoption on distribution system planning.

EDF

EDF suggests that fleet owners are better suited to informing projections of load growth resulting from medium- and heavy-duty EV use than developers, and recommends that utilities solicit their collaboration.

Enel X

Enel X concurs that utilities should forecast EV charging scenarios in the capital planning process, including identification of customers likely to develop high-capacity charging requirements and appropriate outreach through marketing, education, and outreach efforts. It recommends that utilities should cultivate strong business practices for project initiation, interconnection, and upgrades, but cautions that upgrades should only be implemented assuming high-confidence commitments for new charging installations.

EVgo

EVgo submits that the private market already has sophisticated mapping tools to inform station siting in locations that maximize utilization, and claims that it would take utilities years to develop similarly sufficient capabilities to compete with third-party providers. Instead, it argues that utilities should prioritize providing developers with tools to guide development (e.g., load capacity maps) to guide EV infrastructure deployment.

EV Industry Coalition

The EV Industry Coalition argues that utilities should not dictate charging locations to third-party developers, suggesting instead that siting should result from collaboration. It acknowledges, however, that utilities can provide valuable information to EV infrastructure developers to inform the siting process

FreeWire

FreeWire advises that developer input inform utility planning, along with data on EV sales and charging behavior. Developers should be regularly asked about current and future plans for transportation electrification.

Joint Utilities

The Joint Utilities agree that the impacts of EVs and EV charging should be built into their capital forecasting process, but do not believe the details defined in the Whitepaper are needed to assess the impacts on the electric system. The Joint Utilities have been including the impact of EV load into their load forecast in their DSIPs, and state that each utility's own electric load forecast needs to reflect its unique distribution system feature and utility programs. The scenarios identified in the Whitepaper are too prescriptive for process improvements associated with forecasting and the development of system impacts and capital plans. The Joint Utilities recommend that utilities collaborate with developers and note that an open discussion will result in a more complete understanding of possible EV deployment scenarios to be incorporated in distribution planning. For this purpose, it suggests that program participants submit estimates to the utilities of new load generated by each project.

Tesla

Tesla recommends that utilities survey EV charging developers on expansion plans and needs in order to inform long-range planning, and suggests that potential sites for medium- and heavy-duty fleet charging can be identified through existing diesel fleet locations and transportation hubs.

Vrinda

Vrinda advocates creating a planning advisory council that includes utility, Staff, developers, community representatives, and city planning and permitting office representatives. It states that this group should have oversight over the planning process.

XIII. Site Selection

ATE

ATE agrees that the proposed process to identify suitable locations for charging can serve as useful guidance, but urges the Commission to permit flexibility and not force adherence to a rigid matrix.

ChargePoint

ChargePoint acknowledges that utilities should play a significant role in infrastructure deployment, but it is concerned with the proposal that utilities identify and select locations and site host participants. ChargePoint argues that this process could exclude strategic charging locations, and burdens utilities with the daunting task of designing a statewide charging network without the valuable input of experienced private sector actors. Instead, ChargePoint recommends that the program allow a variety of participants, and avoid imposing eligibility criteria based on load capacity and site host business models.

Enel X

Enel X endorses free-market competition for the efficient location of EV charging installations, and adds that utilities should implement suitability criteria to promote specific circuits and customers for charger siting.

Joint Utilities

The Joint Utilities will consider load serving capacity and the strategic location when assessing a proposal. However, it argues that it should be up to charging station operators, site hosts, and developers to evaluate their own business opportunities and workable business cases. The Joint

Utilities propose to play an active role in linking EV charging developers with site hosts as part of the Make-Ready Program implementation.

NYCP

NYCP agrees that utilities should work with municipalities in siting charging stations, especially municipalities involved in the Climate Smart and Clean Energy Communities programs.

XIV. Load-Serving Capacity Maps

City of Albany

City of Albany requests assessments of power grid capacity in areas under consideration for DC Fast Charger installations, to avoid imposing constraints on existing infrastructure that would limit future development.

EDF

EDF recommends that capacity maps include EV load forecasts and planned capacity upgrades.

Enel X

Enel X contends that tools like load serving capacity maps can convey adequate information to developers without increasing the planning role of utilities, adding that the competitive market should guide development without distracting utilities from foundational activities with burdensome analytical requests.

FreeWire

FreeWire states that utility development of load serving capacity maps produced by the utilities by the end of 2020 is reasonable.

Joint Utilities

The Joint Utilities agree that load serving maps are useful for developers, and states their intention to develop and submit these on each utility system data portal. The Joint Utilities recommend that use cases and project implementation

plans should be developed in the EVSE Readiness Technical or Information Sharing Working Groups.

NYC

NYC recommends that load-serving capacity maps should be made available to developers as soon as possible.

NYPA

NYPA agrees with the development and publication of load serving capacity maps. NYPA proposes that the utilities should be required, at minimum, to provide the voltage of each circuit, peak theoretical summer amperage, actual summer amperage over the past five years, and the net kilovolt amps or kW that can be connected to that circuit data.

XV. Strategic Locations

ChargePoint

ChargePoint advises the Joint Utilities to set a minimum power threshold for Regional Economic Development Council (Regional EDC) deployment, warning that an arbitrarily high level will increase capital and operating costs and provide a materially different charging experience.

DEC

DEC supports the recommendation to locate 28,150 kW DC Fast Chargers within upstate economic development regions.

Enel X

Enel X recommends that utilities that serve upstate Regional EDCs should administer the competitive process according to consistent guidelines established by Staff. Enel X agrees that the Commission has a high-level policy role in guiding development in disadvantaged communities and REDCs on the condition that such projects are eligible for greater incentives. Absent that, Enel X supports free-market competition for the efficient location of EV charging installations, and adds that utilities should implement suitability criteria to promote specific circuits and customers for charger siting. Enel X advises that the local electricity

utility should develop broad geographic guidelines for the Regional EDC to ensure appropriate site dispersal and then allow free-market competition to select host sites and projects in each zone.

EVgo

EVgo recommends further assessment of the necessity of solicitations for each Regional EDC.

FreeWire

FreeWire argues that any competitive process be streamlined through the Regional EDC application gateway, and recommends a rolling process for qualifying eligible equipment. It suggests that in place of a competitive solicitation, funding could be administered through vouchers or rebates, with equipment qualified through a registration process with a funding cap. FreeWire predicts this would foster faster deployment and reduce sales impediments.

Greenlots

Greenlots agrees with the Whitepaper assessment that developing EV charging infrastructure in a comprehensive manner is critical, even in areas with limited EV adoption. To address the challenges of EV charging deployment in rural areas, Greenlots posits that flexibility in program design provides a better balance between cost containment concerns and equitable and sufficient infrastructure deployment. Greenlots is concerned that a procurement process with overly prescriptive site locations and private market ownership requirements will delay much-needed infrastructure deployment, citing impediments caused by similar conditions in New Hampshire and Vermont.

Greenlots encourages the Commission to allow utilities to explore alternative program structures in Regional EDCs such as direct utility ownership, which may simplify and expedite the process, particularly when a single utility can plan deployment across several Regional EDCs. A direct ownership model would also address cost concerns, allowing utilities to make bulk purchases and capitalize on replicable site designs at many locations.

Joint Utilities

The Joint Utilities state that each utility that provides service in an Regional EDC will work together to structure similar procurements in the program's first year. It recommends several clarifications and modifications to enhance the Regional EDC proposal. First, they recommend that the utilities solicit bids on a dollar per-plug basis for at least 16 plugs for each Regional EDC. The utilities will divide the plug total by Regional EDC according to customer counts in each Regional EDC with appropriate rounding. The Joint Utilities also propose bid restrictions to allow a minimum of two and maximum of six chargers per site. This competitive procurement should be funded in addition to the overall program budget. The utilities will collaborate to determine the lowest cost mix for at least 16 DC Fast Charger plugs per Regional EDC and the minimum power charging rate should be consistent with the recent Commission decisions in this proceeding on the DC Fast Charger incentive program.

The Joint Utilities stress that collaboration with NYSERDA and NYPA is required in handling DC Fast Charger sites in Regional EDCs. It predicts that a competitive procurement for DC Fast Chargers in seven upstate Regional EDCs could have merit, but suggests NYSERDA assume the lead role to avoid conflicts with current NYSERDA procurement efforts. To this end, the Joint Utilities endorse the allocation and use by NYSERDA of $5 million of previously collected, unallocated ratepayer funds.

NYC

NYC suggests that the Regional EDC approach is too broad to appropriately incentivize EV supply equipment deployment where it is most needed. It notes per-capita disparities between charger access and EV registrations by Regional EDC, and recommends that a more geographically refined county-based assessment of allocations based on vehicle registrations and density would be more appropriate. NYC also acknowledges that ensuring equitable geographic distribution of chargers in its jurisdiction is difficult, noting the disproportionate deployment of EV supply equipment deployed in

Manhattan. NYC contends that its proposed county allocation approach would address needs in communities across the state.

NRDC-SC

NRDC-SC recommends locating upstate DC Fast Charger installations according to expected trip types for an area. In rural areas, local drivers are likely to rely on home charging and therefore fast chargers should be located along major highway corridors. In areas without sufficient home charging access, chargers should be sited to support intra-urban travel. NRDC-SC recommends use of the MJ Bradley EV Infrastructure Location Identification tool to identify locations for DC Fast Charger station sites according to trip distribution, trip generation, and other transportation planning characteristics.

NYPA

NYPA argues that developers should be responsible for siting EV infrastructure development at strategic locations, and notes that these efforts should be closely coordinated with existing or planned stations to avoid undue clustering. Furthermore, NYPA requests that the Commission align EV infrastructure development in strategic locations with plans to install ten or more fast-charging sites in each Regional EDC by the end of 2022.

PIA

PIA notes that network value is determined by the comprehensive coverage it provides. It notes that drivers may not frequently travel to rural areas but will consider that capability when purchasing an automobile, and base decisions to buy an EV on the expectation of adequate charger network coverage statewide. Accordingly, PIA encourages grants to support installations in more remote locations, noting that their actual utilization fails to represent the entirety of their value.

Tesla

Tesla suggests that the Regional EDC competitive solicitation could be designed to request proposals for specific

and discrete areas in each region (e.g., within two miles of the New York State Thruway between mile markers 350 and 410).

XVI. Resiliency and Storm Hardening

AEEI-ACE

AEEI-ACE warns against expecting charging infrastructure to perform functions for which they are not designed. It predicts that unwarranted resilience requirements for these installations will only exacerbate economic challenges facing the industry and potentially stall market acceleration. However, AEEI-ACE recommends that pending further market maturation, overall network resilience should be assessed for emergency preparedness and evacuation feasibility.

ATE

ATE concurs that an emphasis on resilience will contribute to regulatory barriers already confronting EV supply equipment deployment, noting that various electrical and building codes already exist to ensure resilience.

Bloom Energy

Bloom Energy recommends that resilience be considered during the earliest stages of EVSE construction to avoid social and economic risks. Noting that over 90 percent of electricity service loss is caused by distribution failure, it recommends developing a charging network that avoids complete reliance on the distribution grid, perhaps employing onsite microgrids of distributed non-combustion direct current generation that might be particularly useful at bus and other fleet depots. Besides mitigating distribution-related outage risks, microgrids could help avoid peak system demand charges, avoid power inversion and line losses, and obviate or defer capital investment in transmission and distribution networks. Bloom Energy adds that new EV infrastructure be backed by independent systems for resilience.

EDF

EDF notes that EVs with vehicle-to-grid capability can function as grid assets by providing emergency power during

outages, citing recent implementation at Los Angeles Air Force Base. It recommends a local approach to EV supply equipment resilience, remarking that communities will best understand pertinent risks and needs.

FreeWire

FreeWire contends that battery-integrated charging systems provide inherent resilience during power outages. It approves of resilience considerations for EV infrastructure development and endorses recommendation in the DEC Draft New York State Flood Risk Management Guidance for Implementation of Community Risk and Resiliency Act.

Greenlots

Greenlots predicts that managed charging integrated with DER can forestall development of additional capacity, and recommends that utilities develop pilot resilience projects that investigate this combination. It suggests that a comprehensive strategy that complements charging infrastructure with distributed generation and storage can ensure available charging during emergencies and foster EV adoption. However, Greenlots warns against overly-prescriptive site selection and construction requirements, and recommends coordination with local jurisdictions to optimize permitting processes for expedited development.

Joint Utilities

The Joint Utilities recommend that EV developers comply with applicable electric codes and other resilience requirements, and suggest that flood vulnerability and other climate-related risks be considered as a program application criterion.

NYC

NYC notes the importance of flood risk in siting charging infrastructure, and advocates identification of existing and future risks to infrastructure in vulnerable areas. Developers should determine flood risk according to Federal Emergency Management Agency flood insurance products and 2050 floodplain projections where available and take appropriate

floodproofing measures. NYC recommends that siting costs related to flood risk assessment should be covered by the Make-Ready Program, and developers should cover costs of flood protection for customer-side infrastructure not otherwise covered by the Program.

Tesla

Tesla maintains that resilience should not be a consideration in program eligibility, noting that such review is already included in local planning, building, and electrical code evaluation and permitting.

XVII. Outreach and Education

AEEI-ACE

AEEI-ACE argues that it is in the interest of all ratepayers for utilities to take advantage of existing relationships to educate customers on EV and EV infrastructure options. AEEI-ACE recommends that utilities improve access to this information, and submits that utility EV programs include customer education and outreach efforts funded through rates.

ATE

ATE stresses that education and outreach are essential for widespread transportation electrification, and utilities have a vital role to play in these efforts, especially considering their existing relationships with customers and ongoing role providing information on other advanced energy programs. ATE advises that the Commission allow the utilities to propose reasonable budgets for these efforts to be funded through rates.

GECA

GECA agrees that EV-related outreach and education should be ratepayer-funded initiatives. It cites a substantial degree of consumer misinformation and confusion regarding EV market issues, and alleges that the automobile industry and dealers are doing an unsatisfactory job educating customers. To address these deficiencies, GECA requests a well-funded EV education program supported with public money and administered

by a State agency. It strongly supports state-level consumer rebates for EVs but argues that allocating additional funds for consumer education will generate a strong return on investment, and adds that it is relatively easy and cost-effective for utilities to combine existing EV outreach and education with additional information on charging infrastructure and off-peak charging incentives.

Greenlots

Greenlots encourages the Commission to bolster expectations for outreach and education to ensure that utilities use existing relationships with ratepayers to engage not only with current EV owners, but all New York ratepayers to further drive adoption. Greenlots alleges that insufficient customer awareness is the most significant barrier to EV adoption. It claims that relying on stakeholder funds alone for outreach will considerably inhibit the scale at which these activities will be conducted most effectively. It urges meaningful and comprehensive customer outreach to complement a highly visible and widely available EV infrastructure program as a means to foster adoption.

Joint Utilities

The Joint Utilities contend that the Whitepaper proposal is inconsistent with the cost recovery treatment of outreach and education expenses, and is similarly at odds with the economic signals generated by the outcome-based beneficial EAM mechanisms approved and in place for Con Edison, National Grid, and Orange and Rockland Utilities.

NYCP

NYCP urges the Commission to prioritize equity and education in the development of the Make-Ready Program, and offers to work with Staff on a public engagement plan to work with a variety of stakeholders to EV adoption and infrastructure. Furthermore, NYCP supports targeted education and outreach to non-EV-owners to encourage future EV adoption. It calls for substantial investment in public education programs about EVs, and suggests that utilities work with community organizations to educate customers. NYCP encourages the

Commission to direct utilities to educate their customers about beneficial rate designs, charging station locations, opportunities to buy home charging equipment, and consider offering rebates for these to encourage adoption.

PIA

PIA agrees that outreach and education to stimulate EV sales should be ratepayer-funded initiatives. It notes that utilities have an extensive record of encouraging technology adoption, and are similarly well-suited to conducting customer education on rate design. PIA is hopeful that there may be outreach and education opportunities that are ratepayer-funded and carried out by third parties.

Vrinda

Vrinda argues that utilities can be the key matchmakers between EV station developers and station hosts, and therefore should be leading in this effort utilizing ratepayer funding to do so.

ZappyRide

ZappyRide advocates a sustained, utility-centered approach to EV outreach and education to meet policy goals, and adds that ratepayer funding is the most effective approach to ensure the success of these efforts Statewide.

XVIII. Interconnection

AEEI-ACE

AEEI-ACE recommends clarity and transparency, dedicated utility staff, and an expedited review process as interconnection improvements.

Electrify America

Electrify America requests that the Commission define and enforce rules on expedited interconnection for EV charging infrastructure and associated energy storage, citing interconnection costs and delays as significant barriers to charging station deployment.

EV Connect

EV Connect supports the standardization of the EV infrastructure interconnection process to facilitate deployment speed and efficiency. It proposes that EV infrastructure be deployed, operated and managed in a uniform manner, particularly as it relates to high-speed EV charging.

FreeWire

FreeWire recommends that the Commission consider greater flexibility on the proportion of various connectors at each charging location.

Konrad

Konrad advises allowing electric utilities to rate-base interconnection investments to align utility incentives with increased ESVE&I deployment. Konrad requests clarity regarding rate-basing of these investments to minimize utility uncertainty about the program, which could prevent utilities from prioritizing interconnections.

NYPA

NYPA suggests that the Commission should require utilities to establish a single point of contact for EV developers, and conduct desktop evaluations for EV infrastructure interconnection requests.

XIX. Application Portal

ATE

ATE questions the cost-effectiveness of an interconnection online application portal, adding that it does not consider differences in service applications between utilities, and does not consider load-serving capacity maps essential for EV charging. It contends that developers should be able to identify basic infrastructural requirements, and proposes that the State’s distribution system is capable of supporting EV supply equipment without costly upgrades.

EDF

EDF argues for the expeditious availability of an interconnection online application portal, noting that its absence will impede the ability of stakeholders to evaluate proposals.

Enel X

Enel X defers to the Joint Utilities for estimating time necessary to develop interconnection resources, but assumes that the interconnection online application portal will be simpler to implement than hosting capacity maps.

EV Industry Coalition

The EV Industry Coalition recommends an online application for developers and site hosts, and supports streamlined timelines, ideally standardized across service territories, and notes that a 90-business day assessment has been feasible in several jurisdictions. It suggests that utilities provide constructive comments to developers, even for nonviable sites. The EV Industry Coalition also proposes that information on rejected applications be assessed at the midpoint review to address concerns about potentially overburdensome criteria. Additionally, utilities can facilitate network planning of electric vehicle service providers by providing transparent interconnection cost estimates, including the costs incurred by internal resources and costs covered by distribution allowances.

FreeWire

FreeWire states that utility development of an interconnection online application portal by the end of 2020 is reasonable.

Greenlots

Greenlots contends that an efficient interconnection process can promote cost reductions, and urges the Commission to consider other methods for expediting review. It recommends that utilities prioritize frequent communication with stakeholders on developing interfaces and portals, including but not limited to quarterly meetings.

Joint Utilities

The Joint Utilities note that existing procedures should be capable of addressing new load associated with charging infrastructure development, and suggests a portal is unnecessary as each utility still bears responsibility for developing hosting capacity and sharing relevant load-serving data. It recommends that following a Commission Order on EV infrastructure development, utilities either develop EV hosting capacity maps or add substation-level load hosting capacity to existing maps made available on utility system data portals. The Joint Utilities also suggests that the EV Readiness Stakeholder or Information-Sharing Working Group collaboratively develop schedules for further refinement of relevant information.

NYC

NYC recommends that an interconnection online application portal be made available to developers as soon as possible.

NYPA

NYPA endorses a standardized review process with an interconnection online application portal to streamline the interconnection process and capture efficiencies for EV infrastructure interconnections. Further, utilities should be directed to implement an interconnection online application portal for EV infrastructure interconnection applications as soon as possible.

Vrinda

Vrinda submits that utilities should create or enhance an interconnection portal to view the interconnection queue of EV supply equipment projects, provide hosting capacity maps and suggested locations of EV supply equipment infrastructure, publish the status of the application for interconnection in more granular steps to allow transparency, and to establish a dispute resolution mechanism to address developer and utility concerns about a specific site development.

XX. Managed Charging and Vehicle-to-Grid

AEEI-ACE

AEEI-ACE recognizes that flexible EV charging can provide valuable load relief when deployed correctly through managed charging, or conversely, be used to increase consumption on demand when excessive generation results in low wholesale prices (thereby also preventing renewable generation curtailments). With a significant extensive charger network and widespread EV adoption, EVs could be deployed as non-wires alternative assets and be incorporated in distribution planning.

Bloom Energy

Bloom Energy suggests that direct current distributed resources like fuel cells, energy storage systems, and solar generation that are deployed in microgrid formats can support extremely fast charging systems.

FreeWire

FreeWire asserts that EV charging can be coupled with energy storage to yield grid benefits, and argues that this combination is the best way to minimize grid impacts of EV adoption. Also, FreeWire states that the charger-to-grid paradigm may be more beneficial to overcome the inherent issues and conflicts that arise with vehicle-to-grid issues. Furthermore, if the Commission initiates EV rate reform efforts, FreeWire requests that the Commission investigate equitable inclusion of technology solutions like its proprietary Boost Charger system, which limits demand effects on ratepayers by throttling grid draw to 27 kW or less.

GMP

GMP recommends the provision of equivalent rebates for battery storage used to reduce or eliminate local infrastructure costs.

Greenlots

Greenlots propose that the utilities develop load management programs for ratepayer-funded charging infrastructure. It warns that unmanaged load contributions from

EV charging could amplify system peaks and generate local constraints according to the density of EV adoption. Greenlots argues that any authorized EV supply equipment program should ensure grid benefits through managed charging, citing a recent benefit-cost analysis by NYSERDA that predicted a near doubling of societal benefits in such a scenario.

Greenlots argues that smart, networked chargers capable of supporting load management, time-varying rates, and technology-enabled managed charging should be required for all ratepayer-funded make-ready infrastructure. It also advises that networks eligible for maximum incentives should be built according to independent open standards such as OCPP that can accommodate and integrate developing technologies that optimize infrastructural investment and minimize the risk of stranded assets. Greenlots endorses EV-charger communications through ISO 15118, the most widely adopted international standard.

Greenlots suggests that load management is the most important factor in developing at-scale charging programs for ratepayer benefit. It cites a study by M.J. Bradley & Associates that determined that the absence of managed charging would likely lead to significantly higher peak demands resulting in higher costs for ratepayers. Greenlots requests that the Commission reassess utility roles in deploying EV infrastructure considering drastic changes in market conditions to support a more viable and flexible functions.

Joint Utilities

The Joint Utilities stress the importance of developing cost-reflective rate design for EVs and EV supply equipment that encourages optimal charging to improve system efficiency. In the future, EVs and EV supply equipment may provide significant load control or grid injection capabilities, the current state of the market and vehicle-to-grid technology precludes scaling of these use cases. However, the Joint Utilities note current investigations of such potential benefits, including the Con Edison vehicle-to-grid bus pilot and the National Grid bus partnership in Massachusetts. The Joint Utilities propose that cost-based EV rates will encourage future software system deployment, technology improvements, and managed charging, adding that advanced metering or other time-sensitive

metering will be critical in enabling smart charging, especially with third-party collaboration. The Joint Utilities also recommend that utilities should design managed programs for Level 2 chargers.

The Joint Utilities acknowledge that managed charging is an important consideration for fleets or concentrated workplace charging. The Joint Utilities submit that properly designed cost-reflective rates such as Standby Rates offer the appropriate incentives for managed charging by customers.

NRDC-SC

NRDC-SC notes that EVs generate greater utility revenue than incurred costs (even on off-peak charging) and managed charge, which can be facilitated through rate design or direct management, and can be operated to coincide beneficially with intermittent renewable generation. It recommends requiring utilities to consider load management and sustainable rate design practices now rather than at waiting for a midpoint review. NRDC-SC suggests that utilities should require inexpensive smart charging stations or more costly second meters at each station. NRDC-SC adds that not all use cases require a smart charging station.

NYPA

NYPA submits that pairing energy storage with EV infrastructure for fleet charging is not feasible for most transit agencies in the State given the economic and technical challenges of fleet electrification.

XXI. Metering & Technology Standards

AEEI-ACE

AEEI-ACE advises that the Commission establish a stakeholder working group that can evaluate industry standards for possible Commission adoption. AEEI-ACE does not recommend that such a working group develop new standards, citing the existence of sufficient standards and experienced industry standards organization. AEEI-ACE supports smart charging efforts to address demand increases and agrees with Staff in opposing separate submeter requirement, noting the adequacy of

built-in vehicle or charging station for this function. It adds that interoperability standards support fair and equitable access.

ATE

ATE strongly supports open protocols to reduce costs, increase options, mitigate stranded asset risks, increase security, and improve customer experience. ATE maintains that any EV infrastructure connected to utility-supported make-ready infrastructure must be interoperable and compliant with OCPP 1.6, and recommends requirements for open design and architecture for vendors bidding on make-ready interconnection hardware. ATE also recommends that the proposed technical standards stakeholder group include experts from all sectors and be given a defined mission and schedule. ATE endorses adding OCPP to the list of relevant standards, and notes that it is relatively inexpensive and easy to obtain Open Charge Alliance certification. Finally, ATE cautions that a firm with dominant market share today can restrict new competitors by locking its existing non-OCPP hardware, much of which was paid for with federal, state, local, or utility funds, to its own network.

ChargePoint

ChargePoint supports Staff's proposal of a working group to develop standards and protocols for adopting baseline standards for infrastructure programs. ChargePoint agrees with AEEI-ACE and Enel X that the proposed working group is the appropriate venue for evaluating industry standards before adopting baselines for infrastructure programs and adds that it is a strong supporter of open protocols. ChargePoint warns that the recommendation by NRDC-SC proposing active use of open access standards by all EV supply equipment would create implementation problems.

EDF

EDF contends that New York can benefit from existing best practices, including OCPP requirements for Open Automated Demand Response (Open ADR) and credit card readers at publicly-accessible stations. EDF suggests establishing a standing

stakeholder working group comprising participants familiar with emerging practices in other jurisdictions.

Enel X

Enel X agrees that interoperability is a key concern for deployment of ratepayer-funded EV charging infrastructure, and supports open, standards-based communication protocols.

EVBox

EVBox strongly supports an industry-wide adoption of open standards and communication protocols, and supports timing regulation to correspond with market adoption.

FreeWire

FreeWire recommends further consideration of the requirement for OpenADR integration once a path to certification emerges. It also supports (International Electric Code (IEC) Standard 15118 for vehicle-to-charger communications.

Greenlots

Greenlots encourages the Commission to require Open Charge Point Protocol (OCPP) certification for any project receiving full incentives. Greenlots strongly supports requiring third-party OCPP certification as a standardized and verifiable mechanism for ensuring the development of a flexible charging statewide system that can be upgraded to accommodate new market participants, and evolving user needs, and technologies. This mechanism should encourage competition and permit compliant charging stations to connect to open networks. Greenlots notes that OCPP has also evolved to support new technologies and use cases and expects this to continue. Greenlots recommends that the Commission include requirements for the use of open standards in any order relating to EV supply equipment development.

Joint Utilities

The Joint Utilities acknowledge that protocols such as OpenADR provide opportunities to standardize and streamline operations involving different stakeholders and technology providers, but warn of risks of using specific technologies at

this early stage. They recommend that the EV Technology Standards working group address this issue.

NYC

NYC recommends that the Make-Ready Program be adaptable to accommodate new standards from industry interest and argues that any interim program evaluation should review recent EV technology standards and make any necessary efforts to adopt these. The Make-Ready Program should also be able to accommodate nonstandard EV supply equipment to pilot new EV technologies.

NRDC-SC

NRDC-SC recommends that open-access communication standards be used for qualifying EV supply equipment and that these standards should be installed and used on all EV supply equipment at deployment.

Tesla

Tesla advises that the Make-Ready Program should focus on establishing electricity service in a nondiscriminatory fashion instead of imposing interoperability requirements now. It argues that following customer preferences and new technologies during program evaluations are enough to maintain currency.

XXII. Utility Ownership

AEEI-ACE

AEEI-ACE concurs on allowing utility possession of utility-side infrastructure, but also recognizes potential scenarios in which customer-side utility ownership would provide value, particularly before market failures are resolved. It urges the Commission to remain accommodating on this issue and continue to evaluate market failures that may justify utility ownership.

ATE

ATE supports the case for utility ownership of customer-side infrastructure and recommends that utilities be

allowed to propose ownership for certain use cases. ATE acknowledges that utility ownership could help avoid vendor lock-in and achieve full-scale deployment more quickly. It also claims that since the program is relying on ratepayer funds, utilities should retain some control in ensuring continuous and reliable utilization. ATE maintains that market conditions and the regulatory environment have changed significantly since the Commission last ruled on utility ownership, adding that its decision was rooted in concerns over stifling market participation but in seven years, this caution has only produced an underdeveloped EV infrastructure market. ATE also notes that the precedent for prohibition of utility ownership in California cited by the Commission in 2013 has since reversed, resulting in improved market development.

Auto Innovators

Auto Innovators cautions that it is too early in market development to determine an exact role for utilities. It acknowledges that there may be conditions in which a utility ownership model can overcome market barriers efficiently and requests an adaptable approach in assessing possible utility roles.

ChargePoint

ChargePoint states that utility ownership of EV infrastructure would require the establishment of consistent review standards that consider market competition, and notes that this process would require additional stakeholder participation.

EV Industry Coalition

The EV Industry Coalition suggests that distribution system impediments to infrastructure development can be overcome more rapidly with utility investment and ownership.

Electrify America

Electrify America supports the proposed approach of customer-side infrastructure, warning that allowing utility ownership could create challenges to site hosts and lease terms.

Enel X

Enel X does not oppose utility ownership in principle, but it argues that utility ownership is inconsistent with the exclusion of municipal and cooperative utilities and non-jurisdictional public agencies like the NYPA from using ratepayer funds intended to foster free market development.

EVBox

EVBox argues that utility ownership may be beneficial in neglected rural areas, and stresses that public utilities and private sector operators need to coexist in a maturing market.

Greenlots

Greenlots criticizes the alleged implications of utility ownership in the proposal for several reasons. It argues that the proposed approach undervalues benefits and mischaracterizes costs based on a limited view of infrastructure deployment models. Greenlots argues that utility ownership can provide broad benefits, especially in prioritizing faster, more efficient deployment and private sector support during deteriorating economic conditions. It requests that the Commission refrain from prematurely invalidating potentially beneficial ownership models and program designs that may bolster market development and states that the Commission should outline processes by which utilities can propose additional programs to overcome particular market challenges.

Greenlots adds that utility ownership has been proven effective in facilitating charger deployment in more difficult segments and advises the Commission not to overlook this valid approach at this early stage. As an example, Greenlots cites a pilot by San Diego Gas and Electric named Power Your Drive, which was designed around turnkey utility provision and ownership of infrastructure, which exceeded its goal to locate stations in disadvantaged communities with over 30 percent of pilot sites located in these areas and nearly 40 percent at multi-unit dwellings.

Joint Utilities

The Joint Utilities generally agree with the Whitepaper recommendation that utilities should be primarily

occupied with the provision of make-ready infrastructure in support of third-party developers. However, they request that the Commission not prohibit utility ownership outright, particularly given current public health and economic concerns related to the COVID-19 pandemic. They note that utility ownership may be especially helpful in addressing market failures related to EV infrastructure deployment serving low- and moderate-income customers. The Joint Utilities recommend that utility ownership models should allow utilities to recover costs over an appropriate depreciation schedule.

NYCP

NYCP acknowledges that there may be some benefits to utility ownership, but suggests deferring a decision on this issue. It maintains that EV infrastructure is a public good and government entities should not arbitrarily be disqualified from developing it.

XXIII. NYPA and Other Participants

ATE

ATE argues that NYPA should be eligible for make-ready incentives, noting that it uses in-state vendors and labor and provides important economic and job training development. ATE claims that once stations are operation, NYPA will likely establish charging prices that reflect current market conditions and ensure price competitiveness with other charging service providers, and with conventional fossil-based transportation fuels.

CCCNY

CCCNY contends that NYPA participation would benefit ratepayers and support program implementation. It notes that many areas of the state are underserved by publicly-accessible chargers and notes that NYPA is a trusted and qualified entity to foster EV adoption in developing charging sites with transparent pricing practices.

ChargePoint

ChargePoint requests clarification of the definition of "competitive third-party developers" of EV infrastructure, noting that it includes neither investor-owned nor public utilities that are capable of exercising market power. ChargePoint proposes that the proposed eligibility requirements be revised to allow participation by NYPA as a developer, conditioned on an adherence to technology-neutral specifications and the REV Framework Order and Operational Guidance.

City of Albany

The City of Albany agrees that NYPA makes a compelling argument for its program eligibility, and states that incentives should be available to public agencies as well as established market actors. The City of Albany argues that such eligibility would foster the development of EV infrastructure on publicly-owned properties.

DEC

DEC requests that eligibility of the Commission-approved programs be extended to DEC's existing and proposed EV infrastructure programs. It notes that DEC, DPS, and the Joint Utilities should coordinate efforts to advance publicly-accessible charging while avoiding duplicative actions.

DOS

DOS notes that it is examining the feasibility of NYPA investment in DC Fast Charger stations in Downtown Revitalization Initiative (DRI) communities to assist potential EV customers concerned about charging access. DOS suggests that NYPA participation will facilitate equitable infrastructure development in these areas, especially where current economic conditions might otherwise preclude investment. DOS strongly supports NYPA access to make-ready program funds to support state transportation decarbonization efforts.

DOT

DOT supports the request to allow NYPA market participation, noting that the authority currently operates several programs that support DC Fast Charger development and

has stated it will refrain from building in areas with ongoing or committed private sector activities. DOT also points out that NYPA is committed to returning its network to private-sector control when economic conditions allow.

Electrify America

Electrify America supports program eligibility for participation by public entities.

Enel X

Enel X reiterates its position that access to ratepayer funds by municipal and cooperative utilities and non-jurisdictional public authorities is inconsistent with goals to foster free market development. Enel X requests that the Commission deny similar program eligibility requests by the NYPA and the NYAPP and affirm the role of ratepayer funding in stimulating private sector market development. Alternatively, Enel X suggests that these parties develop proposals that complement the Whitepaper proposal.

EV Connect

EV Connect strongly supports participation by NYPA and other public entities, maintaining that their eligibility will ensure deployment in underserved areas in an appropriate and nondiscriminatory fashion.

EVgo

EVgo argues that public power authorities should not be permitted to compete with the private sector and participate in the program. It alleges that allowing NYPA access to ratepayer funds to complete with the private sector violates the REV Framework Order, and would undermine fair and healthy market competition. EVgo acknowledges that NYPA may fulfill a role in developing infrastructure in rural, less-populated areas but any market participation should be conditioned on public hearings on the progress of the Evolve NY program and its market effects.

Greenlots

Greenlots contends that a variety of market actors and business model is necessary to achieve state goals and requests

that the Commission encourage participation by NYPA and other non-private sector actors.

Joint Utilities

The Joint Utilities consider NYPA an important EV infrastructure developer and recommends incentive eligibility, noting that any customers that receive incentives (including NYPA acting as a station owner and operator) should be allocated program costs through delivery rates.

Konrad

Konrad argues that market participation by NYPA and other government entities will benefit ratepayers and should be eligible for incentives.

Mirabito

Mirabito claims that NYPA plays an essential role working with critical private sector entities to advance electric transportation for the public and it applauds current work by NYPA in siting chargers as efficient and equitable.

NYAPP

NYAPP supports expanded eligibility for the program for not only NYAPP municipally and cooperatively-owned utility members, but also NYPA directly. NYAPP suggests that Staff and the Commission should coordinate with NYAPP members, NYPA, NYSERDA, DOT, and DEC to ensure holistic approaches to the charging infrastructure.

NYC

NYC requests that the Commission clarify that non-private sector entities, including municipal governments, are eligible to participate in the Make-Ready Program.

NYPA

NYPA argues that the exclusion of itself and other public entities is counterproductive to state sustainable transportation policies. NYPA notes that it uses competitive procurements to enlist private companies to build and maintain EV infrastructure, which is consistent with the stated program

objective of developing private market expertise. NYPA states that it participates in the market as an EV infrastructure developer for the public good and is willing to accept a long-term investment horizon across a statewide portfolio of sites, helping to build out a balanced portfolio of charging sites.

NYPA also maintains that predicating eligibility for the Make-Ready Program on a connection to surcharge contributions is not necessary where ratepayer collections are used to develop large-scale infrastructure projects for general public use and argues that this contravenes policy goals encouraging developers to enter the marketplace. It contends that there is no basis to distinguish NYPA from other EV infrastructure developers by requiring its customers to pay a surcharge to establish NYPA access to program funds and adds that it would not be participating as a load-serving entity on behalf of its customers. Furthermore, NYPA asserts that some of its customers are taxpayer-supported governmental entities that should not be subject to paying for this program twice.

NYPA submits that if the Commission approves NYPA participation as a developer on the condition that a related contribution to the surcharge that recovers program costs, the payments made by NYPA as a station owner should be considered sufficient. NYPA reiterates that its proposed program eligibility as a developer is separate and distinct from its commodity customers and its role as a load-serving entity.

NYPA addresses initial comments by ChargePoint that imply that NYPA will acquire or exercise market power as a station owner or selector of vendors. It states a commitment to own and operate stations it develops for a limited time only, before selling this infrastructure to private market actors when they become more attractive to private investment. NYPA contends that it is assuming a more significant market risk during this initial period of low utilization rates as EV adoption develops.

NYPA also counters that its efforts as an infrastructure owner are to stimulate competitive market development and states its commitment to fair and equitable cooperation with the EV industry in New York, citing its current portfolio of awarded contracts to many private sector vendors.

NYPA reiterates that its intention is not to acquire excessive market power.

NYPA accuses ChargePoint of unfairly equating its market role with similar participation by public utilities. NYPA objects to this characterization and notes that without a defined service territory or ownership of a distribution network, it possesses no alleged advantages in EV infrastructure market participation. It further notes that its investment outlays cannot be recovered through cost-based rates as its role as an infrastructure developer and a load-serving entity for commodity customers remain separate and distinct. NYPA argues that its stations will rely on market revenues and it anticipates recovering capital costs upon anticipated transfers to private sector ownership, and further notes that its revenue is supplied by generation and transmission operations, rather than taxpayer revenues.

Finally, NYPA asserts that it operates two infrastructure development models that are distinct from utility ownership cases. In one, NYPA invests capital to own charging equipment located on a public or private site host and establishes a commercial relationship to invest, build, own, and operate the facility. NYPA explains that its investments are subject to the same market risks that confront private sector developers and NYPA relies on site performance to cover operating costs, as do private sector developers. Under its second model, NYPA provides independent advisory services to customers that own and operate charging infrastructure, supplying guidance, procurement and construction support to the customer following a transparent and competitive procurement open to all prequalified vendors. NYPA claims that in assuming the same risks as other developers, it should be eligible for program participation and affirms its commitment to be subject to the same rules and requirements as other participants.

NYTA

NYTA urges the Commission to support the request by NYPA to participate in the program, arguing that this will encourage a faster and broader deployment of charging infrastructure statewide.

PIA

PIA supports program participation by NYPA and other public entities. It argues that as supplier of public power, NYPA should play a key role in developing EV infrastructure. Furthermore, PIA notes that municipalities are frequent leaders in installing EV charging infrastructure in their jurisdictions.

Tesla

Tesla advises that the assessments of current and future development by other charging developers such as NYPA are required.

XXIV. Underserved Communities

AEEI-ACE

AEEI-ACE supports increasing EV use by low- and moderate-income costumers and encourages the Commission to allow utilities to develop separate program proposals to address the medium- and heavy-duty vehicle sectors expeditiously.

ATE

ATE cautions that there will not be a “one-size-fits-all” solution to serving disadvantaged communities. ATE recommends that Staff and the Joint Utilities identify best practices in serving these customers by engaging disadvantaged communities directly to learn their needs.

ChargePoint

ChargePoint recommends that the Commission authorize utilities to propose additional incentives to support EV supply equipment deployment at strategic locations and underserved communities. ChargePoint suggests that authorization for additional incentives may be granted temporarily and reassessed during review.

City of Albany

The City of Albany criticizes the proposed ten-mile radius requirement as too broad to isolate infrastructure development for disadvantaged residents in urban areas with abrupt geographical variation in socioeconomic status. The City

of Albany proposes including public transportation electrification in the program as a more beneficial approach.

Clean Transportation Coalition

The Clean Transportation Coalition urges more work to deliver benefits to all customers and low- and moderate-income customers in particular.

DEC

DEC generally supports the White Paper's proposed inclusion of DC Fast Chargers near environmental justice areas. DEC notes that the Clean Transportation New York mitigation plan prioritizes the use of New York's VW Settlement allocation to site light-duty Level 2 and DC Fast Chargers in or adjacent to DEC potential Environmental Justice areas (within 0.5 miles, according to current DEC criteria). DEC states that it recently completed an evaluation of Level 2 charger locations funded by the Charge Ready NY program and found that approximately 20 percent of Level 2 chargers are located within a half mile of a DEC PEJA. Because this frequency of Level 2 chargers near Environmental Justice areas was achieved without any incentive or program requirement, DEC recommends that the DPS consider reducing the proposed 10-mile radius of DC Fast Charger from an Environmental Justice area to five miles.

DOT

DOT supports suggestions by NYPA in proposing additional criteria to ensure that EV supply equipment benefits are realized by disadvantaged communities. DOT recommends station utilization designation according to DEC PEJA and NYSERDA low- and moderate-income definitions, and adding deployment of electric buses as another criterion for considering the effects of EVSE investment on these communities. DOT suggests the a 10-mile radius should be modified to more directly focus on the potential of the infrastructure to be used by or directly benefit residents of these communities. DOT acknowledges this approach will require greater involvement of the Commission but is likely to address the needs of disadvantaged communities more effectively. Lastly, DOT suggests that the program increase its investment goals to 30 or

40 percent to align with Climate Leadership and Community Protection Act (CLCPA) targets for clean energy investment.

Enel X

Enel X agrees with the proposal but requests clarification on whether the purpose of identifying "disadvantaged" or "environmental justice" communities is to target communities with low income levels, high proportions of renters, high pollution burdens, or some combination of these characteristics. Enel X agrees that providing greater incentives is appropriate in incentivizing DC Fast Charger development in disadvantaged communities but reiterates concerns that the proposed radius may inadvertently encourage EV supply equipment installation in adjacent communities.

EVgo

EVgo supports deploying chargers in low- and-moderate-income communities, and notes that more than 40 percent of EVgo's sites in California are in low-income communities.

FreeWire

FreeWire recommends additional incentives ranging from $20,000 to $30,000 to encourage DC Fast Charger deployments in disadvantaged communities. It also advocates the development of a platform similar to CalEnviroScreen, a mapping tool by the California Office of Environmental Health Hazard Assessment that identifies communities vulnerable to pollution.

Greenlots

Greenlots contends that charging infrastructure investment in disadvantaged communities can encourage transportation electrification in these areas but should not be conflated with the need for or promotion of a broad shift to single-passenger vehicles. Instead, chargers could better serve rideshare drivers and passengers in disadvantaged areas by being located there, rather than ten miles away or more.

Greenlots warns that establishing minimum requirements for numbers of chargers in disadvantaged communities, rather than a wide radius, may result in less station development in these smaller areas. It suggests that rather than drawing a

wider circle that will diffuse the beneficial impacts for these communities, utilities should be able to offer more turnkey solutions that simplify charger installation and access for developers.

Greenlots maintains that efforts should focus on medium- and heavy-duty EVs for all communities – including Environmental Justice and low- and moderate-income communities – to benefit from transportation electrification. In addition to disadvantaged communities relying on transit vehicles, they also disproportionately endure transportation-related air pollution attributed to port activities and the trucking industry. Greenlots urges the Commission to direct utilities to propose programs that address the medium- and heavy-duty EV sector. Greenlots also states that utilities need flexibility to meet the needs of low- and moderate-income and Environmental Justice communities and suggests that the Commission establish nonprescriptive guidance and targets for serving these customer classes.

Joint Utilities

Joint Utilities state that the Commission should use existing definitions for low- and moderate-income and Environmental Justice communities such as the DEC list of proposed Environmental Justice communities organized by county. Joint Utilities suggests that utilities should target a certain percentage (5 or 10 percent) of total installations for siting in low- and moderate-income communities.

MTA

MTA disagrees with the proposal that 20 percent of the program budget for publicly-accessible DC Fast Charger make-ready infrastructure go to stations within ten miles of disadvantaged communities, arguing that this is not an appropriate or effective plan to serve EV needs in these areas. MTA alleges that the proposal ignores population density and demographic distribution characteristics particular to New York City, where areas exhibiting extreme socioeconomic differences can be in proximity (under 10 miles). It also observes that many disadvantaged communities can be compact and that many low- and moderate-income residents do not drive and rely on public

transportation. Instead, the MTA advocates the use of existing demographic and transportation access resources like the Accessibility Observatory of the University of Minnesota to provide a more refined approach to target appropriate charging infrastructure investment. Finally, the MTA agrees with the charge by EDF that omitting medium- and heavy-duty EV infrastructure misses an opportunity to achieve environmental benefits in environmental justice areas.

NYC

NYC alleges that the Staff proposal to facilitate EV supply equipment deployment in underserved communities would be inappropriate and ineffective. In this proposal, most of NYC would be defined as an environmental justice area. Instead, NYC recommends that the proposed 10-mile rule be applied only to areas with lower population densities and that an alternative means of supporting electrified transportation for Environmental Justice communities in dense areas be identified.

NYC explains that most low-income residents in its jurisdiction do not drive and suggests that existing surveys (e.g., the Accessibility Observatory at the University of Minnesota) of areas with limited transportation supply may provide a more appropriate and refined means of targeting effective investment. It also notes that investment in fleet charging likely would have a greater effect on disadvantaged communities than the proposed approach.

NYC also notes that light-duty EV adoption may fail to realize anticipated health benefits for at-risk communities with low car ownership rates and warns that locating charging infrastructure in their vicinity may achieve the perverse effect of increasing road traffic in these areas. It also disagrees with Staff's prediction of an increase in EV ridesharing mileage in disadvantaged areas, as these services are not always offered at affordable prices for low-income residents. NYC recommends that the proposal should instead focus on encouraging fast-charging EV infrastructure in depots, near the residences of rideshare drivers, and areas with significant trip volume.

NYC warns that EV deployment is even more urgent during the current public health crisis caused by the novel coronavirus, noting that low-income residents already bear the

brunt of transportation-related air pollution and exhibit higher rates of respiratory illness. Air quality improvements in disadvantaged communities are even more necessary as transportation emissions can exacerbate the effects of COVID-19 and other respiratory ailments. NYC recommends that the program also foster workforce development opportunities during the gradual economic recovery from the pandemic.

NYCP

NYCP recommends that a sufficient number of EV charging stations be installed in disadvantaged communities, especially at multi-unit apartment buildings. NYCP warns that the proposed requirement to locate stations within a maximum distance of ten miles of disadvantaged communities will result in ineffective siting and recommends this limit be reduced to two miles. NYCP also notes that disadvantaged communities are often located near ports and transit hubs with excessive air pollution problems and recommends EV adoption to counter these effects. It recommends collaboration between utilities and other stakeholders to develop program and incentives to electrify commercial vehicles and public transportation fleets.

NRDC-SC

NRDC-SC argues that CLCPA Climate Justice Working Group or the federal Environmental Protection Agency (EPA) definitions could be used to accurately identify disadvantaged communities. It also cites definitions provided in the State of California Greenhouse Gas Reduction Fund Investment Plan and Communities Revitalization Act, and suggests the use of the EPA EJSCREEN, an Environmental Justice screening and mapping tool. NRDC-SC foresees difficulties in identifying low- and moderate-income communities by relying on census data, federal poverty guidelines, and income due to the density of the NYC metropolitan area.

NRDC-SC also maintains that the proposed ten-mile radius is too large for some urban areas and may inadvertently result in charging station “deserts” in vulnerable communities. It recommends a minimum 20 percent of DC Fast Charger make-ready infrastructure installations in urban areas be installed within one mile of a disadvantaged community. In upstate and nonurban

areas, they suggest that the Commission should shrink the distance that charging infrastructure can be installed from a disadvantaged community. NRDC-SC recommends that all make-ready infrastructure in disadvantaged communities be eligible for a 90 percent cost rebate and 15 percent of Level 2 make-ready funds be allocated to these communities. It also argues that utilities that exceed expectations in serving disadvantaged communities be entitled to performance incentives.

NYPA

NYPA accepts the proposed ten-mile radius for rural areas, but advocates a smaller, four-mile radius for use in urban and suburban locations. To increase the likelihood that qualifying infrastructure is developed to benefit disadvantaged communities, NYPA recommends that the conditions for maximum incentive eligibility be expanded to include the following criteria: expected station utilization, designation according to DEC PEJA, NYSERDA low- and moderate-income, and “transit desert” definitions, and indicators from the Environmental Protection Agency EJSCREEN Environmental Justice Screening and Mapping Tool. NYPA also suggests eliminating the proposed developer contribution for public Level 2 charger deployments, warning that the current definition of “public accessibility” will inhibit infrastructure development in disadvantaged communities without high rates of vehicle ownership that rely on ridesharing. Lastly, NYPA requests program funding for transit fleet electrification that provides direct benefits to environmental justice communities.

Tesla

Tesla recommends that utilities work with local stakeholders to design criteria for serving disadvantaged communities based on service territory conditions, where higher incentive levels should be applied. Tesla also supports program eligibility for medium- and heavy-duty EVs to reduce transportation-related air pollution in disadvantaged communities.

Vrinda

Vrinda posits that the development of charging infrastructure in low- and moderate-income communities should be linked to the availability of EVs in these communities. If there are affordable EV programs launched in a community, that community should get EV supply equipment infrastructure on a priority basis. But the arbitrary allocation of funds and rules to deploy EV supply equipment in a specific community may lead to wastage of resources and ultimately burden all ratepayers, including low- and moderate-income and environmentally impacted communities.

XXV. Commercial Fleets

AEEI-ACE

AEEI-ACE states that exceptional regulatory considerations for medium- and heavy-duty EV use require urgent attention, and recommends that utilities propose programs to counteract barriers to adoption in these sectors immediately. AEEI-ACE notes a range of benefits with this approach, including air pollution mitigation, noise pollution reductions, and lower fuel and maintenance costs. It argues that the Commission should address this market segment promptly and effectively to meet CLCPA targets and without waiting for program maturation, and adds that utilities should be required to propose separate fleet programs. AEEI-ACE does not support the proposed new Fleet Assessment service, but urges that alternative action in this area is needed immediately.

ATE

ATE recommends urgent action on medium- and heavy-duty EV charging policy, noting that because current municipal and commercial demand exceeds supply, adoption is taking place where costs are lowest. ATE proposes additional program funding for this transportation sector, arguing that it should not compete with the light-duty market financially. ATE states that managed charging and customer outreach are the most effective ways to promote fleet electrification with minimal grid impacts, and adds that providing fleet advisory services to customers would be prudent.

ChargePoint

ChargePoint agrees with the MTA recommendation to include medium- and heavy-duty garages, depots, and other fleet electrification components in the program. ChargePoint also notes that the environmental and economic benefits of commercial fleet electrification will accrue for all customers and residents regardless of EV ownership.

DEC

DEC predicts that transportation electrification of the light-duty market will significantly affect medium- and heavy-duty EV transportation locally, and recommends establishing a schedule for developing infrastructure for the latter. It also advises that utilities consider electrified transit bus charging requirements in assessing light-duty make-ready investments.

DOT

DOT strongly supports the NYPA recommendation to extend eligibility to public transportation fleets in the first phase of the program.

Drive Electric LI

Drive Electric LI cites the benefits of developing charging infrastructure to accommodate medium- and heavy-duty EVs and in using charging facilities to complement DER capabilities. Drive Electric LI maintains that solar generation and energy storage can complement DC Fast Charger infrastructure to benefit fleet electrification and the distribution grid, and suggests that the Commission could assess costs and benefits through field demonstration projects. Drive Electric LI stresses that mitigating demand charges for medium- and heavy-duty EVs at DC Fast Charger facilities is a critical issue. It recommends continuing the per-plug incentive to help offset demand charges and adds that complementary energy storage or solar generation could also be beneficial in minimizing these costs.

EDF

EDF urges recognition of the particular concerns facing medium- and heavy-duty EV adoption, and emphasizes that lot charging at fleet depots requires special attention to efficient rate design and mitigation of grid constraints and installation costs. EDF recommends that effects of transportation electrification on the distribution grid can be minimized with a comprehensive impact study that evaluates incremental load attributed to EV charging on the transmission system and at the feeder level. EDF notes that this will only be successful with planned cooperation between utilities and fleet operators and recommends rate design considerations for fleet EV charging to achieve economic and environmental benefits. It cites California data that demonstrate that EV rate design can result in lower charging costs without shifts to non-EV customers.

EDF cautions that electrification of the medium- and heavy-duty EV transportation sector requires distinctly different approaches than those for the light-duty EV market. It recommends a potential study to identify market barriers to prevent costly delays to EV adoption in the sector and to mitigate air quality problems prevalent in disadvantaged communities. EDF acknowledges that the Make-Ready Program is likely to develop charging infrastructure that could be used by some medium- and heavy-duty EVs, but alleges the scale of the program is too limited to induce wholesale electrification of these transportation sectors.

Enel X

Enel X recommends the development of commercial rate options for fleet EV charging with price signals that reflect temporal and locational costs to achieve grid benefits to keep fleet charging under specified capacities. Enel X contends that development of commercial EV charging tariffs that avoid noncoincident demand charges would benefit all electric transportation sectors equally. These rate design alternatives could incorporate coincident demand or capacity subscription charges and could expose ratepayers to time-dependent price signals through time-varying volumetric components. Enel X suggests that there are possible rate designs that can provide

needed relief from noncoincident demand charges while reflecting cost causation and cites the current Standby and Buyback Proceeding as a model for EV charging rates.

EV Connect

EV Connect proposes that public transportation fleet charging infrastructure be eligible for incentives, as it would aid in achieving state environmental policy goals.

EV Industry Coalition

The EV Industry Coalition recommends that utilities propose complementary programs within the year to support medium- and heavy-duty EV charging and address fleet charging concerns neglected by the Staff proposal, noting that five public transit agencies are currently subject to a State mandate to convert to zero-emissions vehicles. The EV Industry Coalition warns that without immediate and decisive action to authorize utility investments for fleet electrification and to design complementary rates, efforts to foster commercial EV adoption will fall short. Citing its own experience in organizing the largest deployment of electric school buses in North America, the EV Industry Coalition recommends that utilities develop program proposals allocating a minimum of $10,000 per bus for charging infrastructure. It calls on the Commission to provide guidance to the utilities on developing appropriate charging programs to support commercial fleets and require that utilities develop and file program proposals within the year, with a total statewide program budget of at least $300 million. Alternatively, the EV Industry Coalition suggests that Staff convene a workshop to explore best practices for commercial fleet programs and that delays in addressing this transportation sector are not in the public interest.

Fleet charging can also generate greater load concentrations per site that require appropriate make-ready investment and comprehensive services to enable scaling. Conversely, fleet charging also represents a greater source of load management potential if appropriate rates are used to shift charging from system peaks. These issues can be addressed with commercial EV rates and would promote charging access for fleet operators. The EV Industry Coalition cites TOU EV rates in

California and elsewhere that facilitate off-peak charging, and recommends review of work by the California VGI working group.

FreeWire

FreeWire acknowledges that larger EV classes create specific charging challenges, especially in grid-constrained areas and advocates managed charging, energy storage, and other innovations to support medium- and heavy-duty vehicle electrification.

Greenlots

Greenlots proposes that the Commission issue guidance and a time-bound directive for utilities to develop programs to serve medium- and heavy-duty EV customers to avoid further delays in addressing this transportation class. It also recommends development of a Fleet Assessment Service to advise on technology-enabled managed charging solutions that address system constraints and generate ratepayer benefits. Greenlots recommends greater make-ready infrastructure incentives for fleet charging projects as it predicts the State will not be able to achieve EV infrastructure targets without extensive fleet electrification. Greenlots requests prompt efforts to electrify commercial transportation, and urges the Commission to develop protocols for serving these markets as well as recommending utility-administered EV programs designed for medium- and heavy-duty EVs within the year. Greenlots concurs with the EV Industry Coalition in proposing an additional $300 million statewide budget to serve the medium- and heavy-duty EV sectors.

Joint Utilities

The Joint Utilities urge the Commission to propose additional incentives for fleet charging, and suggest that the utilities could fulfill the fleet advisory service role proposed in the Whitepaper to coordinate large-scale fleet electrification, but note that these activities. The Joint Utilities will generate administrative costs not covered by proposed incentives. The Joint Utilities note that Con Edison is already administering a medium- and heavy-duty EV fleet program, and observe that the other utilities are engaged in

program development and expect imminent proposals. Noting the greater air pollution mitigation and GHG reduction potential of larger EV classes, the Joint Utilities state their support these efforts and emphasize the urgency in implementing fleet and medium- and heavy-duty EV charging infrastructure. Finally, the Joint Utilities propose that utility performance incentives can play in promoting cost containment for these activities.

MTA

MTA submits that utilities should take an active role in fleet charging station planning, and should offer a Fleet Assessment service. MTA suggests that the Commission adopt a deadline of 45 days for a utility's detailed response to additional power supply applications associated with medium- and heavy-duty EV fleet charging. MTA requests that the Commission not disrupt the Con Edison fleet-specific program included in its most recent rate case.

MTA submits that the Make-Ready Program should also apply to fleet vehicles and proposes that a statewide fleet electrification program could complement the light-duty Whitepaper proposals. MTA contends that some of the incremental revenues gained by the increased EV load could be considered as an offset to some portion of the program costs. MTA requests that the Commission address the challenging operating costs incurred by electric fleet operators, such as the disparity in operating costs based on fleet location. It also suggests that the Commission establish separate service classifications for electrified fleet charging using the same load and cost criteria used to develop conventional utility service classifications.

MTA asserts that the submetering of fleet charging is essential for allowing EV operators and utilities to effectively monitor energy usage and increase efficiency. For instance, during the its own electric bus pilot, MTA observed that manufacturer specifications for charging telematics were often inaccurate.

MTA identifies several more impediments to public transit fleet electrification. It notes that significant capital and operating costs still preclude wholesale adoption, including expensive infrastructure development necessary for time-constrained (e.g., overnight) charging of entire fleets and

the cost of consuming large quantities of electricity. MTA requests that the Commission order the creation of a Fleet EV infrastructure Working Group to consider the challenges of fleet electrification, a Fleet EV infrastructure Make-Ready Program, and a new service classification for medium- and heavy-duty EV fleets.

MTA also recommends that the Commission authorize incentives for transit electrification in the first round of the Make-Ready Program, and direct utilities to develop smart charging programs for transit fleets to alleviate the system impact of transit fleet electrification and reduce the cost to operate electrified transit fleets. It notes that opportunities to support the electrification of varied types of fleets differ from one utility service territory to another. The MTA adds that bus and related transit services fleets represent an opportunity that can have a substantial impact on reducing greenhouse gas emissions in disadvantaged communities. Accordingly, MTA requests that the Commission designate all transit bus depots located in Environmental Justice areas as Strategic Locations as defined in the Whitepaper.

NYC

NYC stresses the importance of developing protocols for encouraging fleet electrification as soon as possible. It recommends that any fleet-oriented make-ready program in the Con Edison service territory should exploit the $9 million in funds allocated for fleet infrastructure approved in the company's present three-year rate plan. NYC also warns that proposed public accessibility standards would limit the value of the program for dedicated fleet charging. NYC advises that the Commission commit to creating procedures for medium- and heavy-duty EV make-ready infrastructure development and direct Staff to issue a Whitepaper addressing this subject.

NYPTA

NYPTA urges immediate extension and expansion of the Make-Ready Program to public transit services to meet state fleet electrification goals for this sector. NYPTA acknowledges that public transit charging sites will not be open to the general public, but recommends that they be eligible for funding

at the higher 90 percent level, noting that fleet electrification of public transit provides significant public service and health benefits. It argues that lower incentive levels will be insufficient to cover the significant investment required for transit fleet electrification. NYPTA recommends that at least $50 million be reserved to cover early estimated make-ready costs for transit systems and argues that MTA costs should be added to this amount.

NYPTA notes several challenges particular to fleet electrification, including access to sufficient electrical power to charge hundreds of vehicles at a single location, power connections to bus depots, and retrofitting existing or constructing new facilities to accommodate these vehicles and their charging requirements. NYPTA also observes that transit charging must continue functioning during power outages and that emergency backup resources for resilience should be included in eligible make-ready costs. It further recommends coordinating local power needs of transit facilities and light-duty EV charging to ensure capacity for all users.

Finally, NYPTA suggests that additional utility revenue generated by transit electrification and off-peak charging can fund continued make-ready program expansion, rather than being allocated to government-subsidized public transportation systems.

Nikola Corp.

Nikola Corp. also supports the inclusion of medium- and heavy-duty EV issues in this proceeding, including rate design proposals. It cites developments in hydrogen vehicle production, and encourages the Commission to consider this emerging technology and applicable rate design options to support the advancement of zero-emissions transportation.

NRDC-SC

NRDC-SC advises the Commission to develop fleet electrification guidance expeditiously. It also notes that projects that exploit vehicle-to-grid technologies will provide grid support and additional financial incentives for fleet electrification. NRDC-SC concurs that investment in charging infrastructure for medium- and heavy-duty EVs is essential to

support electrification by 2035 of the five largest transit fleets outside of New York City. It recommends developing guidance to support electrification of these sectors as soon as possible. Citing recent analysis by the California Electric Transportation Coalition that predicts electric trucks and buses will have the lowest total ownership costs by 2030 even without purchase incentives, NRDC-SC recommends electrification of the medium- and heavy-duty automobile sector for both economic, environmental, and public health reasons.

NRDC-SC observes that most parties recommend extensive investment in medium- and heavy-duty EV infrastructure, citing beneficial mitigation of grid impacts (larger EVs use larger batteries) and pollution emissions associated with conventional fossil fuel automobiles. NRDC-SC advocates adequate price signals, managed charging, and rate design to minimize grid impacts and maximize benefits for all customers. It urges the Commission to issue guidance of the electrification of this transportation sector and related infrastructure development.

NYAPP

NYAPP recommends the expansion of the program to include all utility light-duty vehicles in the program. NYAPP adds that the Commission should also urge support from DEC for use of the VW settlement funds for this purpose. NYAPP urges the Commission to acknowledge that NYAPP is also interested in EV infrastructure on a statewide basis and is engaged in deployment of EVs and charging infrastructure. NYAPP notes some of their members' efforts in investing in EV infrastructure have been hindered by others that have not installed EV infrastructure, and therefore funding through the Commission is crucial.

NYC

NYC urges the Commission to include fleet electrification in the program.

NYPA

NYPA advises the Commission to authorize Make-Ready Program incentives for public transit electrification in the first round, arguing that this will benefit disadvantaged

communities that rely on public transportation in areas where EV adoption is otherwise minimal. NYPA recommends smart charging programs to promote fleet electrification with minimal distribution grid impacts, especially through off-peak charging.

Tesla

Tesla argues that the program should be expanded to include medium- and heavy-duty EV applications to address public health problems in disadvantaged communities associated with diesel fuel use in commercial transportation applications. Tesla notes that from a technical perspective, there is little difference between a large DC Fast Charger charging station and fleet charging infrastructure. Tesla advocates rate reform to encourage fleet electrification, particularly recommending TOU rates.

XXVI. Other Issues

AEEI-ACE

AEEI-ACE contends that it is crucial to remove any elements of the proposed program that slow implementation in view of the public health concerns around the COVID-19 pandemic.

AEEI-ACE requests that the Commission commit to addressing fundamental rate design issues in a separate track, and recommends this should occur within the year. AEEI-ACE claims that demand charges comprise a substantial portion of EV supply equipment operating costs, especially for DC Fast Charger sites, which are difficult to recover through revenues while station utilization is low. It alleges that non-coincident peak (NCP) demand charges provide an insufficient signal to developers and customers to modify charging behavior. AEEI-ACE recommends that the Commission conduct a comprehensive review of EV rate design that assesses the overall effectiveness of the DC Fast Charger Infrastructure Program and the current reliance on NCP demand charges. AEEI-ACE also notes that commercial rate reform is a foundational effort in developing vehicle-to-grid capabilities, especially employing time-of-use rates.

ATE

ATE considers ratemaking an issue best addressed on a case-by-case basis by the utilities, stating that market conditions are too premature to address these concerns. However, ATE agrees with Staff that it may be prudent to assess ratemaking issues at the midpoint review of the DC Fast Charger Per-Plug Incentive Program.

ChargePoint

ChargePoint argues that developing appropriate commercial rate designs for EV charging is essential for the success of the Make-Ready Program. If the Commission chooses to delay these considerations, ChargePoint recommends that in the meantime it modify definitions in the Tier 1 incentive of the DC Fast Charger per-plug program. It states that a Tier 1 plug incentive should include plugs capable of simultaneously charging at or above 75 kW or plugs capable of independently charging at or above 62.5 kW and sharing power to charge one vehicle at or above a combined 125 kW. ChargePoint claims that there is no difference in charging times between 125 kW and 175 kW DC Fast Chargers and that modifying this definition will decrease average deployment costs and increase and accelerate the deployment of high-value plugs, all while providing a similar charging experience.

EDF

EDF recommends tariffs that incentivize optimal consumption and provide sufficient transparency on grid conditions. It predicts that smart charging practices will change as the grid develops to accommodate EV adoption, with time-varying price signals encouraging beneficial off-peak charging initially before a range of more sophisticated methods develop. EDF also proposes investigating more refined price signals through submetering, updated billing software to allow smart pricing, and OCPP and Open ADR standards. EDF contends that rates calibrated for EV charging can be reconciled with the principles of cost-of-service ratemaking. It urges the Commission to examine pricing structures to foster cost-effective and beneficial medium- and heavy-duty EV fleet electrification.

Electrify America

Electrify America observes that some utilities have imposed additional requirements and conditions on applicants to the DC Fast Charger Per-Plug Incentive Program that were not included in the Commission order. Electrify America recommends a single non-utility program administrator for any incentive programs with clearly defined requirements that facilitate developer confidence. Electrify America requests that the Make-Ready Program proposed in the Whitepaper be administered expediently, consistently, and in compliance with the Commission Order.

Enel X

Enel X points out that the COVID-19 crisis has affected uncertainty around the implementation of the program.

Enel X suggests that increased electric demand from EV charging can avoid exacerbating capacity constraints and instead increase overall grid use to increase reliance on renewable generation. This could ensure that any cost increases resulting from greater load are minimized and offset by greater revenue. Enel X agrees that it is important to integrate new EV charging load in a manner that increases utilization of the existing distribution system and maximizes ratepayer benefits. It stresses that the most efficient way to accomplish this is through utility solutions that enable and develop the third-party charging market. In addition to rate design, Enel X recommends dynamic load balancing across on-site EV chargers to avoid consumption increases and optional tariffs for certified load management solutions that partially avoid distribution interconnection upgrades. It also proposes that the Commission examine incentive extensions for customers enrolled in smart charging options that match load with intermittent renewable generation or performance incentives for installations that permanently produce off-peak load.

EVgo

EVgo agrees that rate reform and TOU rates are critical to furthering EV adoption and cites nationwide efforts in developing commercial and technology-neutral, low-load factor rates in several jurisdictions.

EV Industry Coalition

The EV Industry Coalition predicts that the proposal will fall short of achieving its goals due to programmatic complexities not present in make-ready programs administered in other jurisdictions. It warns that this complexity risks setting the market on an unsatisfactory trajectory that cannot be reviewed and course-corrected until 2023. The EV Industry Coalition is concerned that the program will see limited participation due to an overly complex structure, administratively burdensome data reporting, and prescriptive requirements. The EV Industry Coalition maintains that the proposed site evaluation methods will inadvertently delay deployments by months and significantly increase costs. It also alleges that the make-ready proposal fails to address other near-term market needs including commercial EV rate design, load management strategies, and fleet charging applications. The EV Industry Coalition advises that Staff consider program design best practices to create simple incentives as used in other programs across the country. It also encourages Staff to look at best practices from the recently approved Con Edison program, which provides a more streamlined program design and includes an annual allotment for fleet funding that is accessible by medium- and heavy-duty EV fleets.

The EV Industry Coalition recommends developing EV charging rates for residential and commercial EV charging applications (i.e., public and private; light, medium, and heavy-duty), as well as developing utility programs and policies that encourage managed charging strategies that can put downward pressure on electricity rates, especially rate design and managed charging to reduce operating costs. It argues that EV charging costs must be easily understood by all customers and lowering these costs below the expense of refueling with fossil fuels should be a program goal. While acknowledging that the Commission has avoided technology-specific rates, the EV Industry Coalition suggests that optional rates aligned with grid constraints that accommodate the low load-factors associated with EV charging could remove significant barriers to EV adoption for several customer classes. It suggests that general service rates could be modified to provide more refined price signals about optimal charging times or include demand

limiters to foster lower load-factor charging. It also recommends that all utilities file programs to develop cost-based, technology neutral charging rates for commercial customers.

The EV Industry Coalition also encourages the Commission to consider technology-enabled strategies to manage load, especially for fleet depots and other longer dwell-time locations that permit greater flexibility on charging schedules and speeds. This could reduce costs for station owners, site hosts, and ratepayers and the EV Industry Coalition advocates a working group to develop managed charging solutions. The EV Industry Coalition also recommends investigating the load management potential of vehicle-to-grid technologies involving large EV fleets acting as aggregated DERs that could generate additional revenue for operators.

The EV Industry Coalition asserts that establishing commercial rate options that are available for opt-in by EV site hosts will ensure that EVs are price-competitive for consumers and facilitate EV adoption. The EV Industry Coalition recommends that Staff work with utilities and relevant industries to develop new rate options that better reflect the cost-causation profile of EVs. While acknowledging that Staff proposes a demand charge holiday as one option, the EV Industry Coalition notes that there are other rate design options for mitigating the effects of demand charges on EV customers and that a demand-based rate is only one of several possible rate structures. The EV Industry Coalition remarks that utilities in other jurisdictions have recently implemented other technology-neutral economic development or low load-factor rates.

Additionally, the EV Industry Coalition notes that subscription-style rates, though they impose added administrative burdens, have recently emerged as new options, and that many utilities also incorporate load management components in their offerings to help shape EV load as appropriate for specific use cases to complement EV-specific rates. These programs, most of which are optional and focus on Level 2 and fleet applications, exploit smart-charging capabilities to help respond to grid- and site-specific conditions through load shifting and demand response. The EV Industry Coalition contends that DC Fast Charger stations will

not proliferate at the rate needed without removing systemic barriers that undermine fundamental economics. In the near term, EV Industry Coalition suggests New York consider a novel rate design that could serve all nonresidential applications for EV charging, applicable to large Level 2 stations, DC Fast Chargers, and fleets alike. The EV Industry Coalition notes that the DC Fast Charger per plug incentive has failed to realize the market-moving effects of comprehensive rate design in other jurisdictions. Therefore, the EV Industry Coalition suggests the Commission require utilities to file new commercial tariffs applicable to all nonresidential EV use cases within the year in which proposals should be cost-based and include time-of-use elements.

Greenlots

Greenlots agrees with other parties that EV charging should increase effective utilization of existing grid resources and respond to grid constraints. It contends that it is essential to develop rates that send accurate price signals that reflect both system and local grid constraints. Instead of TOU rates, Greenlots encourages the Commission to examine technology-based managed charging strategies either as an independent method or in concert with various rate structures to shape, utilize, and dispatch flexible EV loads. It asserts that managed charging and real-time pricing can maximize system benefits and reduce costs for ratepayers and site hosts. Greenlots stresses that smart networked chargers are critical in allowing consumers and site hosts to benefit from advanced rates and charging programs, as in customized “set it and forget it” options. Managed charging programs offer maximum customer control while simplifying engagement, effectively responding to individual price signals and charging needs without relying on active and ongoing behavior changes, by allowing customers to set technology-facilitated preferences.

Greenlots acknowledges the difficulties in ensuring sufficient participation in new rate options, but it notes that managed charging supports Commission preferences for limiting technology-specific rates as technology can enable load management with both conventional and dynamic rate designs, whether general or EV-specific. Greenlots encourages the

Commission to require that all chargers be networked and to mandate or encourage customer participation in managed charging and demand response programs in a future Order but states that these approaches need not be prescriptive.

Joint Utilities

The Joint Utilities urge the Commission to consider the integration of demand-based delivery rate and time-varying supply charges to provide accurate price signals to EV customers. The Joint Utilities support Commission actions that promote the use of cost-based rates and suggests that potential ratemaking improvements could include volumetric (per kWh charges), fixed charges (per meter charges), and demand-based charges (per kW charges) for delivery. Improvements could also be made to the supply portion of the bill for those customers who take supply from the utility so that energy costs more closely align with market prices. The inherent flexibility of EV charging schedules will allow EV customers to benefit from more refined rate designs. However, the Joint Utilities contend that discounted rate design is not an efficient method for scaling transportation electrification. The Joint Utilities maintains that it is critical for the Commission to clearly define make-ready investments and establish guidance for investments in future-proofing infrastructure.

The Joint Utilities support standby rates as a sound delivery rate design option for EV charging. To complement the granular delivery rate, the Joint Utilities recommend that the Commission finish the process begun in the Standby Order and permit customers of all classes to opt into the standby rates. Joint Utilities suggest that the Commission reject recommendations from stakeholders that the utilities establish one or more new rate classes specifically for EV and EV infrastructure customers. The Joint Utilities warn that structuring a rate design specifically to promote a given technology is inconsistent with the fundamental rate design principles of technology neutrality, cost causation, and transparency, which the Commission has endorsed as guiding principles in other proceedings.

NRDC-SC

NRDC-SC encourages the Commission to examine ratemaking activities that may complement the existing DC Fast Charger Per-Plug Incentive Program now rather than waiting for a midpoint program review, citing the downward pressure on rates exerted by transportation electrification for all utility customers in those service areas. NRDC-SC proposes EV time-of-use (TOU) "whole-house" rates, active management charging programs, and demand response programs as solutions to managing EV load and ensuring charging benefits the grid.

NYC

NYC suggests that Staff investigate technologies that eliminate the need for separate EV charging metering to reduce costs. NYC proposes that meters in smart Level 2 chargers might be considered revenue-grade sub-meters for residential TOU rates according to the Commission's metering policies and suggests this be investigated as a solution to the additional cost associated with separate meters for residential charging. It also recommends examining fleet charging load profiles and the possibility of developing specific rates for this customer class.

NYCP

NYCP supports this proposal for statewide electrification of the transportation sector by developing light-duty EV infrastructure, and recommends swift action to address inadequate and unreliable current charging infrastructure to reduce impediments to EV adoption like range anxiety.

NYPA

NYPA recommends the Commission approve the proposed program after incorporating the following revisions: expansion of program eligibility criteria to allow participation by NYPA and other public entities as EV infrastructure developers, consideration of regional differences in determining installation numbers for each service territory, standardization of interconnection practices, incorporation of public transportation fleet electrification efforts, confirmation that

disadvantaged communities receive tangible benefits, future-proofing requirements, declining incentives over time, and coordinated development of infrastructure at strategic locations.

PIA

PIA cites the ratepayer benefits of off-peak charging, citing the downward pressure on rates caused by this behavior.

Tesla

Tesla recommends the program be divided into two tracks. According to Tesla, the first track would be an EV Make-Ready Program that covers infrastructure investments in front of the meter and is rooted and integrated into existing line extension and service request processes. Tesla states that this track would direct utilities to update tariff sheets with new allowances for commercial EV charging accounts without other technology, process, or program requirement, and that support for a customer's EV charging deployment would come in the form of waiving all, or a portion, of CIAC or EDF charges. Tesla suggests that cost containment could include setting a per site or stall allowance for upgrades on the utility side of the meter or extending the revenue test to ten or more years. The second track would encompass a program that includes make-ready investments on the customer side of the meter which follows the form described in the Whitepaper. Tesla argues that proposed program requirements that are redundant or in conflict with external processes such as electrical and building permit requirements should be removed.

Tesla argues that the program should build off of the tried-and-true non-discriminatory service connection process, rather than imposing arbitrary eligibility and technology requirements that are not based on safety or reliability standards. Instead, Tesla asserts that the Make-Ready Program should be strongly rooted in the BCA framework. The program should seek to be as inclusive as possible and avoid program requirements that may increase program costs or ultimately hinder transportation electrification. Tesla contends that the program is administratively cumbersome with prescriptive requirements, steps, and processes.

Tesla states that time-of-use rates are the most effective way to ensure potential value of EV charging to the grid. Tesla argues that attempts to change EV charging behavior with software or administrative interjections without providing clear price signals through time-variant rates will be economically and administrative inefficient and lead to poor customer experiences. Tesla advises that delaying an examination of rate design until 2023 is far too late and, rather than encouraging investment through near-term rate reform, is likely to put more ratepayer funding at risk. Tesla recommends that the Commission direct utilities to develop rate proposals specific to commercial EV accounts or general TOU rates applicable to all commercial customers.

APPENDIX B

Plug Counts

	Make-Ready Program	Consolidated Edison	Central Hudson	New York State Electric & Gas	Niagara Mohawk	Orange & Rockland	Rochester Gas and Electric
Workplace Level 2	35,217	12,776	2,091	5,821	10,105	1,765	2,659
Public Level 2	18,556	5,763	1,113	3,458	5,623	1,080	1,519
Total Level 2	53,773	18,539	3,204	9,279	15,728	2,845	4,178
DC Fast Chargers	1,500	457	69	250	504	71	149

	Rest of State
Workplace Level 2	9,898
Public Level 2	6,129
Total Level 2	16,027
DC Fast Chargers	510

Program Budgets

	Statewide Total	Consolidated Edison	Central Hudson	New York State Electric & Gas	Niagara Mohawk	Orange & Rockland	Rochester Gas and Electric
Level 2 Plugs	53,773	18,539	3,204	9,279	15,728	2,845	4,178
Level 2 Budget	$ 385,777,871	$ 191,643,671	$ 17,653,800	$ 51,126,000	$ 86,658,600	$ 15,675,600	$ 23,020,200
DC Fast Charger Plugs	1,500	457	69	250	504	71	149
DC Fast Charger Budget	$ 94,705,747	$ 42,015,747	$ 3,487,000	$ 12,628,000	$ 25,459,500	$ 3,586,000	$ 7,529,500
Incentive Budget	$ 480,483,618	$ 233,659,418	$ 21,140,800	$ 63,754,000	$ 112,118,100	$ 19,261,600	$ 30,549,700
Futureproofing	$ 38,438,689	$ 18,692,753	$ 1,691,264	$ 5,100,320	$ 8,969,448	$ 1,540,928	$ 2,443,976
Implementation & Fleet Assessment Service	$ 72,072,543	$ 35,048,913	$ 3,171,120	$ 9,563,100	$ 16,817,715	$ 2,889,240	$ 4,582,455
Make-Ready Program	$ 590,994,850	$ 287,401,084	$ 26,003,184	$ 78,417,420	$ 137,905,263	$ 23,691,768	$ 37,576,131
Transit Authority Make-Ready Program	$ 10,000,000	$ 2,960,000	$ -	$ -	$ 5,090,000	$ -	$ 1,950,000
Total	**$ 600,994,850**	**$ 290,361,084**	**$ 26,003,184**	**$ 78,417,420**	**$ 142,995,263**	**$ 23,691,768**	**$ 39,526,131**

Environmental Justice Programs	
Expanded Mobility Pilot	$ 25,000,000
Environmental Justice Innovation Prize	$ 40,000,000
MHDV Make-Ready Pilot Program	$ 15,000,000
MHDV Competitive Pilot	$ 20,000,000
Total Budget	**$ 700,994,850**

APPENDIX C

Level 2 EAM metric

$$EAM\ Award = \left\{\left[\left(\frac{\$\ incentive}{plug}_{Public,baseline}\right)\left(Plugs\ incented_{Public,actual}\right) + \left(\frac{\$\ incentive}{plug}_{Non-public,baseline}\right)\left(Plugs\ incented_{Non-public,actual}\right) + \left(\frac{\$\ incentive}{plug}_{DAC,baseline}\right)\left(Plugs\ incented_{DAC,actual}\right)\right] - \left[\left(\$\ incentive_{Public,actual}\right) + \left(\$\ incentive_{Non-public,actual}\right) + \left(\$\ incentive_{DAC,actual}\right)\right]\right\}(30\%)$$

BASELINE PER-PLUG INCENTIVE COSTS

Plug Type	Upstate	Con Edison
Public Level 2	= $6,000/plug * 90% **= $5,400/plug**	= $11,257/plug * 90% **= $10,131/plug**
Non-public Level 2	= $6,000/plug * 50% **= $3,000/plug**	= $11,257/plug * 50% **= $5,629/plug**
Disadvantaged Communities (DAC)	= $6,000/plug * 100% **= $6,000/plug**	= $11,257/plug * 100% **= $11,257/plug**

MINIMUM PLUG REQUIREMENTS

Utility	Minimum Number of Plugs Required to earn Mid-point EAM	Minimum Number of Plugs Required to earn End of Program EAM
Central Hudson	641	3,204
Con Edison	3,708	18,539
Niagara Mohawk	3,146	15,728
NYSEG	1,856	9,279
Orange and Rockland	569	2,845
RG&E	836	4,178

APPENDIX C

DCFC EAM metric

$$EAM\ Award = \left\{\left[\left(\frac{\$\ incentive}{kW}_{Public,baseline}\right)\left(kW\ incented_{Public,actual}\right) + \left(\frac{\$\ incentive}{plug}_{DAC,baseline}\right)\left(kW\ incented_{DAC,actual}\right)\right] - \left[\left(\$\ incentive_{Public,actual}\right) + \left(\$\ incentive_{DAC,actual}\right)\right]\right\}(30\%)$$

BASELINE PER-kW INCENTIVE COSTS

Plug Type	Upstate	Con Edison
Public DCFC	= $55,000/plug / 150 kW/plug * 90% **= $330/kW**	= $100,109/plug / 150 kW/plug * 90% **= $601/kW**
Disadvantaged Communities (DAC) DCFC	= $55,000/plug / 150 kW/plug * 100% **= $367/kW**	= $100,109/plug / 150 kW/plug * 100% **= $667/kW**

MINIMUM PLUG REQUIREMENTS

Utility	Minimum Number of Plugs Required to earn Mid-point EAM	Minimum Number of Plugs Required to earn End of Program EAM
Central Hudson	14	69
Con Edison	91	457
Niagara Mohawk	101	504
NYSEG	50	250
Orange and Rockland	14	71
RG&E	30	149

APPENDIX C

	BASELINE							PROGRAM PERFORMANCE INPUTS						COMPUTATION OF EAM					
	Average Make-Ready [1]	Public L2 Incentive % [2]	Public L2 Target Incent. [3]=[1]*[2]	Non-Public L2 Incentive % [4]	Non-Public L2 Target Incentive [5]=[1]*[4]	Disadv Community L2 Incentive % [6]	Disadv Community L2 Target Incentive [7]=[1]*[6]	Public L2 # Plugs Par $ Incentive Spent [8]	Public L2 # Plugs Par $ Incentive Spent [9]	Non-Public L2 # Plugs Par $ Incentive Spent [10]	Non-Public L2 # Plugs Par $ Incentive Spent [11]	Disadv Comm L2 # Plugs Par $ Incentive Spent [12]	Disadv Comm L2 # Plugs Par $ Incentive Spent [13]	Target Program Cost [14]=([3]*[8])+([5]*[10])+([7]*[12])	Actual Program Cost [15]=[9]+[11]+[13]	Savings Share [16]	Company Share ($ 000s) [17]=([14]-[15])*[16]	EAM Award ($ 000s) [18]=IF([17]>0, [17], 0)
Con Edison																			
Con Edison 20% savings at Midpoint Review	$ 11,257	90%	$ 10,131	50%	$ 5,629	100%	$ 11,257												
	$ 11,257	90%	$ 10,131	50%	$ 5,629	100%	$ 11,257	927	$ 7,513,372	2076	$ 9,347,813	705	$ 6,348,948	$ -	$ 29,012,666	$ 23,210,133	30%	$ 1,741	$ 1,741
Upstate Utilities																			
NMPC 20% savings at Midpoint Review (NMPC)	$ 6,000	90%	$ 5,400	50%	$ 3,000	100%	$ 6,000												
	$ 6,000	90%	$ 5,400	50%	$ 3,000	100%	$ 6,000	912	$ 3,939,840	1636	$ 3,926,400	598	$ 2,870,400	$ -	$ 13,420,800	$ 10,736,640	30%	$ 805	$ 805

Input Cells

APPENDIX C

	BASELINE							PROGRAM PERFORMANCE INPUTS					COMPUTATION OF EAM						
	Average Make-Ready per Plug	Average kW/plug	Public DCFC Incentive %	Public DCFC Target Incentive ($/kW)	Disadv. Comm DCFC Incentive %	Disadv. Comm DCFC Target Incentive ($/kW)		Public DCFC kWs installed	Public DCFC $ incentive spent	Disadv Comm DCFC kWs installed	Disadv Comm DCFC $ incentive spent		Target Program Cost	Actual Program Cost	Savings Share	Company Share ($000s)		EAM Award ($ 000s)
	[1]	[2]	[3]	[4]=[1]/[2]*[3]	[6]	[7]=[1]/[2]*[6]		[8]	[9]	[10]	[11]		[12]=([4]*[8])+([7]*[10])	[13]=[9]+[11]	[14]	[15]=([12]-[13])*[14]		[16]=IF([15]>0, [15], 0)
Con Edison																		
EXAMPLE: 20% savings at Midpoint Review	$ 100,109	150	90%	$ 601	100%	$ 667		7,583	$ 3,643,807	6,067	$ 3,239,260		$ 8,603,835	$ 6,883,068	30%	$ 516,230		516,230
	$ 100,109	150	90%	$ 601	100%	$ 667												
Upstate Utilities																		
EXAMPLE: 20% savings at Midpoint Review (NMPC)	$ 55,000	150	90%	$ 330	100%	$ 367		8417	$ 2,222,088	6733	$ 1,975,013		$ 5,246,377	$ 4,197,101	30%	$ 314,783		314,783
	$ 55,000	150	90%	$ 330	100%	$ 367												
Input Cells																		

PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265

Public Meeting held December 20, 2018

Commissioners Present:

Gladys M. Brown, Chairman, Statement
Andrew G. Place, Vice Chairman
Norman J. Kennard
David W. Sweet
John F. Coleman, Jr.

Pennsylvania Public Utility Commission	R-2018-3000124 R-2018-3000829
Office of Consumer Advocate	C-2018-3001029
Jason Dolby	C-2018-3001074
Peoples Natural Gas Company LLC	C-2018-3001152
Office of Small Business Advocate	C-2018-3001566
Duquesne Industrial Intervenors	C-2018-3001713
Leonard Coyer	C-2018-3002424
NRG Energy Center Pittsburgh LLC	C-2018-3002755

v.

Duquesne Light Company

OPINION AND ORDER

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BY THE COMMISSION:

Before the Pennsylvania Public Utility Commission (Commission) for consideration and disposition are the Exceptions of Duquesne Light Company (Duquesne or the Company) and the Duquesne Industrial Intervenors (DII), filed on October 29, 2018, to the Recommended Decision (R.D.) of Administrative Law Judge (ALJ) Katrina L. Dunderdale, issued on October 18, 2018, in which she, *inter alia*, granted the Joint Petition for Approval of Settlement Stipulation (Joint Settlement Petition or Partial Settlement) that was filed on September 14, 2018, by Duquesne, the Commission's Bureau of Investigation and Enforcement (I&E), the Office of Consumer Advocate (OCA), the Office of Small Business Advocate (OSBA), Clean Air Council (CAC), the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (CAUSE-PA), ChargePoint, Inc. (ChargePoint), Community Action of Pennsylvania (CAAP), DII, the Keystone Energy Efficiency Alliance (KEEA), the Natural Resources Defense Council, Inc. (NRDC), NRG Energy Center Pittsburgh LLC (NRGP), and Wal-Mart Stores East, LP and Sam's East, Inc. (Wal-Mart), (collectively the Joint Petitioners). The Partial Settlement proposes to resolve all but one of the contested issues related to the rate proceeding. The remaining contested issue reserved for litigation involves the proposed rate increase by Duquesne to its Tariff Rider No. 16 – Service to Non-Utility Generating Facilities (Rider No. 16).[1] With regard to the outstanding issue, the ALJ supported DII's position and recommended that Duquesne file a tariff supplement to reduce the present Rider No. 16 rate from $2.50 kW to $0.352 per kW to reflect the actual cost of receiving service under Rider No. 16. Duquesne and DII filed Replies to Exceptions on November 5, 2018.

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[1] As discussed, *infra*, Duquesne initially proposed an increase in Tariff Rider No. 16's existing rate of $2.50 per kW rate to $8.00 per kW, but subsequently withdrew its request in an attempt to satisfy Peoples' concerns about the increase. Notwithstanding, the withdrawal of the rate increase, DII continued to oppose the Company's existing Rider No. 16. R.D. at 116.

For the reasons discussed below, with regard to the sole outstanding issue involving Tariff rider No. 16 that was left unresolved by the terms of the Partial Settlement, we shall grant Duquesne's Exceptions and deny DII's Exceptions so that Duquesne Light Company will not be required to decrease the rate in Tariff No. 16 for "back-up" service that can be elected by eligible customers that meet a portion of their load with their own generating facilities. Accordingly, we shall adopt the ALJ's Recommended Decision, as modified, and grant the Joint Settlement Petition which approves the Partial Settlement, without modification, consistent with this Opinion and Order.

As discussed below, the genesis of this proceeding involved a general rate increase in which Duquesne proposed a base rate change that would have increased its annual distribution revenue by $133.8 million, a 16.4% increase over present revenues, on a distribution revenue basis, based on a fully projected future test year (FPFTY) ending December 31, 2019. Joint Settlement, Appendix E. Our approval of the Joint Petition, which embodies a so-called "black box" settlement, permits Duquesne to file new tariff rates designed to provide an overall distribution base rate increase of $92.7 million, an 8.1% over present revenues, on a distribution revenue basis. *Id*.

I. History of the Proceeding[2]

On March 28, 2018, Duquesne[3] filed Supplement No. 174 to Tariff Electric – Pa. P.U.C. No. 24 (Supplement No. 174) to become effective May 29, 2018,

[2] An abbreviated procedural history of the proceeding is found here. See the Recommended Decision, pp. 1-7, for a more detailed history of the proceeding.

[3] Duquesne is a "public utility" and an "electric distribution company," as those terms are defined in Sections 102 and 2803 of the Public Utility Code (Code), 66 Pa. C.S. §§ 102 and 2803, and provides electric distribution and transmission services to approximately 596,000 customers in Allegheny and Beaver Counties, Pennsylvania.

containing a proposed general increase in electric distribution rates of approximately $133.8 million in additional annual base rate operating revenues based upon data for a Fully Projected Future Test Year (FPFTY) ending December 31, 2019. The proposed base rate increase included $52.2 million of revenues currently recovered by surcharges. Therefore, the proposed annual revenue increase to customers over current rates was $81.6 million.

On April 6, 2018, the Office of Consumer Advocate (OCA) filed a public statement and formal complaint at Docket No. C-2018-3001029. In addition to the formal complaint filed by the OCA, formal complaints were filed by Jason Dolby at Docket No. C-2018-3001074; the Peoples Natural Gas Company LLC (Peoples) at Docket No. C-2018-3001152; James Fedell at Docket No. C-2018-3001473;[4] the Office of Small Business Advocate (OSBA) at Docket No. C-2018-3001566; Duquesne Industrial Intervenors (DII) at Docket No. C-2018-3001713; Leonard Coyer at Docket No. C-2018-3002424; and NRG Energy Center Pittsburgh LLC (NRG Pittsburgh or NRGP) at Docket No. C-2018-3002755.

On April 19, 2018, the Commission suspended the effective date of Supplement No. 174 by operation of law, pursuant to Section 1308(d) of the Code, 66 Pa. C.S. § 1308(d), until December 29, 2018, unless permitted by Commission Order to become effective at an earlier date, and instituted an investigation into the lawfulness, justness, and reasonableness of the rates, rules, and regulations proposed in Supplement No. 174.

[4] On June 1, 2018, the presiding officer issued the Fifth Interim Order which bifurcated the formal complaint filed by James Fedell at Docket No. C-2018-3001473 from the base rate proceeding, and marked the formal complaint proceeding as closed due to the filing of a Certificate of Satisfaction, in accordance with 52 Pa. Code § 5.24.

Peoples filed a formal complaint against Duquesne, at Docket No. C-2018-3001152, on April 10, 2018. On May 1, 2018, Duquesne filed a Motion for Partial Judgment on the Pleadings against Peoples. Duquesne contended Peoples lacked standing to pursue a claim against Duquesne's proposed changes to Rider No. 16 because Peoples did not receive service under the Rider and thus, Peoples lacked standing to pursue a claim on behalf of its customers who might use Rider No. 16.

On May 15, 2018, the Office of Administrative Law Judge scheduled one public input hearing to be conducted in the afternoon of June 14, 2018, in the City of Pittsburgh, Allegheny County, Pennsylvania and another public input hearing to be conducted in the evening of June 14, 2018, in Beaver Falls, Beaver County, Pennsylvania. Notice was published in two newspapers of general circulation on June 1, 2018, and June 8, 2018.

On May 18, 2018, the Commission consolidated the temporary rates proceeding for Duquesne at Docket No. R-2018-3000829 with the pending Section 1308(d) rate proceeding at Docket No. R-2018-3000124, pursuant to the Commission's Order adopted May 17, 2018 at Docket No. M-2018-2641242 concerning the Tax Cuts and Jobs Act of 2017 (TCJA). The Commission specified the parties were expected to address the effect of the federal tax rate reductions and other changes in the TCJA on the justness and reasonableness of the consumer rates charged during the term of the suspension period and, in particular, whether a retroactive surcharge or other measure is necessary to account for the tax rate changes that became effective on January 1, 2018.

On May 22, 2018, the ALJ issued an Interim Order which granted Duquesne's Motion for Partial Judgment on the Pleadings against Peoples. The Interim Order noted Peoples was still a party in the base rate proceeding due to its status as a customer of Duquesne.

Also, on May 22, 2018, Peoples filed a Petition for Interlocutory Review and Answer to Material Question on an Expedited Basis (*IR Petition*) with the Commission, pursuant to 52 Pa. Code § 5.302(a). Peoples asked the Commission if the presiding officer erred in the Interim Order dated May 22, 2018, when granting the Motion for Partial Judgment on the Pleadings filed by Duquesne on May 1, 2018. Peoples and DII filed briefs in support of the *IR Petition*, and Duquesne filed a brief in opposition to the *IR Petition*.

On May 31, 2018, KEEA filed a Petition to Intervene. KEEA averred it consisted of over forty entities which implement energy efficiency improvements, and the proposed changes to Rider No. 16 could impact negatively the ability of KEEA entities to offer these energy efficiency improvements to customers of Duquesne.

On June 14, 2018, the ALJ conducted an afternoon public input hearing at which ten people appeared and testified under oath, and an evening public input hearing at which two people appeared and testified under oath. On the same date (June 14, 2018), the Commission issued its Opinion and Order on Peoples' *IR Petition* in which it answered in the affirmative the material question of whether the May 22, 2018 Interim Order (which granted the Motion for Partial Judgment on the Pleadings) erred by precluding Peoples, as a developer of Combined Heat and Power projects, from contesting Duquesne's proposed increase to the Back-up Rate for Combined Heat and Power projects. The Commission then returned the matter to the Office of Administrative Law Judge for further proceedings.

On August 15, 2018, the ALJ convened the Parties and conducted the Evidentiary Hearing in Harrisburg, Pennsylvania. Present were the following Parties: Duquesne, BIE, OCA, OSBA, Wal-Mart, ChargePoint, DII, CAUSE-PA, CAAP, NRDC, NRG Pittsburgh, KEEA and Peoples. The Presiding Officer concluded the proceedings on August 17, 2018. The August 15, 2018 Evidentiary Hearing generated Transcript

pages 169 through 388; the August 16, 2018 Evidentiary Hearing generated Transcript pages 389 through 639, and August 17, 2018 Evidentiary Hearing generated Transcript pages 640 through 678. The documents that were marked and admitted into evidence at the evidentiary hearing are itemized by party in an eighteen-page document marked as "Appendix A" attached to the Recommended Decision.

At the start of the August 15, 2018 Evidentiary Hearing, Duquesne advised the ALJ that a Partial Settlement in principle had been reached between Duquesne and all of the other active parties except Peoples. Duquesne also advised that the Partial Settlement covered all issues except the Rider No. 16 issue. Duquesne provided the presiding officer with a confidential summary list of the settlement provisions. The Evidentiary Hearing proceeded on the litigated issue involving Rider No. 16.

At the start of the August 17, 2018 Evidentiary Hearing, Duquesne advised the Presiding Officer that it officially had withdrawn its request to amend Rider No. 16, and that Peoples no longer objected to the settlement. However, DII indicated it still wished to pursue its objection to Rider No. 16 and requested the opportunity to question witnesses on August 17, 2018, and to brief the Commission on its position. Both requests were granted. On September 6, 2018, Main Briefs were received from Duquesne and DII.

On September 14, 2018, Reply Briefs (R.B.) were received from Duquesne and DII. On the same date, Duquesne, on behalf of all signatories, filed the Joint Settlement Petition including attached Statements in Support. The following parties joined with Duquesne in requesting that the Commission approve the proposed resolution: BIE, OCA, OSBA, CAUSE-PA, DII, CAAP, Wal-Mart, ChargePoint, KEEA, NRG Pittsburgh, CAC, and NRDC. Peoples and IBEW indicated they had no objection to the Partial Settlement.

On September 14, 2018, the ALJ issued a letter to all formal Complainants in which she advised them of their right to comment, agree or object to the Partial Settlement and how their responses could be included in the record in this proceeding. On October 2, 2018, the record was closed. The record is comprised of Transcript Pages 1 through 678 in addition to the statements and exhibits listed in Appendix A of the Recommended Decision.

As noted, Exceptions were filed by Duquesne and DII on October 29, 2018. Duquesne and DII filed Replies to Exceptions on November 5, 2018.

II. Introduction

As a preliminary matter, we note that any issue that we do not specifically delineate shall be deemed to have been duly considered and denied without further discussion. The Commission is not required to consider expressly or at length each contention or argument raised by the parties. *Consolidated Rail Corp. v. Pa. PUC*, 625 A.2d 741 (Pa. Cmwlth. 1993); also see, generally, *University of Pennsylvania v. Pa. PUC*, 485 A.2d 1217 (Pa. Cmwlth. 1984).

In her Recommended Decision, the ALJ made seventy Findings of Fact and reached eleven Conclusions of Law. R.D. at 145-155, 178-180. The Findings of Fact and Conclusions of Law are incorporated herein by reference and are adopted without comment unless they are either expressly or by necessary implication rejected or modified by this Opinion and Order.

A. Legal Standards

The purpose of this investigation is to establish distribution rates for Duquesne's customers that are "just and reasonable" pursuant to Section 1301 of the

Code. A public utility seeking a general rate increase is entitled to an opportunity to earn a fair rate of return on the value of the property dedicated to public service. *Bluefield Water Works and Improvement Co. v. Public Service Comm'n of West Virginia,* 262 U.S. 679 (1923).

In determining what constitutes a fair rate of return, the Commission is guided by the criteria set forth in *Bluefield, supra* and *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944). In *Bluefield* the United States Supreme Court stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

Bluefield, 262 U.S. at 692-3.

The policy of the Commission is to encourage settlements, and the Commission has stated that settlement rates are often preferable to those achieved at the conclusion of a fully litigated proceeding. 52 Pa. Code §§ 5.231, 69.401. A full settlement of all the issues in a proceeding eliminates the time, effort and expense that otherwise would have been used in litigating the proceeding, while a partial settlement

may significantly reduce the time, effort and expense of litigating a case. A settlement, whether whole or partial, benefits not only the named parties directly, but, indirectly, all customers of the public utility involved in the case.

Rate cases are expensive to litigate, and the reasonable cost of such litigation is an operating expense that is recovered in the rates approved by the Commission. Partial or full settlements allow the parties to avoid the substantial costs of preparing and serving testimony and the cross-examination of witnesses in lengthy hearings as well as the preparation and service of briefs, reply briefs, exceptions and replies to exceptions, together with the briefs and reply briefs necessitated by any appeal of the Commission's decision; yielding significant expense savings for the company's customers. For this and other sound reasons, settlements are encouraged by long-standing Commission policy.

Despite the policy favoring settlements, the Commission does not simply rubber stamp settlements without further inquiry. In order to accept a rate case settlement such as that proposed here, the Commission must determine that the proposed terms and conditions are in the public interest. *Pa. PUC v. York Water Co.*, Docket No. R-00049165 (Order entered October 4, 2004); *Pa. PUC v. C. S. Water and Sewer Assoc.*, 74 Pa. P.U.C. 767 (1991).

With regard to the burden of proof in this matter, Section 315(a) of the Code provides:

> **§ 315. Burden of proof**
>
> **(a) Reasonableness of rates.—**In any proceeding upon the motion of the commission, involving any proposed or existing rate of any public utility, or in any proceedings upon complaint involving any proposed increase in rates, the burden of proof to show that the rate involved is just and

> reasonable shall be upon the public utility. The commission shall give to the hearing and decision of any such proceeding preference over all other proceedings and decide the same as speedily as possible.

66 Pa. C.S. § 315(a). Consequently, in this proceeding, Duquesne has the burden to prove that the rate increase proposed by the Partial Settlement is just and reasonable. The Joint Petitioners have reached an accord on many of the issues and claims that arose in this proceeding and submitted the Settlement. The Joint Petitioners have the burden to prove that the Partial Settlement is in the public interest.

III. Joint Petition for Partial Settlement

A. Terms and Conditions of the Partial Settlement

As noted, the Joint Petitioners agreed to the Partial Settlement covering all issues except for one – the issue involving the proposed revisions by Duquesne to Rider No. 16 (Service to Non-Utility Generating Facilities). The Partial Settlement, if approved, will result in a net increase in annual base distribution operating revenues of $92.7 million. This increase includes $52.2 million of revenues that are currently recovered from customers through various surcharges.[5] Thus, the remaining $40.5 million attributed to non-surcharge revenues represent approximately a 50% reduction to the $81.6 million originally proposed by Duquesne on its base rates. The Joint Petitioners have agreed, *inter alia,* to a base rate increase, an allocation of that revenue increase to the rate classes, a rate design for each rate class, universal service, customer service, time of use, and master metering matters, and an Electric Vehicle ChargeUp Pilot

[5] The Partial Settlement reflects a roll-in of current recoveries under the Smart Meter Charge (SMC), Distribution System Improvement Charge and the Purchase of Receivable Portion of the Retail Market Enhancement Surcharge. Partial Settlement Appendix F at ii-iii.

(EV Pilot) program. As noted, the Partial Settlement further provides that the Parties to this proceeding have reserved for litigation, the issues related to Rider No. 16 – Service to Non-Utility Generating Facilities. All parties in this proceeding either support or do not oppose the Partial Settlement. Partial Settlement at 1-2.

The Settling Parties stated that the Partial Settlement was achieved after an extensive investigation of Columbia's filing, including extensive informal and formal discovery and the filing of direct, rebuttal, surrebuttal and rejoinder testimony by a number of the Joint Petitioners. Partial Settlement ¶ 61 at 19-20. They also stated that the Partial Settlement is in the public interest for the reasons set forth in their respective Statements in Support. Partial Settlement ¶ 64 at 20.

The Joint Settlement Petition contains the terms and conditions of the Partial Settlement and Appendices A through T. Appendix A to the Partial Settlement sets out the tariff supplements to be filed and to become effective in accordance with the Partial Settlement. Appendix B sets out the proof of revenues. Appendix C presents the present rates, the proposed rates, and the effects of the Partial Settlement on each rate class. Appendix D presents the allocation of the tax refund resulting from the TCJA. Appendix E represents the revenue allocation to each class at the net settlement increase of $40.5 Million. Appendix F sets forth the proposed Findings of Fact, Conclusions of Law, and Ordering Paragraphs. Appendices G through R represent the Statements in Support filed by Duquesne, I&E, the OCA, the OSBA, CAUSE-PA, DII, ChargePoint, Walmart, NRDC, KEEA, NRGP[6], and CAAP, respectively. Appendices S and T are letters of non-opposition filed by Peoples and IBEW.

[6] NRGP supports only the provisions of the Partial Settlement relating to the stipulation between NRGP and Duquesne as set forth in Section E, Paragraph No. 60 of the Settlement. NRGP does not oppose the remainder of the Settlement. Partial Settlement at 2, n.2.

The essential terms of the Partial Settlement are set forth in Paragraph Nos. 30 through 60 of the Joint Petition, which is shown below in full as it appears in the Joint Petition:

A. REVENUE REQUIREMENT AND ACCOUNTING

30. The distribution rates set in this proceeding will be designed to produce increased base operating revenues of $92.7 million based upon the pro forma level of operations for the twelve months ended December 31, 2019, inclusive of the $52.2 million of revenues recovered under current surcharges, for a net increase in revenues of $40.5 million.

31. Duquesne Light will provide a refund to customers of $24 million, which includes interest. This amount resolves the parties' positions regarding the return of 2018 federal income tax expense savings and 2018 Excess Deferred Income Taxes ("EDIT"). Duquesne Light will refund this amount beginning January 2019 through a one- or two -time bill credit on a distribution revenue basis. The provision of this credit to customers will be subject to audit to ensure that the Company has returned the full amount of the credit to customers in the manner referenced herein. The allocation of the tax refund is set forth in **Appendix D**. As set forth in **Appendix D**, the credit for most customers will be a fixed amount per customer based upon the allocation of the refund to class divided by the number of customers in the class as of December 1, 2018. The credit for other customers will be an individual calculation based on the percentage of each customers' base distribution revenue to the class distribution revenue for the period of December 1, 2017 through November 30, 2018.

32. The level of revenue requirement included in this Settlement reflects the resolution of the parties' positions in the dispute regarding the application of 66 Pa.C.S. § 1301.1 in this case.

33. As of the effective date of rates in this proceeding, Duquesne Light will be eligible to include plant additions in the Distribution System Improvement Charge ("DSIC") once the total eligible account balances exceed the levels projected by the Company in this proceeding at December 31, 2019. The foregoing provision is included solely for purposes of calculating the DSIC, and is not determinative for future ratemaking purposes of the projected additions to be included in rate base in an FPFTY filing.

34. For purposes of calculating its DSIC, Duquesne Light shall use the equity return rate for electric utilities contained in the Commission's most recent Quarterly Report on the Earnings of Jurisdictional Utilities and shall update the equity return rate each quarter consistent with any changes to the equity return rate for electric utilities contained in the most recent Quarterly Earnings Report, consistent with 66 Pa. C.S. § 1357(b)(3), until such time as the DSIC is reset pursuant to the provisions of 66 Pa. C.S. § 1358(b)(1).

35. Duquesne Light will continue to use normalization accounting with respect to the benefits of the tax repairs and Internal Revenue Code ("IRC") Section 263A deductions. Duquesne Light will reverse EDIT with regard to prior tax repairs and IRC Section 263A deductions pursuant to the Average Rate Assumption Method ("ARAM") used to reverse EDIT associated with accelerated depreciation deductions. The remaining unamortized EDIT balance will continue as a reduction to rate base in all future base rate proceedings until the full amount is returned to ratepayers.

36. Duquesne Light will be permitted to amortize its costs related to the following:

(i) Electrical Model — Commencing with the effective date of rates in this proceeding (December 29, 2018), the Company will be permitted to amortize the estimated non-labor expenses for the field inventory and graphic design tool of $20.6 million related to the development and implement-

tation of the electrical model over a five year period for an annual amortization of $4.12 million per year.

37. Commencing with calendar year 2019, Duquesne Light will deposit into its pension trusts an amount equal to $10 million per year; provided, however, that contribution(s) in any year in excess of the foregoing may be used on a cumulative basis to satisfy future contribution obligations under this Settlement. The Settlement provides for recovery of the expense component of $5 million (50% of the average cash contributions) of projected future pension contributions. Additionally, Duquesne Light will be permitted to include the other 50% of actual pension contributions from January 1, 2007, forward, net of related accumulated deferred income taxes, in rate base for rate making purposes. The rate base adjustment for pensions shall be the amount necessary to adjust the Accounting Standards Codification ("ASC") 715 capitalized pension amounts to equal accumulated capitalized pension contributions, net of applicable deferred income taxes, from January 1, 2007 forward. The depreciation expense for book and ratemaking purposes will be based on the ASC 715 capitalized amounts. The adjusted amounts will be used for reporting rate base in reports to the Commission. If Duquesne Light concludes that a contribution less than $10 million to the pension trust is appropriate, the Company may reduce the pension contribution and will record a regulatory liability on its books of account that is equal to 50% of the reduction to the pension contribution below the level of $10 million. Any regulatory liability recorded will be reduced to the extent of 50% of contributions in excess of $10 million in subsequent years. If a regulatory liability remains at the time of the Company's next rate proceeding, the regulatory liability amount will be returned to ratepayers as directed in the next base rate proceeding. Any amount recorded as a regulatory liability shall not bear an interest obligation. Duquesne Light shall provide a report and affidavit attesting to the actual contributions to pension trusts during each calendar year. The report and affidavit shall be publicly filed with the Commission, with copies provided to I&E, OCA and OSBA on or before January 31 of the following calendar

year, with the first report and affidavit due on or before January 31, 2020.

38. The Company's distribution rate allowance for Other Post Employment Benefits ("OPEBs") is based upon the estimated ASC 715 cost for the FPFTY of approximately $0.4 million ($0.3 million on a distribution basis), which reflects a two-year normalization of the Net Periodic Benefit Cost for historic and future test year distribution costs. The distribution expense component included in rates is approximately 50% of this estimated cost less the annual effect of the 3-year amortization of the regulatory liability of $2.6 million ($2.2 million on a distribution basis) as explained in Duquesne Light St. No. 2, p. 29, for a net distribution credit of $0.6 million. The remaining 50% of actual ASC 715 cost will be the amount to be capitalized on the Company's books. The actual labor capitalization ratio will be used to determine the split between capitalized and expensed amounts. The Company accounts for and funds OPEBs through a Voluntary Employees Beneficiary Associated ("VEBA") trust, into which it will deposit the full amount of annual costs calculated by the Company's actuary pursuant to ASC 715. Retiree OPEBs and administrative costs of maintaining the trusts and/or accounts are paid from amounts deposited in the trust. The Company accounts for the difference between the net periodic postretirement benefit expense determined annually by the actuary in accordance with ASC 715 and the amount of ASC 715 postretirement benefit expense used to establish rates. That difference is recorded as a regulatory asset or liability and will be expensed or credited in future base rate proceedings in determining OPEB expense included in rates.

39. Duquesne Light's jurisdictional separation study of distribution and transmission costs and assets shall be approved for purposes of this case only and shall hold no precedential value in a future base rate proceeding. All parties reserve the right to challenge the jurisdictional separation study in future matters.

40. Duquesne Light will file a Total Company Pennsylvania jurisdictional report showing capital

expenditures, plant additions and retirements, by month, for the Future Test Year ("FTY") ending December 31, 2018, and the FPFTY ending December 31, 2019, by July 31 of each of the years following the test years. In Duquesne Light's next base rate proceeding, the Company will prepare a comparison of its actual expenses and rate base additions for the twelve months ending December 31, 2019, to its projections in this case. However, it is recognized by Joint Petitioners that this is a black box settlement that is a compromise of the Joint Petitioners' positions on various issues.

41. Commencing with implementations subsequent to May 1, 2015, the Company shall be permitted to capitalize the development costs for cloud-based information systems. The Company will record the costs related to the development of cloud-based information systems as a regulatory asset at the time such costs are incurred. The Company shall begin amortization of the costs after the systems are placed in service. Amortization of the regulatory asset will be included in the Company's depreciation claim and the unamortized balance in the regulatory asset account will be included in rate base in the Company's current and future base rate proceedings. Nothing in this provision shall preclude a challenge to the prudence or reasonableness of specific cloud-based expenditures in a future base rate proceeding.

42. In each base rate case in which the Company proposes to recover costs of cloud-based information systems that were recorded in the regulatory asset, pursuant to paragraph 41 as a capital cost for ratemaking purposes, the Company will provide a listing of the cloud-based computing costs by year, as well as the expected useful life of each item. This requirement applies to the costs of cloud-based information systems recorded in the regulatory asset that were not capitalized for Generally Accepted Accounting Principles ("GAAP") purposes.

43. The timing of a Company notice with regard to annual dividends in excess of 85% of annual net income will be revised to the following: The Company must provide notice and explanation to the Commission when annual

dividend payments in the preceding 12 months ended March 31st exceed 85% of annual net income of the prior calendar year. With the revised language, the Company will be able to adjust its distributions in the first quarter of the following year in order to avoid inadvertently violating the advance notice requirement currently in place.

44. Duquesne Light will update the unbundled costs that are currently recovered in default service rates that were previously approved by the Commission as part of the Petition of Duquesne Light Company for Approval of a Default Service Plan for the Period June 1, 2017, to May 31, 2021, at Docket No. P-2016-2543140. Exhibit DBO-5 reflects the updated unbundling costs. These updated unbundling costs will be fixed and reconciled only for differences between projected and actual consumption. The Company would reflect the updated unbundled costs in rates effective June 1, 2019, the first effective default service supply rate change for all classes after new distribution rates become effective December 29, 2018.

B. DUQUESNE LIGHT PROGRAMS

45. The Electric Vehicle ChargeUp Pilot ("EV Pilot") is resolved on the following terms and conditions:

a. The Company's proposed DC Fast Charging Evaluation will be limited to make ready infrastructure, as defined in DLC Statement No. 6, and fast charging stations owned by the Company to be used solely for the Company and the Port Authority of Allegheny County electric bus evaluation. The cost associated with this investment included in rate base in this case is $500,000.

b. The Company's Level 2 charging proposal will be limited to the Company's investment in make ready infrastructure to provide electric service to charging stations owned by other parties with at least 4 charging stations available to the public. The Company's total

investment in these facilities under the pilot will be limited to $1.3 million: approximately $650,000 of this investment will be capital investment in front of and including the meter, and approximately $650,000 will be expense investment in the form of rebates behind the meter. The Company will be permitted to capitalize all costs for infrastructure in front of and including the meter. The Company will be permitted to provide a rebate for costs for infrastructure behind the meter and will be permitted to record these rebate costs as a regulatory asset. The Company will provide a report in its next base rate proceeding. The report will evaluate customer participation and feedback, public access to charging stations and charger station usage and identify the charging station revenues received by the Company from charging station owners. Report results will be broken down by year. Determination of the appropriate method of cost recovery for the behind the meter Level 2 rebate costs will be deferred to the Company's next base rate case.

c. Customer education costs with regard to the EV Pilot in this proceeding are reduced to $200,000 to reflect the reduction in scope of the pilot in this settlement.

d. The Company will assess the EV Pilot data and develop a plan for an EV load management program to be proposed in its next base rate case proceeding.

e. Customer Electric Vehicle Registration Incentives in this proceeding are reduced to $70,000 per year. Any unused portion of the $70,000 per year will be addressed in the next base rate proceeding.

f. The Company will develop annual public reports, submitted to the Commission, to track

the progress of the EV Pilot implementation. Metrics include:

i. Charging infrastructure deployed over time, including by location and date of activation;

ii. Charging infrastructure installation costs by site type (broken out by capital and rebate costs);

iii. For all charging stations deployed through the EV Pilot: the usage rate by site type and charger type;

iv. Estimated avoided air emissions resulting from the programs.

46. Duquesne Light's revised Light Emitting Diode ("LED") Street Light Program, as explained in Duquesne Light Statement No. 6 and as set forth in Rate SM of the Company's tariff Supplement No. 174, is approved. See Duquesne Light Exhibit No. DBO-1.

47. Duquesne Light's proposed fee free bank card payment program, as described in DLC Statement No. 7, is approved.

48. Duquesne Light withdraws its Woods Run Microgrid proposal without prejudice.

C. REVENUE ALLOCATION AND RATE DESIGN INCLUDING CUSTOMER CHARGE

49. The revenue allocation to each class at the net settlement increase of $40.5 million is reflected in **Appendix E**.

50. The fixed monthly charge for Rates RS, RA, RH and GS will be increased from $10.00 per month to $12.50 per month

D. UNIVERSAL SERVICE, CUSTOMER SERVICE, TIME OF USE SERVICE AND MASTER METERING

51. Duquesne Light agrees that its proposal to remove the phrase "for which service is requested" from its retail tariff Rule No. 5a is withdrawn.

52. Within 120 days of the entry of a Commission order approving this settlement, Duquesne Light agrees to hold a non-confidential collaborative with all interested stakeholders to obtain stakeholder input regarding residential time-of-use rates. Duquesne Light agrees to continue with a second non-confidential collaborative with all interested stakeholders to obtain additional stakeholder input regarding residential time-of-use rates within 30 to 60 days after its initial collaborative. Duquesne Light agrees to consider in good faith the issues and suggestions raised in the collaboratives. Duquesne Light agrees to make a proposal regarding time-of-use rates in its next default service rate filing, unless the Commission directs that Duquesne Light make a time-of-use rate filing prior to its next default service rate filing. All parties retain all rights to challenge the rates, terms and conditions proposed by Duquesne Light with regard to its time-of-use rates. This paragraph 52 does not supersede any Commission directive relating to time-of-use rates that conflicts with the provisions herein.

53. Duquesne Light intends to provide anonymized aggregate energy usage data for residential multifamily buildings that are 50,000 square feet or larger and will provide periodic updates to the Income Eligible Program Advisory Group regarding the status of implementation. Duquesne Light further agrees to participate in any working group established by the City of Pittsburgh to address the issue of energy efficiency benchmarking for multifamily buildings.

54. Starting with its 2019 program year, Duquesne Light will use its best efforts to ensure that 10% of its completed Low Income Usage Reduction Program ("LIURP") jobs are for electric heating customers, and will

provide reports on its progress toward reaching that goal to members of its Income Eligible Advisory Group. Duquesne Light will increase its LIURP budget by $140,740 annually to accommodate for the increased cost to remediate electric heating customer usage. Duquesne Light agrees to review the list of customers with high Customer Assistance Program ("CAP") credits (over $1,000) from the prior year and prioritize those customers for LIURP treatment when possible. If the list has been exhausted, Duquesne Light will use the high usage CAP customer list as well as eligible customers requesting weatherization. This prioritization will continue unless Duquesne Light evaluates the cost-effectiveness of the prioritization, and reviews that evaluation with stakeholders.

55. Within 60 days of the effective date of rates, Duquesne Light will revise its medical certificate policy and accompanying procedures to accept medical certificate renewals if the customer's current bill or budget bill amount is paid in full by the due date while under the protection of a medical certificate. Customers will not be limited to two medical certificate renewals if the provisions of this paragraph are met. Upon submission of an initial medical certificate, Duquesne Light will inform customers that they can continue to renew their medical certificate and continue to receive medical certificate protection if they continue to pay their current bill or budget bill amount in full by the due date for the duration of their medical condition or emergency, and that they remain responsible for any outstanding balance. Duquesne Light will also refer customers to any available bill payment assistance programs, including CAP, Hardship Fund, Customer Assistance Referral Evaluation Services ("CARES"), and Low Income Home Energy Assistance Program ("LIHEAP"), and will work with customers protected by a medical certificate to establish an equitable payment arrangement for outstanding arrears pursuant to Commission rules. Duquesne Light will share its revised policy with parties to this proceeding, and will provide an opportunity for feedback and suggestions. Duquesne Light may amend this policy in response to future Commission rulemakings, orders or policy. Duquesne Light will be

permitted to write off any outstanding balances overdue for more than one year for customers that have medical certificates for a period of one year or longer.

56. Within 60 days of the effective date of rates, Duquesne Light will revise its Protection From Abuse Order ("PFA") policy and accompanying procedures to accept PFAs or civil or criminal court orders with evidence of domestic violence toward an applicant for service, a current customer, or a member of the applicant or customer's household, consistent with 66 Pa. C.S. § 1417 and 52 Pa. Code Ch. 56, subsections L-V. Duquesne Light will share its revised policy with the Income Eligible Program Advisory Group, and will provide an opportunity for feedback and suggestions.

57. Duquesne Light will engage in discussions regarding budget billing issues with its Income Eligible Program Advisory Group and will consider proposals to address these issues in its next base rate proceeding. If prior to the next base rate proceeding, consensus is reached among the Income Eligible Program Advisory Group and the Company on implementation of particular budget billing proposals and the Company determines that those proposals will have minimal or no revenue impact, Duquesne Light agrees that it will implement those proposals as soon as practicable.

58. Duquesne Light will conduct a competitive selection process, such as a Request for Proposal, for the purpose of determining its universal service program provider(s). Duquesne Light will invite local community based organizations ("CBO") to participate in the competitive selection process. Final selection of universal service program providers will be determined in accordance with Duquesne Light's processes and procedures. A description of CBO participation in Duquesne Light's universal services programs will be included in its Universal Services and Energy Conservation Plan that is filed with the Commission for review and approval.

59. Within 180 days of the effective date of rates, Duquesne Light will convene a non-confidential collaborative

with all parties to this proceeding, and all interested stakeholders who are developers of multifamily housing within its service territory, to discuss the feasibility of revising its retail tariff to permit master-metering of multifamily housing. Parties to the collaborative will specifically consider:

a. Under what circumstances master-metering would be permitted, and the factors Duquesne Light would require a building owner to meet before approving a master-metering configuration;

b. The impact that any such tariff change would have on low income tenants' ability to continue to afford utility service;

c. The impact of individual customers not utilizing Advanced Metering Infrastructure ("AMI") meters; and

d. The impact that any such change would have on the Company's revenue allocation and the ability to meet its projected revenue requirements.

The parties to the collaborative will make a good faith effort, in coordination with the Company, to develop consensus on the scope of a tariff revision that permits master-metering, taking into consideration all of the foregoing factors. Additional collaborative meetings will be held thereafter, as necessary, but not less than on an annual basis, in an effort to reach consensus on any issues which remain unresolved after the first collaborative is held. Based on feedback from the collaborative meetings, Duquesne Light will present a proposal regarding master-metering of multifamily housing buildings as a part of its next general base rate case. The treatment of any alleged confidential information during the collaborative will be subject of an agreement of the parties and stakeholders participating in the collaborative.

E. OTHER ISSUES

60. Duquesne Light, on behalf of itself and its affiliates, will not develop or fund (except such projects incented through Duquesne Light Act 129 programs) a

> project for the generation or distribution of steam, hot water, or chilled water (except for self-service) within the then-certificated service territory of NRGP, without sending letter notification to NRGP at least forty-five (45) days prior to the commencement of any construction activities or funding disbursements related to any such project. The letter notification will identify the customers that will be served, what service will be provided, and how service will be provided. Duquesne Light will cooperate in providing additional information to NRGP with respect to such project upon request from NRGP.

Partial Settlement at 8-19.

The Joint Petitioners included a comparison of the distribution and total bills for a residential rate RS customer using 600 kWh at present, proposed, and settled rates. As shown in the first column (Distribution Increase) in the table below, the Joint Petitioners indicated that an RS customer who presently pays $44.28 in monthly distribution charges will pay $48.64 (9.85% increase over present rates) under the Settlement compared to $52.94 (19.55% increase over present rates) as originally proposed by the Company. The second column (Total Bill Increase), which include transmission, generation and additional surcharges, in addition to distribution charges, indicates that an RS customer who presently pays $98.15 in their total bill will pay $102.51 (4.44% increase over present rates) under the Settlement compared to $106.80 (8.82% increase over present rates) as originally proposed by the Company.

Distribution Increase		**Total Bill Increase**	
Present Distribution Bill	$44.28	Present Total Bill	$98.15
Proposed Distribution Bill	$52.94	Proposed Total Bill	$106.80
Proposed Percentage Distribution Increase	19.55%	Proposed Percentage Total Increase	8.82%
Settled Distribution Bill	$48.64	Settled Total Bill	$102.51
Settled Percentage Distribution Increase	9.85%	Settled Percentage Total Increase	4.44%

Partial Settlement at 3, Appendix C at 1.

In addition to the specific terms to which the Joint Petitioners have agreed, the Partial Settlement contains other general terms and conditions typically found in settlements submitted to the Commission. Specifically, the Joint Petitioners agreed that the Partial Settlement is conditioned upon the Commission's approval of all the terms and conditions contained therein without modification. The Joint Settlement Petition establishes the procedure by which any of the Joint Petitioners may withdraw from the Partial Settlement and proceed to litigate this case, if the Commission should act to modify or reject the Settlement. In addition, the Joint Petitioners asserted that although the Partial Settlement is proffered to settle the instant case, it may not be cited as precedent in any future proceeding, except to the extent required to implement any term specifically agreed to by the Joint Petitioners. The Joint Petitioners further submitted that the Partial Settlement is made without any admission against, or prejudice to, any position which any of the Joint Petitioners might adopt in future proceedings, except to the extent necessary to effectuate or enforce any term specifically agreed to in the Partial Settlement before us. Partial Settlement ¶¶ 65-69 at 20-21. Moreover, the Joint Petitioners waived their right to file Exceptions in this case if the ALJ, in her Recommended Decision, recommended the Commission adopt the Partial Settlement in full. However, the Joint Petitioners expressly submitted that they did not waive their rights to file Exceptions in response to issues reserved for litigation. *Id.* ¶ 71 at 21.

The Joint Petitioners respectfully requested that the ALJ and the Commission approve the Partial Settlement, including all terms and conditions thereof, subject to the resolution of the issue reserved for litigation. Partial Settlement at 21-22.

B. Highlighted Issues

At the hearing in this proceeding, the ALJ informed the Joint Petitioners of her concerns regarding certain of the provisions of the Partial Settlement and requested that the Joint Petitioners, particularly Duquesne, provide justification in their respective Statements in Support for why these elements should remain in the Settlement. Tr. at 67-77. These issues are discussed in more detail below.

1. Proposed Changes to Rider No. 21

In its initial filing, Duquesne proposed to update its Rider No. 21 – Net Metering Service to reflect a requirement that rate payers who are customer generators must install a generation meter at all new net metered facilities after December 29, 2018. This proposal was not opposed by any other Party and was preserved without modification in the Partial Settlement. Duquesne Statement in Support at 29. At the hearing, the ALJ instructed the Joint Petitioners to explain the specific proposed changes to Rider 21 and to also explain how these changes will remain in compliance with the Commission's regulations at 52 Pa., Code § 75.14, related to meters and metering. Tr at 675-76.

a. Positions of the Parties

Duquesne explained that under this proposal, it would install an additional meter at new net metered facilities to measure the facility's total generation output and that the customer would be responsible for installing the meter socket for the generation meter. Duquesne noted that although this would not be required for existing net metered facilities or those in the interconnection queue, it reserved the right to retrofit such facilities with a generation meter at its expense. Duquesne reasoned that its proposal supports distributed generation implementation by enabling Duquesne to gather more

granular data regarding net metered facility generation output, which could be useful for Duquesne in distribution planning and operations and could also be useful in the aggregate to the Commission and other interested parties. Duquesne Statement in Support at 29.

Duquesne claimed that this proposal is consistent with our regulations at 52 Pa. Code § 75.14 because it does not implicate the requirement under this section that a customer-generator facility must be equipped with a bidirectional meter. Rather, Duquesne submitted that it would continue to equip net metered facilities with a bidirectional net meter for billing-related purposes, including the measurement of net consumption and/or excess generation credits. Thus, according to Duquesne, net-metered customers would not experience any change in the manner, speed, or degree at which they realize the benefits of net metering because the generation meter would be used solely for data collection purposes. Duquesne Statement in Support at 29-30.

Duquesne also noted that the incremental costs associated with its proposal would be allocated consistent with its existing practice. Namely, Duquesne would bear the costs of the generation meter and customers would bear the costs of installing the new meter socket which would accommodate this meter. Duquesne argued that procuring and installing an additional meter socket would result in incremental customer costs of about $75. In Duquesne's view, this cost is reasonable in light of the benefits that it claims the generation meters will yield. Further, Duquesne explained that the revenue impacts of these incremental costs are reflected in the negotiated black box revenue requirement. Duquesne Statement in Support at 31.

b. ALJ's Recommendation

The ALJ recommended that Duquesne's request to amend its Rider No. 21, as outlined above, be denied. The ALJ found Duquesne's proposal to be contrary to the

language of 52 Pa. Code § 75.13(k), which prohibits an EDC from charging a fee or other type of charge to a net metered customer generator if that fee or charge is not applied to other customers of the EDC who are not customer-generators. The ALJ pointed out that under this regulation, an EDC may not require additional equipment unless the Commission specifically authorizes the additional equipment. The ALJ concluded that Duquesne failed to justify why it is just or reasonable to impose a new fee on new customer-generators that does not apply to other customers. According to the ALJ, while collecting information to assist with future planning is a valid exercise, such data collection does not justify the cost associated with the installation of the generation meter socket. In the ALJ's view, Duquesne's proposed revision would discourage the installation of new generating facilities, resulting in a reduction in energy conservation efforts, which is contrary to the goals of the Commission. R.D. at 163-64.

2. Allowed Smart Meter Costs

In this proceeding, Duquesne requested permission to roll its SMC into base rates. Additionally, Duquesne noted that its smart meter installations will be completed by the end of 2019, which corresponds to the FPFTY in this proceeding. Duquesne Statement in Support at 6. At the hearing, the ALJ inquired as to whether the inclusion of smart meter costs complies with prior Commission Orders and whether the Commission has already granted permission for this type of cost to be included. Tr. at 676

a. Positions of the Parties

Duquesne asserted that all SMC costs have been subject to audit as part of the reconcilable surcharge and any costs that were previously included in the surcharge remain subject to audit pursuant to the Commission's rules and regulations. Duquesne represented that any smart meter costs that were not previously included in its SMC were

included in the test years in this proceeding and were subject to review by the Parties to this proceeding. Citing to Section 2807(f)(7) of the Code, 66 Pa. C.S. § 2807(f)(7), Duquesne submitted that electric distribution companies are permitted to recover smart meter costs through an automatic adjustment clause or through base rates. Therefore, Duquesne reasoned that its proposal to roll its SMC into base rates and to recover remaining smart meter costs in base rates is appropriate. Duquesne Statement in Support at 6-7.

The OCA submitted that Duquesne's proposal should be approved without modification because it is consistent with the Code and with prior Commission orders. Specifically, the OCA cited to *Petition of West Penn Power Company for Approval of Smart Meter Deployment Plan,* Docket No. R-2014-2428742. OCA Statement in Support at 22-23.

b. ALJ's Recommendation

The ALJ recommended approval of this Partial Settlement provision. The ALJ highlighted the assertions of Duquesne and the OCA that the smart meter costs included in Duquesne's rate base do not include any previously-denied smart meter costs. The ALJ also highlighted Duquesne's assertion that the smart meter costs that are included in base rates are subject to audit. R.D. at 164-65.

3. Allocation of 2018 Tax Refund

The ALJ requested that the Joint Petitioners provide an allocation, by rate class, of the 2018 tax refund that is outlined in Paragraph No. 31 of the Partial Settlement. Tr. at 676.

a. Positions of the Parties

As noted above, the Joint Petitioners presented the proposed tax refunds by rate class in Appendix D to the Settlement.

b. ALJ's Recommendation

The ALJ found that in laying out the proposed refunds by rate class, the Joint Petitioners did not provide an estimate of the refund amounts to be disbursed to the medium and large commercial and industrial classes, or for Rate SM.[7] Instead, the ALJ pointed out that the Joint Petitioners included a footnote indicating that each such customer will have its refund calculated individually based on the percentage of actual base distribution revenue. The ALJ determined that the Joint Petitioners failed to provide any detail or guidance as to how Duquesne will calculate the amounts to be refunded to the Commercial and Industrial classes and failed to explain why an estimate cannot be provided for the customer classes with a single customer or a small number of customers. Therefore, the ALJ recommended that Duquesne be directed to file with the Commission's Bureau of Technical Utility Services (TUS) a list or calculation of how the $24 million tax refund will be allocated to the various rate classes. R.D. at 166-168.

Notwithstanding the above, the ALJ found the $24 million tax refund to be an appropriate amount. The ALJ pointed out that this amount more than doubles the refund amount initially suggested by Duquesne. The ALJ concluded that Duquesne's proposal to refund its customers in the first one or two pay periods of 2019 is in the public interest because refunds will be provided to these customers in a timely manner. R.D. at 168.

[7] Rate SM is for Street light Municipal customers.

4. Electric Vehicle Program

With regard to the EV Pilot Program outlined in Paragraph No. 45 of the Partial Settlement, the ALJ instructed the Joint Petitioners to (1) explain who will receive the EV Pilot rebates, (2) explain the allocation of EV Pilot costs to the customer classes and (3) provide justification for why consumers should pay the costs to install the stations that will be owned by third parties. Tr. at 676.

a. Positions of the Parties

In its Statement in Support, Duquesne explained that the EV Pilot rebates will be available to customers that register their EV with Duquesne. Duquesne submitted that this will permit the Company to enter the EV into the electrical model and evaluate the impacts on the system, which will assist in grid planning. Additionally, Duquesne explained that the rebates are designed to encourage third parties to purchase and install public chargers to allow the EV pilot to succeed. Duquesne pointed out that under the Partial Settlement, the rebates are not included in the rate increase, but will be recorded as a regulatory asset and claimed in a future rate case. Duquesne Statement in Support at 17-18.

Duquesne next explained that there is no specific allocation of EV Pilot costs to customer classes. Instead, they are allocated across all classes. Further, Duquesne clarified that it is not installing charging stations other than the DC Fast Charging stations for its own use and for the Port Authority of Allegheny County (PAAC) electric bus evaluation pilot. Duquesne stated it will provide make ready infrastructure and rebates for certain behind the meter equipment. According to Duquesne, because these stations must be available to the general public and not for private use, this ensures that the stations will be available to all people in Duquesne's service territory and not just to a limited subset. Additionally, Duquesne argued that this

will allow it to evaluate the effect of adding the Level 2 chargers to its distribution grid for grid planning purposes and will increase the usage of its distribution system, which benefits all customers. Duquesne Statement in Support at 18-19.

In its Statement in Support, I&E submitted that the Partial Settlement permits limited implementation of the EV Pilot in a manner that ensures that it benefits the public without imposing unwarranted costs. I&E highlighted, *inter alia,* that under the Partial Settlement, Duquesne has limited the scope of its proposed DC Fast Charging Evaluation Station to stations owned by Duquesne to be used solely for Duquesne and the PAAC electric bus evaluation pilot. I&E argued that by limiting DC Fast Charging costs to Company use and costs for the PAAC electric bus evaluation, Duquesne has tailored its expenditures to costs reasonably associated with a broader public benefit for ratepayers instead of just costs incurred for the benefit of a very small consumer group. I&E explained that this satisfies the concern I&E had that all ratepayers were being asked to pay for a program providing an insignificant portion of the rate base in which only 0.05% of vehicle registrations in Allegheny County were electric vehicles. I&E also noted that by agreeing that the costs for behind the meter Level 2 infrastructure rebates will be recorded as a regulatory asset, with such costs deferred to Duquesne's next rate case, and only if there is adequate justification, this alleviates the concern of I&E and other parties that rate base should not unreasonably subsidize individual customer projects unless they definitively benefit a broader rate base. I&E Statement in Support at 24.

In its Statement in Support, the OCA contended that it would be improper to require residential ratepayers to subsidize the costs of a program that will only benefit the commercial classes. Therefore, the OCA submitted that Duquesne's agreement to defer the appropriate method of any recovery of rebates until Duquesne's next base rate proceeding is in the public interest. The OCA highlighted that Duquesne provides for specific reporting requirements to evaluate customer participation and feedback. The

OCA noted that this will afford interested Parties the opportunity to assess how the funds were used, from whom the charging station revenues were received, and to ensure that Duquesne is compliant with the terms of the Partial Settlement. Additionally, the OCA asserted that the provision of the Partial Settlement, wherein Duquesne will dedicate all of the charging stations it owns to the use of the Company and the PAAC will prevent Duquesne from becoming a competitor in an unregulated market. According to the OCA, were Duquesne to own EV chargers, as any other third party, this would have the effect of allowing a regulated utility to enter an unregulated competitive market with the risk being borne by captive ratepayers. OCA Statement in Support at 15-16.

In its Statement in Support, the OSBA, likewise, trumpeted the provision of the Partial Settlement that contemplates that the cost of rebates will not be recovered in base rates, but instead recorded as a regulatory asset with the appropriate cost recovery deferred to Duquesne's next base rate case. The OSBA submitted that the Partial Settlement's reduction in the scope of the EV Pilot, coupled with the reduced recovery of pilot costs in base rates will benefit Duquesne's small business customers. OSBA Statement in Support at 4-5.

In its Statement in Support, CAUSE-PA pointed out that under the Partial Settlement, the cost of the pilot has been reduced from $3.1 million to $2.07 million. Like the other Joint Petitioners, *supra,* CAUSE-PA noted that the Partial Settlement provides an opportunity to evaluate whether $650,000 of the $2.07 million (*i.e.* the amount allocated to rebates) can be recovered from ratepayers in Duquesne's next base rate proceeding. CAUSE-PA argued that the EV pilot is in the public interest because it provides significant investment into the electrification of public transportation and has a tangible public benefit to low income customers who are more likely to use public transportation as compared to higher income customers. CAUSE-PA Statement in Support at 5.

In its Statement in Support, ChargePoint submitted that the EV pilot balances customer needs and desires, Company objectives, and ratepayer benefits and costs, while ensuring that the Competitive EV charging market in Pennsylvania can continue to develop in a sustainable manner. ChargePoint highlighted that the EV Pilot will provide a significant foundation for ensuring that new load is incorporated in a safe, reliable, and efficient manner. ChargePoint also pointed out that the Pilot will generate substantial information regarding customer experience and EV charging data, which will be provided annually to the Commission for review and will be useful for future distribution planning and load management program development. ChargePoint submitted that the EV Pilot Program incorporates a set of guiding principles which considers all major stakeholders impacted by the Pilot. Thus, ChargePoint argued that the EV Pilot program is in the public interest because it will ensure that investments appropriately reduce market barriers, minimize costs, and maximize benefits to ratepayers. ChargePoint Statement in Support at 6.

In its Statement in Support, NRDC argued that the information gathered from the Pilot will support improved capacity utilization and other power objectives of the Commonwealth and that all ratepayers will benefit from the estimated reductions in utility customer bills that will result from increased EV charging in Pennsylvania. NRDC Statement in Support at 4-5.

b. ALJ's Recommendation

The ALJ determined that the costs of the EV Pilot Programs should be approved as just and reasonable without any definitive class allocation. The ALJ reasoned that the impact will be relatively small and, because these costs relate to a pilot, some expenditures are needed before the Parties and the Commission can make a determination as to whether the EV incentives and provisions will create a larger public benefit. The ALJ also found that the EV Pilot Program, as modified by the provisions in

the Partial Settlement, will reduce the impact on the base rates substantially while providing incentives for third parties to pay to install Level 2 charging stations for public use. The ALJ pointed out that while the use of EVs within Duquesne's service territory is statistically small, the benefits of a population that drives EVs cannot be realized if public charging stations are not easily available. Therefore, the ALJ recommended that this portion of the Partial Settlement be adopted. R.D. at 168-69.

5. Time of Use Rates

As noted above, Paragraph No. 52 of the Partial Settlement provides that Duquesne will hold a collaborative to discuss residential TOU rates and will make a proposal regarding TOU rates in its next default service rate filing, unless it is ordered by the Commission to do so earlier. At the hearing, the ALJ asked the Joint Petitioners to address whether Duquesne should be required to make a TOU filing prior to its next default service rate filing. Tr. at 676.

a. Positions of the Parties

Duquesne submitted that it should not be required to make a TOU filing outside of its default service filings. Duquesne reasoned that TOU rates are appropriate for generation charges but not for distribution charges, and accordingly, issues regarding generation charges should be addressed in default service proceedings. Duquesne also noted that the collaborative process contemplated in Paragraph No. 52 of the Partial Settlement will occur in 2019 and that Duquesne will make its next default service filing in 2020. In Duquesne's view, this is a reasonable timeframe for considering TOU proposals and developing a new TOU program. Duquesne Statement in Support at 24-25.

The OCA noted that Duquesne has agreed to hold a collaborative between interested stakeholders to consider TOU rate issues and suggestions and that Duquesne has also agreed to make a proposal regarding TOU rates in its next default service rate filing. The OCA represented that it understands the importance and complexity of the issues surrounding residential TOU rates and that it will participate in the collaborative. OCA Statement in Support at 23.

KEEA, likewise, highlighted Duquesne's agreement to make a proposal regarding TOU rates in its next default service filing. KEEA submitted that Duquesne's agreement to establish a collaborative process on TOU rates is significant. KEEA asserted that the collaborative process is an important step to establishing a TOU program structure that encourages investments in energy efficiency and renewable energy, produces substantial peak demand reductions, and sends the proper price signal to customers to conserve electricity and engage in energy efficiency. As Duquesne does not currently offer a TOU program, KEEA proffered that Duquesne should not be required to make a TOU proposal prior to its next default service filing. Rather, KEEA contended that it is in the best interest of the public for stakeholders to have an opportunity to provide input, via the collaborative process, on how the program should be designed. KEEA Statement in Support at 4-5.

NRDC adopted the position of KEEA as to the provisions of the Partial Settlement that concern TOU rates. NRDC concurred with the other Joint Petitioners that the collaborative process is an important first step towards establishing an appropriate TOU program. NRDC Statement in Support at 3.

b. ALJ's Recommendation

The ALJ agreed with Duquesne and the other Joint Petitioners who addressed this issue in their respective Statements in Support that there is no need to

mandate that Duquesne make a TOU proposal prior to its next default service rate filing. The ALJ determined that Electric Generation Suppliers serving in Duquesne's service territory are capable of supplying TOU rates and that, at this time, a TOU proposal is best handled as a supply or generation charge. The ALJ also determined that because TOU rates could reduce customer charges and peak demands and thereby better reflect proper price signals which encourage energy efficiency and conservation, the collaborative process contemplated in Paragraph No. 52 of the Partial Settlement is the optimal method to develop a TOU proposal for which Duquesne can include in its next default service rate filing. Therefore, the ALJ recommended that this portion of the Partial Settlement be adopted. R.D. at 170.

6. Effect of Medical Certificate Program Changes for Ratepayers with Balances in Excess of $10,000

At the hearing, the ALJ asked whether the provision outlined in Paragraph No. 55 of the Partial Settlement applies to consumers with balances that are greater than $10,000, and if it does apply, how such instances will be handled. Tr. at 677.

a. Positions of the Parties

Duquesne explained that this provision was adopted as a result of CAUSE-PA's concerns that Duquesne's current medical certificate policy is not consistent with the Commission's regulations which allow for unlimited medical certificates for customers with a medical condition who continue to pay their current charges or budgeted bill in full. Duquesne noted its own concern that customers could have large unpaid balances if they continue to obtain medical certificates for an extended period but do not pay their past due balances. Duquesne asserted that the provision outlined in Paragraph No. 55 satisfies Duquesne Light's concerns by clarifying that Duquesne will write off outstanding balances that are overdue for more than one year for

customers that have medical certificates for one year or longer. Duquesne provided clarification that this provision of the Partial Settlement would apply to any outstanding balances that are $10,000 or greater. Additionally, Duquesne Light averred that it will continue to follow all Commission regulations and orders with respect to balances that are greater than $10,000. Duquesne Statement in Support at 26.

Cause-PA expressed its support for the proposed changes to Duquesne's medical certificate policies, as set forth in Paragraph No. 55 of the Partial Settlement. CAUSE-PA submitted that these changes are critical to ensuring that Duquesne's policies are in line with the Commission's guidance in relation to 52 Pa. Code § 56.116. In response to the ALJ's question on this issue, CAUSE-PA stated that the provision, as proposed, would be applied to all accounts where the household has been protected by a medical certificate for a year or longer regardless of the amount owed. Additionally, CAUSE-PA posited that this is unlikely to be very many accounts because obtaining a medical certificate is not easy and it is expected that utilities will attempt to work with the household for a more permanent resolution of the debt such as a payment agreement. CAUSE-PA Statement in Support at 8-9.

b. ALJ's Recommendation

The ALJ highlighted Duquesne's assertion that despite the provision in the Partial Settlement that permits it to write off outstanding unpaid balances, Duquesne will continue to follow all Commission regulations and orders with respect to outstanding balances exceeding $10,000. Based on this assurance, the ALJ recommended that the Commission adopt this provision of the Partial Settlement. R.D. at 171.

C. ALJ's Overall Recommendation

The ALJ found the Partial Settlement, generally is an equitable, fair, and reasonable resolution of this proceeding and, therefore, it is in the public interest. For these reasons the ALJ recommended that the Commission approve the Partial Settlement, except as discussed in the resolution of the highlighted issues, outlined, *supra*, and in the discussion on the sole outstanding issue that was reserved for litigation, *infra*. R.D. at 159.

D. Disposition

The Joint Petitioners advised the ALJ that they did not oppose the Partial Settlement. The Settlement also was served on the *pro se* Complainants who were non-signatories to the Settlement. None of the *pro se* Complainants filed a response or objection to the Partial Settlement.

Based on our review of the Partial Settlement, we find that there are numerous settled issues therein that are beneficial to customers. Among those provisions are: (1) the reduced revenue increase compared to the Company's originally requested revenue increase; (2) the tax refund related to collections from customers in 2018 and the return of EDIT; (3) the agreement that Duquesne must realize a base level of plant investment before any incremental expenditures can be recovered through a DSIC; (4) the agreement that Duquesne will amortize the costs related to the Electrical Model over five years instead of relying on the higher expense levels the Company projected to occur in the FPFTY; (5) the inclusion of key provisions concerning the amount of Duquesne's ongoing pension contributions and Duquesne's agreement to provide a report and affidavit attesting to the actual contributions during each calendar year; (6) the inclusion of specific provisions for meeting the Company's OPEB requirements; (7) the agreement that in each base rate case for which Duquesne seeks to recover cloud-based

information systems that were recorded in the regulatory asset as a capital cost for ratemaking purposes, it must provide a listing of cloud-based computing costs by year, along with the expected useful life of each item; (8) the agreement that Duquesne will modify its EV Pilot Program to narrowly tailor its expenditures to costs reasonably associated with a broader public benefit for ratepayers while also permitting the Company to incent EV usage in its service territory, which will increase usage of the distribution system and also allow the Company to evaluate the impacts of EV usage on the grid; (9) the agreement that Duquesne will revise its LED Street Lighting Program, by expanding the program for conversion of mercury vapor, high pressure sodium lights to LEDs; (10) the agreement that Duquesne's fee free bank card program will be implemented; (11) the agreement that Duquesne will withdraw its Woods Run Microgrid Proposal, without prejudice; (12) the agreement that the fixed monthly customer charge for Rates RS, RA, RH, and GS will be increased from $10.00 per month to $12.50 per month and that the fixed smart meter charge will be rolled into volumetric rates, resulting in a reduction in the customer charge from $14.17 per month to $12.50 per month; (13) the agreement that Duquesne will convene a non-confidential collaborative with all interested stakeholders to obtain stakeholder input regarding TOU rates and that Duquesne will make a TOU proposal in its next default service rate filing; (14) the commitment of Duquesne to participate in any working group established by the City of Pittsburgh to address the issue of energy efficiency benchmarking for multifamily buildings; (15) the commitment of Duquesne to use its best efforts to ensure that 10% of its completed LIURP jobs are for electric heating customers and to review its list of customers with high CAP credits from the prior year and to prioritize those customers for LIURP treatments when possible; (16) the agreement that Duquesne will withdraw certain proposed tariff changes, which will eliminate the potential for ambiguity regarding the balances Duquesne could assess on customers or applicants who reside in one property yet move to another property; (17) the commitment of Duquesne to revise its medical certificate policy but that Duquesne will continue to follow all Commission regulations and orders with respect to outstanding account balances that are greater than

$10,000; (18) the agreement that Duquesne will revise its PFA policy and accompanying procedures to accept PFAs or criminal court orders with evidence of domestic violence toward an applicant for service, a current customer, or a member of the applicant or customer's household; (19) the commitment of Duquesne to engage in discussions regarding budget billing issues and to consider proposals to address budget billing concerns by the parties in its next base rate proceeding; (20) the commitment of Duquesne to conduct a competitive selection process to select its universal service program providers and to invite local community based organizations to participate in the process; (21) the Commitment of Duquesne to convene a collaborative to discuss master-metering issues related to multifamily housing, and to hold additional collaborative meetings, as necessary, to reach consensus on any issues that remain unresolved after the initial collaborative; and (22) the assertion of Duquesne that the smart meter costs included in its rate base do not include any previously-denied smart meter costs.

The Partial Settlement resolves the majority of the issues impacting residential consumers, business customers and the public interest at large and represents a fair balance of the interests of Duquesne and its customers. The benefits of approving the Partial Settlement are numerous and will result in significant savings of time and expenses for all Parties involved by avoiding the necessity of further administrative proceedings, as well as possible appellate court proceedings, conserving precious administrative resources. Moreover, the Partial Settlement provides regulatory certainty with respect to the disposition of issues which benefits all parties. For the reasons stated herein and in the settling Parties' Statements in Support, we agree with the ALJ's conclusion that the Joint Settlement Petition is in the public interest. Additionally, as no Party excepted to the ALJ's recommendation that Duquesne's request to amend its Rider No. 21 be denied, we shall adopt this recommendation.

In light of the above, we shall adopt the ALJ's recommendation to grant the Joint Settlement Petition and adopt the Partial Settlement, as modified, consistent with the ALJ's recommended modifications in Section III. B. Highlighted Issues, *supra,*

IV. Rider No. 16

A. Burden of Proof

Typically, in proceedings before the Commission, the public utility has the burden to establish the justness and reasonableness of every element of its rate increase in all proceedings conducted under Section 1308(d) of the Code, 66 Pa. C.S. § 1308(d). The standard of proof which a public utility must meet is set forth in Section 315(a) of the Code, 66 Pa. C.S. § 315(a), which specifies that, "[i]n any proceeding upon the motion of the Commission, involving any proposed or existing rate of any public utility, or in any proceeding upon complaint involving any proposed increase in rates, the burden of proof to show that the rate involved is just and reasonable shall be upon the public utility." The Commonwealth Court has upheld this standard of proof[8] and has applied it in base rate proceedings.

In this proceeding, the burden of proof lies squarely with Duquesne. Duquesne is the public utility seeking permission from the Commission to increase its base rates and to implement and/or alter programs. The burden of proof does not shift to a statutory party or individual party (whether an entity or an individual) which challenged the requested rate increase. Instead, the utility's burden, to establish the justness and

[8] *Lower Frederick Twp. v. Pa. PUC*, 409 A.2d 505, 507 (Pa. Cmwlth. 1980). *See also*, *Brockway Glass v. Pa. PUC*, 437 A.2d 1067 (Pa. Cmwlth. 1981).

reasonableness of every component of its rate request, is an affirmative one and remains with the public utility throughout the course of the rate proceeding.[9]

Under the Code, rates charged by public utilities must be just and reasonable and cannot result in unreasonable rate discrimination. 66 Pa. C.S. §§ 1301 and 1304.

A public utility seeking a general rate increase has the burden of proof to establish the justness and reasonableness of every element of the rate increase request. 66 Pa. C.S. § 315(a); *Pa. PUC v. Aqua Pennsylvania,* Docket No. R-00038805, (Order entered August 5, 2004).

As the Commonwealth Court explained: "While it is axiomatic that a utility has the burden of proving the justness and reasonableness of its proposed rates, it cannot be called upon to account for every action absent prior notice that such action is to be challenged."[10] Therefore, while the ultimate burden of proof does not shift from the utility, a party proposing an adjustment to a ratemaking claim bears the burden of presenting some evidence or analysis tending to demonstrate the reasonableness of the adjustment.[11]

However, a party that raises an issue that is not included in a public utility's general rate case filing bears the burden of proof. As the proponent of a Commission order with respect to its proposals, DII bears the burden of proof as to proposals that

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[9] There is no similar burden placed on parties which challenge a proposed rate component. See, *Berner v. Pa. PUC*, 382 Pa. 622, 631, 116 A.2d 738, 744 (1955).

[10] *Allegheny Center Assocs. v. Pa. PUC*, 570 A.2d 149, 153 (Pa. Cmwlth. 1990).

[11] *See*, *e.g.*, *Pa. PUC v. PECO,*1990 Pa. PUC Lexis 155; *Pa. PUC v. Breezewood Telephone Company*, 1991 Pa. PUC Lexis 45.

Duquesne did not include in its filing. Duquesne's existing Rider No. 16 provisions are deemed just and reasonable because those tariff provisions previously were approved by the Commission. Therefore, DII, as the party challenging a previously-approved tariff provision, bear the burden to demonstrate the Commission's prior approval is no longer justified. *See Pa. PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2010-2215623, *et al.* (Order entered March 15, 2012).

As we proceed in our review of the various positions espoused in this proceeding, we are reminded that we are not required to consider expressly or at great length each and every contention raised by a party to our proceedings. *University of Pennsylvania v. Pa. PUC*, 485 A.2d 1217, 1222 (Pa. Cmwlth. 1984). Moreover, any exception or argument that is not specifically addressed herein shall be deemed to have been duly considered and denied without further discussion.

B. Rider No. 16 – Service to Non-Utility Generating Facilities

1. Background

The Commission's Combined Heat and Power (CHP) Policy Statement[12] provides a helpful description of CHP as follows:

> Combined Heat and Power (CHP) is the concurrent production of electricity or mechanical power and useful thermal energy (heating and cooling) from a single source of energy. Unlike central station generation, it is a type of distributed generation which is located at or near the point of consumption. It is a suite of technologies that can use a variety of fuels to generate electricity or power at the point of use, allowing the heat that would normally be lost in the

[12] *Final Policy Statement on Combined Heat and Power*, Docket No. M-2016-2530484, (April 5, 2018) (CHP Policy Statement).

power generation process to be recovered to provide needed heating and cooling.

Customers that receive all of their electricity from the utility or via the grid are known as "full requirements" customers. Customers with onsite generation such as CHP are "partial requirements" customers and typically require a different set of services which includes continuous electricity service for the portion of usage that is not provided by the onsite generator, as well as service for periods of scheduled outages or unscheduled (also known as forced) outages. EPA Standby Rate Study[13] at 4.

Rider No. 16 addresses both Supplementary Power and Back-up Power.[14] Duquesne's current Rider No. 16 defines Supplementary Power as "electric energy and capacity supplied by the Company or by an electric generation supplier (EGS) to a non-utility generating facility and regularly used in addition to that electric energy which the non-utility generating facility generates itself." Back-up Power is defined as "electric energy and capacity supplied by the Company to a non-utility generating facility during any outage of the non-utility generating facility's electric generating equipment . . . " Rider No. 16, Supplement No. 91 to Electric Tariff Pa. P.U.C. No. 24.

As part of Supplement No. 174, Duquesne originally proposed to increase the rate charged for "back-up service" under Rider No. 16 for eligible customers that meet a portion of their load with their own generating facilities. Duquesne proposed to increase the rate for Rider No. 16 service from $2.50 per kW to $8.00 per kW for the

[13] Peoples Ex. No. JWS-9 (US EPA, *Standby Rates for Customer-Sited Resources: Issues Considerations and the Elements of Model Tariffs* (2009) (EPA Standby Rates Study).

[14] Duquesne proposed to rename these terms to Supplementary Service and Back-up Service and revised the definitions of each term. Although Duquesne has withdrawn the proposed changes to Rider 16, we will use the term service as it is more descriptive.

level of demand specified by the customer in its contract for back-up service. According to Duquesne, Rider No. 16 proposed increase was designed to provide better price signals to potential customers considering construction of distributed generation with back-up charges that better reflect the actual cost to provide back-up distribution service. Duquesne Initial Brief (I.B.) at 1-2.

Three intervening parties addressed the proposed changes to Rider No. 16 – the OSBA, Peoples, and DII.[15] Other parties to the case neither opposed nor supported the proposed changes to Rider No. 16. *Id.* at 4.

At the August 17, 2018 evidentiary hearing, Duquesne notified the ALJ that the Company was withdrawing its proposed changes to Rider No. 16 and would leave in place the existing Rider No. 16 terms. *Id.* at 10. Upon the Company's withdrawal of the proposed changes to Rider No. 16, Peoples withdrew its opposition to the settlement of all issues in the case. DII, on behalf of its members excluding Duquesne University, continued to litigate the issue. DII argued that the existing Rider No. 16 rate should be further discounted. *Id.* at 11.

2. Memorandum of Understanding Between Duquesne Light Company and Duquesne University

On June 25, 2018, after Duquesne filed its general rate case with the Commission, Duquesne entered into a Memorandum of Understanding (MOU)[16] with Duquesne University, the only customer currently electing to receive service under Rider No. 16. Under the terms of the MOU, the Company and Duquesne University agreed,

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[15] DII includes Duquesne University, the Allegheny County Airport Authority, Linde Energy Services Corporation, United States Steel Corporation, and the University of Pittsburgh. Duquesne University is not objecting to the terms of Rider No. 16 and has signed a Memorandum of Understanding with Duquesne.

[16] Duquesne Exh. CJD-1-R.

subject to the Commission's approval, that the University could continue to receive back-up service under the current rate of $2.50 per kW for a period of five years effective January 1, 2019. Duquesne I.B. at 8-9. Any increases in the Back-up Service rate during that period would only apply to new Rider No. 16 customers. Duquesne St. 1-R.

Duquesne provided that the Commission previously approved excluding existing customers with on-site generation from changes in back-up rates and charges when new, increased back-up rates and charges were proposed and approved for prospective application. Duquesne I.B. at 9 (citing PECO Tariff Electric – Pa. P.U.C. No. 5, Original Page No. 68; Joint Settlement Petition, Appendix D, p. 4 at Docket No. R-2015-2468981).

3. Positions of the Parties

a. Duquesne's Position

Duquesne agreed to withdraw its proposed changes to Rider No. 16 and retain the existing rate of $2.50 per kW. Duquesne noted that except for certain members of DII, all parties – including the only two customers that actually elected, or may elect, service under Rider No. 16 in the future – either support or do not oppose the Company's decision to maintain the existing Rider No. 16 rate at $2.50 per kW as applied to back-up contract demand. Duquesne averred that the existing Rider No. 16, together with the valuable option customer-generators retain to take general service without Rider No. 16, allow such customers to avoid significant transmission and distribution charges. Duquesne noted that unlike other Pennsylvania electric distribution companies, it allows customers the flexibility to choose whichever option a customer might prefer. According to Duquesne, Rider No. 16 is an option that may be very attractive to an eligible customer depending on the characteristics of its on-site generation, how the customer chooses to operate its on-site generation, differences in charges under Rider No. 16 versus charges in

the customer's applicable rate schedules, and the customer's load characteristics. Duquesne I.B. at 13-14 (citing Duquesne St. 16-R at 19-24, Duquesne St. 16-RJ at 11-12, 17; OSBA St. 1-R at 6).

b. DII's Position

DII stated that CHP generation projects are often sized based on the account's thermal load requirements, not the electrical load requirements. According to DII, this factor makes the rates, terms and conditions for services provided by the utility a critical aspect of the customer's economic decision when evaluating a potential CHP project. DII averred that CHP systems typically operate in parallel with the local electric utility, and the CHP system power output is often supplemented by energy purchased from an EGS or default service provider. DII I.B. at 5-6 (citing Peoples St. 4 at 4; DII St. 1 at 10, 12, 13, 15-16; DII St. 1-S at 24).

DII stated that the back-up power rate must be calculated using a load factor or diversity adjustment, but the current 30% load factor used by Duquesne is excessive in light of the single Rider No. 16 customer's actual unplanned outage rate of 2.5% (and other factors such as general availability statistics for CHP and other distributed generation systems). DII proposed a 5% load factor yielding a Back-up rate of $0.352 per kW and proposed a new Maintenance rate (for planned maintenance) of $0.235 per kW. DII I.B. at 8-9.

4. ALJ's Recommendation

The ALJ found that Duquesne failed to meet its burden to prove that the present rate charged to customers under Rider No. 16 is based on facts and is just and reasonable. The ALJ recommended that Duquesne file a tariff to reduce the existing distribution charge in Tariff Rider No. 16 from $2.50 to $0.352. However, the ALJ was

not persuaded by DII's argument that Rider No. 16 should be split into two rates to reflect Stand-by and Maintenance and recommended that the request by DII for the two separate rates based on when in time a CHP relies on distribution service from the EDC be denied. The ALJ found that DII should have an opportunity to put forward this argument in the next base rate case at which time it can more fully develop its contention that a separate maintenance rate is needed for distributed generation and/or CHP customers. R.D. at 178.

5. Duquesne's Exception No. 1 Regarding the Burden of Proof

a. Duquesne's Exception No. 1

Duquesne contends that the ALJ erred in assigning to Duquesne the burden of proof with regard to DII's proposal to reduce the existing approved Rider No. 16 rate from the presently tariffed rate of $2.50 to $0.35 per kW. Duquesne avers that the ALJ accepted DII's position because she believed that the Company did not "meet its burden of proof that the rate charged to customers under Rider No. 16 is based on facts and is just and reasonable." Duquesne notes that the ALJ made this finding notwithstanding the extensive evidence it presented including the testimony of OSBA witness Kalcic (not mentioned in the R.D.), the Commission's approval of the existing Rider No. 16 rate in Duquesne's last base rate case, and the fact that the existing rate is unopposed by the only current Rider No. 16 customer (*i.e.*, Duquesne University), as well as the only customer with a CHP project that intends to apply for service under Rider No. 16 (*i.e.* Peoples). Duquesne Exc. at 5-6 (citing R.D. at 178).

According to Duquesne, the ALJ inappropriately assigned the burden of proof with regard to DII's entirely new proposal for back-up service rate design to the Company. Duquesne asserts that a new, alternative proposal made by another party cannot be adopted without requiring the proponent to meet the burden of showing by a

preponderance of substantial evidence that its proposal is "just and reasonable."[17] Duquesne Exc. at 6.

Duquesne contends that the Commission has repeatedly held that, while a utility has the burden to prove that a proposed rate (or an existing rate that is the subject of a Commission investigation) is just and reasonable, a party that advances a proposal that the utility did not include in its filing carries the burden of proof as to that contrary proposal. Duquesne argues that the authority furnished by those precedents and the Commission's reaffirmation and summary of the extensive precedent on this issue in *Petition of Metropolitan Edison Co.*, conforms to the reasonable principle that a party should not have to "prove the negative." Duquesne Exc. at 9-10.

b. DII's Reply

In Reply, DII contends that the ALJ appropriately assigned the burden of proof to Duquesne. DII provides that it is inequitable to shift the burden of proof onto a party that is forced to defend against a utility's dramatic cost increases and eleventh-hour shift in litigation position. According to DII, Commission precedent demonstrates that Duquesne possesses the burden of proof for its entire rate case, especially issues it raised in its filing. DII R. Exc. at 5.

The current Rider No. 16 rate of $2.50/kW was proposed in Duquesne's previous rate case at Docket No. R-2013-2372129. At that time, Duquesne witness William Pfrommer, the Senior Manager of Rates and Tariff Services, explained the methodology for calculating the rate as follows:

[17] *Petition of Metropolitan Edison Co. et al.*, Docket Nos. P-2015-2508942, P-2015-2508948, P-2015-2508936; P-2015-2508931 (Final Order entered Apr. 19, 2018) pp. 16-17 (*Petition of Metropolitan Edison Co.*).

> The Company is proposing a distribution rate of $2.50 per kW. This is based on an average of the primary demand costs per kW in Mr. Gorman's Exhibit 6-2B and a load factor of 30%. The load factor is an estimate based on the availability of the current customer, a review of other utility tariffs, and the expectation of the need for the Company to provide back-up power.

Peoples St. 2 at 9 (citing Docket No. R-2013-2372129 - Duquesne St. 12 at 19 and Exh. 6-2B).

In this proceeding, DII considered the 30% load factor as excessive and proposed a new factor of 5% in light of the single Rider No. 16 customer's actual unplanned outage rate of 2.5% (and other factors such as general availability statistics for CHP and other distributed generation systems). DII witness Crist accepted Duquesne's cost analysis in Duquesne Exhibit No. 6-4H but applied an allocation factor of 5%. DII recommended that Duquesne modify its tariff by decreasing the back-up rate from $2.50 to $0.352 per kW and adding a new Maintenance Rate of $0.235 per KW. DII Brief at 8-9 (citing DII St. 1 at 25-26).

c. Disposition

As noted, Duquesne disagrees with the ALJ's assignment to the Company of the burden of disproving the reasonableness and legality of DII's proposal to reduce the existing, approved Rider No. 16 rate. We agree with Duquesne. In Duquesne's prior rate case, we determined that the existing Rider No. 16's provisions were deemed just and reasonable because those tariff provisions previously were approved by the Commission and the party challenging a previously-approved tariff provision bears the burden to demonstrate the Commission's prior approval is no longer justified. *See Pa. P.U.C. v. Duquesne Light Co.*, Docket No. R-2013-2372129 (Order entered April 23, 2014) at 20-21 citing *Pa. P.U.C. v. Columbia Gas of Pennsylvania, Inc.*, Docket No.

R-2010-2215623, *et al.* (Order entered March 15, 2012). In this proceeding, we remain of the same mindset. Therefore, consistent with well-established precedent, we conclude that the DII, as the proponent of a change to an existing tariffed rate that has been approved by the Commission, is responsible for bearing the burden of proof as to whether the present tariff rate in Rider No. 16 is unreasonable and should be replaced with its proposed rates. Accordingly, we shall grant Duquesne's Exception No. 1.

6. Duquesne's Exception No. 2 Regarding the "As Used" Basis for Rider No. 16

a. Duquesne's Exception No. 2

In its second Exception, Duquesne avers that the ALJ erred because she did not expressly recommend that DII's proposal to modify the application of the Rider No. 16 on an "as used" basis should be rejected.

In support of its request that DII's proposal should be explicitly rejected Duquesne references the three purported reasons put forth by DII as to why DII believes the demand charge in Rider No. 16 should be applied only on an "as used" basis. In response to DII's argument that the "as used" application encourages efficient operation of the CHP system by incenting customer-generators to avoid outages, Duquesne argued that it is unreasonable for the demand charge to be applied on an "as used" basis because CHP customers must replace the generation their units do not provide during an outage. Duquesne maintains that generation replacement costs are substantial and that its witness, Neil S. Fisher calculated this cost to be over $49 per MWH. Duquesne also notes that back-up distribution charges are only a small fraction (less than 3-4%) of a CHP customer's total bill and these customers will be sufficiently motivated to avoid unplanned outages by the generation replacement costs rather than any back-up

distribution costs incurred. Duquesne Exc. at 12-13 (citing Duquesne St. 16-R at 30, Revised Fig. 4; Duquesne St. 16-R at 28, Fig. 3).

Secondly, Duquesne disagrees with DII's contention that back-up demand charges should be applied on an "as-used" basis because that is the way demand charges are applied for general service rates. Duquesne notes that because demand charges are applied on an "as used" basis for general service, they are much higher than the $2.50 per kW rate of Rider No. 16. Duquesne avers that a CHP customer who believes it can operate its generator efficiently and avoid outages during on-peak periods has the flexibility to remain on its general service rate without electing Rider No. 16. Duquesne also contends that the "spikes and dips" in usage that general service customers exhibit and which DII alluded to as a reason to apply a back-up rate on an "as used" are not a measure of the peak demand that the system must be designed to meet. Duquesne Exc. at 13 (citing Duquesne St. 16-RJ at 6-7; Duquesne I.B. at 27, Duquesne R.B at 27-29; Duquesne St. 14-R at 30).

Finally, Duquesne disagrees with DII's argument that applying the demand charge to "as used" demand is necessary to conform Rider No. 16 to the billing practice for the existing Rider No. 16 customer. Duquesne submits that it has signed an MOU with Duquesne University under which the demand charge will apply to the university's contracted demand charge, and thus makes the terms of Rider No. 16 and the MOU consistent. Duquesne Exc. at 13-14 (citing Duquesne I.B. at 8-9, Duquesne Exh. CJD-1-R; Duquesne St. 1-R at 11).

b. DII's Replies

In Reply, DII avers that the Company's MOU with Duquesne University refers to contract peak demand and this language mirrors the Tariff, which was being applied as basing charges on actual demand. DII also notes that the EPA Standby Rates

Study states that utilities may apply "an agreed-upon contract demand" but suggests non-contract options as well, including actual monthly demand. DII R.Exc. at 9-10 (EPA Standby Rates Study at B-5,6). DII also notes that with actual demand charges, the operators of onsite generation systems are motivated to avoid outages, because even a brief outage can increase the customer's demand charges for the month. DII R. Exc. at 10.

c. Disposition

Although the Recommended Decision does not address this issue, DII proposed that Rider No. 16 rate should apply on an "as used" basis. We note that Rider No. 16 rate is voluntary, and the customer has the option to choose whether to remain on the full requirements rate or operate within its contracted level of back-up demand. Because the rate is voluntary and applies to the negotiated contracted level of back-up demand, we are persuaded that the Rider No. 16 rate should not be applied on an "as used" basis. We are further persuaded by People's witness Jamie Scripps who explained that the "best practices" included in the EPA Standby Rates Study specifically noted that back-up rates may be applied to an agreed-on contract demand rather than on an "as used" basis. Peoples St. 3 and 3-R, EPA Standby Rates Study. Therefore, we hereby grant Duquesne's Exception No. 2. Accordingly, DII's proposal to modify the applications of the Rider No. 16 on an "as used" basis is hereby rejected.

7. Duquesne's Exception No. 3 Regarding DII's Proposed Rider No. 16 Rate

a. Duquesne's Exception No. 3

Duquesne states that the ALJ erred in recommending adoption of DII's proposed Rider No. 16 rate of $0.35 per kwh. Duquesne claims the $0.35 rate is contrary

to the record evidence and Commission-approved principles of distribution rate design. In noting that its Rider No. 16 involves distribution service and not generating capacity, Duquesne submits that throughout this case, DII tried to impose criteria that is appropriate only for designing standby *generation* rates to the back-up rate for distribution service. Duquesne Exc. at 14.

Duquesne avers that the service it provides to eligible customers electing Rider No. 16 ensures that capacity is available on the distribution system up to the level of kW demand for which those customers contract with the Company. Furthermore, Duquesne submits that if a customer-generator expects Duquesne to provide back-up distribution service whenever its generator is not operating, the contracted level of capacity must be available 24 hours per day, 365 days per year (24-7-365), because, as DII witness Crist acknowledged, and as operating data for the existing Rider No. 16 customer confirms, outages of customers' generators occur at any time, including during class and system peak periods. Duquesne Exc. at 14 (citing Duquesne St. 16-R at 12-13; Duquesne I.B. at 19-30; Duquesne R.B. at 13-27; Tr. at 612; Duquesne St. 14-R at 29-30).

Duquesne notes that the Commission found that unlike the supply costs of energy that vary as customers' consumption varies, distribution service costs do not vary in the short run in proportion to a customer's daily or monthly levels of consumption. Duquesne Exc. at 15 (citing the Alternative Ratemaking Policy Statement at 16). [18] Despite those Commission decisions, Duquesne asserts that DII contends that the fully-allocated cost of providing distribution service to eligible customers under Rider No. 16, as calculated by Duquesne witness Howard S. Gorman's cost of service study,[19] should be discounted by multiplying that cost by 5% (*i.e.*, a 95% discount) to reflect how often

[18] *Fixed Utility Distribution Rates Policy Statement*, Docket No. M-2015-2518883 (May 3, 2018) (Alternative Ratemaking Policy Statement).

[19] DLC Statement No. 14 and accompanying exhibits.

Mr. Crist estimates a back-up customer may use the distribution system. Duquesne alleges that although Mr. Crist tried to call his proposed multiplier a "load factor" and persuaded the ALJ to do the same, his description (*e.g.*, "unplanned outage hours")[20] confirms that 5% is an estimate of the "forced outage rate" of customers' on-site generation. Duquesne claims that Mr. Crist mislabeled his multiplier a "load factor" to create the misconception that he was replicating the approach that Duquesne's witness used in its 2013 base rate case to judgmentally reduce the over $6.00 per kW rate to $2.50 per kW. Duquesne Exc. at 15 (citing Tr. at 323-324).

According to Duquesne, DII is of the view that customer-generators should receive back-up service at a rate that absolves them from paying all but a small fraction (5%) of the costs to have distribution capacity available 24-7-365 to meet their needs. In Duquesne's view, DII witness Crist's recommendations would exempt back-up customers from costs that all other Duquesne distribution customers pay, even though customers with generation could (and did) impose the same peak demands that they would have if they had not installed on-site generation. Duquesne Exc. at 17-18 (citing Tr. at 619-20).

Duquesne alleges that DII's proposed 5% multiplier measures the frequency with which a customer-generator imposes its demands, which is a measure of usage or consumption but not demand. Therefore, Duquesne avers that applying a 5% multiplier to the fully-allocated cost of distribution service calculates charges that are proportional to a back-up customer's energy usage rather than distribution costs. Duquesne submits that the ALJ's Recommended Decision on pages 174-175 accepts this proposition as evidenced by the mistaken belief that the Company is providing distribution "service" only when electricity from external sources is actually being

[20] DII Statement No. 1 at 25; 18-20. *See also* DII Statement No. 1-SR at 11:16-18.

delivered by the Company to a customer's meter during its generator outages. Duquesne Exc. at 18.

According to Duquesne, DII was incorrect in relying on the RAP Study[21] to support its position that the fully-allocated costs of furnishing distribution service should be multiplied by a "forced outage rate" to determine an appropriate back-up distribution rate. Duquesne notes that the portions of the RAP Study DII tried to rely upon have nothing to do with rates for distribution service. Rather, the RAP study clearly states that forced outage rates should be used only to calculate "generation reservation charges." Duquesne Exc. at 19 (citing DII I.B. at 36-38, RAP Study at 13).

b. DII's Replies

In Reply, DII contends that they have consistently argued that a load factor should be maintained and based on historical data and industry norms (*i.e.* 5% based on the record evidence in this proceeding). DII also contends that their approach is consistent with Duquesne's position in the Company's last rate case, but with additional and improved data. DII R. Exc. at 11. DII provides that Duquesne's witness Pfrommer used the term "load factor" in Duquesne's 2013 rate case proceeding to describe the assumption that was being applied in determining the current back-up service rate. DII R. Exc. at 11 (citing Exh. JC-6 (Pfrommer 2013 Testimony)).

DII argues that distributed generation customers do not impose the same cost on the distribution system as full-requirements customers. DII states that onsite generation customers have dramatically different usage patterns and should not be charged for back-up service as if they are using the distribution system 100% of the hours

[21] James Selecky, Kathryn Iverson, Ali Al-Jabir, *Standby Rates for Combined Heat and Power Systems – Economic Analysis and Recommendations for Five States* (Feb 2014) (RAP Study). Peoples Ex. JWS-6.

of the year. They contend that in the absence of a proper cost of service study analyzing Rider No. 16 as a separate class, a load factor ensures that onsite generation customers get the appropriate diversity recognition in back-up rates. DII R.Exc. at 11-12 (citing DII Brief at 32-34, DII St. 1-S at 11, Peoples St. 4-SR at 3).

c. Disposition

We agree with Peoples witness Daniel that the "continued use of a 30% load factor can be viewed as a reasonable compromise that maintains the *status quo* from Duquesne's prior base rate case – in which we found Duquesne's rates to be just and reasonable." Peoples St. 2-R at 15. The development of recommendations regarding standby rates and maintenance rates may be part of the Commission's CHP Working Group's future activities. DII and other distributed generation customers can participate in the CHP Working Group process regarding these rates. Thus, we find that the present Rider No. 16 design provides a reasonable estimate of distribution costs for CHP customers and should not be reduced to DII's recommended levels, at this time. For these reasons, we shall grant Duquesne's Exception No. 3 and reverse the ALJ's recommendation on this matter.

8. Duquesne's Exception No. 4 Regarding the Record Evidence for the Rider No. 16 Rate

a. Duquesne's Exception No. 4

Duquesne contends that the ALJ erred in finding that Duquesne's existing rate in its Rider No. 16 is not supported by substantial evidence. Duquesne argues that it has the obligation under Rider No. 16 to serve the customer's peak demand any time it may occur, and therefore, its costs to build, own and operate its distribution system to serve a customer under its Rider No. 16 are not reduced simply because a customer may use back-up distribution service only intermittently, as substantial record evidence

demonstrates. In other words, Duquesne emphasizes that as an EDC, it bears the fixed costs of building and maintaining its distribution system without regard to how frequently the system may be used by customers, Duquesne Exc. at 24- 25 (citing Duquesne St. 16 at 17-18, Duquesne St. 14-R at 27).

Duquesne opines that in light of the testimony presented by its witnesses and the data it provided in support of its costs to provide service under Rider No. 16, the ALJ's Recommended Decision was wrong to question whether Duquesne "used any historical data" to substantiate the costs underlying Rider No. 16. In this regard, Duquesne acknowledged that its witness Gorman provided an analysis of the existing Rider No. 16 customer's performance data that showed in June 2016, the customer's peak demand was coincident with the peak demand of the Rate GL class (Duquesne University receives general service on Rate GL); in two other months the customer's demand was at least 90% of its monthly peak when the Rate GL class peak occurred, contributing to the class monthly peaks; and when the customer reached its annual peak demand, the Rate GL class demand was at 98% and the Company's peak was at 97% of its annual peak demand. Duquesne Exc. at 26 (citing Duquesne St. 14-R at 29-30, Duquesne I.B. at 21, R.D. at 177).

Duquesne contends that it provided additional evidence that Rider No. 16 is not excessive or unreasonable and this evidence was not considered by the ALJ in her Recommended Decision. Duquesne claims that Rider No. 16 is both reasonable and non-excessive because: it is not mandatory; it meets or exceeds the benchmark for best practices; and customers can achieve substantial savings on transmission and distribution charges. Duquesne Exc. at 30-33.

b. DII's Replies

DII rejoins that Duquesne has provided no evidence for a $2.50 back-up rate. DII contends that no witness testified to support a $2.50/kW rate and Duquesne witness Gorman indicated that he did not know why a 30% availability figure was used. DII R. Exc. at 18-19 (citing Tr. at 323-26).

DII provides that Duquesne University's performance data under Rider No. 16 did not differentiate between forced outages or planned maintenance and therefore, it was unknown why the generator was unavailable. DII contends that if the Rider No. 16 rate differentiated between Back-up Service and Maintenance Service, a customer like Duquesne University would negotiate its downtimes or maintenance to ensure they were not down during anticipated peaks. DII R.Exc. at 20 (citing DII R.B. at 12-13, DII St. 1-S at 12-13).

DII further submits that the testimony of Peoples witness Daniel and Duquesne witness Fisher fails to support Duquesne's current position. DII notes that Mr. Daniel stated, "continued use of a 30% load factor can be viewed as a compromise." DII argues that Mr. Fisher's comparison of Duquesne's rates with other Pennsylvania utilities is insufficient to justify the Rider No. 16 rates, as these rates may also be unnecessarily inflated. DII R. Exc. at 21-22 (citing Peoples St. 2-SR at 15 and Tr. at 663).

c. Disposition

We agree with Duquesne that the ALJ erred in adopting DII's position that the Rider No. 16 rate should be reduced from $2.50 to $0.352 by using a load factor of 5%. In reaching this determination, we believe that the ALJ incorrectly equated the 30% load factor used by Duquesne in its previous rate case with a usage factor. Duquesne's

30% factor was not based on how often a CHP generator fails to run; rather, it approximates 30% of the fully-allocated cost of service as calculated by Duquesne witness Gorman in the 2013 rate case. The 30% factor considers more than the availability of the CHP customer's generator. It was not an analytically-derived, cost-of-service based factor – nor was it intended to be. It was proposed and accepted in a settlement in the 2013 case. Duquesne R.Exc. at 29. During the prior rate case, William Pfrommer, the Senior Manager of Rates and Tariff Services, explained the methodology for calculating the rate as follows:

> The Company is proposing a distribution rate of $2.50 per kW. This is based on an average of the primary demand costs per kW in Mr. Gorman's Exhibit 6-2B and a load factor of 30%. The load factor is an estimate based on the availability of the current customer, a review of other utility tariffs, and the expectation of the need for the Company to provide back-up power.

Peoples St. 2 at 9 (citing Docket No. R-2013-2372129 - Duquesne St. 12 at 19 and Exh. 6-2B).

We further find that there is substantial evidence in the record supporting the current Rider No. 16 rate. In this regard. we agree with Peoples witness Daniel who calculated the cost of service and used the same 30% multiplier to arrive at a rate very similar to the existing Rider No. 16 rate. In support of the use of the 30% multiplier, Mr. Daniel stated:

> It is my understanding that no party opposed the Company's Rider No. 16 rate calculation methodology in its prior rate case. The Company witness in the last case explained that the back-up rate was based on estimated availability of the Rider No. 16 customer, a review of other utility tariffs, and the expectation of the need for the Company to provide back-up power. Accordingly, the Commission should require that the

> Rider 16 distribution charge be calculated using the same rate calculation methodology supported by Duquesne and approved by the Commission in the Company's previous rate case.

Peoples St. 2 at 10-11.

We also conclude that the $2.50 Rider No. 16 rate is reasonable because it is voluntary, and the customers can achieve savings through Rider No. 16 because it is less than the applicable full requirements rate. If Rider No. 16 is not the best fit for a particular CHP customer, it can remain on full requirements service. Duquesne witness Fisher analyzed the savings options for a CHP customer under Rider No. 16 and the full requirements rates and determined that customers with on-site generation can achieve substantial savings using the Company's back-up rates in Rider No. 16. Mr. Fisher calculated the savings for a typical CHP customer with a 5 MW total connected load with a 2 MW on-site generator. His calculations showed that if this customer had elected Rider No. 16 and experienced a 32-hour monthly outage, the customer would save at least $258,000 per year in transmission and distribution (T&D) charges, or 37% of the customer's total T&D charges. Duquesne Exc. at 32 (citing Duquesne St. 16-R at 20, 22). The record further provides evidence that customers that install CHP in Duquesne's service area can also avoid a higher percentage of T&D charges than those customers located in PECO's and PPL's service areas. Duquesne St. 16-R at 43-44.

Accordingly, we shall grant Duquesne's Exception No. 4.

9. Duquesne's Exception No. 5 Regarding a Separate Class for Rider No. 16 Customers

a. Duquesne's Exception No. 5

Duquesne avers that the ALJ erred in finding that Rider No. 16 customers should have been treated as a separate class in Duquesne's Cost of Service Study in the last rate case. In this proceeding, the ALJ adopted the position of DII witness Crist who characterized the Rider No. 16 customers as a class of customers with a 95% operational availability with 5% downtime. Duquesne disagreed with Mr. Crist's analysis. Duquesne Exc. at 34 (citing R.D. at 175).

Duquesne points out that Mr. Crist did not perform a fully-allocated cost of service study. Rather, Mr. Crist used Duquesne witness Gorman's cost of service study[22] for Rider No. 16 eligible customer classes and discounted that cost by applying a 5% multiplier. Duquesne notes further that Mr. Crist did not treat the current single Rider No. 16 customer as a class but recommended that in the future, when there are more Rider No. 16 customers, those customers could be treated as a separate class. Duquesne Exc. at 34-35 (citing Tr. at 588, DII St. 1-S at 11).

b. DII's Replies

In Reply, DII agrees with the ALJ that Rider 16 Service customers should be treated as a distinct class. Regarding cost of service, DII states that it agrees with Duquesne's stated goal of reaching cost of service. DII contends that this is why it recommends studying Rider No. 16 customers as a class. DII avers that the class of Rider No 16 customers should bear the appropriate costs of the distribution system, determined

[22] DLC Statement No. 14 and accompanying exhibits.

by studies that appropriately reflect the non-coincident nature of the individual customer's reliance on back-up service. DII R.Exc. at 24.

c. Disposition

As noted, Duquesne only has one Rider No. 16 customer. As such, we are of the opinion that one customer does not make a class and that it would be premature to establish a separate customer class until such time as additional projects come on line and sufficient operational data is collected. Additionally, other proposed CHP projects have not yet been built in Duquesne's territory, and when they are built, it is likely that actual performance may vary. Thus, any new Rider No. 16 customers may not have the same operating profile as does the existing Rider No. 16 customer such as outage rates, peak demand size and time of outage occurrence. Since we do not know the diversity of a potential class for Rider No. 16 customers, it is too early at this time to characterize a class of CHP customers without actual performance data. Therefore, we shall grant Duquesne's Exception No. 5 and reverse the ALJ's recommendation on this matter.

10. DII's Exception No. 1 Regarding a Separate Maintenance Rate

a. DII's Exception No. 1

DII alleges that the ALJ erred in recommending that the Commission not require a separate maintenance rate for Rider No. 16. DII provides that a planned maintenance rate encourages coordination of outages with the EDC, so that maintenance of onsite generation systems is performed at a mutually beneficial time for the customer and the local distribution utility. DII maintains that the RAP Study indicates that daily maintenance rates should be lower than daily standby rates, accounting for the fact that "maintenance outages . . . would be coordinated with the utility and scheduled during

periods when system generation requirements are low." DII Exc. at 4 (citing Exhibit No. JWS-6 at 5).

DII maintains that a planned maintenance rate provides customer-generators reliability benefits. First, DII suggests a separate and lower rate for maintenance service that would encourage routine maintenance of the distributed generation units and increase long-term availability and reliability of the generation as a whole. DII references its witness Crist testimony in which he noted that setting the maintenance rate lower than the back-up rate would encourage customers to engage in necessary maintenance to avoid unplanned outages. DII Exc. at 5 (citing DII St. 1 at 26). DII continues by noting that a separate and lower rate for maintenance service encourages customers with onsite generation to keep their generation running at utility peak periods. DII Exc. at 5 (citing Peoples St. 2 at 22).

According to DII, a separate rate for planned maintenance would allow for the development of clear reliability data by distinguishing between forced outages and scheduled maintenance. DII contends that this would assist the Commission and the utility in developing true cost-based rates in future proceedings. DII Exc. at 6.

b. Duquesne's Replies

In its Reply, Duquesne contends that unplanned outages for Rider No. 16 customers can and do occur during on-peak periods, and there is no valid cost of service basis for establishing a back-up rate that is 95% below the fully-allocated cost of service as DII proposes and even less reason to establish a separate "maintenance" rate that is even further below the fully-allocated cost of service. Duquesne R.Exc. at 5.

Duquesne explains that if a back-up rate is applied to a customer's contracted level of back-up demand – as the terms of Rider No. 16 currently provide and

as "best practices" for back-up rate design deem proper – then no purpose is served by setting a second rate for "maintenance" outages. Duquesne R.Exc. at 5-6 (citing Duquesne Exc. at 11-12). Duquesne explains further that as Rider No. 16 is currently structured, the customer pays a single rate applied to the level of back-up demand for which it contracts. According to Duquesne, the customer is then entitled to receive back-up distribution service up to the maximum hourly limit set forth in Rider No. 16 irrespective of when or why a generator outage occurs. Duquesne R.Exc. at 6.

Duquesne contends that the cost of generation is sufficient incentive for a customer-generator to schedule maintenance during off-peak periods. Duquesne R.Exc. at 9. Regarding PURPA applicability, Duquesne notes that PURPA regulations apply only to "qualifying facilities" that meet qualification criteria established by PURPA and have been certified by FERC. Duquesne states that FERC's regulations do not apply to customer-owned behind-the-meter generation that is not certified as a "qualifying facility." Duquesne R.Exc. at 10 (citing 18 CFR § 292.301(a)). Duquesne avers that DII's attempt to rely upon the PURPA regulations is an example of DII's attempt to appropriate principles and rate criteria that only apply to the generation supply service and erroneously apply them to distribution service. Duquesne R.Exc. at 12.

c. Disposition

Based upon our review of this matter, we are of the opinion that insufficient information has been provided to require Duquesne to provide a separate maintenance rate in the existing Rider No. 16 at this time.

Based on the record, it is unclear if the lack of a maintenance rate for Rider No. 16 has deterred development of onsite generators. Duquesne has only one customer on Rider No. 16, and that customer does not object to maintaining the current Rider No. 16 rate. Additionally, Peoples has withdrawn its objection in this proceeding.

DII also did not adequately analyze on-system generator use of existing rate schedules. DII witness Heller admits in discovery that "base rate schedule GL and L do not raise significant obstacles to Pitt's plans to develop more onsite generation" and DII's witness Sprys admits Allegheny County Airport did not evaluate or consider this option [Option C] in their analysis.[23] For example, Rate Schedule L and HVPS Customers can reduce their distribution charges by scheduling their generator outages during off-peak periods, subject to applicable minimum charges.[24]

Also, we agree with Duquesne that whether or not a customer is eligible for Rider No. 16, the Company must size its equipment to meet the customer's peak demand. This is the case for Duquesne, because the Rider No. 16 is voluntary, and the customer could return to full requirements delivery service upon switching back the otherwise applicable rate schedule. Thus, Duquesne must arrange for distribution system capacity to be available to serve its customers at any time, unless this optionality was eliminated in the tariff. As Duquesne asserts, it costs the same to build a distribution system that will be used every day (as with a non-generation customer) as it does for a distribution system that will be used once or twice a year but is reserved for use during the remainder of the year. We agree with Duquesne that it may not avoid distribution costs when the customer plans its generation outages to occur at off-peak times if the customer has the option to revert to its otherwise applicable rate schedule. Duquesne St. 16-R at 8.

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[23] Duquesne 16-R at 10.

[24] Duquesne 16-R at 14. For rate schedule L, the Minimum Charge shall be the Demand Charge based on 70% of the Contract *On-Peak* Demand for transmission and distribution and the Demand Charge as calculated under Rider No. 9 for Company supplied supply.

V. Conclusion

Based on our review of the record, and consistent with the foregoing discussion we shall: (1) grant the Exceptions filed by Duquesne Light Company in this proceeding; (2) deny the Exceptions filed by the Duquesne Industrial Intervenors; and (3) modify the ALJ's Recommended Decision, consistent with this Opinion and Order; **THEREFORE,**

IT IS ORDERED:

1. That the Exceptions filed by the Duquesne Light Company on October 29, 2018, are granted, consistent with this Opinion and Order.

2. That the Exceptions filed by the Duquesne Industrial Intervenors on October 29, 2018, are denied, consistent with this Opinion and Order.

3. That the Recommended Decision of Administrative Law Judge Katrina L. Dunderdale, issued on October 18, 2018, is modified, consistent with this Opinion and Order.

4. That Duquesne Light Company shall not place into effect the rates, rules, and regulations contained in Supplement No. 174 to Tariff Electric Pa. P.U.C. No. 24, the same having been found to be unjust, unreasonable, and therefore unlawful.

5. That the Joint Petition for Approval of Settlement Stipulation filed by Duquesne Light Company, the Bureau of Investigation and Enforcement, the Office of Consumer Advocate, the Office of Small Business Advocate, the Coalition for

Affordable Utility Services and Energy Efficiency in Pennsylvania, the Duquesne Industrial Intervenors, the Community Action Association of Pennsylvania, Wal-Mart Stores East, LP and Sam's East, Inc., ChargePoint, Inc., the Keystone Energy Efficiency Alliance, NRG Energy Center Pittsburgh LLC, Clean Air Council, and the Natural Resources Defense Council, Inc. at Docket Nos. R-2018-3000124 and R-2018-3000829, including all terms and conditions as clarified, is approved.

6. That Duquesne Light Company is hereby authorized to file the tariff supplement contained in Appendix "A" to the Joint Petition for Approval of Settlement Stipulation on less than statutory notice, to be effective on at least one day's notice after entry of the Commission's Final Order, for service rendered on and after December 29, 2018, designed to produce $92.7 million in additional annual base rate operating revenue based upon the pro forma level of operations at December 31, 2018, consistent with the Commission's Final Order in this proceeding.

7. That Duquesne Light Company shall allocate the authorized increase in operating revenue to each customer class and shall implement the rate design as set forth in Appendix "A" to the Joint Petition for Approval of Settlement Stipulation.

8. That the Formal Complaints filed against the base rate proceeding at R-2018-3000124 by the Office of Consumer Advocate at C-2018-3001029; Peoples Natural Gas Company LLC at C-2018-3001152; Office of Small Business Advocate at C-2018-3001566; Duquesne Industrial Intervenors at C-2018-3001713; and NRG Energy Center Pittsburgh LLC at C-2018-3002755, are dismissed and marked closed, consistent with the Joint Petition for Approval of Settlement Stipulation.

9. That Duquesne Light Company shall refund to customers $24 million, which sum includes interest, through a one or two-time bill credit on a distribution revenue basis, to return to ratepayers $19.2 million in 2018 tax savings associated with the Tax Cut and Jobs Act of 2018, inclusive of the effect of deferred income taxes and a gross-up of income taxes, and 2018 protected and unprotected EDIT.

10. That Duquesne Light Company shall file with the Commission's Bureau of Technical Utility Services a list that shall detail by rate class how much in dollars will be refunded to each rate class as a result of the Tax Cut and Jobs Act of 2017 refund. The list shall be filed at Docket No. R-2018-3000829 on or before January 29, 2019.

11. That the Formal Complaints of Jason Dolby at C-2018-3001074; and Leonard Coyer at C-2018-3002424, are dismissed and marked closed.

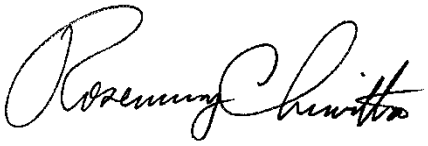
12. That Duquesne Light Company shall not alter the terms of Tariff Rider No. 21 to require new customer-generators to install a second meter socket for a generation meter prior to receiving net-metering services.

13. That upon acceptance and approval by the Commission of the tariff revisions filed by Duquesne Light Company, consistent with this Order, the investigation at Docket No. R-2018-3000124 shall be marked closed.

14. That upon acceptance and approval by the Commission of the $24 million refund to customers, which sum includes interest, through a one or two-time bill credit on a distribution revenue basis, pursuant to the Tax Cut and Jobs Act of 2017, the proceedings at Docket No. R-2018-3000829 shall be marked closed.

15. That the Memorandum of Understanding between Duquesne Light Company and Duquesne University of the Holy Spirit regarding Tariff Rider No. 16 signed June 25, 2018, is hereby approved.

BY THE COMMISSION,



Rosemary Chiavetta
Secretary

(SEAL)

ORDER ADOPTED: December 20, 2018

ORDER ENTERED: December 20, 2018

The Narragansett Electric Company

d/b/a National Grid

INVESTIGATION AS TO THE PROPRIETY OF PROPOSED TARIFF CHANGES

Compliance Filing

Amended Settlement Agreement Compliance Attachment 1 through Compliance Attachment 2 Schedule 13

Book 1 of 7

August 16, 2018

Submitted to:
Rhode Island Public Utilities Commission
RIPUC Docket Nos. 4770/4780

Submitted by:

nationalgrid

The Narragansett Electric Company
d/b/a National Grid

Amended Settlement Agreement
Docket Nos. 4770 and 4780
August 16, 2018

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
nationalgrid

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SCHEDULE A 1

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

In Re: The Narragansett Electric Company d/b/a National Grid's Application to Change Electric and Gas Base Distribution Rates	)	Docket No. 4770
In Re: The Narragansett Electric Company d/b/a National Grid's Proposed Power Sector Transformation (PST) Vision and Implementation Plan	)	Docket No. 4780

AMENDED SETTLEMENT AGREEMENT

The Narragansett Electric Company d/b/a National Grid (the Company)[1] enters into this amended settlement agreement (the Settlement Agreement) with the Division of Public Utilities and Carriers (Division); the Office of Energy Resources (OER); the U.S. Department of the Navy and the Federal Executive Agencies (collectively, Navy/FEA); Conservation Law Foundation (CLF); Energy Consumers Alliance of New England, Inc. d/b/a People's Power and Light (PPL)[2]; Sierra Club (SC)[3]; Natural Resources Defense Council (NRDC)[4]; Acadia Center (Acadia); Northeast Clean Energy Council (NECEC); the George Wiley Center (GWC); New

[1] The term "Company" refers to The Narragansett Electric Company's electric and gas distribution operations on a collective basis. The electric and gas distribution operations of The Narragansett Electric Company together represent the entirety of the regulated operations conducted in Rhode Island by the Company. In this Settlement Agreement, the regulated entity is referred to as the Company. Where there is a need to refer to the individual electric and gas distribution operations of the Company, the terms "Narragansett Electric" or "Narragansett Gas," respectively, are used in this Settlement Agreement.

[2] PPL intervened in Docket No. 4770 individually and in Docket No. 4780 jointly with Sierra Club and Natural Resources Defense Council.

[3] SC intervened in Docket No. 4780 jointly with PPL and Natural Resources Defense Council.

[4] NRDC intervened in Docket No. 4780 jointly with PPL and Sierra Club.

Energy Rhode Island (NERI); Wal-Mart Stores East, LP and Sam's East, Inc. (collectively, Wal-Mart); Direct Energy Business, LLC, Direct Energy Services, LLC, and Direct Energy Solar (collectively, Direct Energy)[5]; ChargePoint, Inc. (ChargePoint)[6]; and National Railroad Passenger Corporation (Amtrak)[7] (collectively, the Settling Parties and, each individually, a Settling Party[8]), with regard to the Company's Application for Approval of a Change in Electric and Gas Base Distribution Rates Pursuant to R.I. Gen. Laws §§ 39-3-10 and 39-3-11 (the Application) and the Company's proposed Power Sector Transformation (PST) Vision and Implementation Plan (PST Plan). The Company submitted the Application and the PST Plan to the Rhode Island Public Utilities Commission (the PUC) on November 27, 2017.

Background:

The Company's Application to the PUC requested a change in base distribution rates to address a total Rate Year[9] revenue deficiency of $41,294,907 for Narragansett Electric and a total revenue deficiency of $30,322,543 for Narragansett Gas. The Company's Application was filed to seek recovery of costs necessary for the safe and reliable operation of the Company's electric and gas distribution systems for the benefit of Rhode Island customers. On March 2, 2018, the Company revised its request to account for the impacts of the Tax Cuts and Jobs Act (the Tax Act), which reduced the federal corporate income tax rate from 35 percent to 21 percent. The March 2, 2018 revision reduced the Company's Rate Year revenue deficiency to $27,434,395 for Narragansett Electric and $18,408,489 for Narragansett Gas. This revision also

[5] Direct Energy is an intervenor in Docket No. 4780 only.

[6] ChargePoint is an intervenor in Docket No. 4780 only.

[7] Amtrak is an intervenor in Docket No. 4770 only.

[8] PPL, SC, and NRDC intervened jointly in Docket No. 4780 and together are considered a Settling Party with respect to that docket.

[9] The Rate Year is the twelve-month period ending August 31, 2019.

included a $6.7 million correction from a miscalculation of accumulated deferred taxes in the Company's filing that the Division identified. Subsequently, on May 9, 2018, the Company made a second revision to its request to account for additional impacts of the Tax Act and to address certain corrections identified during the course of discovery in Docket No. 4770, also including the acceptance of an adjustment that was recommended by the Division to the amortization of excess deferred income taxes. The May 9, 2018 revision reduced the Company's Rate Year revenue deficiency to $18,877,761 for Narragansett Electric and $15,451,041 for Narragansett Gas. Accordingly, after the Company's second revision to its revenue requirement, the Company's total requested revenue increase was $34,328,802.

Additionally, concurrent with filing the Application, the Company filed its PST Plan to propose investments to further the State of Rhode Island's power sector transformation goals, as identified through the Docket No. 4600 proceedings and through the power sector transformation stakeholder process, which resulted in the Rhode Island Power Sector Transformation Phase One Report to Governor Gina M. Raimondo. The PST Plan included requests for limited Rate Year funding and a proposed funding mechanism for the Company's proposed power sector transformation investments. The PUC separated the PST Plan from the Application and created Docket No. 4780 to assess the PST Plan. After the PUC initiated Docket No. 4780, the Company revised its request related to the PST Plan and requested: (1) approval of $2 million in Rate Year funding to conduct a planning process for the implementation of Advanced Metering Functionality (AMF); (2) approval of its proposed annual PST Plan process, whereby the Company would submit annual PST Plans for the PUC and Division to review and approve PST investments; (3) approval of the Company's proposed PST Provision, which provided for the

recovery of PST Plan costs on a fully reconciling basis; and (4) guidance from the PUC on the categories of proposed PST investments outlined in the Company's PST Plan filing.

The Settling Parties have filed testimony with the PUC, engaged in discovery and negotiations regarding the matters specified in the articles of this Settlement Agreement, and asserted competing and disputed claims with regard to certain issues contained in the Application and the PST Plan, including, but not limited to: (a) the magnitude of the proposed revenue deficiencies for Narragansett Electric and Narragansett Gas; (b) the scope and structure of the Company's proposed power sector transformation programs, such as AMF implementation, electric vehicle enablement, and grid modernization technology upgrades; (c) a multi-year rate plan; (d) the structure and role of performance incentive mechanisms; and (e) the appropriate cost recovery mechanisms.

The Settling Parties now wish to resolve the contested issues raised by (1) the Division, Navy/FEA, Wal-Mart, NERI, and Acadia in direct testimony and OER and GWC in written comments filed with the PUC on April 6, 2018 in Docket No. 4770; (2) Amtrak in its motion to intervene out of time filed with the PUC on June 1, 2018 in Docket No. 4770; (3) CLF jointly with PPL/SC/NRDC and CLF jointly with NRDC/PPL in direct testimony filed with the PUC on April 17, 2018 in Docket No. 4780; and (4) the Division, Navy/FEA, NERI, Acadia, Direct Energy, ChargePoint, and CLF jointly with NECEC in direct testimony and OER in written comments filed with the PUC on April 25, 2018 in Docket No. 4780, on mutually agreeable terms.

The Settling Parties believe that a settled resolution will reduce costs for Rhode Island customers through the elimination of resource-consuming litigation and achieve a just and reasonable result that takes into account the diverse views of all the Settling Parties.

Accordingly, in consideration of the exchange of promises herein contained, the Settling Parties hereby agree, subject to approval by the PUC, as follows:

ARTICLE I: INTRODUCTION

A. Procedural History

Docket No. 4770: At the outset of these proceedings, the PUC ordered that the Company's PST Plan be moved into Docket No. 4780 and be considered on a separate procedural schedule. Additionally, the PUC directed that it would not consider any settlement proposal until after the Division and intervenors submitted direct testimony setting forth their positions on the various elements of the Company's Application.

Since filing its Application on November 27, 2017, the Company has responded to 1,439 data requests issued by the PUC, the Division, the Navy/FEA, Wal-Mart, NERI, and Acadia. The Division and the intervenors also have responded to data requests issued by the Company and the PUC. On April 6, 2018, the following Division and Intervenor witnesses filed direct testimony in Docket No. 4770: Division Witnesses Tim Woolf (Policy), Michael Ballaban jointly with David J. Effron (Revenue Requirement), Tina Bennett jointly with Alan Neale (Gas Business Enablement), Gregory Booth (Grid Modernization), Matthew Kahal (Cost of Capital and Return on Equity), Tim Woolf jointly with Melissa Whited (Additional Cost of Capital Considerations and Benefit Cost Analysis), Roxie McCullar (Depreciation), Roger Colton (Low Income Discount and Income Eligible Proposals), John Athas (Electric Allocated Cost of Service and Rate Design), and Bruce Oliver (Gas Allocated Cost of Service and Rate Design), raising issues relating to the calculation of the proposed revenue requirement, the computation of allowable uncollectible expense, the cost of capital, and other ratemaking issues including, but not limited to, cost allocation, rate design, the appropriate structure and role of performance

incentive mechanisms, and the appropriate cost recovery mechanisms for grid modernization investments.

- Navy/FEA Witness Ali Al-Jabir, raising issues relating to rate design and revenue allocation;
- Wal-Mart Witness Gregory W. Tillman, raising issues relating to revenue allocation, rate design, and return on equity – as well as the impact of the Tax Act;
- NERI Witness Karl Rabago, raising issues relating to the Company's proposed revenue requirement, return on equity, rate design, forecasting, revenue allocation, and the streetlighting tariff; and
- Acadia Witness Mark LeBel, raising issues relating to rate design and return on equity.

The following parties also intervened in Docket No. 4770 and filed written comment:

- OER in relation to the alignment of the Company's proposals with the State of Rhode Island's overall policy goals for the future of the power sector; and
- GWC in relation to the Company's low income discount rate design proposals.

CLF, NECEC, PPL, and Amtrak intervened in Docket No. 4770, but did not file direct testimony or written comment.

On May 9, 2018, the Company filed rebuttal testimony responding to the issues contested by the Division and the intervenor witnesses. Specifically, the Company filed the rebuttal testimony of Company Witnesses Robert E. Hevert (return on equity and capital structure); Ned Allis (depreciation); Joseph F. Gredder (electric forecasting); Theodore E. Poe, Jr. (gas forecasting); John Gilbert, Daniel J. DeMauro, and Mukund Ravipaty (information systems); Anthony Johnston and Christopher J. Connolly (Gas Business Enablement); Raymond J. Rosario, Jr., Alfred Amaral, III, and Ryan M. Constable (operational expense); Maureen Heaphy

(human resources); Melissa Little (revenue requirement); Howard S. Gorman (electric allocated cost of service study, revenue allocation, and rate design); Paul M. Normand (gas allocated cost of service study, revenue allocation, and rate design); Ann E. Leary and Scott McCabe (gas and electric pricing, respectively); Kayte O'Neill (PST policy); Rob Sheridan (grid modernization); John Leana (AMF); and Meghan McGuinness and Timothy R. Roughan (performance incentive mechanisms). These witnesses responded to the positions of the Division and intervenor witnesses on each of the identified issues.

To date, the PUC has held 13 open meetings on December 20, 2017, January 3, January 19, February 2, March 5, April 13, April 16, April 17, April 23, May 15, May 16, June 7, and June 19, 2018, at which the PUC analyzed the Company's Application and the respective positions of the Company, the Division, and the intervenors.

Docket No. 4780: Since the initial filing of its Application and the PST Plan on November 27, 2017, and, after the PUC initiated Docket No. 4780 for separate consideration of the PST Plan, the Company has responded to 469 data requests issued by the PUC, the Division, the Navy/FEA, PPL/SC/NRDC, NERI, and NECEC. On April 17, 2018 and/or April 25, 2018, the following Division and Intervenor witnesses filed direct testimony in Docket No. 4780:

- Division Witnesses Gregory Booth, raising issues relating to the Company's proposed grid modernization investments, and Tim Woolf jointly with Melissa Whited, raising issues related to: (a) multi-year rate plans, (b) performance incentive mechanisms, (c) the Company's electric vehicle proposals, (d) the Company's electric heat proposals, (e) the Company's electric storage initiative, (f) the Company's proposal for Company-owned solar generation, (g) AMF, and (h) the Company's benefit-cost analyses;

- Navy/FEA Witness Ali Al-Jabir, raising issues relating to: (a) cost recovery mechanisms for PST proposals; (b) cost allocation and rate design; and (c) performance incentive mechanisms;
- CLF jointly with PPL/SC/NRDC Witness Douglas B. Jester, raising issues relating to AMF and the Company's electric vehicle proposals;
- CLF jointly with PPL/NRDC Witness Benjamin A. Stafford, raising issues relating to the Company's electric heat proposals;
- NERI Witness Karl Rabago, raising issues relating to: (a) overall PST policy and vision; (b) cost recovery mechanisms for PST investments; (c) performance incentive mechanisms; and (d) benefit cost analyses;
- NECEC and CLF Witness Nathan Phelps, raising issues relating to: (a) the Company's proposed grid modernization investments; (b) AMF; (c) the Company's electric storage initiative; (d) the Company's proposal for Company-owned solar generation; and (e) the Company's proposed Income Eligible Customer Rewards Program;
- NECEC and CLF Witness Ronald J. Binz, raising issues relating to performance-based regulation, performance incentive mechanisms, and recovery of PST-related costs;
- Direct Energy Witness Frank Lacey, raising issues relating to: (a) the Company's proposed grid modernization investments; (b) AMF; (c) time-varying rates and (d) the Company's electric vehicle proposals;

- Acadia Witness Mark LeBel, raising issues relating to: (a) performance incentive mechanisms; (b) AMF; (c) the Company's electric vehicle proposals, and (d) the Company's electric heat proposals; and
- ChargePoint Witness David Packard, raising issues relating to the Company's electric vehicle proposals.

OER also intervened in Docket No. 4780 and filed written comment raising issues relating to: (a) performance incentive mechanisms; (b) the Company's proposed grid modernization investments; (c) AMF; (d) the Company's electric vehicle proposals; (e) the Company's electric heat proposals; (f) the Company's electric storage initiative; (g) the Company's proposal for Company-owned solar generation; and (h) cost recovery mechanisms for PST proposals. The GWC also intervened in Docket No. 4780 but did not file direct testimony or written comment.

In addition to the pre-filed written testimony and the responses to data requests that have been filed in Docket No. 4780, the PUC also held technical sessions on the various elements of the Company's PST Plan. Specifically, on January 26, 2018, the PUC held a technical session on the Company's proposed grid modernization investments and cost recovery mechanisms. On January 31, 2018, the PUC held a technical session on the Company's proposed performance incentive mechanisms. On February 8, 2018, the PUC held a technical session on the Company's AMF proposal. On February 20, 2018, the PUC held two technical sessions: one on the Company's electric vehicle proposals, and another on the Company's electric heat proposals. On February 21, 2018, the PUC held two more technical sessions: one on the Company's electric storage initiative, and another on the Company's proposal for Company-owned solar generation.

The Settling Parties have conducted ongoing settlement discussions. The Company and the Division have conducted bilateral negotiations on the various proposals in the Application and the PST Plan. Additionally, the Company has held additional bilateral negotiations with certain other intervening parties to address specific areas of interest and concern to those parties. To supplement those bilateral negotiations and ensure that the positions of all the Settling Parties received appropriate attention and consideration, the Division and the Company arranged for several face-to-face meetings at which all intervenors had an opportunity to raise and advocate for the issues that were of principal concern to them and to negotiate the substance of this Settlement Agreement. Ultimately, the Company and the Division drafted the Settlement Agreement to include all the issues and matters raised by all the Settling Parties during these negotiations. After the Company and the Division completed drafting the Settlement Agreement, they shared the draft with all the intervenors and provided them an opportunity for further comments and revision. This Settlement Agreement, therefore, is the product of a collaborative, inclusive, and comprehensive process that fairly considered the interests of all parties and stakeholders.

The Settlement Agreement was initially filed with the PUC on June 6, 2018. The PUC commenced the hearing on the Settlement Agreement on June 12, 2018; held 11 days of settlement hearings on June 14, June 15, June 18 through June 22, June 25 through June 28, 2018; and concluded the hearing on July 18, 2018. The PUC subsequently held a series of open meetings on July 2, July 3, July 18, July 20, and July 31 to discuss the Settlement Agreement and the testimony from the settlement hearings. On August 3, 2018, the PUC held an open meeting at which the PUC approved the Settlement Agreement filed on June 6, 2018 with modifications.

Following the PUC's open meeting decision, the Settling Parties convened to review and discuss the PUC's modifications, which have been incorporated into this Settlement Agreement.

B. Settling Parties' Statement

This Settlement Agreement is based on extensive discovery and negotiations among the Settling Parties concerning all issues involved in: (1) establishing new base distribution rates for the Company's electric and gas operations to become effective September 1, 2018; and (2) making investments in new programs and initiatives to facilitate power sector transformation. The Settling Parties agree that the outcome of this Settlement Agreement is just and reasonable and in the public interest.

C. Scope

The Settlement Agreement addresses the full scope of all issues presented in and resolves all issues contested among the Settling Parties in both Docket No. 4770 and Docket No. 4780 and establishes base distribution rates for the Company's electric and gas residential, commercial and industrial (C&I), and outdoor lighting customers in Rhode Island.

ARTICLE II: TERMS OF SETTLEMENT

A. Multi-Year Rate Plan Overall Framework

As a result of the collaborative and inclusive settlement negotiations among the Settling Parties in addition to bilateral negotiations between the Company and the Division on the various proposals in the Application and the PST Plan, the Settling Parties have developed a comprehensive set of terms and conditions for a three-year rate plan for Narragansett Electric and Narragansett Gas. The terms and conditions of this rate plan are set forth below and in the Attachments to this Settlement Agreement. Specifically, this Settlement Agreement addresses the following topics:

1. Effective Date and Term;
2. Changes in Revenue Requirements for Three Rate Years;
3. Base Distribution Rate Changes for Rate Year 2 and Rate Year 3;
4. Narragansett Electric - Revenue Requirement;
5. Narragansett Electric - Revenue Allocation, Rate Design, and Tariffs;
6. Narragansett Electric - Earnings Report and Earnings Sharing Mechanism;
7. Narragansett Electric - Other Tariffs and Reconciling Mechanisms;
8. Narragansett Gas - Revenue Requirement;
9. Narragansett Gas - Revenue Allocation, Rate Design, and Tariff;
10. Narragansett Gas - Earnings Report and Earnings Sharing Mechanism;
11. Narragansett Gas - Other Tariffs and Reconciling Mechanisms;
12. Gas Business Enablement Program;
13. Cyber Security and Information Services (IS) Technology Modernization Programs;
14. Commencement of Investments to Enable a Modern Grid;
15. Grid Modernization Plan (GMP);
16. AMF;
17. Clean Energy Programs;
18. Capital Efficiency Mechanism for Narragansett Electric;
19. Performance-Based Incentive Mechanisms;
20. Tracking and Deferral of Certain “Special Sector” Program Costs and Revenues;
21. Next Rate Case Filing;
22. Additional Provisions; and
23. Other Provisions.

B. Definitions

"**Docket 4600 Guidance Document**" means the PUC's Guidance on Goals, Principles and Values for Matters Involving The Narragansett Electric Company d/b/a National Grid adopted on October 27, 2017 in Docket No. 4600-A.

"**Effective Date**" means September 1, 2018, or such other date as the PUC may determine.

"**ISR**" means the infrastructure, reliability, and safety planning and cost recovery process governed by Section 39-1-27.7.1(c), (d) of Rhode Island General Laws.

"**Rate Year 1**," sometimes referred to herein as "RY1," means September 1, 2018 through August 31, 2019.

"**Rate Year 2**," sometimes referred to herein as "RY2," means September 1, 2019 through August 31, 2020.

"**Rate Year 3**," sometimes referred to herein as "RY3," means September 1, 2020 through August 31, 2021.

The three rate years are referred to herein collectively as "Rate Years," or "RYs," and individually as a "Rate Year," or "RY."

"**Test Year**," means July 1, 2016 through June 30, 2017.

C. Rate Plan

1. Effective Date and Term

The term of the Company's electric and gas rate plan is three years, beginning September 1, 2018 and continuing through August 31, 2021 (Rate Plan or MRP). For administrative reasons, certain targets and mechanisms are on different twelve-month schedules (*e.g.,* calendar year (CY) periods), as provided herein. In addition, unless specifically noted in this Settlement

Agreement, all terms of this Settlement Agreement will continue in effect until changed by the PUC.

2. Changes in Revenue Requirements for Three Rate Years

This Settlement Agreement provides for the following changes in base distribution rate annual revenue requirements for Narragansett Electric and Narragansett Gas for each of the Rate Years of the Rate Plan (*i.e.*, Rate Year 1, Rate Year 2, and Rate Year 3) to provide funding for the Company's electric and gas operations and PST Plan initiatives, including: Updated AMF Business Case (as defined in Section 16 below); GIS Investments; System Data Portal; DSCADA; other Grid Modernization investments; Electric Transportation; and Electric Storage.

	Narragansett Electric ($M)	Narragansett Gas ($M)	Total ($M)
Base Case			
Rate Year 1	$12.0	$5.8	$17.8
Rate Year 2	$3.9	$5.7	$9.6
Rate Year 3	$2.5	$3.4	$5.9
Subtotal – Base Case	$18.4	$14.9	$33.3
Power Sector Transformation			
Rate Year 1	$2.1	$0.0	$2.1
Rate Year 2	$6.6	$1.9	$8.4
Rate Year 3	$1.9	$0.6	$2.5
Subtotal – PST	$10.6	$2.5	$13.0
Base Case plus PST			
Rate Year 1	$14.1	$5.8	$19.9
Rate Year 2	$10.5	$7.6	$18.0
Rate Year 3	$4.3	$4.0	$8.4
TOTAL	$28.9	$17.4	$46.3

A summary of the revenue requirement settlement terms is provided in Attachment 1, Page 1. The base case components of the base distribution revenue requirements for Narragansett Electric and Narragansett Gas are set forth in Attachment 2, Schedules 1-ELEC and

2-GAS, respectively. The PST Plan components of the base distribution revenue requirements for Narragansett Electric and Narragansett Gas are set forth in Attachment 4 and Attachment 5.

To reach a settlement in these proceedings, the Company accepted the majority of the downward adjustments to operating expenses and rate base that were recommended by the Division, as outlined in the table below.

	Rate Year ($M)		
	1	2	3
Company Base Rate Request			
March 2, 2018 (REV-1) Base Rate Request	$45.8		
Refund of Excess Deferred Taxes	($9.0)		
A&G Expense Reclassification to Capital	($4.5)		
March 2, 2018 (REV-1) Base Rate Request adjusted	$32.4[10]		
Settlement Adjustments			
Subtotal - Expense Adjustments	($14.3)		
Subtotal - Rate Base Adjustments	($3.1)		
Adjustment to Revenue Requirement for Rate Base Adjustments	($0.3)		
Total Adjustments	($14.6)		
Subtotal - Adjusted Base Rate Request	$17.8	$9.6	$5.9
PST Additions			
PST Adjustments	$2.1	$8.4	$2.6
Total Settlement - Base Case plus PST	$19.9	$18.0	$8.5

As detailed in Attachment 2, for Rate Year 1, the revenue requirements are based on the following parameters and adjustments:

a. A return on equity (ROE) of 9.275 percent;

b. A capital structure recommended by the Division and overall cost of capital, including a 51 percent common equity ratio. The resulting weighted average cost of capital (WACC) is applicable to the calculation of the revenue requirements associated with the

[10] As described in Section 4.h. (Narragansett Electric) and Section 8.h. (Narragansett Gas), the Company will include all other revenue requirement adjustments either (1) identified during discovery, (2) in the preparation of the May 9, 2018 rebuttal cost of service, and (3) resulting from changes presented in the rebuttal testimony in its compliance filing revenue requirement in this docket. These adjustments account for the difference between the Company's adjusted March 2, 2018 request of $32.4 million and the request of $34.3 million submitted with the Company's rebuttal filing on May 9, 2018.

ISR Plans and any other reconciling mechanism that calculates a return based on the approved WACC, which is the same as it is today;

c. A reduction in depreciation expense of $3.1 million. The Company's depreciation rates for Narragansett Electric and Narragansett Gas have been reduced and are set forth in Attachment 2, respectively;

d. The impacts of the tax rate change to 21 percent and the amortization of excess accumulated deferred income taxes (ADIT);

e. A reduction to Administrative and General expense to reflect a reclassification to capital;

f. An adjustment to labor expense to reflect a smooth hiring pattern over the term of the Rate Plan for all incremental full time equivalents (FTEs) that were included in the Company's November 27, 2017 initial filing but have not yet been filled, as shown on Attachment 2, Schedule 12 and Attachment 3, Workpaper 4;

g. An adjustment to the calculation of the average of net write-offs as a percentage of total revenues for the five years ended June 30, 2017 for Narragansett Gas to eliminate the twelve-month period ended June 30, 2013 from this calculation. The average write-off rate is applied to the Rate Year 1 revenue to calculate the pro forma Rate Year 1 uncollectible accounts expense. This adjustment reduces the average Narragansett Gas write-off rate from 2.08 percent to 1.91 percent;

h. An adjustment to reflect the Division's position on Gas Growth capital;

i. Adjustments to reflect the Division's position on Gas Business Enablement and the IS Technology Modernization Programs (see Sections 12 and 13 below);

j. Existing reconciling mechanisms for costs recovered outside of base

distribution rates remain in effect as operating today, as listed in Attachment 22; and

k. Adjustment to Service Company rents and Gas Business Enablement for reduced ROE at 9.275 percent; and

l. Adjustment for the depreciation expense impact of the growth adjustment.

3. Base Distribution Rate Changes for Rate Year 2 and Rate Year 3

Under the Rate Plan governed by this Settlement Agreement, base distribution rates for Narragansett Electric and Narragansett Gas shall change annually at the start of each Rate Year, effective September 1, 2018, September 1, 2019, and September 1, 2020. The annual increase in base distribution rates shall be allocated to each of Narragansett Electric's and Narragansett Gas's respective rate classes in the same proportion as determined from the final revenue allocation of the revenue requirements for Rate Year 1. The allocation of the increases to rate classes is presented in Attachment 8 for Narragansett Electric and Attachment 16 for Narragansett Gas, and base distribution rates based upon each rate class's Rate Year revenue requirement for Rate Year 2 and Rate Year 3 is contained in Attachment 9 for Narragansett Electric and Attachment 16 for Narragansett Gas.

a. The development of each Rate Year's base distribution rates consistent with the Rate Plan governed by this Settlement Agreement is incorporated in this Settlement Agreement, and through the PUC's approval of this Settlement Agreement, the base distribution rates for the Rate Years are approved for implementation, subject to any changes pursuant to Sections 8, 15, and/or 16;

b. Bill impacts for all rate classes comparing the rates in effect at the time of the Company's initial filing and Rate Year 1; Rate Year 1 and Rate Year 2; and Rate

Year 2 and Rate Year 3, are presented in Attachment 10 and Attachment 17 for Narragansett Electric and Narragansett Gas, respectively; and

c. The PUC's approval of the base distribution rates contained in this Settlement Agreement represents its determination that the proposed base distribution rates are reasonable and consistent with the MRP.

On or before June 1 of each year of the Rate Plan, Narragansett Electric shall submit to the PUC its Summary of Retail Delivery Rates tariff updating this tariff to reflect the base distribution rates approved by the PUC as part of this Settlement Agreement, together with testimony and supporting schedules explaining and itemizing the change in revenue requirement from the prior September 1 through the upcoming September 1, unless otherwise changed pursuant to a separate proceeding before the PUC consistent with Sections 8, 15, and/or 16.

The rate schedule provisions of Narragansett Gas's tariff contained in Attachment 19 include the base distribution rates for each of the Rate Years.

4. Narragansett Electric - Revenue Requirement

a. *Revenue Requirements for the Rate Years*. This Settlement Agreement provides that the base distribution rates for Narragansett Electric shall be set in these proceedings based on a Rate Year 1 revenue requirement increase of $14.1 million, a Rate Year 2 revenue requirement increase of $10.4 million, and a Rate Year 3 revenue requirement increase of $4.4 million, using a test-year ended June 30, 2017 (Test Year), as detailed in Attachment 1 to this Settlement Agreement.[11] The resulting revenue requirements for the Rate Years are: $293.2 million for RY1, $303.5 million for RY2, and $308.0 million for RY3. The base case revenue requirement for Rate Year 1 was determined using a total rate base of $729.5 million; pro forma

[11] Schedule A to this Settlement Agreement lists the attachments supporting this Settlement Agreement. Schedule A also provides a cross-reference to the bound volume that contains each respective attachment.

Test Year operating revenues of $279.2 million; distribution operating expenses of $150.6 million; income taxes of $1.1 million; and an overall rate of return of 6.97 percent. The base case revenue requirement for Rate Year 1 established by the Settling Parties allows for recovery of a revenue deficiency of $12.0 million in Rate Year 1, which represents a reduction of $29.3 million from the November 27, 2017 original request and a reduction of $6.9 million from the May 9, 2018 second revision to the cost of service.

b. *Calculation of Rate Base*. The Settling Parties agree that rate base for Narragansett Electric for the Rate Years shall be calculated to include capital additions approved in the ISR Plans for Fiscal Year 2014 (Docket No. 4382), Fiscal Year 2015 (Docket No. 4473), Fiscal Year 2016 (Docket No. 4539), Fiscal Year 2017 (Docket No. 4592), and estimated Fiscal Year 2018 (Docket No. 4682), estimated Fiscal Year 2019, and estimated Fiscal Year 2020 additions through Rate Year 1 (*i.e.*, August 31, 2019). Narragansett Electric's rate base for the Rate Years also shall be calculated to include non-ISR capital additions through August 31, 2021.[12] Narragansett Electric's rate base for the Rate Years also shall reflect the unamortized cost of long-term debt issuance expense. ISR-eligible capital additions for Rate Year 2 and Rate Year 3 will be addressed in the ordinary course outside of base distribution rates through the ISR Plan and included for recovery in future ISR Plans.

c. *Other Adjustments*. The revenue requirements contained in Attachment 2 reflect adjustments agreed to by the Settling Parties associated with the Tax Cuts and Jobs Act, a change in the Company's A&G capitalization policy, and estimated Service Company excess deferred federal income taxes.

[12] Capital additions currently recovered through the ISR Plan will be included in rate base as of September 1, 2018, concurrent with the effective date of new base distribution rates in these proceedings. Therefore, the capital-related portion of the ISR factor will be set to zero as of September 1, 2018.

d. *Operating Expenses*.

i. Uncollectible Accounts Expense

The Settling Parties agree that the recovery of distribution-related uncollectible-accounts expense[13] shall be calculated using Narragansett Electric's actual five-year average ratio of actual distribution net write-offs as a percentage of distribution revenues (as calculated in Docket No. 4323 and Docket No. 4065) ending with the Test Year, or 1.30 percent. The actual, five-year average write-off rate of 1.30 percent shall also be used to calculate recovery of the uncollectible accounts expense allowance in those reconciling mechanisms that provide for the recovery of uncollectible account expense.

ii. Non-Deferrable Storm Expense

This Settlement Agreement provides that the amount of non-deferrable storm expense allowed for recovery through base distribution rates shall be set at $3,193,756[14] annually, subject to the following: If the actual level of non-deferrable storm expense in any calendar year commencing in 2019 is greater than $5,193,756, then the amount in excess of $5,193,756 shall be charged to the Storm Contingency Fund (the Storm Fund). If the actual level of non-deferrable storm expense in any calendar year commencing in 2019 is less than $1,193,756, then the amount by which $1,193,756 exceeds the actual non-deferrable storm expense in that calendar year shall be credited to the Storm Fund. Because new base distribution rates go into effect on September 1, 2018, the dead band for 2018 shall be applied to the average of

[13] This amount does not include the commodity-related portion of uncollectible accounts expense, which is recovered through various reconciling mechanisms as governed by their respective tariff provisions (see Pre-Filed Direct Testimony of Company Witness Melissa A. Little at Page 47 (Bates Page 51 of Book 8). The calculation of uncollectible account expense is provided in Schedule MAL-22 (Rev-2) (Rebuttal Book 3).

[14] Represents the five-year average of non-deferrable storm expense for the twelve month periods ended June 30, 2013 to June 30, 2017 (see Schedule MAL-31 (Rev-2) at Page 7, Line 13, Column (e)).

$3,722,000[15] for 8/12^{ths} of the year and $3,193,756 for 4/12^{ths} of the year, or $3,545,919.

iii. Storm Contingency Fund

As further described on Attachment 23, the Storm Contingency Fund is subject to the provisions of the Joint Proposal and Settlement between the Company and the Division filed with the PUC on September 25, 2017 in Docket No. 4686 and approved by the PUC on April 27, 2018 (Docket No. 4686 Settlement Agreement).

The total base distribution rate contributions to Narragansett Electric's Storm Fund effective September 1, 2018 will be $7.3 million annually, which includes:

(1) $4.3 million in annual base distribution rate contributions; and

(2) $3.0 million of supplemental Hurricane Sandy base distribution rate contributions through their currently scheduled expiration in March 2021. Thereafter, the continuation of this supplemental $3.0 million annual Storm Fund contribution will be subject to PUC review.

In addition, a contribution of $21.1 million annually is credited to the Storm Fund from the Storm Fund Replenishment Factor through its currently scheduled expiration in June 2021.

e. *Return on Rate Base*

i. Capital Structure

The Settling Parties agree that the revenue requirement established by this Settlement Agreement for Narragansett Electric shall be determined by the WACC and its components, as shown in Attachment 2.

[15] The amount of non-deferrable storm expense allowed for recovery through base distribution rates for Narragansett Electric was set at $3,722,000 in Docket No. 4323, representing the five-year average of non-deferrable storm costs for calendar years 2007 to the 2011 test year in Docket No. 4323. As approved in Docket No. 4323, a $2,000,000 dead band was established, which would trigger additional charges to the Storm Fund for non-deferrable storm costs in excess of $5,722,000 in a calendar year, or credits to the Storm Fund for non-deferrable storm costs less than $1,722,000. See Docket No. 4686 Settlement Agreement, Paragraph (9), at 3.

The actual capital structure shall be adjusted further to include the long-term debt issued on July 27, 2018 pursuant to the separate Settlement Agreement entered into between the Division and the Company dated February 15, 2017, in Division Docket D-17-36, which was approved as set forth in the Division's Report and Order issued February 19, 2017, and as set forth in the statement of basic terms that the Company filed with the Division on August 1, 2018.

ii. Cost of Long-Term Debt

As stated above, the new long-term debt shall be pro-formed at an interest rate of 3.919 percent and debt expense estimated at 0.46 percent, or $1.61 million. Upon completion of the long-term debt issuance, the revenue requirement established by the Settlement Agreement shall be adjusted to use the actual weighted cost of long-term debt and debt expense after the new debt issuance. The Company shall make a filing to the PUC within 60 days of the completion of the long-term debt issuance to adjust base distribution rates for Narragansett Electric to incorporate the actual debt rate and issuance costs in base distribution rates.

iii. Return on Common Equity

The Settling Parties agree that the return on common equity shall be set at 9.275 percent.

iv. Weighted Average Cost of Capital

The computation of the WACC established by this Settlement Agreement is set forth in Attachment 2. The weighted average cost of capital set forth in Attachment 2, as adjusted pursuant to Section 4(e), above, shall be used for ratemaking purposes, including in the ISR Plan, until the next base distribution rate proceeding for Narragansett Electric.

f. *Miscellaneous Corrections*. The Settling Parties agree that Narragansett Electric shall make all corrections (1) identified during discovery, (2) in the preparation of the May 9, 2018 rebuttal cost of service, and (3) resulting from changes presented in the rebuttal

testimony of Company Witness Melissa A. Little in finalizing the cost of service for Narragansett Electric.

5. Narragansett Electric - Revenue Allocation, Rate Design, and Tariffs

a. *Allocated Cost of Service*. The Settling Parties agree, for the purpose of settlement in these proceedings (except with respect to the customer charge as reflected in this Settlement Agreement), to use the allocated cost of service study (ACOSS) included in Attachment 6, consistent with the ACOSS filed by Narragansett Electric on May 9, 2018.[16] In future rate cases, the Company shall include all costs associated with the PST programs and investments in its revenue requirements and ACOSS.

b. *Revenue Allocation and Rate Design*. The Settling Parties agree that Narragansett Electric's revenue allocation contained in Attachment 8, prepared consistent with the Updated Revenue Allocation (Schedule HSG-3(R)) filed with the PUC on May 9, 2018, and which shall be incorporated into the design of base distribution rates, shall include:

i. A reduction to present revenue for Rate X-01 of $322,000, which is a reduction from Rate X-01 present revenue of $692,000 (shown on Line 40 in Attachment 8, Page 2) to $370,000 to address the concerns raised by Amtrak in these proceedings regarding the significant difference between Rate X-01 revenue at present rates and Rate X-01's allocated rate year revenue requirement. This represents a reduction that balances a significant benefit to Amtrak with the impact this reduction will have on other customers. In addition, the Company will commit, on a going forward basis, to (1) in future general rate cases, propose other changes to address any remaining difference between Rate X-01 revenue at then-present rates and Rate X-01's allocated rate year revenue requirement resulting from an ACOSS filed in those general

[16] See Rebuttal Testimony of Company Witness Howard S. Gorman, at Page 5 (Bates Page 7 of Rebuttal Book 6), and Schedule HSG-1A(R), at Bates Page 37 of Rebuttal Book 6.

rate cases, and will specifically propose to address any difference, to the extent the ACOSS identifies a significant difference in relation to differences identified for the Company's other rate classes, and (2) inform Amtrak of its next general rate case filing for Narragansett Electric reasonably in advance of such filing.

ii. The allocation of the annual base distribution rate allowance of the revenue requirements associated with Grid Modernization programs and Special Sector Programs, as described in Sections 15 and 20, respectively, and the Rate Year 2 and Rate Year 3 annual base distribution rate increases as stated above in Section 4.

The Settling Parties agree with Narragansett Electric's rate design included in Attachment 9, which reflects:

i. The Rate A-16/Rate A-60 rate design reflects a monthly customer charge of $6.00 and a base distribution per-kWh rate sufficient to recover the remaining Rate A-16/Rate A-60 revenue requirement after consideration of the $6.00 customer charge.

ii. The Rate A-60 customer charge shall be phased-in over the term of the Rate Plan as proposed by the Company in its initial filing as follows: a customer charge of $2.00 effective September 1, 2018; a customer charge of $4.00 effective September 1, 2019; and a customer charge of $6.00 effective September 1, 2020.

iii. The Rate C-06 rate design reflects a monthly customer charge of $10.00 and a base distribution per-kWh rate sufficient to recover the remaining Rate C-06 revenue requirement after consideration of the $10.00 customer charge.

iv. The Rate G-32 rate design reflects impact of the results of the ACOSS submitted on May 9, 2018 in Schedule HSG-1A(R) which redefines transmission level voltage to be electric service received at no less than 69 kV.

c. *Other Settlement Provisions*. The Settling Parties agree to the following:

i. For customers receiving delivery service on Rate A-60, a total bill discount shall be applied. Specifically, (a) the percentage discount off of the total amount billed shall be 25 percent, and (b) for customers receiving benefits through Medicaid, General Public Assistance, and/or the Family Independence Program, an additional discount of 5 percent off of the total amount billed. The Settling Parties agree that Narragansett Electric shall implement the Low Income Discount Recovery Factor (LIDRF) calculated in Attachment 20. Customers billed on Rate A-60 shall not be assessed the LIDRF.

ii. A revision to the Credit for High Voltage Delivery (HVD) provision contained in the Large Demand Rate (G-32) retail delivery service tariff (Rate G-32 Tariff) and Large Demand Backup Service Rate (B-32) retail delivery service tariff (Rate B-32 Tariff) that defines transmission level voltage to be electric service at no less than 69 kV.

iii. The Fox Point Hurricane Barrier (Hurricane Barrier) operated by the United States Army Corps of Engineers (USACE)[17] is designed to protect the City of Providence from flooding and is tested periodically. The USACE has begun conducting its periodic testing of the Hurricane Barrier during off-peak hours, as defined in the Rate G-32 Tariff, to avoid the demand ratchet provision for the assessment of billing demand that would occur for testing during peak hours.

To address the concerns raised by Navy/FEA with respect to the Hurricane Barrier, if the Hurricane Barrier is operated during peak hours, as defined in the Rate G-32 Tariff, as a result of a weather event, (1) immediately following the operation of the Hurricane Barrier during peak hours, the USACE will contact the Company, in writing, notifying the Company that a weather

[17] The USACE is represented in these proceedings by the Navy on behalf of the FEA.

event required the operation of the Hurricane Barrier; (2) after review and confirmation of the conditions at the time of the Hurricane Barrier's operation during peak hours, the Company will waive the demand ratchet provision resulting from the operation of the Hurricane Barrier during peak hours, for the 11 billing months following the month of peak hour operation (billing months 2 through 12). This waiver would be pursuant to the Rate G-32 Tariff under the Demand provision, which defined billing demand "under ordinary load conditions;" and (3) the USACE will be billed based on the billing demand as determined pursuant to the Rate G-32 Tariff based on peak hours metered demand measured in kW and kVa during the month of operation. If the USACE tests the Hurricane Barrier during peak hours, the demand ratchet of the Rate G-32 Tariff would apply for the billing of distribution demand charges in months 2 through 12. However, the USACE can avail itself of the Optional Determination of Demand provision in the Rate G-32 Tariff.

To ensure that the billing account remains on Rate G-32 as a result of the Hurricane Barrier's continued testing during off-peak hours, the Company has revised the availability provision of the Rate G-32 Tariff and the Rate B-32 Tariff to define customers eligible for Rate G-32 and Rate B-32 based on metered demand during all hours, rather than billing demand, which is determined during peak hours. This change will allow a large customer, such as the Hurricane Barrier, respond to the price signals of Rate G-32 and Rate B-32 and remain on Rate G-32 and Rate B-32, and not be transferred to the General C&I Rate (G-02) tariff.

iv. The Company shall add to Rate S-05 another operating schedule allowing customer-owned light-emitting diode (LED) streetlights to operate at an output level that would result in 3,080 annual operating hour equivalents. As this operating schedule is preferred by NERI as compared to the operating schedule Narragansett Electric presented in its

May 9, 2018 rebuttal testimony in Schedule PP-6(R), Narragansett Electric will withdraw its May 9, 2018 operating schedule proposal. In addition, for purposes of billing LED streetlights that operate at an output level that is less than the Dusk-to-Dawn operating schedule existing in the Rate S-05 tariff, the annual operating hour equivalent of such a streetlight shall be compared to the operating schedules contained in the Rate S-05 tariff. If the streetlight's annual operating hour equivalent is no more than five percent of an existing operating schedule's annual operating hour equivalent, the streetlight shall be placed on that operating schedule. If the streetlight's annual operating hour equivalent exceeds the annual operating hour equivalent of an existing operating schedule by more than five percent, the streetlight shall be placed on the operating schedule with the next highest annual operating hour equivalent.

v. The Company shall implement a returned check fee of $8.00.

vi. The Company shall cancel its Optional Telephone or Web Page Payment Provision, RIPUC No. 2154.

d. *Miscellaneous Corrections*. The Settling Parties agree that Narragansett Electric shall make all corrections (1) identified during discovery, (2) in the preparation of the May 9, 2018 rebuttal ACOSS and rate design, and (3) resulting from changes presented in the rebuttal testimony of Company Witness Howard S. Gorman in finalizing the ACOSS, revenue allocation, and rate design.

e. *Bill Impacts and Tariffs*. Attachment 10 sets forth the electric bill impacts resulting from this Settlement Agreement. Attachment 12 presents the other rates and charges that are impacted by this Settlement Agreement, consistent with what was initially filed on November 27, 2017. Attachment 13 contains the tariffs and tariff provisions, marked to show changes from those currently in effect, that are proposed to become effective September 1, 2018.

The impact of this Settlement Agreement on the monthly bill of a 500 kWh residential customer receiving Standard Offer Service, as compared to the rates which were in effect at the time of the Company's filing in this case, in each of the Rate Years is as follows:

	Dollar Increase	Percent Increase
Rate Year 1	$3.67	3.5%
Rate Year 2	$1.03	0.9%
Rate Year 3	$0.44	0.4%

6. Narragansett Electric - Earnings Report and Earnings Sharing Mechanism

a. *Annual Earnings Report*. The Company shall file with the PUC and the Division annual earnings reports for Narragansett Electric consistent with and in a form similar to that which the Company has been filing for several years, most recently in Docket No. 4323, calculating electric regulatory earnings for the calendar year with the additions/changes set forth in subsections b. through d. below. The timing of the filing of the annual earnings report for Narragansett Electric shall be May 1 of each year.

b. *Definitions*.

i. **"Actual Earnings"** means earnings including all Performance Incentives earned for the applicable calendar year.

ii. **"Base Earnings"** means earnings excluding all Performance Incentives earned for the applicable calendar year. The Base Earnings calculation also shall exclude any financial penalties incurred by Narragansett Electric that may have been assessed by the PUC or the Division during the calendar year, and the report shall disclose those excluded amounts separately.

iii. **"EE Performance Incentive"** means the Energy Efficiency Program (EEP) Incentive.

iv. **"Performance Incentives"** means the EE Performance Incentive; any earned System Reliability Procurement incentives; LTCR Remuneration Costs; RE Growth Remuneration Costs; Performance Incentive Mechanisms Incentives; and any other performance incentive that has been or may be approved by the PUC in a future proceeding and that was earned and recorded by Narragansett Electric for performance applicable to the calendar year.

v. **"Performance Incentive Mechanisms Incentives"** means the incentives earned from the incentive mechanisms as set forth in Section 19 of this Settlement Agreement.

c. *Calculation of Earnings for Annual Earnings Report*. The Company shall show the calculation of the regulatory earned return on distribution rate base and the earned return on distribution common equity, in two ways:

i. Actual Earnings for the applicable calendar year; and

ii. Base Earnings for the applicable calendar year.

d. *Earnings Sharing With Customers*. If and when the Base Earnings exceed the allowed ROE of 9.275 percent in any calendar year, the amount in excess of 9.275 percent will be deemed "shared earnings."

i. If the level of earnings is greater than the allowed ROE of 9.275 percent, but is less than or equal to 10.275 percent, 50 percent of the shared earnings in this tier shall be credited to customers and the Company shall

retain 50 percent of the shared earnings, which shall not be reflected in any earnings reports.

ii. If the level of earnings is greater than 10.275 percent, 75 percent of the shared earnings in this tier shall be credited to customers and the Company shall retain 25 percent of the shared earnings, which shall not be reflected in any earnings report.

Narragansett Electric shall retain 100 percent of any excess earnings of the Actual Earnings that are attributable to any of the Performance Incentives. Any shared earnings credited to customers shall be credited to the Storm Fund, unless the PUC otherwise directs the credit to customers in another manner.

7. Narragansett Electric - Other Tariffs and Reconciling Mechanisms

The Settling Parties agree that this Settlement Agreement does not (and is not intended to) amend, modify, or change in any respect any tariff or mechanism currently in effect for Narragansett Electric for costs recovered outside of base distribution rates pursuant to any statute or prior PUC order that is not specifically addressed in this Settlement Agreement, or contained in Attachment 22.

Consistent with the impact of the results of a general rate case and the PUC's rulings thereon, the Company shall implement changes to its other factors and charges associated with its various reconciling mechanisms, effective September 1, 2018, to reflect updated net write off percentages, WACCs, and consolidation of Rate G-32 and Rate G-62. In its compliance filing pursuant the PUC's approval of the Rate Plan, the Company shall file schedules in support of the requisite changes to its other factors and charges that will be reflected in its bills to customers effective September 1, 2018, as illustrated in Attachment 12.

8. Narragansett Gas - Revenue Requirement

a. *Revenue Requirements for the Rate Years*. This Settlement Agreement provides that base distribution rates for Narragansett Gas shall be set in these proceedings based on a Rate Year 1 revenue requirement increase of $5.7 million, a Rate Year 2 revenue requirement increase of $7.6 million, and a Rate Year 3 revenue requirement increase of $4.0 million, using a test-year ended June 30, 2017, as detailed in Attachment 2 to this Settlement Agreement. The resulting revenue requirements for the Rate Years are: $218.6 million for RY1, $226.2 million for RY2, and $230.2 million for RY3. The revenue requirement for Rate Year 1 was determined using a total rate base of $760.6 million; pro forma Test Year operating revenues of $212.8 million; distribution operating expenses of $86.1 million; income taxes of $5.7 million; and an overall rate of return of 7.15 percent. The revenue requirement for Rate Year 1 established by the Settling Parties allows for recovery of a revenue deficiency of $5.8 million in Rate Year 1, which represents a reduction of $24.4 million from the November 27, 2017 original request and a reduction of $9.6 million from the May 9, 2018 second revision to the cost of service.

As noted in Attachment 23 , the Company will credit the Net Revenue received for Narragansett Gas storm response services performed in other jurisdictions, including those outside of National Grid USA operating companies' service territories, back to customers through the Distribution Adjustment Charge, applicable.

b. *Calculation of Rate Base*. The Settling Parties agree that rate base for Narragansett Gas for the Rate Years shall be calculated to include capital additions approved in the ISR plans for Fiscal Year 2014 (Docket No. 4380), Fiscal Year 2015 (Docket No. 4474), Fiscal Year 2016 (Docket No. 4540), Fiscal Year 2017 (Docket No. 4590), and estimated Fiscal

Year 2018 (Docket No. 4678), estimated Fiscal Year 2019, and estimated Fiscal Year 2020 additions through Rate Year 1 (*i.e.*, August 31, 2019).[18] Narragansett Gas' rate base for the Rate Years also shall be calculated to include non-ISR capital additions through August 31, 2021. The Narragansett Gas rate base also shall reflect the unamortized cost of the long-term debt issuance expense. ISR-eligible capital additions for Rate Year 2 and Rate Year 3 will be addressed in the ordinary course outside of base distribution rates through the ISR and included for recovery in future ISR Plans.

c. *Other Adjustments.* The revenue requirements contained in Attachment 2 reflect adjustments agreed to by the Settling Parties associated with the Tax Cuts and Jobs Act, a change in the Company's A&G capitalization policy, and estimated Service Company excess deferred federal income taxes.

d. *Operating Expenses*

i. Uncollectible Accounts Expense

The Settling Parties agree that the recovery of distribution-related uncollectible-accounts expense[19] shall be calculated using Narragansett Gas's actual five-year average ratio of actual distribution net write-offs as a percentage of distribution revenues (as calculated in Docket No. 4323 and Docket No. 3943) ending with the Test Year, except as follows:

> The twelve-month period ended June 30, 2013 will be eliminated from this calculation for Narragansett Gas for the Rate Year(s) in these proceedings. This adjustment reduces the average write-off rate that is applied to the Rate Year 1

[18] Capital additions that are being recovered currently through the ISR will be included in rate base as of September 1, 2018, concurrent with the effective date of new base rates in these proceedings. Therefore, the capital-related portion of the ISR factor will be set to zero as of September 1, 2018.

[19] This amount does not include the commodity-related portion of uncollectible accounts expense (see Pre-Filed Direct Testimony of Company Witness Melissa A. Little at Page 47 (Bates Page 51 of Book 8). The calculation of uncollectible account expense is provided in Schedule MAL-22 (Rev-2) (Rebuttal Book 3).

revenues to calculate the pro forma Rate Year 1 uncollectible accounts expense. This adjustment reduces the average Narragansett Gas write-off rate from 2.08 percent to 1.91 percent.

The write-off rate of 1.91 percent also shall be used to calculate the uncollectible accounts expense allowance in those reconciling mechanisms that provide for the recovery of uncollectible account expense.

e. *Return on Rate Base*

i. Capital Structure

The Settling Parties agree that the revenue requirement established by this Settlement Agreement for Narragansett Gas shall be set, as shown on Attachment 2. The actual capital structure shall be adjusted further to include the long-term debt issued on July 27, 2018 pursuant to the separate Settlement Agreement entered into between the Division and the Company dated February 15, 2017, in Division Docket D-17-36, which was approved as set forth in the Division's Report and Order issued February 19, 2017, and as set forth in the statement of basic terms that the Company filed with the Division on August 1, 2018.

ii. Cost of Long-Term Debt

As stated above, the new long-term debt shall be pro-formed at an interest rate of 3.919 percent and debt expense estimated at 0.46 percent, or $1.61 million. Upon completion of the debt issuance, the revenue requirement established by the Settlement Agreement shall be adjusted to use the actual weighted cost of long-term debt and debt expense after the new debt issuance. The Company shall make a filing to the PUC within 60 days of the completion of the issuance to adjust base distribution rates to incorporate the actual debt rate and issuance costs in distribution rates.

iii. Return on Common Equity

The Settling Parties agree that the return on common equity shall be set at 9.275 percent.

iv. Weighted Average Cost of Capital

The computation of the pre-tax WACC established by this Settlement Agreement is set forth in Attachment 2. The weighted average cost of capital set forth in Attachment 2, as adjusted pursuant to Section 8(e), above, shall be used for ratemaking purposes, including in the ISR Plan, until the next base-distribution rate proceeding for Narragansett Gas.

f. *Miscellaneous Corrections*. The Settling Parties agree that Narragansett Gas shall make all corrections (1) identified during discovery, (2) in the preparation of the May 9, 2018 rebuttal cost of service, and (3) resulting from changes presented in the rebuttal testimony of Company Witness Melissa A. Little in finalizing the cost of service for Narragansett Gas.

9. Narragansett Gas - Revenue Allocation, Rate Design, and Tariff

a. *Allocated Cost of Service*. The Settling Parties agree, for the purpose of settlement in these proceedings, to use the ACOSS included in Attachment 14, consistent with the ACOSS filed by Narragansett Gas on April 3, 2018.

b. *Revenue Allocation and Rate Design*. The Settling Parties agree that Narragansett Gas' revenue allocation contained in Attachment 16, prepared consistent with the Division's recommended revenue allocation filed with the PUC on April 6, 2018,[20] shall be incorporated into the design of base distribution rates. The Settling Parties agree to the allocation of the annual base distribution rate allowance of the revenue requirements associated with Grid Modernization programs allocable to Narragansett Gas, as described in Section 15, and

[20] Schedule BRO-4 of the Direct Testimony of Witness Bruce R. Oliver on behalf of the Division.

the Rate Year 2 and Rate Year 3 annual base distribution rate increases as stated above in Section 8.

The Settling Parties agree with Narragansett Gas' rate design included in Attachment 16, which reflects:

i. The rate designs for Rates 10/11 and Rates 12/13 reflect a monthly customer charge of $14.00 and uniform base distribution per-therm rates sufficient to recover the remaining revenue requirement of these two rate classes after consideration of the $14.00 customer charge.

ii. The rate designs for Rates 10/11 and Rates 12/13 reflect different uniform base distribution per-therm rates effective during the peak months of November through April as compared to uniform base distribution per-therm rates effective during the non-peak months of May through October.

iii. The rate design for Rate 21 reflects a monthly customer charge of $25.00 and uniform base distribution per-therm rates sufficient to recover the remaining revenue requirement of these two rate classes after consideration of the $25.00 customer charge.

iv. The rate designs for Rate 21 reflects different uniform base distribution per-therm rates effective during the peak months of November through April as compared to uniform base distribution per-therm rates effective during the non-peak months of May through October.

c. *Other Settlement Provisions*. The Settling Parties agree to the following:

i. For customers receiving delivery service on Rates 11 and 13, a total bill discount shall be applied. Specifically, (a) the percentage discount off of the total amount billed shall be 25 percent, and (b) customers receiving benefits through Medicaid,

General Public Assistance, and/or the Family Independence Program, an additional discount of 5 percent off the total amount billed. The Settling Parties agree that Narragansett Gas shall implement the LIDRF calculated in Attachment 20. Customers billed on Rates 11 or 13 shall not be assessed the LIDRF.

ii. The Company shall implement a returned check fee of $8.00.

iii. Narragansett Gas shall remove the Optional Credit Card Payment Provision from its tariff.

iv. Narragansett Gas will weather-normalize the demand billing units of its medium, large, and extra-large commercial and industrial rate classes in future general rate cases.

v. Narragansett Gas shall revise the language in the Distribution Adjustment Clause of its tariff to clarify the determination of System Pressure costs consistent with the Division's recommendation.

vi. Narragansett Gas shall revise the language in the Gas Cost Recovery (GCR) Clause of its tariff that will allow for it to include in its annual GCR factor filings an estimate of operation and maintenance (O&M) expense associated with its liquefied natural gas (LNG) activities as a component of fixed gas supply costs. This estimate is subject to reconciliation to actual LNG O&M expense incurred during the applicable GCR factor term, subject to the PUC's review of reasonableness and prudency, consistent with the other fixed gas supply costs, which also are subject to the PUC's review and approval. The implementation of this change in ratemaking treatment of LNG O&M expense is intended to capture any decreases in LNG O&M expense noted by the Division in its April 6, 2018 direct testimony. The amount of LNG O&M expense can be lower or higher than the amount removed from the Rate Year 1

distribution revenue requirement. The proposed revisions to the GCR Clause are included in Attachment 19.

d. *Miscellaneous Corrections*. The Settling Parties agree that, in finalizing the ACOSS, revenue allocation, and rate design, Narragansett Gas shall make all corrections identified during discovery.

e. *Bill Impacts and Tariff*. Attachment 17 sets forth the gas bill impacts resulting from this Settlement Agreement. Attachment 18 presents the other rates and charges that are impacted by this Settlement Agreement, consistent with what was initially filed on November 27, 2017. Attachment 19 contains the tariff, marked to show changes from that currently in effect, proposed to become effective September 1, 2018.

The impact of this Settlement Agreement on the annual bill of an 845 therm residential heating customer, as compared to the rates which were in effect at the time of the Company's filing in this case, in each of the Rate Years is as follows:

	Dollar Increase (Decrease)	Percent Increase (Decrease)
Rate Year 1	($10.78)	(0.9%)
Rate Year 2	$23.01	1.9%
Rate Year 3	$11.94	1.0%

10. Narragansett Gas - Earnings Report and Earnings Sharing Mechanism

a. *Annual Earnings Report*. The Company shall file with the PUC and the Division annual earnings reports for Narragansett Gas consistent with and in a form similar to that which the Company has been filing for several years, most recently in Docket No. 4323, calculating gas regulatory earnings for the calendar year with the additions/changes set forth in subsection b. below. The timing of the filing of the annual earnings report for Narragansett Gas

shall change from September 1 to May 1 each year to align with the timing of the filing of the Company's earnings report for Narragansett Electric on May 1 of each year. The Company's Annual Report to the PUC for Narragansett Gas will reflect the twelve-month period ending December 31. The Company will file its gas earnings report for Fiscal Year 2018 on or before September 1, 2018. The Company will file its first gas earnings report for the twelve-month period ending December 31, 2018 by May 1, 2019.

b. *Calculation of Earnings for Annual Earnings Report*. The Company shall show the calculation of the regulatory earned return on distribution rate base and the earned return on distribution common equity, in two ways:

i. Earnings including all Performance Incentives (as hereinafter defined below) earned for the applicable calendar year (Actual Total Earnings); and

ii. Earnings excluding all Performance Incentives earned for the applicable calendar year (Base Earnings). The Base Earnings calculation also shall exclude any financial penalties incurred by Narragansett Gas that may have been assessed by the PUC or the Division and recorded during the calendar year, and the report shall disclose those excluded amounts separately.

For purposes of this Section, the term "Performance Incentives" refers to each of the following incentives:

i. Energy Efficiency Program (EEP) incentive;

ii. The Company's share of any incentive earned pursuant to the Natural Gas Portfolio Management Plan recorded during the calendar year;

iii. The Company's share of any incentive earned or penalties incurred pursuant to the Gas Procurement Incentive Plan recorded during the calendar year; and

iv. Any other performance incentive that may be approved by the PUC in a future proceeding that was earned and recorded by Narragansett Gas for performance applicable to the calendar year, unless the PUC determines at the time of approval that any such future incentive should be included in the calculation of Base Earnings.

For informational purposes, the Company shall include a separate calculation of the basis point value on the earned return on distribution common equity resulting from and for each of the individual Performance Incentives.

c. *Earnings Sharing With Customers*. If and when the Narragansett Gas Base Earnings exceed the allowed ROE of 9.275 percent in any calendar year, the amount in excess of 9.275 percent will be deemed "shared earnings."

i. If the level of Base Earnings is greater than the allowed ROE of 9.275 percent but is less than or equal to 10.275 percent, 50 percent of the shared earnings in this tier shall be credited to customers and the Company shall retain 50 percent of the shared earnings, which shall not be reflected in any earnings reports.

ii. If the level of Base Earnings is greater than 10.275, 75 percent of the shared earnings in this tier shall be credited to customers and the Company shall retain 25 percent of the shared earnings, which shall not be reflected in any earnings reports.

Narragansett Gas shall retain 100 percent of any excess gas earnings of the Actual Total Earnings that are attributable to any of the Performance Incentives. Any shared gas earnings credited to customers shall be credited to the Distribution Adjustment Clause (DAC), unless the PUC otherwise directs the credit to customers in another manner.

11. <u>Narragansett Gas - Other Tariffs and Reconciling Mechanisms</u>

The Settling Parties agree that this Settlement Agreement does not (and is not intended

to) amend, modify, or change in any respect any tariff or mechanism currently in effect for Narragansett Gas for costs recovered outside of base distribution rates pursuant to any statute or prior PUC order that are not specifically addressed in this Settlement Agreement, or contained in Attachment 22.

Consistent with the impact of the results of a general rate case and the PUC's rulings thereon, the Company shall implement changes to its other factors and charges associated with its various reconciling mechanisms, effective September 1, 2018, to reflect updated net write off percentages, LNG O&M expense, WACCs, and cash working capital percentages. In its compliance filing pursuant the PUC's approval of the Rate Plan, the Company shall file schedules in support of the requisite changes to its other factors and charges that will be reflected in its bills to customers effective September 1, 2018, as illustrated in Attachment 18.

12. Gas Business Enablement Program

a. *Program Scope; Service Company Rents; Overall Capital Investment*. The Company will continue to implement the Gas Business Enablement Program during the term of the Rate Plan. The Gas Business Enablement Program is a shared investment across all National Grid USA operating companies, which will be implemented and owned by the National Grid USA Service Company, Inc. (Service Company), with a portion of the costs allocated to the Company. The total Service Company costs of the Gas Business Enablement Program for capital expenses and project operating expenses relating to the capital investment (excluding run the business costs) are forecasted to be $478.3 million through Fiscal Year (FY) 2023.

b. *Capital Investment Levels for the Company*. The revenue requirements for Narragansett Electric and Narragansett Gas include 85 percent of the Company's share, as charged to the Company by the Service Company as a rent expense, of the annual revenue

requirement on forecasted Gas Business Enablement Program capital investments. The rent expense charged to the Company for the Gas Business Enablement Program includes the return on, and the amortization of, the Company's allocated portion of current Gas Business Enablement Program capital investments along with incremental Gas Business Enablement Program capital investments that are forecasted to be placed in service during the Rate Years. Notwithstanding the specified program level spending amounts, nothing in this Settlement Agreement is intended to alter the Company's flexibility during the term to substitute, change, or modify the timing of its Gas Business Enablement Program capital investments to deliver the scope of the Gas Business Enablement Program.

c. *10-Year Amortization of Operating and Maintenance (O&M) Costs for the Company*. The revenue requirements for Narragansett Electric and Narragansett Gas for each Rate Year include 85 percent of the Company's forecasted annual non-recurring O&M expense for the Gas Business Enablement Program to be charged to the Company during each Rate Year, amortized over 10 years and including a return at Narragansett Electric's and Narragansett Gas's WACC, as applicable. The revenue requirements include a reduction to the non-recurring O&M expense allowance in each Rate Year, representing 100 percent of Type I forecasted O&M savings and 85 percent of Type II forecasted O&M savings expected to be realized as a result of the Gas Business Enablement Program.

d. *Run-the-Business Costs.* The revenue requirements include forecasted incremental costs to maintain the Gas Business Enablement technology in the Rate Years at the level proposed by the Company in its initial filing: $779,580, $1.2 million, and $1.3 million, respectively, for Narragansett Gas. In the Company's initial request, it included an offset to these run-the-business costs representing 100 percent of Type I forecasted O&M savings. As

part of the settlement, the Company has agreed to further offset these costs by an amount representing 85 percent of Type II forecasted O&M savings expected to be realized as a result of the Gas Business Enablement Program. The adjustment to reflect these additional savings result in a reduction to the revenue requirement of $49,823, $157,867, and $265,584 in each Rate Year, respectively.

e. *Deferral*. To the extent the Company incurs costs less than the Narragansett Electric and Narragansett Gas revenue requirement allowances included in base distribution rates for the items described in Section 12.b. and 12.c. above, the Company shall create a regulatory liability to defer that amount to be returned to customers. The credit to customers of the balance of the regulatory liability account shall be determined from the Company's next general rate case or extension of the Rate Plan governed by this Settlement Agreement. To the extent the Company incurs costs in excess of the Narragansett Electric and Narragansett Gas revenue requirement allowances included in base distribution rates for the items described in Section 12.b. and 12.c. above, the Company shall create a regulatory asset to defer that amount, but in no case will the deferral to the regulatory asset result in recovery of a total cost in excess of the Company's forecasted revenue requirement allowances included in base distribution rates for the items described in Section 12.b. and Section 12.c. above, of $43.8 million ($38.3 million for Narragansett Gas and $5.5 million for Narragansett Electric). The recovery of the balance of the regulatory asset account shall be determined from the Company's next general rate case or extension of the Rate Plan governed by this Settlement Agreement. All Gas Business Enablement costs to be recovered shall be subject to the PUC's review of the reasonableness and prudency of such costs. The Company will accrue carrying charges on the deferral balances using the pre-tax WACC.

f. *Gas Business Enablement Program Reporting*. The Company will file quarterly Gas Business Enablement Program reports with the PUC and the Division within 60 days after the end of each quarter of each Rate Year. The report will address the status of the Gas Business Enablement Program and budget, including: (i) a narrative explaining overall program status; (ii) detail on budgets and actual spending; (iii) identification of allocations of costs to the Company; (iv) explanations of variances between budgeted and actual spending; and (v) an update on the status of the deferral balance created pursuant to subsection e. above, including, at a minimum, the increase, decrease, and balance of the deferral at the end of each quarter.

The Company will work with the Division to accommodate more in-depth reviews by the Division, PUC Staff, or the Division's consultants of the systems associated with Gas Business Enablement during the term of the Rate Plan.

13. <u>Cyber Security and Information Services (IS) Technology Modernization Programs</u>

a. *Scope of Programs; Service Company Rents; Overall Capital Investment*. The Company will continue to implement the Cyber Security and IS Technology Modernization Programs during the term of the Rate Plan. The Cyber Security and IS Technology Modernization Programs are shared investments across all National Grid USA operating companies, which will be implemented and owned by the Service Company, with a portion of the costs allocated to the Company. The total Service Company costs of the Cyber Security and IS Technology Modernization Programs for capital investments and project operating expenses relating to the capital investment (excluding run the business costs) are included in the revenue requirement.

b. *Capital Investment Levels for the Company*. The revenue requirements for Narragansett Electric and Narragansett Gas include 85 percent of the Company's share, as charged to the Company by the Service Company as rent expense, of the annual revenue requirement on forecasted Cyber Security and IS Technology Modernization Programs capital investments. The rent expense charged to the Company for the Cyber Security and IS Technology Modernization Programs includes the return on, and the amortization of, the Company's allocated portion of current Cyber Security and IS Technology Modernization Program capital investments and incremental Cyber Security and IS Technology Modernization Programs capital investments that are forecast to be placed in service during the Rate Years. Notwithstanding the specified program level spending amounts, nothing in this Settlement Agreement is intended to alter the Company's flexibility during the term to substitute, change, or modify the timing of its Cyber Security and/or IS Technology Modernization Programs capital investments to deliver the scope of the Cyber Security and/or IS Technology Modernization Programs.

c. *Deferral*. To the extent the Company incurs costs less than the Narragansett Electric and Narragansett Gas revenue requirement allowances included in base distribution rates for the items described in Section 13.b. above, the Company shall create a regulatory liability to defer that amount to be returned to customers. The credit to customers of the balance of the regulatory liability account shall be determined from the Company's next general rate case or extension of the Rate Plan governed by this Settlement Agreement. To the extent the Company incurs costs in excess of the Narragansett Electric and Narragansett Gas revenue requirement allowances included in base distribution rates for the items described in Section 13.b. above, the Company shall create a regulatory asset to defer that amount, but in no

case will the deferral of the regulatory asset result in recovery of a total cost in excess of the Company's forecasted revenue requirement of $17.3 million ($5.2 million for Narragansett Gas and $12.1 million for Narragansett Electric). The recovery of the balance of the regulatory asset account shall be determined from the Company's next general rate case or extension of the Rate Plan governed by this Settlement Agreement. All Cyber Security and IS Technology Modernization Program costs to be recovered shall be subject to the PUC's review of the reasonableness and prudency of such costs. The Company will accrue carrying charges on the deferral balances using the pre-tax WACC.

d. *Cyber Security and IS Technology Modernization Programs Reporting*. The Company will file quarterly Cyber Security and IS Technology Modernization Programs reports with the PUC and the Division within 60 days after the end of each quarter of each Rate Year. The report will address the status of the Cyber Security and IS Technology Modernization Programs and budgets, including: (i) a narrative explaining overall program status; (ii) detail on budgets and actual spending; (iii) identification of allocations of costs to the Company; (iv) explanations of variances between budgets and actual spending, and (v) an update on the status of the deferral balance created pursuant to subsection c. above, including, at a minimum, the increase, decrease, and balance of the deferral at the end of each quarter. In the report for the last quarter of each Rate Year (quarter ending March 31), the Company will also include (i) any cost or timeline differences that exceed ten percent for the Rate Year; and (ii) the latest Cyber Security and IS Technology Modernization Programs sanction papers authorized during that Rate Year.

The Company will work with the Division to accommodate more in-depth reviews by the Division, PUC Staff, or the Division's consultants of these programs during the term of the Rate

Plan. The Company commits to submit to the Division and PUC the report produced by the independent cyber security consultant who reviewed the Company's cyber security investments and strategy no later than 30 days after the approval of the Settlement Agreement. The report will be filed under the protection of confidentiality.

14. Commencement of Investments to Enable a Modern Grid

The Company shall commence implementation of the following initiatives that the Company originally identified in its PST Plan filing in Docket No. 4780, as provided below:

a. *System Data Portal*

Narragansett Electric will implement this project beginning in Rate Year 1. The revenue requirement in Rate Year 1 will include $0.5 million for up to two FTEs in support of this project; the revenue requirement in Rate Year 2 will include an incremental $0.2 million for one additional FTE in Rate Year 2.

b. *Control Center Enhancements*

i. Geographic Information System (GIS) Data Enhancement Project

Narragansett Electric will commence the GIS Data Enhancement Project, as proposed in its initial filing, in Rate Year 1, and will use reasonable efforts to complete it within 12 months after the project is commenced. The Company's allocated share of the GIS Data Enhancement Project is $427,000, which will be amortized over the three years of the MRP and included in Narragansett Electric's revenue requirement, with a return at the customer deposit rate. Narragansett Electric will commence populating the system with Rhode Island information in Rate Year 2. An allowance of $1 million will be included in the revenue requirements for Rate Year 2 and Rate Year 3 for this project.

ii. Distribution Supervisory Control and Data Acquisition (DSCADA) and Advanced Distribution Management System (ADMS)

Narragansett Electric shall begin the DSCADA/ADMS project, as proposed in its initial filing, during the MRP. To provide Narragansett Electric an opportunity to coordinate implementation of DSCADA/ADMS with its Massachusetts affiliates, Narragansett Electric shall have the discretion to determine the commencement date of the DSCADA/ADMS project. An allowance for the Company's multi-jurisdictional share of the DSCADA/ADMS project in an amount of $0.4 million to cover the initial costs for project Requirements and Definition will be included in the revenue requirement in Rate Year 2. If, however, the DSCADA/ADMS project commences on a later schedule during the MRP, the allowance shall be deferred and applied to the cost of the project, regardless of the timing of completion, and the deferral of which will accumulate interest at the customer deposit rate. A three-year project development and deployment phase will then commence with an expected in-service date beyond the term of the MRP; therefore, revenue requirements for the deployment are not included in this plan.

iii. Remote Terminal Unit (RTU) Separation

Narragansett Electric will begin a program to separate distribution RTUs from transmission RTUs in support of DSCADA/ADMS. Distribution system data will be disaggregated from transmission system data by separating the field RTUs that capture the data and incorporating it into the Company's Supervisory Control and Data Acquisition (SCADA) system. In addition to enabling dedicated DSCADA, a secondary benefit from creating a bright line separation between transmission operations and distribution operations is that it eliminates FERC Critical Infrastructure Protection (CIP) oversight, and its associated risks and costs, from distribution operations. Allowances of $0.0 million, $0.2 million, and $0.3 million are included in Rate Year 1, Rate Year 2, and Rate Year 3 revenue requirements, respectively, for RTU investments.

c. *Other Grid Modernization Investments*. In addition to these foundation initiatives, the following IS-related grid modernization investments are included in the Rate Year 2 and Rate Year 3 revenue requirements: Enterprise Service Bus, Data Lake, PI Historian, Advanced Analytics, Telecommunications, and Cybersecurity.

15. Grid Modernization Plan (GMP)

a. Narragansett Electric will engage with stakeholders via the PST Advisory Group or relevant subcommittee, to develop a comprehensive Grid Modernization Plan (GMP), in parallel with the collaborative effort to develop the Updated AMF Business Case. The GMP will provide a full assessment of the various initiatives being contemplated, including an explanation and evaluation of how the initiatives link to each other. The assessment will consider short and long-term initiatives to include active and future programs. The GMP will present implementation plans outlining the details and technologies over a five-year horizon plus an outline of how this plan aligns with the longer term (i.e., a ten year roadmap). The GMP will provide a roadmap of potential investments beyond the term of the current MRP; requests to fund those investments will be included as part of a general rate case, MRP, or ISR Plan filings.

b. Narragansett Electric will file the GMP with the PUC within a reasonable time after, or in conjunction with, the filing of the Updated AMF Business Case, as described in Section 16, below, but in any event no later than six (6) months following the filing of the Updated AMF Business Case to allow the PUC to consider the GMP and Updated AMF Business Case together.

c. The GMP will take into account the time period for any proposed AMF implementation, and it will include, at a minimum:

i. Objectives for the electric grid to advance the Goals for the Energy System and Rate Design Principles, and potential visibility requirements of the benefit-cost framework in Docket 4600 Guidance Document.

ii. Explanation of the role of currently active programs;

iii. Investments and technology deployments planned through the end of any proposed AMF implementation;

iv. Functionalities to achieve those objectives;

v. Review of options for candidate technologies to deliver those functionalities;

vi. Transparent, updated benefit cost analyses that fully incorporate the Docket No. 4600 framework;

vii. An implementation plan that provides a detailed explanation of the prioritization, sequencing, and pace of investments;

viii. A plan and explanation for the integration and leveraging of customer-side technologies and resources in the near and long-term;

ix. Identification of the possible communications solutions that address current and future needs and support a wide array of potential grid modernization programs and activities;

x. Explanation of congruency with grid modernization activities in New York and Massachusetts;

xi. A plan and explanation of how the selected investments and implementation plan address risks of redundancy or obsolescence; and

xii. A description of how the GMP, in particular the distribution planning components, addresses the relationship between electrification of heating and transportation and energy efficiency to allow for the furtherance of overall reduced peak demand while also encouraging electrification of heating and transportation.

d. The Settling Parties recognize that the Company's GMP and associated Company proposals will be subject to consideration by the PUC in a separate docket in conjunction with the Updated AMF Business Case, and all interested parties will have an opportunity to participate in any such docket prior to PUC action on the GMP and proposals contained therein. The Settling Parties acknowledge and agree that the PUC will make a final determination on whether and how to implement the GMP.

e. To the extent it is determined by the PUC that implementation of any grid modernization initiatives not already funded in the MRP should move forward, and Narragansett Electric must begin to incur costs during the MRP to begin the implementation process, the MRP may be re-opened to include the revenue requirement for any such approved initiatives during the term of the MRP in base distribution rates, as approved by the PUC.

16. <u>AMF</u>

a. *Updated AMF Business Case.* Provided this Settlement Agreement is approved by the PUC, the Company will commence the next phase of work to refine and update its AMF business case (referred to herein as the Updated AMF Business Case) for the Company's proposed AMF investments. Design and procurement efforts undertaken during that phase will be in coordination with the development of a similarly updated AMF business case for the Company's New York affiliate as part of a collaborative with the New York Public Service Commission Staff and other interested parties in that jurisdiction. The Company will use

reasonable efforts to file the Updated AMF Business Case for Rhode Island with the PUC no later than February 1, 2019, which will include an evaluation of shared communications infrastructure and various ownership models for key AMF components, including the potential for incremental revenue that might be generated by these models in the future. Furthermore, the Updated AMF Business Case will address data governance regarding customer, non-regulated power producer (NPP), and third party access to system and customer data, with the proper privacy and security protections in place. The Updated AMF Business Case will propose to implement AMF in the most cost-effective way, and will provide a cost estimate that can be relied upon for purposes of establishing future revenue requirements for deployment of AMF in Rhode Island.

The Company's share of the costs to develop the Updated AMF Business Case is forecasted to be approximately $2 million. An allowance for this forecasted cost is included in the revenue requirements, which will be spread evenly over the three years of the MRP.

b. *Stakeholder Process and Regulatory Filing*. The Company will convene a preliminary meeting with Division staff and the Office of Energy Resources (OER) to develop a common understanding of the next phase of work, to identify areas of the current AMF business plan (as filed in Docket No. 4780, Book One, Chapter 4) requiring further exploration or refinement, and to identify areas for input from the PST Advisory Group (as defined in Section 17(e) below), or relevant subcommittee. An output of this preliminary meeting of the Company, the Division, and OER will be a document to formally agree on additional areas of exploration, pending the PUC's approval of the Company's $2 million funding request for the Updated AMF Business Case. The schedule for the phase of work starting August 1, 2018 and concluding February 1, 2019 with the filing of the Updated AMF Business Case is further discussed below:

i. Between August 1, 2018 and November 15, 2018, the Company will refine and update its AMF business case. As part of this process, the Company will engage stakeholders, via the PST Advisory Group, or relevant subcommittee, to explore and develop a common understanding of specific AMF proposal areas, a customer engagement plan for AMF, including the role of non-regulated power producers (NPP), and assumptions and rationale upon which a proposal to develop time varying rates will be based.

ii. By September 15, 2018, the Company will convene a second meeting with Division staff and OER to present its Updated AMF Business Case addressing stakeholder identified areas, and further discuss additional questions, comments, or proposed modifications for the Company's consideration.

iii. By October 30, 2018, the Company will convene a third meeting with Division staff and OER. At this meeting, the Company will seek clarification, as required, of stakeholder concerns and comments on the Company's Updated AMF Business Case, and provide new information, if any, to address stakeholder concerns and comments.

iv. The Company will use reasonable efforts to file the Updated AMF Business Case with the PUC for review and approval of the funding necessary to deploy statewide AMF in Rhode Island in a timeframe consistent with the Updated AMF Business Case no later than February 1, 2019. The Updated AMF Business Case will contain the following elements:

- A refined and updated AMF business plan, benefit-cost analysis (BCA), and a detailed customer engagement plan;
- An updated AMF deployment schedule with a BCA (using the Societal Cost Test) for different meter deployment periods;

- Revenue requirement for AMF deployment;
- Deployment proposals, a proposal for cost recovery of AMF, and any activities associated with implementation of AMF;
- A proposal to allocate AMF costs among rate classifications;
- Assumptions upon which a proposal to develop time varying rates will be based;
- A Data Governance Plan regarding timely customer, NPP, and third-party access to system and customer data, (e.g., elements may include, but are not limited to, customer assigned peak load contribution, energy and capacity loss factors, interval usage, or other information needed for efficient wholesale and retail market participation) in place and billing quality customer data (e.g., elements may include, but are not limited to, electric usage in kilowatt-hours containing both "register reads" and "interval reads") with the proper privacy and security protections;
- Updated costs for AMF deployment based on information gained from a procurement effort;
- Transparent, updated benefit cost analysis that fully incorporates the Docket No. 4600 framework;
- Investigation of alternative business models and ownership models;
- Analysis of data latency;
- Deployment details;
- Role of non-regulated power producers, including articles to share customer information and customer engagement;
- Ownership model for assets and telecom;

- Detailed AMF functionalities, how Rhode Island will achieve those functionalities, and a timeline for when those functionalities will be available;
- Identification of the most cost effective way to achieve the functionalities, and how the functionalities align to the policy objectives;
- Explanation of whether the realization of those functionalities will require additional future work and costs over 20 years;
- Identification of what functionalities the AMF will achieve that are part of the grid modernization plan and which are in addition to the Grid Modernization Plan;
- Identification of which functionalities are dependent on a full-scale roll out instead of a targeted roll out;
- Business cased based on both a Rhode Island-only scenario and a Rhode Island/New York scenario;
- A business case based on the length (duration) of meter deployment;
- Identification of the critically linked parts of grid modernization and AMF; and
- Identification of whether the AMF solution would allow for proper net metering according to the tariff.

The Settling Parties recognize that the Company's Updated AMF Business Case and associated Company proposals in relation to time varying rates will be subject to consideration by the PUC in a separate docket, and all interested parties will have an opportunity to participate in any process provided prior to PUC action on the Updated AMF Business Case and proposals contained therein. The Settling Parties acknowledge and agree that the PUC will make a final

determination on whether and how to implement AMF and time varying rates in the Company's service territory.

c. To the extent it is determined by the PUC that deployment of AMF should move forward and the Company must incur costs during the MRP to begin the deployment process, the MRP may be re-opened to propose the revenue requirement for any such approved initiatives during the term of the MRP in base distribution rates, as approved by the PUC.

17. Clean Energy Programs

The Solar Demonstration Program for Income Eligible Customers and the Income Eligible Customer Rewards Program, originally proposed in the Company's PST Plan filing in Docket No. 4780, are hereby withdrawn. Narragansett Electric will implement a portfolio of clean energy programs in other areas that the Company originally identified in its PST Plan filing in Docket No. 4780, with some modifications to the programs, as provided below:

a. *Electric Transportation*. The Settling Parties recognize that the Company has a role in facilitating the growth of Electric Vehicle (EV) adoption and scaling of the market for EV charging equipment to advance Rhode Island's zero emission vehicles and greenhouse gas emissions policy goals. In furtherance of these goals, Narragansett Electric will implement a phased electric transportation initiative over the term of the MRP, which will be comprised of the following components: (i) Off-Peak Charging Rebate Pilot, (ii) Charging Station Demonstration Program, (iii) Discount Pilot for Direct Current Fast Charging (DCFC) Station Accounts, (iv) fleet advisory services, and (v) Electric Transportation Initiative Evaluation. The revenue requirement for this initiative will include $0.7 million in Rate Year 1, $1.1 million in Rate Year 2, and $2.1 million in Rate Year 3. The costs of this initiative shall be subject to a deferral mechanism, as described in Section 20, below.

i. Off-Peak Charging Rebate Pilot

Narragansett Electric will offer an Off-Peak Charging Rebate as a pilot to reward customers for charging their EV during off-peak hours, study customer charging patterns at various charging locations and levels, understand customer responsiveness to time-differentiated price signals, and evaluate technology and partnership alternatives to monitor and report charging. Participating customers will earn a rebate for every kWh charged between 9 p.m. and 1 p.m. The off-peak charging rebate will be 6 cents per kWh during the summer months (June through September), and 4 cents per kWh in all other months. Narragansett Electric reserves the right to offer the higher rebate value in the winter months if, for example, system conditions warrant, or to otherwise modify the rebate value. Narragansett Electric will evaluate the rebate value following the first full year of the program and will include any findings and recommendations in the Annual Evaluation Report, as discussed in subsection d., below.

ii. Charging Station Demonstration Program

Narragansett Electric will demonstrate new approaches to electric charging infrastructure development. Narragansett Electric may not own any of the Level 2 charging ports (*i.e.*, charging power between 10-20 miles per hour) to be developed as part of this initiative. Narragansett Electric also may not own any of the DCFC ports to be developed as part of this initiative. Prior to Rate Year 2, Narragansett Electric may propose to re-evaluate utility ownership of Level 2 and DCFC ports as a program design modification in the Annual Program Modification Report. The proposed categories of charging stations under the program are set forth in the tables below.

Charging Station Demonstration Project: Level 2

Level 2	Total Sites	Ports Per Site	Total Ports
Workplaces	14	10	140
Apartment Buildings	6	6	36
Income Eligible Community Sites	6	6	36
Public Transit Stations	6	10	60
Government light-duty fleet	**3**	**8**	**24**
Corporate light-duty fleet	3	8	24
Total	**38**		**320**

Charging Station Demonstration Project: DCFC

DCFC	Total Sites	Ports per Site	Total Ports
Public DCFC	4	5	20
Public transit buses	2	5	10
Rideshare company charging hub	1	5	5
Other heavy-duty/DCFC (port, airport)	2	4	8
Municipal school buses	3	1	3
Total	**12**		**46**

Narragansett Electric may not act to preclude third party provider market development. This Settlement Agreement does not impose any limitations or prohibitions on non-utility product and competitive service providers from offering EV-related products and services, including charging station hardware and software, to the government light duty fleets or to site hosts located in underserved market segments.

As part of this program, Narragansett Electric will provide site hosts with the Make-Ready work necessary to host a charging station up to the costs as provided in this section. As such, Narragansett Electric will be responsible for making the site ready for charging to be installed, owned, and operated by the Site Host. For all Make-Ready sites, Site Hosts will have a

choice of both EV charging equipment and network services. The Company will pre-qualify options for equipment and network services. All pre-qualified equipment will have open standards for communications and operations.

For DCFC stations, the Company will work closely with the PST Advisory Group, or relevant subcommittee, to ensure that DCFC stations deployed via this initiative are complementary to deployments using the Volkswagen Settlement Agreement funds administered by the Rhode Island Department of Environmental Management. Narragansett Electric will coordinate with OER and will reserve up to twenty-five percent (25%) of the DCFC ports to be allocated to State-funded, -supported, or -hosted stations that deliver benefits to the public. The Company will seek to co-locate one of the DCFC sites with a storage unit, as further described in subsection d. of this section, below. Deployment of the remaining DCFC sites will be in coordination with OER and the Division. For energy supply for the charging stations, the site host is the customer of record and accordingly will select competitive generation supply or standard offer service (the Company does not, and should not, have a say in the customer's decision on its choice of energy supplier).

iii. Discount Pilot for Direct Current Fast Charging Station Accounts

Narragansett Electric will offer a time-limited discount on the electric bills for dedicated DCFC electric accounts. This discount pilot will be available on a first come, first served basis, with the annual value limited to $300,000 per year. Any existing or new customers with General C&I Rate G-02 or Large Demand Rate G-32 for dedicated DC Fast Charging purposes will be eligible for the discount, provided that twenty five percent (25%) of the stations receiving the discount shall be in stations that enable electric public transit. The monthly bill discount will be based on a per kW credit set at the same rate as the applicable (Rate G-02 or Rate G32)

distribution demand charge. The discount for participants who enroll in Rate Year 1 will be equal to one hundred percent (100%) of the distribution demand charge for a period of three years from the start of service. Sixty (60) days prior to enrollment for Rate Year 2 and Rate Year 3, the Company shall make, as part of the Electric Transportation Evaluation and Annual Program Modification Report, with input from the PST Advisory Group, a recommendation for the appropriate level of discount for new participants in such Rate Year based on enrollment data and lessons learned, for approval by the PUC. The results of the pilot and any proposed DCFC demand charges or rebates will be reviewed as part of the next MRP, which may include a phase out over years four, five, and six with the details of such phasing out to be included in the next MRP.

iv. Fleet Advisory Services

As a new component of the program arising from the settlement discussions, and not included in the Company's original filing, Narragansett Electric will, through a combination of internal and third-party expertise, offer a new advisory service to support electrification of customer fleets, the scope of which will include conducting long-term fleet electrification studies for a total of approximately twelve (12) fleet operators in Rhode Island, including government light-duty, corporate light-duty, public transit, government medium/heavy-duty (on-road and off-road), and municipal school buses. This program will replace Narragansett Electric's originally proposed Company Fleet Expansion program, which shall be eliminated, and Narragansett Electric will reallocate thirty-six percent (36%) of the funds previously identified for the Company Fleet Expansion program to fleet advisory services, provided that twenty-five percent (25%) of the funds address fleets owned by government or public transit entities.

v. Electric Transportation Initiative Evaluation

Narragansett Electric is committed to evaluating each element of the electric transportation initiative on an annual basis, and sharing its learnings with stakeholders and industry participants. In furtherance of this goal, Narragansett Electric will produce and publicly present an Annual Evaluation Report, using the metrics provided in the original filing, with appropriate modifications to be made to reflect the programs as approved in this Settlement Agreement within two months following the end of each Rate Year, describing implementation of the electric transportation initiative, and documenting the information gained through this initiative and any recommendations to enhance the program. The Company will file a copy of the Annual Evaluation Report with the PUC. The Company's Annual Evaluation Report will include, at a minimum, the following information, if available:

- location, category (as defined in the table in Section 17.a.ii. of this Settlement Agreement), in-service date, and utilization of each charging station installed;
- effectiveness of the Discount Pilot for DCFC Station Accounts, accounting for free-ridership and spillover effects;
- learnings on how the Company can integrate Electric Vehicles with minimal impacts on the cost of the distribution system, including an understanding of the effectiveness of the Off-Peak Charging Rebate Pilot;
- evaluation of the effectiveness of each component of the initiative in stimulating consumer adoption of electric vehicles, including an understanding of the effectiveness of the type and level of the incentive;

- results of the Fleet Advisory Services program, including the number of fleet vehicles converted to electric vehicles at the end of each rate year and at the end of the rate plan;
- the incremental CO2 reductions resulting from incremental vehicle adoption as described under the Distributed Energy Resources, CO2: Electric Vehicles metric; and
- evaluation of the Company's impact on fleet electric vehicle adoption.

The process for implementing any findings or recommendations contained in the Annual Evaluation Report will be through the PST Advisory Group, as discussed in subsection (e), below.

b. *Electric Heat*. Narragansett Electric shall not receive any funding for its proposed electric heat initiative through base distribution rates. Narragansett Electric may propose an electric heat initiative similar to the initiative proposed in this docket through the Energy Efficiency program plan, which, if proposed, will: (1) offer equipment incentives to lower the upfront cost barrier for Rhode Island residential customers to convert to efficient cold-climate air-source or ground-source heat pump systems; (2) offer rebates to a mix of standard offer service, competitive supply, and Income Eligible customers with approximately fifty percent (50%) of the rebate budget to be used for Income Eligible customers; and (3) be limited to residential customers for whom efficient electric heating has a Societal Cost Test ratio greater than 1 (e.g., currently delivered fuel customers and electric resistance customers). For standard offer service customers, the rebate level will depend on the installed system. For Income Eligible customers, the rebate level will be one hundred percent (100%) of the all-in cost of heating capacity.

c. *Strategic Electrification Education Fund*. The Settling Parties acknowledge that the ongoing electrification of transportation in Rhode Island has the potential to significantly reduce greenhouse gas emissions and to provide significant distribution system benefits. At the same time, the Settling Parties acknowledge that electric transportation, if not optimally integrated, has the potential to increase peak electric demand with negative consequences for system cost, system efficiency and emissions. To support the electric transportation initiatives discussed above, Narragansett Electric will create a Strategic Electrification Education Fund. The fund shall be administered consistent with R.I. Gen. Laws § 39-2-1.2. The revenue requirement shall include the following amounts for the fund: $7,500 in Rate Year 1 to inform customers of the availability of the off-peak charging rate; $11,250 in Rate Year 2 to inform customers of the availability of the off-peak charging rate; and $18,750 in Rate Year 3 to inform customers of the availability of the off-peak charging rate. The Settling Parties also agree that, prior to the beginning of Rate Year 2, the Company may submit, in consultation with the Division, OER, and the members of the PST Advisory Group, a revised proposal to the PUC for funding the Strategic Electrification Education Fund, consistent with R.I. Gen. Laws § 39-2-1.2. The Settling Parties agree that this provision may be severed from the remainder of this Settlement Agreement without affecting the validity of the overall settlement if the PUC deems this provision inconsistent with its motions.

d. *Energy Storage Demonstration*. The Settling Parties agree that energy storage is critical for achieving a clean energy future as it provides the ability to optimize system performance over time and allows intermittent renewable resources, such as wind and solar, to make a larger contribution to overall generation. The Settling Parties also recognize the Company has a role to effectively integrate storage. To this end, Narragansett Electric will

demonstrate two energy storage solutions: (i) one behind-the-meter storage system co-located with a DCFC site, which will consist of an approximate 250 kW two hour energy storage system, supporting approximately two to six DCFC ports, and (ii) one front-of-the-meter storage system, which will consist of an approximate 500 kW three hour energy storage system for the primary purpose of realizing distribution system value, with the exact storage size and capacity to be determined by system need and location. The revenue requirement for this initiative will include $0.1 million in Rate Year 1, $0.2 million in Rate Year 2, and $0.4 million in Rate Year 3. The costs of this initiative shall be subject to a deferral mechanism, as described in Section 20, below.

Narragansett Electric will procure each storage solution through a competitive RFP process, which will set forth the technical requirements, and will request proposals for both a third party-owned system with a service agreement, and an Engineering Procurement and Construction delivered system owned by the utility, which will explore alternative ownership models on a like-for-like basis, and benefits associated with each model. Narragansett Electric will share the draft RFP with stakeholders, via the PST Advisory Group, for feedback. The Company will file each draft RFP with the PUC no fewer than 30 days before it is issued to ensure that the PUC understands the barriers the pilot demonstration is designed to overcome and the learnings the Company intends to obtain from the project. The proposal(s) that have the best value and that also are compliant with the RFP will be selected. The Company will work with the Division and OER to ensure the procurement process and selection process has been done in an independent, transparent, and fair manner. The costs included in the revenue requirement for this initiative are based on a Company ownership model. The Company will prepare a cost/benefit analysis at the conclusion of each pilot/demonstration using the Docket No. 4600

Benefit-Cost Framework.

e. *Engagement and guidance in support of PST Programs*. The Company and the Settling Parties recognize that the initiatives included in this section are new in nature, with a higher level of uncertainty about the performance and results and that delivery of these programs over the period of the MRP will benefit from broad stakeholder engagement, review, and guidance. To formalize engagement of stakeholders that will be additional to the regular engagement of the Company with the Division and OER, the Company proposes the following:

- Establishment of a "PST Advisory Group," to be chaired by the Company and whose members shall include the Division, OER, and representatives of the following interests: environment, clean energy industry or businesses, low income, NPP, community groups, and additional members as the Company, the Division, and OER may agree. The mission of the PST Advisory Group shall be to review at a high level progress on the delivery of all PST components of the MRP (Grid Modernization, AMF, time-varying rates, Electric Transportation, Storage, and Performance Incentive Mechanisms) and to provide guidance, and prioritization to support successful delivery of the components as a holistic suite. The Advisory Group shall also serve as a connection with other relevant programs / proceedings outside the MRP, for example, the Energy Efficiency Resource Management Council (EERMC), and to enable appropriate participation, alignment and coordination with such programs and proceedings.
- Creation of subcommittees under the PST Advisory Group, including but not limited to: 1) Strategic Electrification Subcommittee, and 2) AMF and Grid Modernization Subcommittee. Subcommittees shall be chaired by the Company and will include

Division and OER participation. The mission of the subcommittees shall be to provide guidance and prioritization on a more granular level in relation to the individual program.

- Quarterly updates: on a quarterly basis, commencing October 2018, the PST Advisory Group, and relevant subcommittees, will each meet to discuss the progress and challenges in the development and implementation of the PST components of the MRP, along with emerging insights and learnings. The schedule will be designed such that, wherever possible, meetings will all take place in one day, with the PST Advisory Group in the morning, followed by sequential subcommittee meetings. Prior to each quarterly meeting the Company will consult with the Division and OER to plan the agenda and topics for discussion. All PST Advisory Group members will have an opportunity to provide input on the agendas for meetings. PUC staff and Commissioners may also provide input on the agendas for topics to be addressed at PST Advisory Group meetings.
- Annual evaluation and program modification: The first PST Advisory Group meeting after the end of each Rate Year shall include a review of results and learnings from the previous year's performance. The meeting will also review recommendations for any modifications to program design or funding for the electric transportation and storage programs. The Company will file any recommendations requiring a transfer of funds between programs, following review by the PST Advisory Group, with the PUC for review and approval.
- In the event that the Company, the Division, and OER unanimously agree to adjust the schedule of meetings in the public interest, they are empowered to do so without

the agreement of all signatories to this Settlement Agreement, but they shall advise all signatories of the revised schedule.

- The Division and OER commit to leverage the guidance of the PST Advisory Group in its engagement with the Company on the development of future PST program development.
- The PST Advisory Group shall participate in two to four technical sessions or open meetings with the PUC. The PUC and all PST Advisory Group members shall have the opportunity to provide input on the creation of the agendas for these technical sessions or open meetings. The subcommittees of the PST Advisory Group shall attend and, if the PUC so directs, shall make presentations at these technical sessions or open meetings.

18. Capital Efficiency Mechanism for Narragansett Electric

The PUC is considering the Capital Efficiency Mechanism for Narragansett Electric in Docket No. 4857.

19. Performance-Based Incentive Mechanisms

The Settling Parties agree that the goal of a performance incentive mechanism is the development of meaningful performance incentives in support of key state energy policy goals. This Settlement Agreement represents a starting point for the role of performance incentive mechanisms in Rhode Island, which the Settling Parties expect will grow over time, both in terms of their financial importance and their role in driving important outcomes. Currently, the Company shall not earn any performance incentives based on values associated with unquantified benefits. The Settling Parties agree that the Division, in consultation with the Company, OER, and the members of the PST Advisory Group shall develop transparent and

well-defined metrics for describing unquantified benefits and providing evidence that such unquantified benefits have been advanced, for purposes of providing a future value for a performance incentive to drive such unquantified benefits. The Settling Parties further acknowledge that the appropriate mix and definitions of performance incentive mechanisms may evolve over time as PST progresses.

Narragansett Electric will implement the following performance incentive mechanism: System Efficiency: Annual MW Capacity Savings. The System Efficiency metric includes minimum, mid, and maximum targets, with an increasing earning opportunity at each level. The Company may earn proportionally for achievements that fall between target levels up to the maximum level.[21] The potential earnings for the System Efficiency metric are calculated as 45% of the Quantified Net Benefits of achieving the metrics, as set forth in Attachment 28. The maximum earnings the Company can achieve from the System Efficiency metric are set forth in the table below.

2019	2020	2021
$362,085	$622,370	$944,141

Additionally, the Settling Parties have identified several additional metrics to be tracked at this time, and for some of which the Company may become eligible for a financial performance incentive during the term of the MRP. These additional metrics are: (1) Distributed Energy Resources: Installed Energy Storage Capacity; (2) Distributed Energy Resources, CO2: Electric Vehicles; (3) Distributed Energy Resources: Light Duty Government and Commercial Fleet Electrification; (4) PST Enablement: Awarded Low-income and Multi-unit EVSE Sites; and (5)

[21] In other words, for achievement at or above the minimum and up to the target level, the award will be calculated as the product of the maximum earnings level and the ratio of the achieved level to the maximum target.

PST Enablement: Distributed Generation (DG) Interconnection – Time to ISA.

a. *System Efficiency: Annual MW Capacity Savings*. The metric for this performance incentive mechanism will be the mega-watts (MW) of annual peak capacity savings. This metric is intended to reflect avoided capacity coincident with the ISO-NE peak hour. The proposed list of eligible resources for Annual MW Capacity Savings includes: (i) Demand Response, which will not be eligible for an incentive under the existing energy efficiency shareholder incentive; (ii) incremental net-metered behind-the-meter PV distributed generation in excess of Company forecast levels; (iii) incremental installed energy storage capacity; and (iv) any additional actions that the Company can identify to reduce peak demand, including non-wires alternatives expected to influence system peak that are not captured already under this or other metrics, and partnerships with third parties to provide peak reduction solutions. Achievement of the target is not based on any pre-determined mix of qualifying resources, but rather a total count of MW savings across all categories. The table below sets forth the targets and maximum earnings opportunity.

Annual MW Capacity Savings: Targets and Maximum Earnings Opportunity

	2019	2020	2021
Minimum	14	17	21
Target	17	21	24
Maximum	20	25	29
Earnings at Maximum ($000)	$362.09	$622.37	$944.14

For reporting performance on this metric, Narragansett Electric will submit resource-specific estimated MW savings. For existing eligible resources, Narragansett Electric will base savings on the following assumptions:

- For solar PV, Narragansett Electric will estimate the peak impact as the product of annual incremental installed capacity in excess of forecast levels available at the time

of the ISO New England system peak, multiplied by a coincidence factor of 0.21. Narragansett Electric will report the forecast capacity and peak impacts of PV included in its annual peak forecast for the compliance year from the most recent annual forecast.[22]

- For residential Demand Response under the Company's Connected Solutions program, Narragansett Electric will report the number of participating customers multiplied by a deemed kW savings value per thermostat of 0.46 kW. Should the Company modify the structure of this program or otherwise expand residential demand response offerings, the calculation of savings will be appropriately modified. Any such modifications to the incentive calculation will be presented to the PUC for approval prior to the commencement of the relevant performance year.
- For commercial and industrial Demand Response, Narragansett Electric will report the average observed MW savings over called events.
- For any resources not listed above, Narragansett Electric will report the calculation of resource-specific savings and provide explanation of any underlying assumptions.

b. *Distributed Energy Resources*

i. Installed Energy Storage Capacity

This metric will be a scorecard metric as described in subsection f., below.

ii. CO2: Consumer Electric Vehicles

The metric is the incremental avoided tons of CO2 resulting from the Company's proposed Electric Transportation Initiative, as shown in the table below. The Company forecast was developed by applying a growth rate in EV sales for 2018 through 2021 derived from the

[22] For example, the Company's 2018 peak forecast projects incremental peak impacts from load-reducing solar PV in 2019 of 7.41 MW (35.3 MW of incremental capacity) in 2019.

Energy Information Administration's Annual Energy Outlook 2018 projection of EV sales in New England, to historic data on EV registrations in Rhode Island from R.L. Polk. The Company's forecast for incremental EVs adopted for years 2019 through 2021 is provided in the table below.

Narragansett Electric Forecast of Incremental EVs Registered in Rhode Island (Number of incremental vehicles)

	2019	2020	2021
Forecast incremental EVs	857	1,180	1,644

The Company will track and report performance by (1) calculating incremental vehicles above Company forecasts; (2) calculating the number of incremental BEVs and PHEVs by multiplying the total number of incremental vehicles by the share of all new registrations that were BEVs, and the share of all new registrations that were PHEVs; and (3) applying per vehicle annual CO2 emissions reduction values as follows:

- Incremental BEVs x 2.32 metric tons CO2
- Incremental PHEVs x 2.08 metric tons CO2

The PUC will evaluate whether to allow a financial performance incentive to be attached to the achievement of this metric prior to Rate Year 2.

iii. Light Duty Government and Commercial Fleet Electrification

This metric is intended to capture the impact of Narragansett Electric's electric transportation initiative on light-duty fleet adoption in Rhode Island relative to predicted market trends. The metric will measure incremental increase – above predicted levels – of government and commercial light-duty fleet electric vehicles in the state on an annual basis. The Company will track and report the incremental registrations (both in total and above the Company forecast

included in Attachment 29) based on R.L. Polk data or an acceptable substitute should the Polk data become unavailable. The PUC will evaluate whether to allow a financial performance incentive to be attached to the achievement of this metric prior to Rate Year 2.

c. *PST Enablement*. This category of incentives will track Narragansett Electric's activities that support broad access to the benefits of power sector transformation activities, or otherwise provide foundational support for power sector transformation objectives. These incentives are reflective of the qualitative benefits of this support and enablement. Incentives are described in more detail below:

i. Activated Apartment Building and Disadvantaged Community EVSE Sites

This metric will track the Company's activation of EVSE sites for apartment buildings and disadvantaged communities. The Company will report the in-service date for make-ready work and charging stations installed in both site categories.

ii. Distributed Generation (DG) Interconnection – Time to ISA

This metric will be a scorecard metric, as described in subsection f., below.

d. *Calculating Incentive Value*. For the System Efficiency performance incentive, the value of the incentive is established using the following steps:

- the quantified net benefits of the relevant initiative were estimated using the Company's BCA assumptions and methodology; and
- 45% of the quantified net benefits were used to determine the utility incentive; the remaining 55% of net benefits will go to customers.

When the Company achieves one of the System Efficiency targets, it will receive an incentive based upon the dollar value associated with the relevant target. The magnitude of the utility incentive will be based upon the BCA results used at the time the Commission approves

the Performance Incentive Mechanism. The utility incentive will not be modified based on after-the-fact reassessment of benefits and costs of the initiatives.

The Settling Parties agree that establishing a certain and meaningful incentive value is essential in order to most effectively drive Company performance in the delivery of the objectives supported by the incentive, and for these reasons, the Settling Parties agree that the System Efficiency Annual MW Capacity Savings performance incentive mechanism targets require a presumption of cost-effectiveness to establish the incentive size based on the BCA results, as more fully described below. For this initiative, the Company will be allowed to earn the incentive regardless of whether it turns out to be cost-effective. The Settling Parties agree and acknowledge that the Company's demand response initiatives are expected to play an important role in achievement of the System Efficiency Annual MW Capacity Savings targets. It is not clear that these programs will be demonstrated as cost-effective based on quantifiable benefits in their initial years; however, given their expected value to the system as they are further developed and expanded, their importance to enabling investment in and development of load management solutions, and the potential savings to participating customers, they are assumed to be cost-effective (via the assumed ratio of costs to benefits for the incentive) for the purpose of setting the value of the Annual MW Capacity Savings incentive.

e. *Reporting Performance*. Narragansett Electric will file an annual performance incentive mechanism report with the PUC no later than March 1 annually (1) comparing the Company's performance relative to each performance incentive mechanism target; (2) describing the savings achieved, (3) calculating incentives earned, including proration of any incentives related to metric achievement between the minimum, midpoint, and the maximum target levels, (4) any targets not achieved, and (5) demonstrating the cost and benefit

impacts of the metric on the energy system, customers, and society using the Docket No. 4600 Benefit-Cost Framework. Narragansett Electric will file a mid-year update on or before September 1 annually that describes the Company's progress toward each Performance Incentive Mechanism metric target and the actions taken by the Company to achieve target performance. The mid-year update also will include an assessment of whether (and, for the Annual MW Capacity Savings performance incentive mechanism, through which measures) the Company expects to meet its annual performance incentive mechanism targets.

f. *Scorecard Metrics*. The Company is proposing to track and report the following scorecard metrics:

i. DG Interconnections

Narragansett Electric will track the number of business days from executed ISA to distribution system modifications by category of interconnection (*i.e.*, simple, expedited, standard). For each category, the Company will calculate and report the averages and the variances from the averages.

ii. DG-Friendly Substation Transformers

Narragansett Electric will base reporting on the number of incremental 3VO installations completed.

iii. Utilization of EVSE in Low-income Areas

Narragansett Electric will report utilization rates at all EVSE sites installed through the Charging Station Demonstration Program. The reports will identify which EVSE sites are in low income areas.

iv. Reduction of Uncollectable Debt

Narragansett Electric will report enrollment in the Arrearage Management Plan (AMP) at the point of potential termination from service for purposes of developing a baseline and eventually setting an improvement target from this baseline, to maintain service to the low-income customer and prevent expansion of uncollectible debt.

v. Increased Stability of Service through Increased Enrollment in the Low Income Discount

Narragansett Electric will report enrollment in the low-income discount, represented by number of customers receiving delivery service on Rate A-60, for the purposes of developing a baseline and eventually setting an enrollment target that improves upon the baseline. Such a target would incentivize expanded enrollment on Rate A-60 thus increasing stability of service and reducing the frequency of the termination/reconnection cycle. This provision shall not be construed to allow customers to remain on Rate A-60 if they no longer are eligible for Rate A-60.

vi. NPP Residential Customer Demand Response Participation

Narragansett Electric will work with NPPs to measure the number of NPP residential customers participating in Narragansett Electric's Connected Solution program or any future demand response program that works with WiFi-enabled or smart thermostat(s) and other connected smart devices to reduce electricity use during periods of high energy demand.

vii. Distributed Energy Resources - Installed Energy Storage Capacity

Narragansett Electric will track incremental installed energy storage capacity. It is the intention of the Settling Parties that Narragansett Electric will coordinate deployment of energy storage with its distribution system planning and heat map activities, and that storage activities

undertaken by Narragansett Electric should provide opportunities for market engagement by NPPs and other third-parties.

viii. PST Enablement - Distributed Generation (DG) Interconnection – Time to ISA

Narragansett Electric will track its performance for the simplified, expedited without supplemental review, and standard tracks in meeting or outperforming tariff timelines for providing an executable interconnection service agreement. Narragansett Electric's performance will be measured by:

- aggregating the average time measured in Business Days necessary to issue an executable Interconnection Service Agreement commencing from the date an application is received, for each track identified above (Aggregate Necessary Tariff Time Frames), and comparing such performance to
- the total aggregate number of Business Days allowed by its Interconnection Tariff to issue an executable Interconnection Service Agreement commencing from the date an application is received (Aggregate Allowed Tariff Time Frames).

g. *Recovery of Earned Incentives.* The Company shall recover any approved performance incentives earned for achieving the performance incentive mechanism targets listed above through the operation of a new reconciling mechanism pursuant to the Performance Incentive Recovery Provision. The Company will make an annual filing with the PUC to request recovery of performance incentives earned pursuant to the Performance Incentive Mechanisms authorized by the PUC and approval of a separate Performance Incentive Factor filing based upon the requested earned incentives.

20. Deferral of Certain "Special Sector" Program Costs and Revenues

a. In recognition of the uncertainty of timing and control of certain Special Sector Programs identified below, a deferral mechanism shall be implemented in accordance with this section.

b. The Special Sector Programs to which this section shall apply includes:

i. The Electric Transportation program, described in Section 17.a. of this Agreement; and

ii. The Energy Storage Demonstration program, described in Section 17.d. (collectively referred to as the Special Sector Programs).

c. The costs and annual base distribution rate allowances allocated to each of the Special Sector Programs shall be separately monitored and reconciled at the end of each Rate Year.

d. To the extent the base distribution rate allowances allocated to the program exceed the actual costs incurred, the Company shall record the difference to a regulatory liability account. To the extent the deferral was caused by a reasonable delay in implementation, the deferral shall be applied to program cost incurrence when the program costs are later incurred. To the extent the deferral was caused by a cost reduction or funds not spent for reasons other than a reasonable delay, the deferral shall be held for the benefit of customers and the PUC shall determine how it shall be applied against other programs or costs that otherwise might have been borne by customers. The amount of any such deferral shall incur carrying charges at the WACC for Narragansett Electric for capital expenses and the customer deposit rate for Narragansett Electric for O&M costs.

e. To the extent the actual costs of a program exceed the base distribution rate allowances that were allocated to the program, the overspending shall be borne by the Company, unless the PUC allows the Company to record the difference to a regulatory asset for recovery at a later date. The PUC shall be under no obligation to approve a regulatory asset; however, a regulatory asset shall only be approved if the Company demonstrates that the costs were prudently incurred consistent with the program objectives and the overspending was out of its reasonable control.

21. Next Rate Case Filing

The Company's next general rate case shall be a combined electric and gas rate case unless the Company and the Division mutually agree that they should be filed separately. When the Company's next rate case is filed, the Company shall file complete revenue requirements for the rate year and no fewer than two additional consecutive twelve-month rate-year periods, to facilitate the PUC's and Division's review and potential approval of a multi-year rate plan.

a. The Company shall submit its next rate case filing to the PUC so that new base distribution rates take effect no later than September 1, 2022. Nothing in this Settlement Agreement shall preclude the Company from filing its next general rate case at any time earlier during the term of this Rate Plan or any extension thereof.

b. If the Division provides its consent to an extension of the term of this Rate Plan, the Division may specify another date upon which new base distribution rates are to become effective beyond September 1, 2022 in its place, but is not required to do so.

i. To the extent new base distribution rates resulting from the filing of the Company's next general rate case are not in effect by September 1, 2022, the Settlement

Agreement shall remain in effect during the interim and if required, the Performance Incentive Mechanism provision shall be extended to cover the additional interim period.

22. Additional Provisions

a. *Excess Deferred Taxes True Up*. As discussed in the Company's response to PUC 4-1 (Supplemental), a copy of which is provided as Attachment 24 hereto, to account for revisions to the corporate tax rate modified by the federal Tax Cuts and Jobs Act (Tax Act), the Company has recorded the $116 million and $51 million estimates of customer-related excess deferred federal income tax for Narragansett Electric and Narragansett Gas, respectively, to a tax regulatory liability account in recognition that customers will be refunded those excess deferred taxes. The Company will be able to calculate more accurately excess deferred taxes and the timing over which they should be returned when its fiscal year ended March 31, 2018 audited financial statements are completed during the late summer 2018. These estimates will become final with the filing of the fiscal year ended March 31, 2018 federal income tax return in December 2018, and the excess deferred tax regulatory liability will be adjusted to reflect that final balance.

This Settlement Agreement provides for a reduction to Narragansett Electric and Narragansett Gas revenue requirements by a high level estimate of excess deferred income tax amortization of $5.1 million and $2.0 million, respectively. The Company will true up these estimates in a supplemental compliance filing to be filed with the PUC in Docket No. 4770 after the Company files its Fiscal Year 2018 federal income tax return in December 2018. The true-up will reconcile the impact of the actual excess deferred tax amortization with the estimated amounts identified above, and will determine the final revenue requirements for Narragansett Electric and Narragansett Gas effective September 1, 2018. From these supplemental revenue

requirements, the Company will calculate the difference between the revenue requirements it began recovering September 1, 2018 and the revenue requirements in the supplemental compliance filing in Docket No. 4770 (Deferred Tax Differential). The Company will submit to the PUC for its review and approval a filing to address the ratemaking treatment of the Deferred Tax Differential for Narragansett Electric and Narragansett Gas no later than March 1, 2019. The filing shall propose the following:

Narragansett Electric: The Company will provide the calculation of the Narragansett Electric Deferred Tax Differential and the revised Annual Target Revenue (ATR) of its Revenue Decoupling Mechanism (RDM), reflecting an adjustment for the Deferred Tax Differential. In addition, Narragansett Electric will evaluate the appropriateness of proposing revised base distribution rates based upon the amount of the true-up to the revenue requirement to reflect the effect of the Deferred Tax Differential if the difference is determined to be of an amount that adjusting base distribution rates would be appropriate. The Company will present its evaluation on the necessity of revising base distribution rates as part of its proposal regarding the ratemaking treatment of the Deferred Tax Differential.

Narragansett Gas: The Company will provide the calculation of the Narragansett Gas Deferred Tax Differential. In addition, Narragansett Gas will evaluate the appropriateness of (i) proposing revised base distribution rates based upon the amount of the true-up to the revenue requirement to reflect the effect of the Deferred Tax Differential as described below, or (ii) proposing that the Deferred Tax Differential be credited through the DAC if the difference is determined to be relatively small such that adjusting base distribution rates would not be needed. The Company will present its evaluation on the necessity of revising base distribution rates as part of its proposal regarding the ratemaking treatment of the Deferred Tax Differential. If

Narragansett Gas proposes to change base distribution rates, the filing shall include the following: (1) for all customers, new base distribution rates effective on a prospective basis on a date determined with respect to the timing of the supplemental compliance filing; (2) for customers included in Narragansett Gas's RDM,[23] revised target revenue-per-customer amounts based upon the supplemental revenue requirements; and (3) for customers excluded from Narragansett Gas's RDM,[24] the difference for this group of customers be credited to, or recovered from, these customers through a one-time adjustment included in the DAC filing submitted to the PUC by August 1, 2019. If Narragansett Gas revises its target revenue-per-customer amounts, the revised revenue-per-customer amounts shall be reflected in its subsequent RDM reconciliation filings submitted to the PUC annually by July 1 until the effective date of base distribution rates resulting from a future general rate case. Any revised target revenue-per-customer amounts shall be subject to Section 22.c. of this Settlement Agreement.

For this high level estimate, this Settlement Agreement provides for the amortization of all property related excess deferred taxes over an approximate 30 year average service life of its assets. The composite depreciation rate currently in effect is 3.40 percent and 3.38 percent for Narragansett Electric distribution plant and Narragansett Gas plant, respectively, both of which equate to average service lives of just under 30 years. The Company agrees to amortize its non-property related excess deferred taxes over a period of ten years, as was proposed by the Division, until the true-up is performed.

b. *Minimum Funding Obligation*. For the purpose of determining its "Minimum Funding Obligation" and the carrying costs that apply to that obligation, the

[23] Pursuant to Narragansett Gas's tariff, customers included in the RDM are those receiving service on Narragansett Gas's residential, small C&I, and medium C&I rate schedules.
[24] Pursuant to Narragansett Gas's tariff, customers excluded from the RDM are those receiving service on Narragansett Gas's large C&I, extra-large C&I, and non-firm rate schedules.

Company shall be permitted to combine the funding of pensions and post-employment benefits other than pensions (PBOPs), thereby offsetting, for example, any deficiencies in PBOPs funding with any excess pension funding. The Company will be required to accrue and defer carrying charges on only the net unfunded pension/PBOP amount. The Minimum Funding Obligation is the Company's obligation to contribute amounts recovered from customers to the pension and PBOP plans as it is being recovered. The Minimum Funding Obligation level is equal to the amount billed to customers plus the amounts of capitalized pension and PBOP costs. The amount billed to customers includes (1) the pension and PBOP allowance in base distribution rates, and (2) plus or minus the amount billed or credited to customers through the PAF. If the Company does not fund its pension and PBOP plans at the Minimum Funding Obligation level, the Company will pay a carrying charge to customers at the weighted average cost of capital. This payment will be applied to the cumulative five-quarter average shortfall between the Minimum Funding Obligation level and amounts the Company contributes to the pension and PBOP plans, plus amounts paid to the Service Company for allocated pension and PBOP costs. The ability to combine the funding of pension and PBOPs will give the Company the flexibility to avoid permanently overfunding the PBOP plan, while at the same time, giving the Company the ability to meet its Minimum Funding Obligation.

c. *Narragansett Gas Forecast of Plant Additions for Gas Growth*. To ensure that customers will be credited with an accurate level of gas growth revenue and to address the Division's concern regarding the Company's growth capital forecast, this Settlement Agreement provides that Narragansett Gas will calculate the difference between the forecast gas-growth capital revenue requirement and the actual gas growth capital revenue requirement in Rate Year 1. Attachment 25 provides an illustrative calculation to be employed at the end of Rate

Year 1. As shown on this attachment, this difference shall be added to or subtracted from the total Revenue Decoupling Mechanism (RDM) class revenue requirement used to establish base distribution rates in these proceedings. This adjusted total RDM class revenue requirement will be divided by the actual average customer totals per rate class during Rate Year 1 to arrive at the class revenue per customer amount to be used in the calculation of RDM adjustments for all periods commencing September 1, 2018, and until new base distribution rates are established for gas service. The method illustrated in Attachment 25 does not establish any precedent for the calculation of RDM adjustments subsequent to future gas base distribution rate cases.

d. *Charitable Contributions*. Intentionally Deleted.

e. *American Gas Association (AGA) and Edison Electric Institute (EEI) Annual Membership Dues*. To settle concerns raised by NERI associated with lobbying costs, which are not included in the Company's revenue requirements for Narragansett Gas and Narragansett Electric, charged to the Company by AGA and EEI, respectively, the Company has agreed to send letters to AGA and EEI requesting information regarding how such trade associations allocate costs between lobbying and non-lobbying expenses and substantiation of the allocation. The Company will provide the responses to the Division and the PUC.

f. *Low Income Reporting*. The Company, the Division, and GWC shall work together with PUC Staff to develop reporting requirements for existing and new electric and natural gas low-income rates, programs, and discounts. These reporting requirements shall be designed to: (1) inform the PUC how the low-income rates, programs, and discounts advance the rate design principles set forth in the Docket 4600 Guidance Document, and (2) provide information needed to support future investigation into a more dynamic low-income-rate design.

23. Other Provisions

a. The Settling Parties agree to request that the PUC adopt the terms of this Settlement Agreement without modification. The Settling Parties intend that this Settlement Agreement will be adopted by the PUC as being in the public interest and agree individually to advocate its adoption by the PUC in its entirety and to act so as to expedite that result.

b. The Settling Parties intend this Settlement Agreement to be a complete resolution of all issues in Docket No. 4770 and Docket No. 4780. It is understood that each provision of this Settlement Agreement is in consideration and support of all the other provisions, and expressly conditioned upon acceptance by the PUC. Except as expressly set forth herein, none of the Settling Parties is deemed to have approved, agreed to, or consented to any principle, methodology, or interpretation of law underlying or supposed to underlie any provision herein, including without limitation with respect to the PUC's August 3, 2018 open meeting decisions (and rationale therefor) regarding charitable contributions, carrying charges, and R.I. Gen. Laws § 39-2-1.2.

c. Except as otherwise stated in this Settlement Agreement, the provisions of the Settlement Agreement apply solely to, and are binding only in the context of, this Settlement Agreement and these proceedings. It is not the intention of this Settlement Agreement that it establishes any binding precedent. None of the positions taken by any Settling Party with respect to this Settlement Agreement nor the fact that a Settling Party is a signatory to this Settlement Agreement, may be referred to, cited by, or relied upon by anyone in any manner as precedent or otherwise in any other proceeding before the PUC or any other regulatory body or before any court of law as proof of assent or agreement by such Settling Party to the approval of any particular regulatory policy or principle that may be interpreted to arise out of this Settlement

Agreement. Concessions made by any Settling Party on any issue do not preclude that party from addressing such issues in future rate proceedings or in other proceedings. Any failure by any Settling Party to abide by the terms of this subsection shall not give rise to any claim against such Settling Party for breach of this Settlement Agreement, unless: (i) the Settling Party is provided notice of such failure and an opportunity to cure such failure; and (ii) such Settling Party does not cure such failure within seven (7) business days after such notice.

d. The Settling Parties recognize that certain provisions of this Settlement Agreement contemplate actions to be taken in the future and agree to cooperate with each other in good faith in taking such actions.

In the event of any disagreement over the interpretation of this Settlement Agreement that cannot be resolved informally among the Settling Parties, the party claiming a dispute will serve a Notice of Dispute on the remaining parties, briefly identifying the provision or provisions of this Settlement Agreement under dispute and the nature of the dispute, and convening a conference in a good faith attempt to resolve the dispute. If any such efforts are not successful in resolving the dispute among the Settling Parties, the matter will be submitted to the PUC for resolution.

e. Except as set forth herein, following the expiration of the term of the Rate Plan, all provisions of this Settlement Agreement will continue until changed by order of the PUC. Except as expressly provided otherwise, any targets, goals, deferral thresholds, or other similar items set forth in this Settlement Agreement for Rate Year 3 will continue beyond Rate Year 3 until modified by the PUC.

f. Nothing in this Settlement Agreement will be construed as precluding the active parties from convening additional conferences and from reaching agreement to extend this

Settlement Agreement on mutually-acceptable terms and from presenting an agreement concerning such extension to the PUC for its approval.

g. The Settling Parties recognize that the PUC has an ongoing obligation to modify rates to protect the public against improper and unreasonable rates that cannot be precluded by a settlement agreement

h. This Settlement Agreement sets forth the entire agreement of the Settling Parties and supersedes any prior or contemporaneous written documents or oral understandings among the Settling Parties concerning the matters addressed herein. In the event of any conflict between this Settlement Agreement and any other document addressing the same subject matter, this Settlement Agreement will control. Notwithstanding the foregoing, nothing in this Settlement Agreement is intended to modify the terms of the Docket No. 4686 Settlement Agreement.

i. Notices and other communications required to be provided or made under the Settlement Agreement shall be in writing and shall be deemed to have been given:

i. When delivered by hand (with written confirmation of receipt);

ii. When received by the addressee if sent by a nationally recognized overnight courier or by certified or registered mail, return receipt requested, postage prepaid; or

iii. On the date sent by e-mail if sent before 5:00 p.m., recipient's time, and on the next day that is not a Saturday, Sunday, or Federal Holiday, if sent thereafter; in each case, to the applicable address and/or email address set forth on Attachment 27; provided that, if any notice is tendered to an addressee and the delivery thereof is refused by such addressee, such notice shall be effective upon such tender.

Any party hereto may change its address and/or email address reflected in Attachment 27 upon 15 days' prior notice of such change to the other parties hereto.

ARTICLE III: SETTLEMENT CONDITIONS

A. This Settlement Agreement is the result of negotiations among the Settling Parties. The discussions that have produced this Settlement Agreement have been conducted on the explicit understanding that all offers of settlement and discussions relating hereto are and shall be privileged, shall be without prejudice to the position of any party or participant presenting such offer or participating in any such discussion, and are not to be used in any manner in connection with these or other proceedings involving any one or more of the parties to this Settlement Agreement or otherwise. The agreement by a party to the terms of this Settlement Agreement shall not be construed as an agreement as to any matter of fact or law for any other purpose.

B. Unless expressly stated herein, the making of this Settlement Agreement establishes no principles and shall not be deemed to foreclose any Settling Party from making any contention in any other proceeding or investigation.

C. The Settling Parties submit this Settlement Agreement on the condition that it be approved in full by the PUC and on the further condition that, if the PUC (i) rejects this Settlement Agreement; (ii) fails to accept this Settlement Agreement as filed; or (iii) accepts this Settlement Agreement subject to conditions unacceptable to any Settling Party hereto, then this Settlement Agreement shall be deemed withdrawn, shall not constitute part of the record in any proceeding or be used for any purpose, and shall be deemed null and void, and the Settling Parties will be free to pursue their respective positions in these proceedings without prejudice.

D. The Settling Parties recognize that the PUC has an ongoing obligation to modify rates to protect the public against improper and unreasonable rates, and that obligation cannot be precluded by a settlement agreement.

E. This Settlement Agreement may be signed in counterparts, each of which shall be deemed an original and all of which together shall constitute one in the same document, and will be binding on each Settling Party when the counterparts have been executed.

[SIGNATURE PAGES FOLLOW]

IN WITNESS WHEREOF, the parties agree that this Settlement Agreement is reasonable and have caused this document to be executed by their respective representatives, each being fully authorized to do so, as of this 16th day of August, 2018.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID

By: _____
Its: PRESIDENT
Dated: 8/15/18

RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS

By: _____
Its:
Dated: _____

RHODE ISLAND OFFICE OF ENERGY RESOURCES

By: _____
Its:
Dated: _____

CONSERVATION LAW FOUNDATION

By: _____
Its:
Dated: _____

DEPARTMENT OF THE NAVY AND THE FEDERAL EXECUTIVE AGENCIES

By: _____
Its:
Dated: _____

THE GEORGE WILEY CENTER

By: _____
Its:
Dated: _____

NORTHEAST CLEAN ENERGY COUNCIL

By: _____
Its:
Dated: _____

WAL-MART STORES, LP AND SAM'S EAST, INC.

By: _____
Their:
Dated: _____

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Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID

By:_____
Its:
Dated:_____

RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS

By: [signature]
Its: Counsel
Dated: August 16, 2018

RHODE ISLAND OFFICE OF ENERGY RESOURCES

By:_____
Its:
Dated:_____

CONSERVATION LAW FOUNDATION

By:_____
Its:
Dated:_____

DEPARTMENT OF THE NAVY AND THE FEDERAL EXECUTIVE AGENCIES

By:_____
Its:
Dated:_____

THE GEORGE WILEY CENTER

By:_____
Its:
Dated:_____

NORTHEAST CLEAN ENERGY COUNCIL

By:_____
Its:
Dated:_____

WAL-MART STORES, LP AND SAM'S EAST, INC.

By:_____
Their:
Dated:_____

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THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID

By:_____
Its:
Dated:_____

RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS

By:_____
Its:
Dated:_____

RHODE ISLAND OFFICE OF ENERGY RESOURCES

By:_____
Its: Attorney
Dated: 8/14/2018

CONSERVATION LAW FOUNDATION

By:_____
Its:
Dated:_____

DEPARTMENT OF THE NAVY AND THE FEDERAL EXECUTIVE AGENCIES

By:_____
Its:
Dated:_____

THE GEORGE WILEY CENTER

By:_____
Its:
Dated:_____

NORTHEAST CLEAN ENERGY COUNCIL

By:_____
Its:
Dated:_____

WAL-MART STORES, LP AND SAM'S EAST, INC.

By:_____
Their:
Dated:_____

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THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID

By:_____
Its:
Dated:_____

RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS

By:_____
Its:
Dated:_____

RHODE ISLAND OFFICE OF ENERGY RESOURCES

By:_____
Its:
Dated:_____

CONSERVATION LAW FOUNDATION

By: [signature]
Its: SENIOR ATTORNEY
Dated: 8/14/18

DEPARTMENT OF THE NAVY AND THE FEDERAL EXECUTIVE AGENCIES

By:_____
Its:
Dated:_____

THE GEORGE WILEY CENTER

By:_____
Its:
Dated:_____

NORTHEAST CLEAN ENERGY COUNCIL

By:_____
Its:
Dated:_____

WAL-MART STORES, LP AND SAM'S EAST, INC.

By:_____
Their:
Dated:_____

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Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID

By:_____
Its:
Dated:_____

RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS

By:_____
Its:
Dated:_____

RHODE ISLAND OFFICE OF ENERGY RESOURCES

By:_____
Its:
Dated:_____

CONSERVATION LAW FOUNDATION

By:_____
Its:
Dated:_____

DEPARTMENT OF THE NAVY AND THE FEDERAL EXECUTIVE AGENCIES

By: Kelsey A. Hahn
Its: Attorney
Dated: 15 Aug 2018

THE GEORGE WILEY CENTER

By:_____
Its:
Dated:_____

NORTHEAST CLEAN ENERGY COUNCIL

By:_____
Its:
Dated:_____

WAL-MART STORES, LP AND SAM'S EAST, INC.

By:_____
Their:
Dated:_____

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Dated:_____

RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS

By:_____
Its:
Dated:_____

RHODE ISLAND OFFICE OF ENERGY RESOURCES

By:_____
Its:
Dated:_____

CONSERVATION LAW FOUNDATION

By:_____
Its:
Dated:_____

DEPARTMENT OF THE NAVY AND THE FEDERAL EXECUTIVE AGENCIES

By:_____
Its:
Dated:_____

THE GEORGE WILEY CENTER



By:_____
Its: Attorney
Dated: 8/15/18

NORTHEAST CLEAN ENERGY COUNCIL

By:_____
Its:
Dated:_____

WAL-MART STORES, LP AND SAM'S EAST, INC.

By:_____
Their:
Dated:_____

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By:_____
Its:
Dated:_____

RHODE ISLAND OFFICE OF ENERGY RESOURCES

By:_____
Its:
Dated:_____

CONSERVATION LAW FOUNDATION

By:_____
Its:
Dated:_____

DEPARTMENT OF THE NAVY AND THE FEDERAL EXECUTIVE AGENCIES

By:_____
Its:
Dated:_____

THE GEORGE WILEY CENTER

By:_____
Its:
Dated:_____

NORTHEAST CLEAN ENERGY COUNCIL

By:_____
Its: Attorney
Dated: 8/15/18

WAL-MART STORES, LP AND SAM'S EAST, INC.

By:_____
Their:
Dated:_____

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Its:
Dated:_____

RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS

By:_____
Its:
Dated:_____

RHODE ISLAND OFFICE OF ENERGY RESOURCES

By:_____
Its:
Dated:_____

CONSERVATION LAW FOUNDATION

By:_____
Its:
Dated:_____

DEPARTMENT OF THE NAVY AND THE FEDERAL EXECUTIVE AGENCIES

By:_____
Its:
Dated:_____

THE GEORGE WILEY CENTER

By:_____
Its:
Dated:_____

NORTHEAST CLEAN ENERGY COUNCIL

By:_____
Its:
Dated:_____

WAL-MART STORES, LP AND SAM'S EAST, INC.

By: Melissa Horne
Their: Attorney
Dated: 8/15/18

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT

By: [signature]
Its: Attorney
Dated: 8/15/2018

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT; SIERRA CLUB; AND NATURAL RESOURCES DEFENSE COUNCIL, jointly

By: [signature]
Their: Attorney
Dated: 8/15/2018

CHARGEPOINT, INC.

By:_____
Its:
Dated:_____

DIRECT ENERGY BUSINESS, LLC; DIRECT ENERGY SERVICES, LLC; AND DIRECT ENERGY SOLAR

By:_____
Their:
Dated:_____

NEW ENERGY RHODE ISLAND

By:_____
Its:
Dated:_____

NATIONAL RAILROAD PASSENGER CORPORATION

By:_____
Its:
Dated:_____

ACADIA CENTER

By:_____
Its:
Dated:_____

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT

By:_____
Its:
Dated:_____

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT; SIERRA CLUB; AND NATURAL RESOURCES DEFENSE COUNCIL, jointly

By:_____
Their:
Dated:_____

CHARGEPOINT, INC.

By: Edward D. Pare, Jr. (JSR)
Its: Attorney
Dated: August 15, 2018

DIRECT ENERGY BUSINESS, LLC; DIRECT ENERGY SERVICES, LLC; AND DIRECT ENERGY SOLAR

By:_____
Their:
Dated:_____

NEW ENERGY RHODE ISLAND

By:_____
Its:
Dated:_____

NATIONAL RAILROAD PASSENGER CORPORATION

By:_____
Its:
Dated:_____

ACADIA CENTER

By:_____
Its:
Dated:_____

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT

By:_____
Its:
Dated:_____

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT; SIERRA CLUB; AND NATURAL RESOURCES DEFENSE COUNCIL, jointly

By:_____
Their:
Dated:_____

CHARGEPOINT, INC.

By:_____
Its:
Dated:_____

DIRECT ENERGY BUSINESS, LLC; DIRECT ENERGY SERVICES, LLC; AND DIRECT ENERGY SOLAR

By: Craig Walkley
Their: Counsel
Dated: 8/15/18

NEW ENERGY RHODE ISLAND

By:_____
Its:
Dated:_____

NATIONAL RAILROAD PASSENGER CORPORATION

By:_____
Its:
Dated:_____

ACADIA CENTER

By:_____
Its:
Dated:_____

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT

By:_____
Its:
Dated:_____

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT; SIERRA CLUB; AND NATURAL RESOURCES DEFENSE COUNCIL, jointly

By:_____
Their:
Dated:_____

CHARGEPOINT, INC.

By:_____
Its:
Dated:_____

DIRECT ENERGY BUSINESS, LLC; DIRECT ENERGY SERVICES, LLC; AND DIRECT ENERGY SOLAR

By:_____
Their:
Dated:_____

NEW ENERGY RHODE ISLAND

By:_____
Its: Counsel
Dated: August 15, 2018

NATIONAL RAILROAD PASSENGER CORPORATION

By:_____
Its:
Dated:_____

ACADIA CENTER

By:_____
Its:
Dated:_____

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT

By:_____
Its:
Dated:_____

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT; SIERRA CLUB; AND NATURAL RESOURCES DEFENSE COUNCIL, jointly

By:_____
Their:
Dated:_____

CHARGEPOINT, INC.

By:_____
Its:
Dated:_____

DIRECT ENERGY BUSINESS, LLC; DIRECT ENERGY SERVICES, LLC; AND DIRECT ENERGY SOLAR

By:_____
Their:
Dated:_____

NEW ENERGY RHODE ISLAND

By:_____
Its:
Dated:_____

NATIONAL RAILROAD PASSENGER CORPORATION

By:_____
Its: Attorney
Dated: 15 August 2018

ACADIA CENTER

By:_____
Its:
Dated:_____

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT

By:_____
Its:
Dated:_____

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT; SIERRA CLUB; AND NATURAL RESOURCES DEFENSE COUNCIL, jointly

By:_____
Their:
Dated:_____

CHARGEPOINT, INC.

By:_____
Its:
Dated:_____

DIRECT ENERGY BUSINESS, LLC; DIRECT ENERGY SERVICES, LLC; AND DIRECT ENERGY SOLAR

By:_____
Their:
Dated:_____

NEW ENERGY RHODE ISLAND

By:_____
Its:
Dated:_____

NATIONAL RAILROAD PASSENGER CORPORATION

By:_____
Its:
Dated:_____

ACADIA CENTER

By: Gregory E Boyd
Its: Attorney
Dated: Aug 15, 2018

SCHEDULE A
List of Attachments

Compliance Attachment No.	Compliance Attachment Name	Book No.
1	Narragansett Electric and Narragansett Gas Revenue Requirement Settlement Terms (Rate Years 1, 2, 3)	1
2	Narragansett Electric and Narragansett Gas Revenue Requirements (Rate Years 1, 2, 3)	1, 2
3	Narragansett Electric and Narragansett Gas Supporting Workpapers, including Cash Working Capital Studies	2, 3, 4
4	Narragansett Electric and Narragansett Gas Grid Modernization Revenue Requirements (Rate Years 1, 2, 3)	5
5	Narragansett Electric Special Sector Programs Revenue Requirements (Rate Years 1, 2, 3)	5
6	Narragansett Electric Allocated Cost of Service Study (Rate Year 1)	5
7	Narragansett Electric Allocator Study	5
8	Narragansett Electric Revenue Allocation (Rate Years 1, 2, 3) (including allocation of results of Rate Year 1 Allocated Cost of Service Study, plus (2) Years 2 and 3 increases, plus (3) PST revenue requirements for Rate Years 1, 2, 3))	5
9	Narragansett Electric Distribution Rate Design (Rate Years 1, 2, 3)	5
10	Narragansett Electric Bill Impacts (November 1, 2017 vs. Rate Year 1, Rate Year 1 vs. Rate Year 2, Rate Year 2 vs. Rate Year 3)	5
11	Narragansett Electric Streetlight Replacement Cost Study	6
12	Narragansett Electric Development of Rates Associated With Various Recovery Mechanisms	6
13	Narragansett Electric Redlined Tariffs (Marked to Show Changes from Those Currently in Effect)	6
14	Narragansett Gas Allocated Cost of Service Study (Rate Year 1)	6
15	Narragansett Gas Allocator Study	7
16	Narragansett Gas Revenue Allocation, Firm and Non-Firm Distribution Rate Design, and Revenue-per-Customer Targets by Rate Class (Rate Years 1, 2, 3; would include (1) allocation of results of Rate Year 1 Allocated Cost of Service Study, plus (2) Years 2 and 3 increases, plus (3) gas-related PST revenue requirements for Rate Years 1, 2, 3))	7
17	Narragansett Gas Bill Impacts (November 1, 2017 vs. Rate Year 1, Rate Year 1 vs. Rate Year 2, Rate Year 2 vs. Rate Year 3)	7
18	Narragansett Gas Development of Rates Associated With the Distribution Adjustment Clause and Gas Cost Recovery Clause	7

SCHEDULE A
List of Attachments

Compliance Attachment No.	Compliance Attachment Name	Book No.
19	Narragansett Gas Redlined Tariff (Marked to Show Changes from that Currently in Effect)	7
20	Narragansett Electric and Narragansett Gas Calculation of the Proposed Low Income Discount Recovery Factor	7
21	Narragansett Electric and Narragansett Gas Calculation of Miscellaneous Fees	7
22	Narragansett Electric and Narragansett Gas Existing Cost Recovery and Reconciling Mechanisms	7
23	Storm Contingency Fund	7
24	Company's Response to PUC 4-1 (Supplemental)	7
25	Illustrative Calculation of Gas Growth	7
26	List of Charitable Organizations – Intentionally Deleted	7
27	Address for Notices to the Settling Parties	7
28	Benefit Cost Analysis and Supporting Inputs for Performance Incentive Mechanisms (including New Program BCA Summaries for EVs)	7
29	Consumer and Light Duty Fleet EV Forecasts and Target Calculations	7
30	Electric Heat Target Calculations – Intentionally Deleted	7

The Narragansett Electric Company d/b/a National Grid
Illustrative Statement of Electric Operations Income and Revenue Deficiency Summary
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

		Settlement			Compliance			Delta		
		Rate Year Ending August 31, 2019 (a)	Base Revenue Increase Required (b)	Rate Year Ending August 31, 2019 with Base Revenue Requirement (c)=(a)+(b)	Rate Year Ending August 31, 2019 (d)	Base Revenue Increase Required (e)	Rate Year Ending August 31, 2019 with Base Revenue Requirement (f)=(d)+(e)	Rate Year Ending August 31, 2019 (g)=(d)-(a)	Base Revenue Increase Required (h)=(e)-(b)	Rate Year Ending August 31, 2019 with Base Revenue Requirement (i)=(f)-(c)
1	Revenues	$279,192,430	$14,081,470	$293,273,900	$279,091,943	$12,038,936	$291,130,879	($100,487)	($2,042,534)	($2,143,021)
2										
3	Purchased Power & Other Reconciling Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0
4										
5	Net Distribution Revenues	$279,192,430	$14,081,470	$293,273,900	$279,091,943	$12,038,936	$291,130,879	($100,487)	($2,042,534)	($2,143,021)
6										
7	Operation & Maintenance Expenses	$152,904,072	$183,467	$153,087,538	$150,603,298	$156,855	$150,760,152	($2,300,774)	($26,612)	($2,327,386)
8										
9	Amortization of Regulatory Deferrals	$332,482	$0	$332,482	$471,908	$0	$471,908	$139,426	$0	$139,426
10										
11	Amortization of Utility Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0
12										
13	Depreciation	$50,128,332	$0	$50,128,332	$50,128,332	$0	$50,128,332	$0	$0	$0
14										
15	Municipal Taxes	$30,530,258	$0	$30,530,258	$30,530,258	$0	$30,530,258	$0	$0	$0
16										
17	Payroll Taxes	$4,198,324	$0	$4,198,324	$4,154,522	$0	$4,154,522			
18										
19	Gross Receipts Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0
20										
21	Other Taxes	$454,406	$0	$454,406	$454,406	$0	$454,406	$0	$0	$0
22										
23	Interest on Customer Deposits	$132,127	$0	$132,127	$132,127	$0	$132,127	$0	$0	$0
24										
25	Total Operating Revenue Deductions	$238,680,001	$183,467	$238,863,467	$236,474,851	$156,855	$236,631,706	($2,205,150)	($26,612)	($2,231,761)
26										
27	Operating Income Before Income Taxes	$40,512,429	$13,898,004	$54,410,433	$42,617,092	$11,882,081	$54,499,173	$2,104,663	($2,015,923)	$88,740
28										
29	Income Taxes	$687,356	$2,918,581	$3,605,936	$1,157,091	$2,495,237	$3,652,328	$469,735	($423,344)	$46,392
30										
31	Operating Income After Income Taxes	$39,825,074	$10,979,423	$50,804,497	$41,460,001	$9,386,844	$50,846,845	$1,634,927	($1,592,579)	$42,348
32										
33	Rate Base	$728,902,391		$728,902,391	$729,509,971		$729,509,971	$607,580		$607,580
34										
35	Rate of Return	5.46%	Line 31(a) / Line 33(a)		5.68%	Line 31(d) / Line 33(d)				
36										
37										
38	Revenue Deficiency									
39	Earned Rate of Return	5.46%	Line 35(a)		5.68%	Line 35(d)		0.22%		
40	Rate Year Required Rate of Return	6.97%	Attachment 2, Schedule 1 ELEC, Page 4, Line 9(c)		6.97%	Compliance Attachment 2, Schedule 1-ELEC, Page 4, Line		0.00%		
41	Rate of Return Deficiency	1.51%	Line 40(a) - Line 39(a)		1.29%	Line 40(d) - Line 39(d)		-0.22%		
42	Rate Base	$728,902,391	Line 33(a)		$729,509,971	Line 33(d)		$607,580		
43	Net Operating Income Deficiency	$10,979,423			$9,386,844			($1,592,579)		
44	Gross Revenue Conversion Factor	1.282533	Line 53(a)		1.282533	Line 53(d)		1.282533		
45	**Revenue Deficiency**	$14,081,470	Line 43(a) * Line 44(a)		$12,038,936	Line 43(d) * Line 44(a)		($2,042,534)		
46										
47	Gross Revenue Conversion Factor									
48	Gross Revenue	1.000000			1.000000					
49	Uncollectible expense	(0.013029)	Attachment 2, Schedule 22, Page 6, Line 15		(0.013029)	Compliance Attachment 2, Schedule 22, Page 6, Line 15				
50	Revenue net of Uncollectibles	0.986971			0.986971					
51	Composite income tax rate	(0.207260)	Line 50(a) x (- 0.21%)		(0.207260)	Line 50(d) x (- 21%)				
52	Net income effect of 1.000 Revenue	0.779707	Line 50(a) + Line 51(a)		0.779707	Line 50(d) + Line 51(d)				
53	Gross Revenue Conversion Factor	1.282533	1 / Line 52(a)		1.282533	1 / Line 52(d)				

Line Notes:
Line 1 - decrease in rate year ISR revenues due to tax reform (lower tax rate, elimination of bonus depreciation and lower pre-tax return on rate base)
Line 9 - increase in projected rate case expenses (Record request 39)
Line 7 - refer to Pages 2 and 3
Line 33 - refer to explanations at Page 4

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Summary - ELECTRIC

			Settlement			Compliance			Delta		
	Operation & Maintenance Expenses:	Schedule Reference	Rate Year Ending August 31, 2019 (a)	Rate Year Ending August 31, 2020 (b)	Rate Year Ending August 31, 2021 (c)	Rate Year Ending August 31, 2019 (d)	Rate Year Ending August 31, 2020 (e)	Rate Year Ending August 31, 2021 (f)	Rate Year Ending August 31, 2019 (g)=(d)-(a)	Rate Year Ending August 31, 2020 (h)=(e)-(b)	Rate Year Ending August 31, 2021 (i)=(f)-(c)
1	Labor	Schedule 12	$51,707,477	$53,560,974	$55,183,457	$50,809,286	$52,633,681	$54,227,114	($898,191)	($927,293)	($956,343)
2	Health Care	Schedule 13	$6,458,547	$6,689,763	$6,892,463	$6,391,424	$6,620,876	$6,821,489	($67,123)	($68,887)	($70,974)
3	Group Life Insurance	Schedule 14	$567,542	$602,957	$635,879	$560,647	$595,688	$628,212	($6,895)	($7,269)	($7,667)
4	Thrift Plan	Schedule 15	$2,426,402	$2,513,267	$2,589,419	$2,398,472	$2,484,577	$2,559,860	($27,930)	($28,690)	($29,559)
5	FAS 112 / ASC 712	Schedule 16	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Service Company Rents	Schedule 17	$13,285,082	$13,656,706	$13,442,382	$13,117,011	$13,497,420	$13,887,951	($168,071)	($159,286)	$445,569
7	Joint Facilities	Schedule 18	$1,065,547	$1,093,891	$1,120,473	$1,176,621	$1,207,920	$1,237,272	$111,074	$114,029	$116,799
8	Uninsured Claims	Schedule 19	$1,858,628	$1,908,068	$1,954,434	$1,840,172	$1,889,121	$1,935,026	($18,456)	($18,947)	($19,408)
9	Insurance Premium	Schedule 20	$2,090,894	$2,146,512	$2,198,672	$2,090,894	$2,146,512	$2,198,672	$0	$0	$0
10	Regulatory Assessment Fees	Schedule 21	$4,286,454	$4,286,454	$4,286,454	$4,286,454	$4,286,454	$4,286,454	$0	$0	$0
11	Uncollectible Accounts	Schedule 22	$4,122,270	$4,305,737	$4,356,617	$4,122,270	$4,279,125	$4,329,551	$0	($26,612)	($27,066)
12	Postage	Schedule 23	$2,557,424	$2,625,451	$2,689,250	$2,557,424	$2,625,451	$2,689,250	$0	$0	$0
13	Strike Contingency	Schedule 24	$8,573	$8,573	$8,573	$8,573	$8,801	$9,015	$0	$228	$442
14	Environmental Response Fund	Schedule 25	$3,078,000	$3,078,000	$3,078,000	$3,078,000	$3,078,000	$3,078,000	$0	$0	$0
15	Paperless Bill Credit	Schedule 26	$551,281	$551,281	$551,281	$551,281	$551,281	$551,281	$0	$0	$0
16	PBOP	Schedule 27	$4,901,371	$4,901,371	$4,901,371	$4,815,932	$4,815,932	$4,815,932	($85,439)	($85,439)	($85,439)
17	Pension	Schedule 28	$6,233,401	$5,075,109	$3,988,824	$6,000,874	$4,842,582	$3,756,296	($232,527)	($232,527)	($232,528)
18	Energy Efficiency Program	Schedule 29	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	Other Operating and Maintenance Expenses	Schedule 30	$38,809,400	$39,834,291	$40,795,469	$37,880,827	$38,881,018	$39,819,031	($928,573)	($953,273)	($976,438)
20	Storm Cost Recovery	Schedule 31	$7,023,726	$7,023,726	$7,023,726	$7,023,726	$7,023,726	$7,023,726	$0	$0	$0
21	Gas Commodity OM	Schedule 32	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	NEP IFA Credit	Schedule 33	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Wheeling	Schedule 34	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Energy Innovation Hub	Schedule 35	$186,193	$153,798	$153,798	$186,193	$153,798	$153,798	$0	$0	$0
25	Gas Business Enablement	Schedule 36	$460,685	$476,534	$457,527	$482,041	$511,352	$494,859	$21,356	$34,818	$37,332
26	Electric Operations	Schedule 37	$611,550	$572,000	$618,083	$611,550	$572,000	$618,083	$0	$0	$0
27	Gas Operations	Schedule 38	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	Customer Affordability Program	Schedule 39	$613,623	$543,256	$288,128	$613,623	$543,256	$288,128	$0	$0	$0
29	Sub Total		$152,904,072	$155,607,719	$157,214,281	$150,603,295	$153,248,571	$155,409,000	($2,300,777)	($2,359,148)	($1,805,281)
30											
31	Purchased Power/ Purchased Gas	Schedule 40	$0	$0	$0	$0	$0	$0	$0	$0	$0
32											
33	Sub Total		$0	$0	$0	$0	$0	$0	$0	$0	$0
34											
35	TOTAL		$152,904,072	$155,607,719	$157,214,281	$150,603,298	$153,248,572	$155,409,002	($2,300,774)	($2,359,147)	($1,805,279)

The Narragansett Electric Company d/b/a National Grid
Summary of Adjustments - Settlement Filing to Compliance Filing
ELECTRIC Operation & Maintenance Expense

	Labor	
1	**Settlement Balance**	**$51,707,475**
2	Remove RE Growth labor captured in Docket 4748 (PUC 3-32/PUC Decision)	($347,134)
3	Additional Service Company A&G overhead study adjustment (DIV 21-10 Supplemental)	($315,185)
4	Remove lobbying costs (Record request 1-4)	($178,815)
5	Remove Band A non-financial variable pay (Rebuttal adjustment)	($112,087)
6	Update 2018 non-union wage increase from 3.0% to 3.25% (Rebuttal adjustment)	$69,444
7	Adjusted O&M % for balance sheet adjustments (accounts 242/184) (PUC 1-31)	($13,192)
8	Additional rebuttal adjustments	($825)
9	FTE Smoothing (Rebuttal adjustment)/Remove CEI Marketing Analyst double-counted in Customer Affordability Program (DIV 3-7/DIV 3-9)	($395)
10	**Compliance Balance**	**$50,809,286**
11		
12	**Health Care**	
13	**Settlement Balance**	**$6,458,547**
14	Labor flow-through	($67,122)
15	**Compliance Balance**	**$6,391,424**
16		
17	**Group Life Insurance**	
18	**Settlement Balance**	**$567,542**
19	Remove lobbying costs (Record Request 1-4); labor flow-through	($6,895)
20	**Compliance Balance**	**$560,647**
21		
22	**Thrift Plan**	
23	**Settlement Balance**	**$2,426,402**
24	Remove lobbying costs (Record request 1-4); labor flow-through	($27,930)
25	**Compliance Balance**	**$2,398,472**
26		
27	**Service Company Rents**	
28	**Settlement Balance**	**$13,285,082**
29	Revised IS forecast (DIV 38-1)	($276,029)
30	Microsoft SaaS Contract/Renewal (Rebuttal adjustment)	$107,958
31	**Compliance Balance**	**$13,117,011**
32		
33	**Joint Facilities**	
34	**Settlement Balance**	**$1,065,547**
35	Reclass of IFA Rents adjustment (Rebuttal adjustment)	$130,387
36	Removal of Airplane charge from Joint Facilities (Rebuttal adjustment)	($19,313)
37	**Compliance Balance**	**$1,176,621**
38		
39	**Uninsured Claims**	
40	**Settlement Balance**	**$1,858,628**
41	Labor flow-through	($18,456)
42	**Compliance Balance**	**$1,840,172**
43		
44	**PBOP**	
45	**Settlement Balance**	**$4,901,371**
46	Labor flow-through	($85,439)
47	**Compliance Balance**	**$4,815,932**
48		
49	**Pension**	
50	**Settlement Balance**	**$6,233,401**
51	Labor flow-through	($232,527)
52	**Compliance Balance**	**$6,000,874**
53		
54	**Other Operating and Maintenance Expenses**	
55	**Settlement Balance**	**$38,809,400**
56	Contractors - Service Company A&G overhead study adjustment (DIV 21-10 Supplemental)	($748,196)
57	Donations - remove all charitable contributions as disallowed (PUC Decision)	($606,735)
58	Third Party Rents - Reclass of IFA Rents adjustment (Rebuttal adjustment)	$531,517
59	Other Benefits - Reclass labor portion of RE Growth costs to labor (PUC 3-32/PUC Decision)	$331,214
60	Contractors - Contact Voltage - remove from base rates to recover through ISR (Rebuttal adjustment)	($231,986)
61	Consultants - Remove lobbying costs (Record request 1-4)	($105,882)
62	Employee Expenses - Service Company A&G overhead study adjustment (DIV 21-10 Supplemental)	($103,094)
63	Contractors - Update RE Growth costs to most recent filing, Docket 4748 (PUC Decision)	$3,142
64	Other - Update RE Growth costs to most recent filing, Docket 4748 (PUC Decision)	$1,887
65	Consultants - Update RE Growth costs to most recent filing, Docket 4748 (PUC Decision)	($441)
66	**Compliance Balance**	**$37,880,827**
67		
68	**Gas Business Enablement**	
69	**Settlement Balance**	**$460,685**
70	Revised project forecast with change in allocations (DIV 17-13)	$21,356
71	**Compliance Balance**	**$482,041**
72		
73	Total Settlement balance for items above	$127,774,080
74	Total Compliance balance for items above	$125,473,307
75	Total change in O&M expense (agrees to Page 2, Line 35)	($2,300,773)

The Narragansett Electric Company d/b/a National Grid
Rate Base Calculation - Electric

	Description	Settlement			Compliance			Delta		
		Rate Year Ending August 31, 2019 (a)	Rate Year Ending August 31, 2020 (b)	Rate Year Ending August 31, 2021 (c)	Rate Year Ending August 31, 2019 (d)	Rate Year Ending August 31, 2020 (e)	Rate Year Ending August 31, 2021 (f)	Rate Year Ending August 31, 2019 (g)=(d)-(a)	Rate Year Ending August 31, 2020 (h)=(e)-(b)	Rate Year Ending August 31, 2021 (i)=(f)-(c)
1	Utility Plant In Service	$1,601,539,723	$1,602,539,723	$1,604,539,723	$1,601,539,723	$1,602,539,723	$1,604,539,723	($0)	$0	$0
2										
3	Property Held for Future Use	$2,496,405	$2,496,405	$2,496,405	$2,496,405	$2,496,405	$2,496,405	$0	$0	$0
4	Less: Contribution in Aid of Construction	$2,756	$2,756	$2,756	$2,756	$2,756	$2,756	($0)	$0	$0
5	Less: Accumulated Depreciation	$688,355,184	$688,470,384	$688,563,184	$688,355,184	$688,470,384	$688,563,184	($0)	$0	$0
6										
7	Net Plant	$915,678,188	$916,562,988	$918,470,188	$915,678,188	$916,562,988	$918,470,188	$0	$0	$0
8										
9	Materials and Supplies	$3,493,676	$3,403,498	$3,327,193	$3,493,676	$3,403,498	$3,327,193	($0)	$0	$0
10	Prepayments	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	Loss on Reacquired Debt	$1,401,214	$1,244,585	$1,112,052	$1,401,214	$1,244,585	$1,112,052	($0)	$0	$0
12	Cash Working Capital	$17,043,665	$17,043,665	$17,043,665	$17,922,078	$17,922,078	$17,922,078	$878,413	$878,413	$878,413
13	Unamortized Interest Rate Lock	$1,638,006	$1,237,463	$898,542	$1,638,006	$1,237,463	$898,542	$0	$0	$0
14	Unamortized Debt Issuance Costs $550M	$901,943	$795,916	$706,200	$901,943	$795,916	$706,200	$0	$0	$0
15	Unamortized Debt Issuance Costs $250M	$866,236	$826,723	$793,290	$866,236	$826,723	$793,290	$0	$0	$0
16	Unamortized Debt Issuance Costs $350M	$848,309	$801,319	$774,113	$577,476	$511,041	$454,826	($270,833)	($290,278)	($319,287)
17	Subtotal	$26,193,050	$25,353,168	$24,655,055	$26,800,630	$25,941,303	$25,214,181	$607,580	$588,135	$559,126
18										
19	Accumulated Deferred FIT	$203,540,205	$201,385,915	$199,252,781	$203,540,205	$201,385,915	$199,252,781	$0	$0	$0
20	Accumulated Deferred FIT -Loss on Reacquired Debt	$540,073	$509,711	$479,349	$540,073	$509,711	$479,349	($0)	($0)	($0)
21	Customer Deposits	$8,888,568	$9,011,230	$9,115,021	$8,888,568	$9,011,230	$9,115,021	($0)	$0	$0
22	Subtotal	$212,968,847	$210,906,856	$208,847,151	$212,968,847	$210,906,856	$208,847,151	$0	($0)	($0)
23										
24	Rate Base	$728,902,391	$731,009,300	$734,278,092	$729,509,971	$731,597,435	$734,837,218	$607,580	$588,135	$559,126

Line Notes

12(g) (h) (i) - Change in Cash Working Capital caused by (1) $1.8 million increase to correct error in Settlement filing; CWC was calculated on total O&M of $133.3 million , which should have been calculated on $148.7 million (total $152.9 million minus uncollectible expense of $4.2 million). Results in an increase of $1.85 million in CWC from Settlement ; (2) decrease in O&M expense from Settlement to Compliance drives a decrease of $275,000; and (3) decrease in tax expense drives a decrease of $691,000 from Settlement.

16(g) (h) (i) - Change in Unamortized debt issuance costs related to new debt issued in July 2018. Original estimate of $2.3 million over a 30 year term; revised to $1.6 million over a 10 year term.

The Narragansett Electric Company d/b/a National Grid
Illustrative Statement of Gas Operations Income and Revenue Deficiency Summary
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

		Settlement			Compliance			Delta		
		Rate Year Ending August 31, 2019 (a)	Base Revenue Increase Required (b)	Rate Year Ending August 31, 2019 with Base Revenue Requirement (c)=(a)+(b)	Rate Year Ending August 31, 2019 (d)	Base Revenue Increase Required (e)	Rate Year Ending August 31, 2019 with Base Revenue Requirement (f)=(d)+(e)	Rate Year Ending August 31, 2019 (g)=(d)-(a)	Base Revenue Increase Required (h)=(e)-(b)	Rate Year Ending August 31, 2019 with Base Revenue (i)=(f)-(c)
1	Revenues	$214,523,590	$5,598,282	$220,121,872	$212,811,375	$5,823,471	$218,634,846	($1,712,215)	$225,189	($1,487,026)
2										
3	Purchased Power & Other Reconciling Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0
4										
5	Net Distribution Revenues	$214,523,590	$5,598,282	$220,121,872	$212,811,375	$5,823,471	$218,634,846	($1,712,215)	$225,189	($1,487,026)
6										
7	Operation & Maintenance Expenses	$87,171,898	$106,784	$87,278,682	$86,147,527	$111,079	$86,258,606	($1,024,372)	$4,295	($1,020,077)
8										
9	Amortization of Regulatory Deferrals	$1,520,606	$0	$1,520,606	$1,577,216	$0	$1,577,216	$56,611	$0	$56,611
10										
11	Amortization of Utility Plant	$426,184	$0	$426,184	$426,184	$0	$426,184	$0	$0	$0
12										
13	Depreciation	$39,136,909	$0	$39,136,909	$39,136,909	$0	$39,136,909	($0)	$0	($0)
14										
15	Municipal Taxes	$26,869,455	$0	$26,869,455	$26,869,455	$0	$26,869,455	$0	$0	$0
16										
17	Payroll Taxes	$2,738,063	$0	$2,738,063	$2,660,389	$0	$2,660,389			
18										
19	Gross Receipts Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0
20										
21	Other Taxes	$227,533	$0	$227,533	$227,533	$0	$227,533	$0	$0	$0
22										
23	Interest on Customer Deposits	$35,184	$0	$35,184	$35,184	$0	$35,184	$0	$0	$0
24										
25	Total Operating Revenue Deductions	$158,125,832	$106,784	$158,232,616	$157,080,397	$111,079	$157,191,476	($1,045,435)	$4,295	($1,041,140)
26										
27	Operating Income Before Income Taxes	$56,397,758	$5,491,498	$61,889,256	$55,730,978	$5,712,392	$61,443,370	($666,780)	$220,894	($445,886)
28										
29	Income Taxes	$5,930,858	$1,153,215	$7,084,072	$5,863,385	$1,199,602	$7,062,987	($67,473)	$46,388	($21,085)
30										
31	Operating Income After Income Taxes	$50,466,900	$4,338,284	$54,805,184	$49,867,593	$4,512,790	$54,380,383	($599,307)	$174,506	($424,801)
32										
33	Rate Base	$762,241,779		$762,241,779	$760,564,795		$760,564,795	($1,676,984)		($1,676,984)
34										
35	Rate of Return	6.62%	Line 31(a) / Line 33(a)		6.56%	Line 31(d) / Line 33(d)				
36										
37										
38	Revenue Deficiency									
39	Earned Rate of Return	6.62%	Line 35(a)		6.56%	Line 35(d)		-0.06%		
40	Rate Year Required Rate of Return	7.19%	Attachment 2, Schedule 1 GAS, Page 4, Line 9(c)		7.15%	Compliance Attachment 2, Schedule 1-ELEC, Page 4, Line		-0.04%		
41	Rate of Return Deficiency	0.57%	Line 40(a) - Line 39(a)		0.59%	Line 40(d) - Line 39(d)		0.02%		
42	Rate Base	$762,241,779	Line 33(a)		$760,564,795	Line 33(d)		($1,676,984)		
43	Net Operating Income Deficiency	$4,338,284			$4,512,790			$174,506		
44	Gross Revenue Conversion Factor	1.290437	Line 53(a)		1.290437	Line 53(d)		1.2904		
45	**Revenue Deficiency**	$5,598,282	Line 43(a) * Line 44(a)		$5,823,471	Line 43(d) * Line 44(d)		$225,189		
46										
47	Gross Revenue Conversion Factor									
48	Gross Revenue	1.000000			1.000000					
49	Uncollectible expense	(0.019074)	Attachment 2, Schedule 22, Page 6, Line 15		(0.019074)	Compliance Attachment 2, Schedule 22, Page 6, Line 15				
50	Revenue net of Uncollectibles	0.980926			0.980926					
51	Composite income tax rate	(0.205994)	Line 50(a) x (- 0.21%)		(0.205994)	Line 50(d) x (- 21%)				
52	Net income effect of 1.000 Revenue	0.774931	Line 50(a) + Line 51(a)		0.774931	Line 50(d) + Line 51(d)				
53	Gross Revenue Conversion Factor	1.290437	1 / Line 52(a)		1.290437	1 / Line 52(d)				

Line Notes:
Line 1 - decrease in rate year ISR revenues due to tax reform (lower tax rate, elimination of bonus depreciation and lower pre-tax return on rate base)
Line 9 - increase in projected rate case expenses (Record request 39)
Line 7 - refer to Pages 6 and 7
Line 33 - refer to Page 8

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Summary - GAS

	Operation & Maintenance Expenses:	Schedule Reference	Settlement Rate Year Ending August 31, 2019 (a)	Settlement Rate Year Ending August 31, 2020 (b)	Settlement Rate Year Ending August 31, 2021 (c)	Compliance Rate Year Ending August 31, 2019 (d)	Compliance Rate Year Ending August 31, 2020 (e)	Compliance Rate Year Ending August 31, 2021 (f)	Delta Rate Year Ending August 31, 2019 (g)=(d)-(a)	Delta Rate Year Ending August 31, 2020 (h)=(e)-(b)	Delta Rate Year Ending August 31, 2021 (i)=(f)-(c)
1	Labor	Schedule 12	$33,465,578	$34,873,821	$35,939,787	$33,330,840	$34,742,707	$35,832,453	($134,738)	($131,114)	($107,334)
2	Health Care	Schedule 13	$4,342,511	$4,525,331	$4,663,806	$4,340,172	$4,524,195	$4,666,255	($2,339)	($1,136)	$2,449
3	Group Life Insurance	Schedule 14	$428,909	$458,375	$483,539	$425,237	$454,578	$479,898	($3,672)	($3,797)	($3,641)
4	Thrift Plan	Schedule 15	$1,525,431	$1,589,652	$1,638,295	$1,517,362	$1,581,698	$1,631,363	($8,069)	($7,954)	($6,932)
5	FAS 112 / ASC 712	Schedule 16	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Service Company Rents	Schedule 17	$4,461,616	$4,661,533	$4,633,242	$4,535,777	$4,755,618	$4,755,358	$74,161	$94,085	$122,116
7	Joint Facilities	Schedule 18	$587,447	$603,073	$617,728	$581,346	$596,810	$611,313	($6,101)	($6,263)	($6,415)
8	Uninsured Claims	Schedule 19	$644,861	$662,015	$678,102	$639,463	$656,472	$672,425	($5,398)	($5,543)	($5,677)
9	Insurance Premium	Schedule 20	$921,924	$946,365	$968,693	$921,924	$946,365	$968,693	$0	$0	$0
10	Regulatory Assessment Fees	Schedule 21	$1,897,662	$1,897,662	$1,897,662	$1,897,662	$1,897,662	$1,897,662	$0	$0	$0
11	Uncollectible Accounts	Schedule 22	$3,396,670	$3,503,454	$3,607,057	$3,396,670	$3,507,749	$3,616,983	$0	$4,295	$9,926
12	Postage	Schedule 23	$1,372,817	$1,409,334	$1,443,580	$1,372,817	$1,409,334	$1,443,580	$0	$0	$0
13	Strike Contingency	Schedule 24	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Environmental Response Fund	Schedule 25	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Paperless Bill Credit	Schedule 26	$265,235	$265,235	$265,235	$265,235	$265,235	$265,235	$0	$0	$0
16	PBOP	Schedule 27	($1,190,723)	($1,190,723)	($1,190,723)	($1,225,024)	($1,225,024)	($1,225,024)	($34,301)	($34,301)	($34,301)
17	Pension	Schedule 28	$3,356,606	$2,573,610	$1,840,992	$3,273,350	$2,490,355	$1,757,736	($83,256)	($83,255)	($83,256)
18	Energy Efficiency Program	Schedule 29	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	Other Operating and Maintenance Expenses	Schedule 30	$27,414,855	$28,140,630	$28,820,179	$26,601,038	$27,305,166	$27,964,413	($813,817)	($835,464)	($855,766)
20	Storm Cost Recovery	Schedule 31	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	Gas Commodity OM	Schedule 32	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	NEP IFA Credit	Schedule 33	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Wheeling	Schedule 34	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Energy Innovation Hub	Schedule 35	$101,186	$83,581	$83,581	$101,186	$83,581	$83,581	$0	$0	$0
25	Gas Business Enablement	Schedule 36	$2,854,116	$3,290,713	$3,333,456	$2,847,275	$3,511,995	$3,665,243	($6,841)	$221,282	$331,787
26	Electric Operations	Schedule 37	$0	$0	$0	$0	$0	$0	$0	$0	$0
27	Gas Operations	Schedule 38	$1,032,482	$955,700	$955,700	$1,032,482	$955,700	$955,700	$0	$0	$0
28	Customer Affordability Program	Schedule 39	$292,714	$295,232	$156,583	$292,714	$295,232	$156,583	$0	$0	$0
29	Sub Total		$87,171,897	$89,544,593	$90,836,494	$86,147,527	$88,755,428	$90,199,451	($1,024,370)	($789,165)	($637,043)
30											
31	Purchased Power/ Purchased Gas	Schedule 40	$0	$0	$0	$0	$0	$0	$0	$0	$0
32											
33	Sub Total		$0	$0	$0	$0	$0	$0	$0	$0	$0
34											
35	TOTAL		$87,171,898	$89,544,592	$90,836,494	$86,147,527	$88,755,428	$90,199,451	($1,024,371)	($789,164)	($637,043)

The Narragansett Electric Company d/b/a National Grid
Summary of Adjustments - Settlement Filing to Compliance Filing
GAS Operation & Maintenance Expense

1	**Labor**	
2	**Settlement Balance**	**$33,465,578**
3	Additional Service Company A&G overhead study adjustment (DIV 21-10 Supplemental)	($148,124)
4	Remove Band A non-financial variable pay (Rebuttal adjustment)	($67,953)
5	CoRecord requestect union wage increase calculation (Rebuttal adjustment)	$58,082
6	Update 2018 non-union wage increase from 3.0% to 3.25% (Rebuttal adjustment)	$37,963
7	Remove lobbying costs (Record request 1-4)	($21,916)
8	FTE smoothing (Rebuttal adjustment)/Remove CEI Marketing Analyst double-counted in Customer Affordability Program (DIV 3-7 / DIV 3-9)	$7,587
9	CoRecord requestect variable pay normalizing adjustment (Rebuttal adjustment)	($376)
10	**Compliance Balance**	**$33,330,840**
11		
12	**Health Care**	
13	**Settlement Balance**	**$4,342,511**
14	Labor flow-through	($2,339)
15	**Compliance Balance**	**$4,340,172**
16		
17	**Group Life Insurance**	
18	**Settlement Balance**	**$428,909**
19	Remove lobbying costs (Record request 1-4); labor flow-through	($3,672)
20	**Compliance Balance**	**$425,237**
21		
22	**Thrift Plan**	
23	**Settlement Balance**	**$1,525,431**
24	Remove lobbying costs (Record request 1-4); labor flow-through	($8,069)
25	**Compliance Balance**	**$1,517,362**
26		
27	**Service Company Rents**	
28	**Settlement Balance**	**$4,461,616**
29	Revised IS forecast (DIV 38-1)	$31,582
30	Microsoft SaaS Contract/Renewal (Rebuttal adjustment)	$42,579
31	**Compliance Balance**	**$4,535,777**
32		
33	**Joint Facilities**	
34	**Settlement Balance**	**$587,447**
35	Removal of Airplane charge from Joint Facilities (Rebuttal adjustment)	($6,101)
36	**Compliance Balance**	**$581,346**
37		
38	**Uninsured Claims**	
39	**Settlement Balance**	**$644,861**
40	Labor flow-through	($5,399)
41	**Compliance Balance**	**$639,463**
42		
43	**PBOP**	
44	**Settlement Balance**	**($1,190,723)**
45	Labor flow-through	($34,301)
46	**Compliance Balance**	**($1,225,024)**
47		
48	**Pension**	
49	**Settlement Balance**	**$3,356,606**
50	Labor flow-through	($83,256)
51	**Compliance Balance**	**$3,273,350**
52		
53	**Other Operating and Maintenance Expenses**	
54	**Settlement Balance**	**$27,414,855**
55	Contractors - Service Company A&G overhead study adjustment (DIV 21-10 Supplemental)	($410,505)
56	Donations - remove all charitable contributions as disallowed (PUC Decision)	($315,697)
57	Employee Expenses - Service Company A&G overhead study adjustment (DIV 21-10 Supplemental)	($60,824)
58	Consultants - Remove lobbying costs (Record request 1-4)	($26,791)
59	**Compliance Balance**	**$26,601,038**
60		
61	**Gas Business Enablement**	
62	**Settlement Balance**	**$2,854,116**
63	Change in Allocations from Finance (DIV 17-13)	($6,841)
64	**Compliance Balance**	**$2,847,275**
65		
66	Total Settlement balance for items above	$77,891,207
67	Total Compliance balance for items above	$76,866,836
68	Total change in O&M expense (agrees to Page 6, Line 35)	($1,024,371)

The Narragansett Electric Company d/b/a National Grid
Rate Base Summary - Gas

	Description	Settlement			Compliance			Delta		
		Rate Year 1 Ending August 31, 2019 (a)	Data Year 1 Ending August 31, 2020 (b)	Data Year 2 Ending August 31, 2021 (c)	Rate Year 1 Ending August 31, 2019 (d)	Data Year 1 Ending August 31, 2020 (e)	Data Year 2 Ending August 31, 2021 (f)	Rate Year Ending August 31, 2019 (g)=(d)-(a)	Rate Year Ending August 31, 2020 (h)=(e)-(b)	Rate Year Ending August 31, 2021 (i)=(f)-(c)
1	Gas Plant In Service	$1,306,857,054	$1,328,015,869	$1,349,443,902	$1,306,857,054	$1,328,015,869	$1,349,443,902	($0)	($0)	($0)
2	Normalizing Adjustment: Smallworld GIS[1]	$3,996,550	$3,996,550	$3,996,550	$3,996,550	$3,996,550	$3,996,550	$0	$0	$0
3	Gas Plant In Service	$1,310,853,604	$1,332,012,419	$1,353,440,452	$1,310,853,604	$1,332,012,419	$1,353,440,451	($0)	($0)	($0)
4										
5	Construction Work In Progress	$44,213,371	$45,444,229	$46,739,869	$44,213,371	$45,444,229	$46,739,869	$0	$0	$0
6										
7	Less: Accumulated Depreciation	$427,173,934	$428,191,816	$429,895,395	$427,173,934	$428,191,816	$429,895,395	$0	$0	$0
8	Normalizing Adjustment: Smallworld GIS[1]	$2,987,945	$3,414,129	$3,840,314	$2,987,945	$3,414,129	$3,840,314	$0	$0	$0
9	Test Year Adjusted Accumulated Depreciation	$430,161,879	$431,605,945	$433,735,709	$430,161,879	$431,605,945	$433,735,709	$0	$0	$0
10										
11	Less: Contribution in Aid of Construction	($946)	($2,250)	($3,622)	($946)	($2,250)	($3,622)	$0	$0	$0
12										
13	Net Plant	$924,906,042	$945,852,952	$966,448,234	$924,906,042	$945,852,952	$966,448,234	($0)	($0)	($0)
14										
15	Additions:									
16	Materials and Supplies	$2,680,174	$2,159,157	$1,610,719	$2,680,174	$2,159,157	$1,610,719	$0	$0	$0
17	Prepaid Expenses, Excluding Taxes	$204,501	$276,014	$351,290	$204,501	$276,014	$351,290	$0	$0	$0
18	Deferred Debits	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	Cash Working Capital	$6,502,325	$6,502,325	$6,502,325	$6,672,954	$6,672,954	$6,672,954	$170,629	$170,629	$170,629
20	Unamortized Interest Lock expense $550M	$717,273	$555,375	$393,477	$717,273	$555,375	$393,477	$0	$0	$0
21	Unamortized Issuance Costs $300M	$368,550	$351,035	$333,519	$368,550	$351,035	$333,519	$0	$0	$0
22	Unamortized Issuance Costs $250M	$26,397	$4,434	$0	$26,397	$4,434	$0	$0	$0	$0
23	Unamortized Issuance Costs $200M	$251,932	$241,287	$230,642	$251,932	$241,287	$230,642	$0	$0	$0
24	Unamortized Issuance Costs $250M	$2,302,437	$2,279,062	$2,255,687	$454,825	$406,525	$358,225	($1,847,612)	($1,872,537)	($1,897,462)
25	Unamortized Issuance Costs Mortgage Bonds	$54,229	$31,304	$8,379	$54,229	$31,304	$8,379	$0	$0	$0
26	Total Additions	$13,107,818	$12,399,994	$11,686,040	$11,430,834	$10,698,085	$9,959,206	($1,676,984)	($1,701,909)	($1,726,834)
27										
28	Deductions:									
29	Accumulated Deferred FIT	$155,641,847	$165,481,552	$172,638,610	$155,641,847	$165,481,552	$172,638,610	($0)	($0)	($0)
30	Merger Hold Harmless Adjustment	$18,662,756	$16,576,053	$14,145,381	$18,662,756	$16,576,053	$14,145,381	$0	$0	$0
31	Customer Deposits	$1,467,477	$1,208,830	$936,570	$1,467,477	$1,208,830	$936,570	$0	$0	$0
32	Total Deductions	$175,772,080	$183,266,434	$187,720,560	$175,772,080	$183,266,434	$187,720,560	($0)	($0)	($0)
33										
34	Rate Base	$762,241,779	$774,986,512	$790,413,714	$760,564,795	$773,284,603	$788,686,880	($1,676,984)	($1,701,909)	($1,726,834)
35										
36	Total Rate Base	$762,241,779	$774,986,512	$790,413,714	$760,564,795	$773,284,603	$788,686,880	($1,676,984)	($1,701,909)	($1,726,834)

[1]Gas Information System

Line Notes

19(g) (h) (i) - Change in Cash Working Capital caused by (1) $450,000 increase to correct error in Settlement filing; CWC was calculated on total O&M of $78.8 million , which should have been calculated on $83.8 million (total $87.2 million minus uncollectible expense of $3.4 million). Results in an increase of $450,00 in CWC from Settlement ; (2) decrease in O&M expense from Settlement to Compliance drives a decrease of $92,000; and (3) decrease in tax expense drives a decrease of $187,000 from Settlement.

24(g) (h) (i) - Change in Unamortized debt issuance costs related to (1) settlement rate base erroneously included total unamortized issuance costs instead of the gas-only portion - decrease of $1.62 million; and (2) revised estimate of issuance costs in July 2018. Settlement included estimated issuance costs of $2.3 million over a 30 year term; revised to $1.6 million over a 10 year term for compliance - decrease of $225,000.

Compliance Attachment 1

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/ 4780
Witness: Little

Compliance Attachment 1

Narragansett Electric and Narragansett Gas Revenue Requirement Settlement Terms

Rate Years 1, 2, 3

The Narragansett Electric Company
d/b/a National Grid
Summary of Revenue Requirement Settlement Terms
Revenue Increases
($ million)

Incremental Revenue

Base case	Narragansett Electric	Narragansett Gas	Total
Rate Year 1	$12.0	$5.8	$17.8
Rate Year 2	$3.9	$5.7	$9.6
Rate Year 3	$2.5	$3.4	$5.9
Subtotal	$18.4	$14.9	$33.3
Power Sector Transformation (PST)			
Rate Year 1	$2.1	$0.0	$2.1
Rate Year 2	$6.6	$1.9	$8.4
Rate Year 3	$1.9	$0.6	$2.5
Subtotal - PST	$10.6	$2.5	$13.0
Base Case plus PST			
Rate Year 1	$14.1	$5.8	$19.9
Rate Year 2	$10.5	$7.6	$18.0
Rate Year 3	$4.3	$4.0	$8.4
TOTAL	$28.9	$17.4	$46.3

Revenue Requirement

Base case	Narragansett Electric	Narragansett Gas	Total
Rate Year 1	$291.1	$218.6	$509.7
Rate Year 2	$295.0	$224.3	$519.3
Rate Year 3	$297.5	$227.7	$525.2
Subtotal	$883.6	$670.6	$1,554.2
Power Sector Transformation (PST)			
Rate Year 1	$2.1	$0.0	$2.1
Rate Year 2	$8.7	$1.9	$10.6
Rate Year 3	$10.6	$2.5	$13.0
Subtotal - PST	$21.3	$4.4	$25.7
Base Case plus PST			
Rate Year 1	$293.2	$218.6	$511.8
Rate Year 2	$303.6	$226.2	$529.9
Rate Year 3	$308.0	$230.2	$538.2
TOTAL	$904.9	$675.0	$1,579.9

The Narragansett Electric Company Summary of Revenue Requirement Settlement Terms Revenue Increases and Cost of Service Adjustments	($ Millions) TOTAL Rate Year	Rate Year 2	Rate Year 3
1 Company Position per REV-1 filing (March 2)	$45.8		
2 Refund of Excess Deferred taxes	($9.0)		
3 Admin & General expense reclass to capital	($4.5)		
3a Company Position adjusted	$32.4		
Settlement Adjustments:			
4 Unfunded Service Co Excess Deferred taxes (3 pt allocator over 3 years)	$3.1		
5 ROE @ 9.275%	($8.0)		
6 Accept Division's adjustment for capital structure and Gas debt rates	($0.9)		
6a Partially accept Division's adjustment to depreciation rates	($3.1)		
7 Adjust Service Company Rents & GBE for reduced ROE at 9.275%	($0.3)		
8 Accept Division's adjustment for GBE (15% slippage, Type II savings)	($1.1)		
9 Accept Division's adjustment for IS (15% slippage)	($0.6)		
10 Accept Division's adjustment for Gas uncollectibles rate	($0.3)		
11 Company's shaping of incremental DG-related FTEs over 3 years	($0.2)		
12 Company's shaping of other incremental FTEs over 3 years	($0.8)		
13 Depreciation expense impact of Growth adjustment	($0.2)		
Amended Settlement Adjustments:			
14 Discovery/Rebuttal adjustments (REV-2) not previously reflected in Settlement	($0.3)		
15 Remove lobbying costs (Record request 1-4)	($0.4)		
16 Remove charitable donations (PUC Decision)	($0.9)		
17 Revised capital structure, debt expense and debt issuance costs	($0.3)		
18 Sub-Total of Expense Adjustments	**($14.3)**	**$0.0**	**$0.0**
Rate base Adjustments:			
19 Partially accept Division's adjustment on Growth forecast	($7.8)		
20 Depreciation Reserve flow through of Growth Adjustment	$0.2		
21 ADIT flow through of Growth Adjustment	$1.0		
22 Excess Deferred Income taxes	$3.5		
23 Sub-Total of Rate base Adjustments	($3.1)	$0.0	$0.0
24 Pre-Tax Return %			
25 Revenue Requirement on Rate base Adjustments	($0.3)		
26 **Total Adjustments**	**($14.6)**	**$0.0**	**$0.0**
27 **Subtotal - Base Rate request adjusted [Note 1]**	**$17.8**	**$9.6**	**$5.9**
Add-ins for PST:			
28 AMI Study at $2M	$0.7	$0.0	$0.0
29 GIS investment (IS)	$0.1	$0.0	$0.0
30 GIS investment (BR)	$0.0	$1.0	$0.0
31 DSCADA	$0.0	$0.4	($0.4)
32 System Data Portal - accept 2/3 in RY, up to 3 FTEs in Year 2	$0.5	$0.2	$0.0
33 All other Grid Mod (excluding DSCADA, GIS, SDP, Feeder Monitoring)	$0.0	$6.2	$1.8
34 **Sub-Total of PST Adjustments - Grid Modernization Programs**	**$1.3**	**$7.9**	**$1.3**
35 Electric Transportation	$0.7	$0.5	$1.0
36 Electric heat	$0.0	$0.0	$0.0
37 Strategic electrification education fund	$0.0	$0.0	$0.0
38 Storage	$0.1	$0.1	$0.2
39 **Sub-Total of PST Adjustments - Special Sector Programs**	**$0.8**	**$0.6**	**$1.2**
40 **Sub-Total of PST Adjustments**	**$2.1**	**$8.5**	**$2.5**
41 **Total Settlement - Base Case plus PST**	**$19.8**	**$18.0**	**$8.4**

Note 1 : The derivation of Rate Year 2 and Rate Year 3 revenue increases are per Pages 4 and 5 of this Attachment. $ 46.3

The Narragansett Electric Company Summary of Revenue Requirement Settlement Terms Revenue Increases and Cost of Service Adjustments	($ Millions) ELECTRIC Rate Year	Rate Year 2	Rate Year 3
1 Company Position per REV-1 filing (March 2)	$27.4		
2 Refund of Excess Deferred taxes	($6.5)		
3 Admin & General expense reclass to capital	($3.0)		
3a Company Position adjusted	$17.9		
Settlement Adjustments:			
4 Unfunded Service Co Excess Deferred taxes (3 pt allocator over 3 years)	$2.3		
5 ROE @ 9.275%	($3.9)		
6 Accept Division's adjustment for capital structure and Gas debt rates	($0.3)		
6a Partially accept Division's adjustment to depreciation rates	($0.9)		
7 Adjust Service Company Rents & GBE for reduced ROE at 9.275%	($0.2)		
8 Accept Division's adjustment for GBE (15% slippage, Type II savings)	($0.2)		
9 Accept Division's adjustment for IS (15% slippage)	($0.4)		
10 Accept Division's adjustment for Gas uncollectibles rate	$0.0		
11 Company's shaping of incremental DG-related FTEs over 3 years	($0.2)		
12 Company's shaping of other incremental FTEs over 3 years	($0.3)		
13 Depreciation expense impact of Growth adjustment	$0.0		
Amended Settlement Adjustments:			
14 Discovery/Rebuttal adjustments (REV-2) not previously reflected in Settlement	($1.2)		
15 Remove lobbying costs (Record request 1-4)	($0.3)		
16 Remove charitable donations (PUC Decision)	($0.6)		
17 Revised capital structure, debt expense and debt issuance costs	$0.0		
18 Sub-Total of Expense Adjustments	**($6.1)**	**$0.0**	**$0.0**
Rate base Adjustments:			
19 Partially accept Division's adjustment on Growth forecast	$0.0		
20 Depreciation Reserve flow through of Growth Adjustment	$0.0		
21 ADIT flow through of Growth Adjustment	$0.0		
22 Excess Deferred Income taxes	$2.5		
23 Sub-Total of Rate base Adjustments	$2.5	$0.0	$0.0
24 Pre-Tax Return %	8.23%		
25 Revenue Requirement on Rate base Adjustments	$0.2		
26 **Total Adjustments**	**($5.9)**	**$0.0**	**$0.0**
27 **Subtotal - Base Rate request adjusted [Note 1]**	**$12.0**	**$3.9**	**$2.5**
Add-ins for PST:			
28 AMI Study at $2M	$0.7	$0.0	$0.0
29 GIS investment (IS)	$0.1	$0.0	$0.0
30 GIS investment (BR)	$0.0	$1.0	$0.0
31 DSCADA	$0.0	$0.4	($0.4)
32 System Data Portal - accept 2/3 in RY, up to 3 FTEs in Year 2	$0.5	$0.2	$0.0
33 All other Grid Mod (excluding DSCADA, GIS, SDP, Feeder Monitoring)	$0.0	$4.3	$1.2
34 **Sub-Total of PST Adjustments - Grid Modernization Programs**	**$1.3**	**$6.0**	**$0.7**
35 Electric Transportation	$0.7	$0.5	$1.0
36 Electric heat	$0.0	$0.0	$0.0
37 Strategic electrification education fund	$0.0	$0.0	$0.0
38 Storage	$0.1	$0.1	$0.2
39 **Sub-Total of PST Adjustments - Special Sector Programs**	**$0.8**	**$0.6**	**$1.2**
40 **Sub-Total of PST Adjustments**	**$2.1**	**$6.6**	**$1.9**
41 **Total Settlement - Base Case plus PST**	**$14.1**	**$10.5**	**$4.3**

Note 1 : The derivation of Rate Year 2 and Rate Year 3 revenue increases are per Pages 4 and 5 of this Attachment. $ 28.9

The Narragansett Electric Company — **($ Millions)**
Summary of Revenue Requirement Settlement Terms — **GAS**
Revenue Increases and Cost of Service Adjustments

		Rate Year	Rate Year 2	Rate Year 3
1	Company Position per REV-1 filing (March 2)	$18.4		
2	Refund of Excess Deferred taxes	($2.5)		
3	Admin & General expense reclass to capital	($1.5)		
3a	Company Position adjusted	$14.4		
	Settlement Adjustments:			
4	Unfunded Service Co Excess Deferred taxes (3 pt allocator over 3 years)	$0.8		
5	ROE @ 9.275%	($4.1)		
6	Accept Division's adjustment for capital structure and Gas debt rates	($0.6)		
6a	Partially accept Division's adjustment to depreciation rates	($2.2)		
7	Adjust Service Company Rents & GBE for reduced ROE at 9.275%	($0.1)		
8	Accept Division's adjustment for GBE (15% slippage, Type II savings)	($1.0)		
9	Accept Division's adjustment for IS (15% slippage)	($0.2)		
10	Accept Division's adjustment for Gas uncollectibles rate	($0.3)		
11	Company's shaping of incremental DG-related FTEs over 3 years	$0.0		
12	Company's shaping of other incremental FTEs over 3 years	($0.5)		
13	Depreciation expense impact of Growth adjustment	($0.2)		
	Amended Settlement Adjustments:			
14	Discovery/Rebuttal adjustments (REV-2) not previously reflected in Settlement	$0.9		
15	Remove lobbying costs (Record request 1-4)	($0.1)		
16	Remove charitable donations (PUC Decision)	($0.3)		
17	Revised capital structure, debt expense and debt issuance costs	($0.3)		
18	**Sub-Total of Expense Adjustments**	**($8.2)**	**$0.0**	**$0.0**
	Rate base Adjustments:			
19	Partially accept Division's adjustment on Growth forecast	($7.8)		
20	Depreciation Reserve flow through of Growth Adjustment	$0.2		
21	ADIT flow through of Growth Adjustment	$1.0		
22	Excess Deferred Income taxes	$1.0		
23	Sub-Total of Rate base Adjustments	($5.6)	$0.0	$0.0
24	Pre-Tax Return %	8.41%		
25	Revenue Requirement on Rate base Adjustments	($0.5)		
26	**Total Adjustments**	**($8.7)**	**$0.0**	**$0.0**
27	**Subtotal - Base Rate request adjusted [Note 1]**	**$5.8**	**$5.7**	**$3.4**
	Add-ins for PST:			
28	AMI Study at $2M	$0.0	$0.0	$0.0
29	GIS investment (IS)	$0.0	$0.0	$0.0
30	GIS investment (BR)	$0.0	$0.0	$0.0
31	DSCADA	$0.0	$0.0	$0.0
32	System Data Portal - accept 2/3 in RY, up to 3 FTEs in Year 2	$0.0	$0.0	$0.0
33	All other Grid Mod (excluding DSCADA, GIS, SDP, Feeder Monitoring)	$0.0	$1.9	$0.6
34	**Sub-Total of PST Adjustments - Grid Modernization Programs**	**$0.0**	**$1.9**	**$0.6**
35	Electric Transportation	$0.0	$0.0	$0.0
36	Electric heat	$0.0	$0.0	$0.0
37	Strategic electrification education fund	$0.0	$0.0	$0.0
38	Storage	$0.0	$0.0	$0.0
39	**Sub-Total of PST Adjustments - Special Sector Programs**	**$0.0**	**$0.0**	**$0.0**
40	**Sub-Total of PST Adjustments**	**$0.0**	**$1.9**	**$0.6**
41	**Total Settlement - Base Case plus PST**	**$5.8**	**$7.7**	**$4.0**

Note 1 : The derivation of Rate Year 2 and Rate Year 3 revenue increases are per Pages 4 and 5 of this Attachment. $ 17.4

The Narragansett Electric Company d/b/a National Grid
Revenue Increases--Rate Years 2 & 3
Electric
Adjusted to exclude impact of items that would otherwise be collected through ISR factors in Rate Years 2 & 3

			Adjustments to Reflect Conditions in Rate Year 2	Adjustments to Reflect Conditions in Rate Year 3
			Electric	Electric
			(a)	(b)
	Operation & Maintenance Expenses:	Schedule		
1	Labor and related benefits	12 through 16	$2,174,993	$1,901,853
2	Service Company Rents	17	$380,409	$390,531
3	All other O&M expenses	various	($16,556)	($149,207)
4	Total Operation & Maintenance expense		$2,538,846	$2,143,177
5				
6	Incremental Depreciation & Amortization	4-ELEC	$879,921	$44,250
7	Incremental Taxes Other than Income taxes	8 & 9	$120,968	$96,490
8	Incremental Interest on Customer Deposits	Wkp 2	$172,340	($4,308)
9				
10	Return & Taxes on Incremental Rate Base	8.23%	$158,236	$266,548
11	**Revenue Deficiency**		**$3,870,311**	**$2,546,157**

The Narragansett Electric Company d/b/a National Grid
Revenue Increases--Rate Years 2 & 3
Gas
Adjusted to exclude impact of items that would otherwise be collected through ISR factors in Rate Years 2 & 3

			Adjustments to Reflect Conditions in Rate Year 2	Adjustments to Reflect Conditions in Rate Year 3
			Gas	Gas
			(a)	(b)
	Operation & Maintenance Expenses:	Schedule		
1	Labor and related benefits	12 through 16	$1,689,568	$1,306,791
2	Service Company Rents	17	$219,840	($260)
3	Gas Business Enablement	36	$664,720	$153,248
4	All other O&M expenses	various	$31,929	($60,847)
5	Total Operation & Maintenance expense		$2,606,057	$1,398,932
6				
7	Incremental Depreciation & Amortization	4-GAS	$1,924,745	$608,784
8	Incremental Taxes Other than Income taxes	8 & 9	$80,670	$61,307
9	Incremental Interest on Customer Deposits	Wkp 2	$45,892	($1,147)
10				
11	Return & Taxes on Incremental Rate Base	8.41%	$1,069,398	$1,294,921
12	**Revenue Deficiency**		**$5,726,762**	**$3,362,798**

The Narragansett Electric Company
d/b/a National Grid
Power Sector Transformation (PST)
PST Annual Revenue Requirement Summary Electric - Synergy

Line No.			Rate Year	Rate Year 2	Rate Year 3
GRID MOD					
	Electric Capex				
1	Feeder Monitoring Sensor		$0	$0	$0
2	RTU Separation		$0	$124,147	$209,992
3	**Electric Capex Total**		**$0**	**$124,147**	**$209,992**
	IS Capex - Electric Only				
4	Enterprise Service Bus		$0	$0	$436,827
5	Data Lake		$0	$46,245	$42,925
6	PI Historian		$0	$23,044	$21,390
7	Advanced Analytics		$0	$519,374	$651,192
8	Telecommunications		$0	$20,077	$27,060
9	Cybersecurity		$0	$658,484	$835,826
10	DSCADA		$0	$0	$0
11	**Electric IS Capex Total**		**$0**	**$1,267,224**	**$2,015,220**
	O&M - Electric Only				
12	Enterprise Service Bus		$0	$402,346	$504,066
13	Data Lake		$0	$388,092	$545,532
14	PI Historian		$0	$515,000	$515,000
15	Advanced Analytics		$0	$299,978	$338,852
16	Telecommunications		$0	$425,022	$636,886
17	Cybersecurity		$0	$802,100	$623,280
18	DSCADA		$0	$0	$0
19	Feeder Monitoring Sensor		$0	$0	$0
20	RTU Separation		$0	$60,000	$60,000
21	GIS Data Enhancements (BR)		$0	$0	$0
22	GIS Data Enhancements (IS)		$0	$0	$0
23	System Data Portal		$0	$0	$0
24	**Electric O&M Total**		**$0**	**$2,892,538**	**$3,223,615**
25	**Subtotal - all other Grid Mod**		**$0**	**$4,283,910**	**$5,448,828**
TOTAL PST					
26	AMI Study	($2M over 3 years)	$666,667	$666,667	$666,667
27	GIS Data Enhancements (IS)	($427,000 over 3 years)	$142,333	$142,333	$142,333
28	GIS Data Enhancements (BR)	(as filed)	$0	$1,028,000	$1,028,000
29	DSCADA	(as filed)	$0	$436,000	$0
30	System Data Portal	(2 FTEs in RY, 3 FTEs by RY2)	$466,667	$700,000	$700,000
31	All other Grid Mod excl. FM, DSCADA, GIS & SDP		$0	$4,283,910	$5,448,828
32	**Subtotal - Grid Modernization**		**$1,275,667**	**$7,256,910**	**$7,985,828**
33	Electric Transporation	(SSP settlement)	$681,300	$1,151,751	$2,151,776
34	Electric Heat	(SSP settlement)	$0	$0	$0
35	Strategic Elec Education Fund	(SSP settlement)	$7,500	$11,250	$18,750
36	Storage	(SSP settlement)	$112,856	$259,668	$411,986
37	**Subtotal - Special Sector Programs**		**$801,656**	**$1,422,669**	**$2,582,511**
38	**Total PST proposal - Electric**		**$2,077,322**	**$8,679,579**	**$10,568,339**
39	Revenue Increases		$2,077,322	$6,602,256	$1,888,760

The Narragansett Electric Company
d/b/a National Grid
Power Sector Transformation (PST)
PST Annual Revenue Requirement Summary Gas - Synergy

0

Line No.		Rate Year	Rate Year 2	Rate Year 3
GRID MOD				
	Gas Capex			
1	Feeder Monitoring Sensor	$0	$0	$0
2	RTU Separation	$0	$0	$0
3	**Gas Capex Total**	**$0**	**$0**	**$0**
	IS Capex - Gas Only			
4	Enterprise Service Bus	$0	$0	$237,393
5	Data Lake	$0	$25,132	$23,327
6	PI istdHian	$0	$0	$0
7	Advanced Analytics	$0	$282,253	$353,889
8	Telecommunications	$0	$10,911	$14,706
9	Cybersecurity	$0	$357,852	$454,228
10	DSCADA	$0	$0	$0
11	**Gas IS Capex Total**	**$0**	**$676,148**	**$1,083,543**
	O&M - Gas Only			
12	Enterprise Service Bus	$0	$218,654	$273,934
13	Data Lake	$0	$210,908	$296,468
14	PI Historian	$0	$0	$0
15	Advanced Analytics	$0	$163,022	$184,148
16	Telecommunications	$0	$230,978	$346,114
17	Cybersecurity	$0	$435,900	$338,720
18	DSCADA	$0	$0	$0
19	Feeder Monitoring Sensor	$0	$0	$0
20	RTU Separation	$0	$0	$0
21	GIS Data Enhancements (BR)	$0	$0	$0
22	GIS Data Enhancements (IS)	$0	$0	$0
23	System Data Portal	$0	$0	$0
24	**Gas O&M Total**	**$0**	**$1,259,462**	**$1,439,385**
25	**Subtotal - all other Grid Mod**	**$0**	**$1,935,610**	**$2,522,928**
TOTAL PST				
26	AMI Study	$0	$0	$0
27	GIS Data Enhancements (IS)	$0	$0	$0
28	GIS Data Enhancements (BR)	$0	$0	$0
29	DSCADA	$0	$0	$0
30	System Data Portal	$0	$0	$0
31	All other Grid Mod excl. FM, DSCADA, GIS & SDP	$0	$1,935,610	$2,522,928
32	**Subtotal - Grid Modernization**	**$0**	**$1,935,610**	**$2,522,928**
33	Electric Transporation	$0	$0	$0
34	Electric Heat	$0	$0	$0
35	Strategic Elec Education Fund	$0	$0	$0
36	Storage	$0	$0	$0
37	**Subtotal - Special Sector Programs**	**$0**	**$0**	**$0**
38	**Total PST proposal - Gas**	**$0**	**$1,935,610**	**$2,522,928**
39	Revenue Increases	$0	$1,935,610	$587,318

The Narragansett Electric Company
d/b/a National Grid
Power Sector Transformation (PST)
PST Annual Revenue Requirement Summary Total RI - Synergy

Line No.		Rate Year	Rate Year 2	Rate Year 3
GRID MOD				
	Total RI Capex			
1	Feeder Monitoring Sensor	$0	$0	$0
2	RTU Separation	$0	$124,147	$209,992
3	**Total RI Capex Total**	**$0**	**$124,147**	**$209,992**
	IS Capex - Total RI Only			
4	Enterprise Service Bus	$0	$0	$674,220
5	Data Lake	$0	$71,377	$66,252
6	PI Historian	$0	$23,044	$21,390
7	Advanced Analytics	$0	$801,627	$1,005,081
8	Telecommunications	$0	$30,988	$41,766
9	Cybersecurity	$0	$1,016,336	$1,290,054
10	DSCADA	$0	$0	$0
11	**Total RI IS Capex Total**	**$0**	**$1,943,372**	**$3,098,763**
	O&M - Total RI Only			
12	Enterprise Service Bus	$0	$621,000	$778,000
13	Data Lake	$0	$599,000	$842,000
14	PI Historian	$0	$515,000	$515,000
15	Advanced Analytics	$0	$463,000	$523,000
16	Telecommunications	$0	$656,000	$983,000
17	Cybersecurity	$0	$1,238,000	$962,000
18	DSCADA	$0	$0	$0
19	Feeder Monitoring Sensor	$0	$0	$0
20	RTU Separation	$0	$60,000	$60,000
21	GIS Data Enhancements (BR)	$0	$0	$0
22	GIS Data Enhancements (IS)	$0	$0	$0
23	System Data Portal	$0	$0	$0
24	**Total RI O&M Total**	**$0**	**$4,152,000**	**$4,663,000**
25	**Subtotal - all other Grid Mod**	**$0**	**$6,219,519**	**$7,971,755**
TOTAL PST				
26	AMI Study	$666,667	$666,667	$666,667
27	GIS Data Enhancements (IS)	$142,333	$142,333	$142,333
28	GIS Data Enhancements (BR)	$0	$1,028,000	$1,028,000
29	DSCADA	$0	$436,000	$0
30	System Data Portal	$466,667	$700,000	$700,000
31	All other Grid Mod excl. FM, DSCADA, GIS & SDP	$0	$6,219,519	$7,971,755
32	**Subtotal - Grid Modernization**	**$1,275,667**	**$9,192,519**	**$10,508,755**
33	Electric Transporation	$681,300	$1,151,751	$2,151,776
34	Electric Heat	$0	$0	$0
35	Strategic Elec Education Fund	$7,500	$11,250	$18,750
36	Storage	$112,856	$259,668	$411,986
37	**Subtotal - Special Sector Programs**	**$801,656**	**$1,422,669**	**$2,582,511**
38	**Total PST proposal - RI**	**$2,077,322**	**$10,615,188**	**$13,091,267**
39	Revenue Increases	$2,077,322	$8,537,866	$2,476,078

Compliance Attachment 2
Schedules 1 -13

Compliance Attachment 2

Narragansett Electric and Narragansett Gas Revenue Requirements

Rate Years 1, 2, 3

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
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Schedule 4-GAS	Amortization of Regulatory Deferrals – Gas
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THE NARRAGANSETT ELECTRIC COMPANY
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THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
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Witness: Little

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Schedule 1-ELEC

Revenue Requirement– Electric

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
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Schedule 1-ELEC
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The Narragansett Electric Company d/b/a National Grid
Illustrative Statement of Electric Operations Income and Revenue Deficiency Summary
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

		Schedule Reference	Test Year Ended June 30, 2017 (a)	Normalizing Adjustments (b)	Test Year Ended June 30, 2017 Adjusted (c) = (a) + (b)	Proforma Adjustments (c)	Rate Year Ending August 31, 2019 (e) = (c) + (d)	Base Revenue Increase Required (f)	Rate Year Ending August 31, 2019 with Base Revenue Requirement (g) = (e) + (f)
1	Revenues	Schedule 2-ELEC	$906,848,280	($627,513,858)	$279,334,422	($242,479)	$279,091,943	$12,038,936	$291,130,879
2									
3	Purchased Power & Other Reconciling Expense	Schedule 3	$304,255,398	($304,255,398)	$0	$0	$0	$0	$0
4									
5	Net Distribution Revenues		$602,592,882	($323,258,459)	$279,334,422	($242,479)	$279,091,943	$12,038,936	$291,130,879
6									
7	Operation & Maintenance Expenses	Schedule 3	$304,575,180	($164,238,756)	$140,336,424	$10,266,874	$150,603,298	$156,855	$150,760,152
8									
9	Amortization of Regulatory Deferrals	Schedule 4-ELEC	$8,454	($8,454)	$0	$471,908	$471,908	$0	$471,908
10									
11	Amortization of Utility Plant	Schedule 5-ELEC	$62,962	($62,962)	$0	$0	$0	$0	$0
12									
13	Depreciation	Schedule 6-ELEC	$69,031,187	($19,869,812)	$49,161,375	$966,957	$50,128,332	$0	$50,128,332
14									
15	Municipal Taxes	Schedule 7-ELEC	$49,702,787	($20,023,313)	$29,679,474	$850,784	$30,530,258	$0	$30,530,258
16									
17	Payroll Taxes	Schedule 8	$8,148,712	($4,435,908)	$3,712,803	$441,719	$4,154,522	$0	$4,154,522
18									
19	Gross Receipts Taxes	Schedule 9	$32,568,650	($32,568,650)	$0	$0	$0	$0	$0
20									
21	Other Taxes	Schedule 9	$434,298	$0	$434,298	$20,108	$454,406	$0	$454,406
22									
23	Interest on Customer Deposits	Workpaper 2-ELEC	$0	$0	$0	$132,127	$132,127	$0	$132,127
24									
25	Total Operating Revenue Deductions		$464,532,229	($241,207,855)	$223,324,374	$13,150,477	$236,474,851	$156,855	$236,631,706
26									
27	Operating Income Before Income Taxes		$138,060,652	($82,050,604)	$56,010,048	($13,392,956)	$42,617,092	$11,882,081	$54,499,173
28									
29	Income Taxes	Schedule 10-ELEC					$1,157,091	$2,495,237	$3,652,328
30									
31	Operating Income After Income Taxes						$41,460,001	$9,386,844	$50,846,845
32									
33	Rate Base	Schedule 11-ELEC					$729,509,971		$729,509,971
34									
35	Rate of Return						5.68%	Line 31(e) / Line 33(e)	
36									
37									
38						Revenue Deficiency			
39						Earned Rate of Return	5.68%	Line 35 (e)	
40						Rate Year Required Rate of Return	6.97%	Page 4, Line 9 (c)	
41						Rate of Return Deficiency	1.29%	Line 40 - Line 39	
42						Rate Base	$729,509,971	Line 33 (e)	
43						Net Operating Income Deficiency	$9,386,844		
44						Gross Revenue Conversion Factor	1.282533	Line 53	
45						**Revenue Deficiency**	$12,038,936	Line 43 / Line 44	
46									
47						Gross Revenue Conversion Factor			
48						Gross Revenue	1.000000		
49						Uncollectible expense	(0.013029)	Schedule 22, Page 6, Line 15	
50						Revenue net of Uncollectibles	0.986971		
51						Composite income tax rate	(0.20726)	Line 50 x (- 21%)	
52						Net income effect of 1.000 Revenue	0.779707	Line 50 + Line 51	
53						Gross Revenue Conversion Factor	1.2825328	1 / Line 52	

The Narragansett Electric Company d/b/a National Grid
Illustrative Statement of Electric Operations Income and Revenue Deficiency Summary
For Rate Year Ending August 31, 2019 to Rate Year Ending August 31, 2020

		Schedule Reference	Rate Year Ending August 31, 2019 (a)	Reflect Conditions in the Rate Year (b)	Rate Year Ending August 31, 2020 (c) = (a) + (b)	Base Revenue Increase Required (d)	Rate Year Ending August 31, 2020 with Base Revenue Requirement (e) = (c) + (d)
1	Revenues	Schedule 2-ELEC	$291,130,879	$0	$291,130,879	$3,870,311	$295,001,190
2							
3	Purchased Power & Other Reconciling Expense	Schedule 3	$0	$0	$0	$0	$0
4							
5	Net Distribution Revenues		$291,130,879	$0	$291,130,879	$3,870,311	$295,001,190
6							
7	Operation & Maintenance Expenses	Schedule 3	$150,760,152	$2,488,420	$153,248,572	$50,426	$153,298,998
8							
9	Amortization of Regulatory Deferrals	Schedule 4-ELEC	$471,908	$0	$471,908	$0	$471,908
10							
11	Amortization of Utility Plant	Schedule 5-ELEC	$0	$0	$0	$0	$0
12							
13	Depreciation	Schedule 6-ELEC	$50,128,332	$879,921	$51,008,253	$0	$51,008,253
14							
15	Municipal Taxes	Schedule 7-ELEC	$30,530,258	$0	$30,530,258	$0	$30,530,258
16							
17	Payroll Taxes	Schedule 8	$4,154,522	$108,881	$4,263,404	$0	$4,263,404
18							
19	Gross Receipts Taxes	Schedule 9	$0	$0	$0	$0	$0
20							
21	Other Taxes	Schedule 9	$454,406	$12,087	$466,493	$0	$466,493
22							
23	Interest on Customer Deposits	Workpaper 2-ELEC	$132,127	$172,340	$304,467	$0	$304,467
24							
25	Total Operating Revenue Deductions		$236,631,706	$3,661,649	$240,293,355	$50,426	$240,343,781
26							
27	Operating Income Before Income Taxes		$54,499,173	($3,661,649)	$50,837,523	$3,819,885	$54,657,408
28							
29	Income Taxes	Schedule 10-ELEC			$2,862,891	$802,176	$3,665,067
30							
31	Operating Income After Income Taxes				$47,974,632	$3,017,709	$50,992,341
32							
33	Rate Base	Schedule 11-ELEC			$731,597,435		$731,597,435
34							
35	Rate of Return				6.56%	Line 31(c) / Line 33(c)	
36							
37							
38				Revenue Deficiency			
39				Earned Rate of Return	6.56%	Line 35 (c)	
40				Rate Year Required Rate of Return	6.97%	Page 4, Line 9 (c)	
41				Rate of Return Deficiency	0.41%	Line 40 - Line 39	
42				Rate Base	$731,597,435	Line 33 (c)	
43				Net Operating Income Deficiency	$3,017,709		
44				Gross Revenue Conversion Factor	1.282533	Line 53	
45				**Revenue Deficiency**	$3,870,311	Line 43 / Line 44	
46							
47				Gross Revenue Conversion Factor			
48				Gross Revenue	1.000000		
49				Uncollectible expense	(0.013029)	Schedule 22, Page 6, Line 15	
50				Revenue net of Uncollectibles	0.986971		
51				Composite income tax rate	(0.20726)	Line 50 x (- 21%)	
52				Net income effect of 1.000 Revenue	0.779707	Line 50 + Line 51	
53				Gross Revenue Conversion Factor	1.2825328	1 / Line 52	

The Narragansett Electric Company d/b/a National Grid
Illustrative Statement of Electric Operations Income and Revenue Deficiency Summary
For Rate Year Ending August 31, 2020 to Rate Year Ending August 31, 2021

		Schedule Reference	Rate Year Ending August 31, 2021 (a)	Reflect Conditions in the Rate Year (b)	Rate Year Ending August 31, 2021 Adjusted (c) = (a) + (b)	Base Revenue Increase Required (d)	Rate Year Ending August 31, 2021 with Base Revenue Requirement (e) = (c) + (d)
1	Revenues	Schedule 2-ELEC	$295,001,190	$0	$295,001,190	$2,546,157	$297,547,347
2							
3	Purchased Power & Other Reconciling Expense	Schedule 3	$0	$0	$0	$0	$0
4							
5	Net Distribution Revenues		$295,001,190	$0	$295,001,190	$2,546,157	$297,547,347
6							
7	Operation & Maintenance Expenses	Schedule 3	$153,298,998	$2,110,003	$155,409,002	$33,174	$155,442,175
8							
9	Amortization of Regulatory Deferrals	Schedule 4-ELEC	$471,908	$0	$471,908	$0	$471,908
10							
11	Amortization of Utility Plant	Schedule 5-ELEC	$0	$0	$0	$0	$0
12							
13	Depreciation	Schedule 6-ELEC	$51,008,253	$44,250	$51,052,503	$0	$51,052,503
14							
15	Municipal Taxes	Schedule 7-ELEC	$30,530,258	$0	$30,530,258	$0	$30,530,258
16							
17	Payroll Taxes	Schedule 8	$4,263,404	$85,155	$4,348,558	$0	$4,348,558
18							
19	Gross Receipts Taxes	Schedule 9	$0	$0	$0	$0	$0
20							
21	Other Taxes	Schedule 9	$466,493	$11,336	$477,829	$0	$477,829
22							
23	Interest on Customer Deposits	Workpaper 2-ELEC	$304,467	($4,308)	$300,158	$0	$300,158
24							
25	Total Operating Revenue Deductions		$240,343,781	$2,246,435	$242,590,217	$33,174	$242,623,390
26							
27	Operating Income Before Income Taxes		$54,657,408	($2,246,435)	$52,410,973	$2,512,983	$54,923,956
28							
29	Income Taxes	Schedule 10-ELEC			$3,178,076	$527,726	$3,705,802
30							
31	Operating Income After Income Taxes				$49,232,897	$1,985,257	$51,218,154
32							
33	Rate Base	Schedule 11-ELEC			$734,837,218		$734,837,218
34							
35	Rate of Return				6.70%	Line 31(c) / Line 33(c)	
36							
37							
38					Revenue Deficiency		
39					Earned Rate of Return	6.70%	Line 35 (c)
40					Rate Year Required Rate of Return	6.97%	Page 4, Line 9 (c)
41					Rate of Return Deficiency	0.27%	Line 40 - Line 39
42					Rate Base	$734,837,218	Line 33 (c)
43					Net Operating Income Deficiency	$1,985,257	
44					Gross Revenue Conversion Factor	1.282533	Line 53
45					**Revenue Deficiency**	$2,546,157	Line 43 / Line 44
46							
47					Gross Revenue Conversion Factor		
48					Gross Revenue	1.000000	
49					Uncollectible expense	(0.013029)	Schedule 22, Page 6, Line 15
50					Revenue net of Uncollectibles	0.986971	
51					Composite income tax rate	(0.20726)	Line 50 x (- 21%)
52					Net income effect of 1.000 Revenue	0.779707	Line 50 + Line 51
53					Gross Revenue Conversion Factor	1.2825328	1 / Line 52

The Narragansett Electric Company d/b/a National Grid
Cost of Capital
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2021

	Description	Capital Structure	Cost Rate	Weighted Return	Taxes	Pre-tax Return
		(a)	(b)	(c) = (a) x (b)	(d)	(e) = (c)+(d)
1	Short Term Debt	0.60%	1.76%	0.01%		0.01%
2						
3	Long Term Debt	48.35%	4.62% (1)	2.23%		2.23%
4						
5	Preferred Stock	0.10%	4.50%	0.00%		0.00%
6						
7	Total Common Equity	50.95%	9.275%	4.73%	1.26% (2)	5.99%
8						
9	Total Capitalization	100.00%		6.97%	1.26%	8.23%

Notes
(1) Company's Effective Cost of Long Term Debt
(2) Line 3(c) / (1-21%) - Line 3(c)

Column Notes
(a) As referenced in Pre-filed Direct Testimony of Robert B. Hevert, page 2 of 2 Lines 14 through 18

Line Notes
1(b) As referenced in Pre-filed Direct Testimony of Robert B. Hevert,, page 78 of 93 Line 13
3(b) As referenced in Pre-filed Direct Testimony of Robert B. Hevert,, page 78 of 93 Line 4
5(b) As referenced in Pre-filed Direct Testimony of Robert B. Hevert,, page 78 of 93 Line 10
7(b) Based on Settlement

Compliance Attachment 2

Schedule 1-GAS

Revenue Requirement – Gas

The Narragansett Electric Company d/b/a National Grid
Illustrative Statement of Gas Operations Income and Revenue Deficiency Summary
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

		Schedule Reference	Test Year Ended June 30, 2017 (a)	Normalizing Adjustments (b)	Test Year Ended June 30, 2017 Adjusted (c) = (a) + (b)	Proforma Adjustments (d)	Rate Year Ending August 31, 2019 (e) = (c) + (d)	Base Revenue Increase Required (f)	Rate Year Ending August 31, 2019 with Base Revenue Requirement (g) = (e) + (f)
1	Revenues	Schedule 2-GAS	$377,158,225	($199,714,435)	$177,443,790	$35,367,585	$212,811,375	$5,823,471	$218,634,846
2									
3	Purchased Power & Other Reconciling Expense	Schedule 3	$136,269,302	($136,269,302)	$0	$0	$0	$0	$0
4									
5	Net Distribution Revenues		$240,888,923	($63,445,133)	$177,443,790	$35,367,585	$212,811,375	$5,823,471	$218,634,846
6									
7	Operation & Maintenance Expenses	Schedule 3	$115,479,365	($28,084,501)	$87,394,863	($1,247,337)	$86,147,527	$111,079	$86,258,606
8									
9	Amortization of Regulatory Deferrals	Schedule 4-GAS	$705,953	$1,309,738	$2,015,691	($438,475)	$1,577,216	$0	$1,577,216
10									
11	Amortization of Utility Plant	Schedule 5-GAS	$1,874,224	$106,546	$1,980,770	($1,554,586)	$426,184	$0	$426,184
12									
13	Depreciation	Schedule 6-GAS	$33,311,851	($15,649)	$33,296,202	$5,840,707	$39,136,909	$0	$39,136,909
14									
15	Municipal Taxes	Schedule 7-GAS	$22,542,352	($453,318)	$22,089,035	$4,780,420	$26,869,455	$0	$26,869,455
16									
17	Payroll Taxes	Schedule 8	($1,294,241)	$3,762,248	$2,468,007	$192,382	$2,660,389	$0	$2,660,389
18									
19	Gross Receipts Taxes	Schedule 9	$11,166,309	($11,166,309)	$0	$0	$0	$0	$0
20									
21	Other Taxes	Schedule 9	$217,464	$0	$217,464	$10,069	$227,533	$0	$227,533
22									
23	Interest on Customer Deposits	Workpaper 2-GAS	$0	$0	$0	$35,184	$35,184	$0	$35,184
24									
25	Total Operating Revenue Deductions		$184,003,277	($34,541,245)	$149,462,033	$7,618,364	$157,080,397	$111,079	$157,191,476
26									
27	Operating Income Before Income Taxes		$56,885,646	($28,903,888)	$27,981,757	$27,749,221	$55,730,978	$5,712,392	$61,443,370
28									
29	Income Taxes	Schedule 10-GAS					$5,863,385	$1,199,602	$7,062,987
30									
31	Operating Income After Income Taxes						$49,867,593	$4,512,790	$54,380,383
32									
33	Rate Base	Schedule 11-GAS					$760,564,795		$760,564,795
34									
35	Rate of Return						6.56%	Line 31(e) / Line 33(e)	
36									
37									
38						Revenue Deficiency			
39						Earned Rate of Return	6.56%	Line 35 (e)	
40						Rate Year Required Rate of Return	7.15%	Page 4, Line 9 (c)	
41						Rate of Return Deficiency	0.59%	Line 40 - Line 39	
42						Rate Base	$760,564,795	Line 33 (e)	
43						Net Operating Income Deficiency	$4,512,790		
44						Gross Revenue Conversion Factor	1.290437	Line 53	
45						**Revenue Deficiency**	$5,823,471	Line 43 / Line 44	
46									
47						Gross Revenue Conversion Factor			
48						Gross Revenue	1.000000		
49						Uncollectible expense	(0.019074)	Schedule 22, Page 7, Line 15	
50						Revenue net of Uncollectibles	0.980926		
51						Composite income tax rate	(0.20599)	Line 50 x (- 21%)	
52						Net income effect of 1.000 Revenue	0.774931	Line 50 + Line 51	
53						Gross Revenue Conversion Factor	1.2904371	1 / Line 52	

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 1-GAS
Page 2 of 4

The Narragansett Electric Company d/b/a National Grid
Illustrative Statement of Gas Operations Income and Revenue Deficiency Summary
For Rate Year Ending August 31, 2019 to Rate Year Ending August 31, 2020

		Schedule Reference	Rate Year Ending August 31, 2019 (a)	Reflect Conditions in the Rate Year (b)	Rate Year Ending August 31, 2020 (c) = (a) + (b)	Base Revenue Increase Required (d)	Rate Year Ending August 31, 2020 with Base Revenue Requirement (e) = (c) + (d)
1	Revenues	Schedule 2-GAS	$218,634,846	$0	$218,634,846	$5,726,761	$224,361,607
2							
3	Purchased Power & Other Reconciling Expense	Schedule 3	$0	$0	$0	$0	$0
4							
5	Net Distribution Revenues		$218,634,846	$0	$218,634,846	$5,726,761	$224,361,607
6							
7	Operation & Maintenance Expenses	Schedule 3	$86,258,606	$2,496,823	$88,755,428	$109,234	$88,864,662
8							
9	Amortization of Regulatory Deferrals	Schedule 4-GAS	$1,577,216	$0	$1,577,216	$0	$1,577,216
10							
11	Amortization of Utility Plant	Schedule 5-GAS	$426,184	$0	$426,184	$0	$426,184
12							
13	Depreciation	Schedule 6-GAS	$39,136,909	$1,924,745	$41,061,654	$0	$41,061,654
14							
15	Municipal Taxes	Schedule 7-GAS	$26,869,455	$0	$26,869,455	$0	$26,869,455
16							
17	Payroll Taxes	Schedule 8	$2,660,389	$74,617	$2,735,007	$0	$2,735,007
18							
19	Gross Receipts Taxes	Schedule 9	$0	$0	$0	$0	$0
20							
21	Other Taxes	Schedule 9	$227,533	$6,052	$233,585	$0	$233,585
22							
23	Interest on Customer Deposits	Workpaper 2-GAS	$35,184	$45,892	$81,076	$0	$81,076
24							
25	Total Operating Revenue Deductions		$157,191,476	$4,548,129	$161,739,605	$109,234	$161,848,840
26							
27	Operating Income Before Income Taxes		$61,443,370	($4,548,129)	$56,895,241	$5,617,527	$62,512,767
28							
29	Income Taxes	Schedule 10-GAS			$6,043,238	$1,179,681	$7,222,918
30							
31	Operating Income After Income Taxes				$50,852,003	$4,437,846	$55,289,849
32							
33	Rate Base	Schedule 11-GAS			$773,284,603		$773,284,603
34							
35	Rate of Return				6.58%	Line 31(c) / Line 33(c)	
36							
37							
38				Revenue Deficiency			
39				Earned Rate of Return	6.58%	Line 35 (c)	
40				Rate Year Required Rate of Return	7.15%	Page 4, Line 9 (c)	
41				Rate of Return Deficiency	0.57%	Line 40 - Line 39	
42				Rate Base	$773,284,603	Line 33 (c)	
43				Net Operating Income Deficiency	$4,437,846		
44				Gross Revenue Conversion Factor	1.290437	Line 53	
45				**Revenue Deficiency**	$5,726,761	Line 43 / Line 44	
46							
47				Gross Revenue Conversion Factor			
48				Gross Revenue	1.000000		
49				Uncollectible expense	(0.019074)	Schedule 22, Page 7, Line 15	

THE NARRAGANSETT ELECTRIC COMPANY
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The Narragansett Electric Company d/b/a National Grid
Illustrative Statement of Gas Operations Income and Revenue Deficiency Summary
For Rate Year Ending August 31, 2020 to Rate Year Ending August 31, 2021

		Schedule Reference	Rate Year Ending August 31, 2020 (a)	Reflect Conditions in the Rate Year (b)	Rate Year Ending August 31, 2020 Adjusted (c) = (a) + (b)	Base Revenue Increase Required (d)	Rate Year Ending August 31, 2021 with Base Revenue Requirement (e) = (c) + (d)
1	Revenues	Schedule 2-GAS	$224,361,607	$0	$224,361,607	$3,362,798	$227,724,405
2							
3	Purchased Power & Other Reconciling Expense	Schedule 3	$0	$0	$0	$0	$0
4							
5	Net Distribution Revenues		$224,361,607	$0	$224,361,607	$3,362,798	$227,724,405
6							
7	Operation & Maintenance Expenses	Schedule 3	$88,864,662	$1,334,789	$90,199,451	$64,143	$90,263,594
8							
9	Amortization of Regulatory Deferrals	Schedule 4-GAS	$1,577,216	$0	$1,577,216	$0	$1,577,216
10							
11	Amortization of Utility Plant	Schedule 5-GAS	$426,184	$0	$426,184	$0	$426,184
12							
13	Depreciation	Schedule 6-GAS	$41,061,654	$608,784	$41,670,438	$0	$41,670,438
14							
15	Municipal Taxes	Schedule 7-GAS	$26,869,455	$0	$26,869,455	$0	$26,869,455
16							
17	Payroll Taxes	Schedule 8	$2,735,007	$55,631	$2,790,638	$0	$2,790,638
18							
19	Gross Receipts Taxes	Schedule 9	$0	$0	$0	$0	$0
20							
21	Other Taxes	Schedule 9	$233,585	$5,676	$239,261	$0	$239,261
22							
23	Interest on Customer Deposits	Workpaper 2-GAS	$81,076	($1,147)	$79,929	$0	$79,929
24							
25	Total Operating Revenue Deductions		$161,848,840	$2,003,733	$163,852,572	$64,143	$163,916,716
26							
27	Operating Income Before Income Taxes		$62,512,767	($2,003,733)	$60,509,035	$3,298,655	$63,807,690
28							
29	Income Taxes	Schedule 10-GAS			$6,723,860	$692,718	$7,416,578
30							
31	Operating Income After Income Taxes				$53,785,175	$2,605,937	$56,391,112
32							
33	Rate Base	Schedule 11-GAS			$788,686,880		$788,686,880
34							
35	Rate of Return				6.82%	Line 31(c) / Line 33(c)	
36							
37							
38				Revenue Deficiency			
39				Earned Rate of Return	6.82%	Line 35 (c)	
40				Rate Year Required Rate of Return	7.15%	Page 4, Line 9 (c)	
41				Rate of Return Deficiency	0.33%	Line 40 - Line 39	
42				Rate Base	$788,686,880	Line 33 (c)	
43				Net Operating Income Deficiency	$2,605,937		
44				Gross Revenue Conversion Factor	1.290437	Line 53	
45				**Revenue Deficiency**	$3,362,798	Line 43 / Line 44	
46							
47				Gross Revenue Conversion Factor			
48				Gross Revenue	1.000000		
49				Uncollectible expense	(0.019074)	Schedule 22, Page 7, Line 15	
50				Revenue net of Uncollectibles	0.980926		
51				Composite income tax rate	(0.20599)	Line 50 x (- 21%)	
52				Net income effect of 1.000 Revenue	0.774931	Line 50 + Line 51	
53				Gross Revenue Conversion Factor	1.2904371	1 / Line 52	

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
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The Narragansett Electric Company d/b/a National Grid
Cost of Capital
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

	Description	Capital Structure (a)	Cost Rate (b)	Weighted Return (c) = (a) x (b)	Taxes (d)	Pre-tax Return (e) = (c)+(d)
1	Short Term Debt	0.60%	1.76%	0.01%		0.01%
2						
3	Long Term Debt	48.35%	4.98% (1)	2.41%		2.41%
4						
5	Preferred Stock	0.10%	4.50%	0.00%		0.00%
6						
7	Total Common Equity	50.95%	9.275%	4.73%	1.26% (2)	5.99%
8						
9	Total Capitalization	100.00%		7.15%	1.26%	8.41%

Notes
(1) Company's Effective Cost of Long Term Debt
(2) Line 3(c) / (1 - 21%) - Line 3(c)

Column Notes
(a) As referenced in Pre-filed Direct Testimony of Robert B. Hevert, page 2 of 2 Lines 14 through 18

Line Notes
1(b) As referenced in Pre-filed Direct Testimony of Robert B. Hevert,, page 78 of 93 Line 13
3(b) As referenced in Pre-filed Direct Testimony of Robert B. Hevert,, page 78 of 93 Line 4
5(b) As referenced in Pre-filed Direct Testimony of Robert B. Hevert,, page 78 of 93 Line 10
7(b) As referenced in Pre-filed Direct Testimony of Robert B. Hevert,, page 83 of 93 Line 13

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/ 4780
Witness: Little

Compliance Attachment 2

Schedule 2-ELEC

Revenue– Electric

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 2-ELEC
Page 1 of 1

The Narragansett Electric Company d/b/a National Grid
Electric Operations Revenues by Component
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

	Description	Test Year Ended June 30, 2017	Normalizing Adjustments	Test Year Ended June 30, 2017 (Adjusted)	Proforma Adjustments	Rate Year Ending August 31, 2019	Adjustments to Reflect Conditions in Rate Year Ending August 31, 2020	Rate Year Ending August 31, 2020	Adjustments to Reflect Conditions in Rate Year Ending August 31, 2021	Rate Year Ending August 31, 2021
		(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) + (d)	(f)	(g) = (e) + (f)	(h)	(i) = (g) + (h)
1	Firm Revenues:									
2	Customer	$56,691,544	($488,501)	$56,203,043	$2,265,282	$58,468,325	12,038,936	$70,507,261	3,870,311	$74,377,572
3	Distribution	$181,979,904	$3,009,507	$184,989,411	($5,602,580)	$179,386,831	-	$179,386,831	-	$179,386,831
4	Revenue Decoupling Mechanism	$2,933,071	$7,047,475	$9,980,546	$3,337,298	$13,317,844	-	$13,317,844	-	$13,317,844
5	Subtotal of Annual Target Revenue	$241,604,519	$9,568,481	$251,173,000	$0	$251,173,000	$12,038,936	$263,211,936	$3,870,311	$267,082,247
6										
7	Infrastructure, Safety and Reliability Capital	$18,366,740	($1,782,009)	$16,584,731	($538,335)	$16,046,396	$0	$16,046,396	$0	$16,046,396
8	Infrastructure, Safety and Reliability Capital Adjustment		$2,904,568	$2,904,568	$437,848	$3,342,416		$3,342,416		$3,342,416
9	Total Base Distribution Revenues	$18,366,740	$1,122,559	$19,489,299	($100,487)	$19,388,812	$0	$19,388,812	$0	$19,388,812
10										
11	Total Base Distribution Revenues	$259,971,259	$10,691,040	$270,662,299	($100,487)	$270,561,812	$12,038,936	$282,600,748	$3,870,311	$286,471,059
12										
13	Other Distribution Revenues:									
14	Forfeited Discounts - Electric	$1,657,293	$0	$1,657,293	$0	$1,657,293	$0	$1,657,293	$0	$1,657,293
15	Misc Service Revenue - Electric	$233,788	$1,276,523	$1,510,311	($141,992)	$1,368,319	$0	$1,368,319	$0	$1,368,319
16	Rent from Electric Property	$3,822,134	($937,241)	$2,884,893	$0	$2,884,893	$0	$2,884,893	$0	$2,884,893
17	Other Electric Revenue - Misc	$1,882,811	$0	$1,882,811	$0	$1,882,811	$0	$1,882,811	$0	$1,882,811
18	Other Elec Rev-Block Island & Dist Surcharges	$9,680,425	($9,086,137)	$594,288	$0	$594,288	$0	$594,288	$0	$594,288
19	Other Elec Rev-CIAC	$1,197,705	($1,197,705)	$0	$0	$0	$0	$0	$0	$0
20	Other Elec Rev-RISE EE Billings	$131,920	($131,920)	$0	$0	$0	$0	$0	$0	$0
21	M-1 Distribution Revenue	$146,486	($3,959)	$142,527	$0	$142,527	$0	$142,527	$0	$142,527
22	Subtotal Distribution Revenue	$278,723,821	$610,601	$279,334,422	($242,479)	$279,091,943	$12,038,936	$291,130,879	$3,870,311	$295,001,190
23										
24	Other Delivery and Commodity Revenue:									
25	Standard Offer Administrative	$10,331,312	($10,331,312)	$0	$0	$0	$0	$0	$0	$0
26	Infrastructure, Safety and Reliability Operating & Maintenance	$8,360,493	($8,360,493)	$0	$0	$0	$0	$0	$0	$0
27	Transmission	$181,281,258	($181,281,258)	$0	$0	$0	$0	$0	$0	$0
28	Competitive Transition Charge	$978,140	($978,140)	$0	$0	$0	$0	$0	$0	$0
29	Commodity	$269,132,978	($269,132,978)	$0	$0	$0	$0	$0	$0	$0
30	Energy Efficiency	$78,518,199	($78,518,199)	$0	$0	$0	$0	$0	$0	$0
31	Pension Adjustment Factor	$4,724,675	($4,724,675)	$0	$0	$0	$0	$0	$0	$0
32	Storm Fund Replenishment Factor	$0	$0	$0	$0	$0	$0	$0	$0	$0
33	RE Growth	$2,033,798	($2,033,798)	$0	$0	$0	$0	$0	$0	$0
34	Long-Term Contracting for Renewable Energy Recovery Provision	$34,690,580	($34,690,580)	$0	$0	$0	$0	$0	$0	$0
35	Net Metering	$3,283,480	($3,283,480)	$0	$0	$0	$0	$0	$0	$0
36	Gross Receipts Tax	$34,789,546	($34,789,546)	$0	$0	$0	$0	$0	$0	$0
37	Total Other Operating Revenues	$628,124,459	($628,124,459)	$0	$0	$0	$0	$0	$0	$0
38										
39										
40	Total Operating Revenues	$906,848,280	($627,513,858)	$279,334,422	($242,479)	$279,091,943	$12,038,936	$291,130,879	$3,870,311	$295,001,190

Column Notes
(a) Per Workpaper PP-1-ELEC Page 1, Column (a)
(b) Lines (2) through (22) Column (c) - Column (a)
(b) Lines (25) through (37): - Column (a)
(c) Lines (2) through (22) per Workpaper PP-1-ELEC, Page 1, Column (b)
(c) Lines (25) through (37): Column (a) + Column (b)
(d) Lines (2) through (22) per Workpaper PP-1-ELEC, Page 1, Column (c)
(d) Lines (25) through (37): No Proforma Adjustments
(e) Column (c) + Column (d)
(f) Line (3) per Schedule 1-ELEC, Page 1, Line (45) Column (e)
(f) Line (7) per Workpaper 12-ELEC, Page 1, Line (17) Column (h)
(g) Column (e) + Column (f)
(h) Line (3) per Schedule 1-ELEC, Page 2, Line (45) Column (e)
(h) Line (7) per Workpaper 12-ELEC, Page 1, Line (17) Column (i)
(i) Column (g) + Column (h)

Line Notes
5 Sum of Line 2 through Line 4
9 Line 7 + Line 8
11 Line 5 + Line 9
22 Sum of Line 11 through Line 22
37 Sum of Line 25 through Line 36
40 Line 22 + Line 37

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/ 4780
Witness: Little

Compliance Attachment 2

Schedule 2-GAS

Revenue – Gas

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 2-GAS
Page 1 of 1

The Narragansett Electric Company d/b/a National Grid
Gas Operations Revenues by Component
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

	Description	Test Year Ended June 30, 2017	Normalizing Adjustments	Test Year Ended June 30, 2017 (Adjusted)	Proforma Adjustments	Rate Year Ending August 31, 2019	Adjustments to Reflect Conditions in Rate Year Ending August 31, 2020	Rate Year Ending August 31, 2020	Adjustments to Reflect Conditions in Rate Year Ending August 31, 2021	Rate Year Ending August 31, 2021
		(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) + (d)	(f)	(g) = (e) + (f)	(h)	(i) = (g) + (h)
	Firm Revenues:									
1	Delivery- Base Revenues excluding AGT,LIHEAP, and Envir Base Rate	$169,061,454	$2,391,422	$171,452,876	$1,955,965	$173,408,841	$5,823,471	$179,232,312	$5,726,761	$184,959,073
2	LIAP in Base Rates			$0		$0	$0	$0	$0	$0
3	Energy Efficiency-Weatherization Program in Base Rates			$0		$0	$0	$0	$0	$0
4	Advanced Gas Technologies in Base Rates			$0		$0	$0	$0	$0	$0
5	Environmental Cost Recovery in Base Rates	$1,402,848	($92,848)	$1,310,000	$0	$1,310,000	$0	$1,310,000	$0	$1,310,000
6	Gas Lights	$22,148	$0	$22,148	$0	$22,148	$0	$22,148	$0	$22,148
7	Sub-Total Delivery Rates	$170,486,450	$2,298,574	$172,785,024	$1,955,965	$174,740,989	$5,823,471	$180,564,460	$5,726,761	$186,291,221
8										
9	Gas Cost Recovery Revenues	$123,331,582	($123,331,582)	$0	$0	$0	$0	$0	$0	$0
10	DAC Revenues	$31,264,074	($31,264,074)	$0	$0	$0	$0	$0	$0	$0
11	Energy Efficiency Revenues	$27,861,870	($27,861,870)	$0	$0	$0	$0	$0	$0	$0
12	Sub-Total Firm Tariff Revenues	$352,943,977	($180,158,953)	$172,785,024	$1,955,965	$174,740,989	$5,823,471	$180,564,460	$5,726,761	$186,291,221
13				$0		$0	$0	$0	$0	$0
14	Special Contract- Dominion Power	$224,996		$224,996	$0	$224,996	$0	$224,996	$0	$224,996
15				$0	$0	$0	$0	$0	$0	$0
16	Non Firm Revenues	$2,466,036	($1,030,032)	$1,436,004	$0	$1,436,004	$0	$1,436,004	$0	$1,436,004
17										
18	Total Billed Revenues	$355,635,009	($181,188,985)	$174,446,024	$1,955,965	$176,401,989	$5,823,471	$182,225,460	$5,726,761	$187,952,221
19							$0	$0	$0	$0
20	**Other Operating Revenues:**						$0	$0	$0	$0
21							$0	$0	$0	$0
22	Miscellaneous Fees/Credits						$0	$0	$0	$0
23	Paperless Bill Credits			$0		$0				
24	Account Restoration Fee		$81,848	$81,848	$232,454	$314,302	$0	$314,302	$0	$314,302
25	Customer Arrearage Fee (Late Payment Fees)	($1,428)	$411,080	$409,652		$409,652	$0	$409,652	$0	$409,652
26	Return Check Fee		$63,735	$63,735	($33,984)	$29,751	$0	$29,751	$0	$29,751
27	AMR Opt Out Fee	$286	$0	$286	$0	$286	$0	$286	$0	$286
28	Sub-total Fees/Credits	($1,143)	$556,663	$555,520	$198,470	$753,990	$0	$753,990	$0	$753,990
29										
30	Rental Expense	$248,262		$248,262		$248,262	$0	$248,262	$0	$248,262
31	AFUDC- Equity/Debt	$0	($23,725)	($23,725)		($23,725)	$0	($23,725)	$0	($23,725)
32	Miscellaneous Revenue Adjustments	($51,583)		($51,583)		($51,583)	$0	($51,583)	$0	($51,583)
33	Non Utility Billing		$937,241	$937,241		$937,241	$0	$937,241	$0	$937,241
34										
35	Revenue Decoupling Adj	$1,332,052		$1,332,052	($3,916,702)	($2,584,650)	$0	($2,584,650)	$0	($2,584,650)
36	ISR FY16 Recon FY 17	$24,428,803	($24,428,803)	$0	$37,129,852	$37,129,852	$0	$37,129,852	$0	$37,129,852
37	On System Margin Adj	($63,674)	$63,674							
38	Settlement Agreement DK 4323 Article III. B.4.	($322,761)	$322,761	$0		$0	$0	$0	$0	$0
39	Gross Receipts Tax Revenues	$10,722,138	($10,722,138)	$0		$0	$0	$0	$0	$0
40				$0		$0	$0	$0	$0	$0
41	Off System Sales	$10,540,373	($10,540,373)							
42	Unbilled Revenues & Cost	($7,340,302)	$7,340,302	$0		$0	$0	$0	$0	$0
43	EE Shareholder Incentive	$1,541,775	($1,541,775)	$0		$0	$0	$0	$0	$0
44	NGPMP Shareholder Incentive	$904,843	($904,843)							
45				$0		$0	$0	$0	$0	$0
46	Offsetting Manual Journal Entries			$0		$0	$0	$0	$0	$0
47	LIAP in Base Rates	($1,664,685)	$1,664,685	$0		$0	$0	$0	$0	$0
48	Energy Efficiency-Weatherization Program in Base Rates	($200,000)	$200,000	$0		$0	$0	$0	$0	$0
49	Advanced Gas Technologies in Base Rates	($313,393)	$313,393							
50	Environmental Cost Recovery in Base Rates	($1,368,476)	$1,368,476	$0		$0	$0	$0	$0	$0
51	GCR Deferral	$8,305,653	($8,305,653)							
52	DAC Deferral	($23,700,728)	$23,700,728	$0		$0	$0	$0	$0	$0
53	EE Deferral	($555,371)	$555,371							
54	Other Accounting Adj.	($918,567)	$918,567	$0		$0	$0	$0	$0	$0
55				$0	$0	$0	$0	$0	$0	$0
56	Total Other Operating Revenues	$21,523,216	($18,525,450)	$2,997,766	$33,411,620	$36,409,386	$0	$36,409,386	$0	$36,409,386
57										
58	Total Operating Revenues	$377,158,225	($199,714,435)	$177,443,790	$35,367,585	$212,811,375	$5,823,471	$218,634,846	$5,726,761	$224,361,607
59										
60	Gas Cost Expense									
61										
62	Total	$135,754,254	($135,754,254)	$0	$0	$0	$0	$0	$0	$0
63										
64	Net Margin	$241,403,971	($63,960,182)	$177,443,790	$35,367,585	$212,811,375	$5,823,471	$218,634,846	$5,726,761	$224,361,607

Column Notes

(a)	Per Company Books
1(b)	Schedule PP-1-GAS Pg. 2 Ln.24 Col (e)
1(d)	Schedule PP-1-GAS Pg. 2 Ln.24 Col (g)
5(b)	Normalization Adjustment to establish Environmental base rate recovery at $1,310,000
16(b)	Gas Costs for Non Firm Sales Customers
24(b)	Account Restoration Fee Reallocated from FERC Acct. 908.
24(d)	Schedule PP-3(a) Pg 1 Ln 12
25(b)	Customer Arrearage Fees Reallocated from FERC Acct. 419
26(b)	Return Check Fess Reallocated from Narragansett Electric
26(d)	Schedule PP-3(c) Pg 1 Ln 28
31(b)	AFUDC Reallocated from FERC Acct. 419
33(b)	Non Utiliy Billing Reallocated from Narragansett Electric
35(d)	Schedule PP-1 (c)-GAS Pg. 1 Ln 7
36(d)	Workpaper 12-GAS (REV-2)

Line Notes

7	Sum of Line 1 through Line 6
12	Sum of Line 7 through Line 11
18	Sum of Line 12 through Line 16
28	Sum of Line 23 through Line 27
56	Sum of Line 28 through Line 54
58	Line 18 + Line 56
64	Line 58 + Line 62

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/ 4780
Witness: Little

Compliance Attachment 2

Schedule 3

Operation & Maintenance Expense Summary

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Summary (ELECTRIC & GAS)

		Schedule Reference	Test Year Ended June 30, 2017(Per Books)			Normalizing Adjustments			Test Year Ended June 30, 2017(as Adjusted)		
			Total	Electric	Gas	Total	Electric	Gas	Total	Electric	Gas
			(a) = (b) + (c)	(b)	(c)	(d) = (e) + (f)	(e)	(f)	(g) = (h) + (i)	(h) = (b) + (e)	(i) = (c) + (f)
	Operation & Maintenance Expenses:										
1	Labor	Schedule 12	$90,778,557	$54,756,249	$36,022,308	($16,463,419)	($10,639,332)	($5,824,087)	$74,315,139	$44,116,917	$30,198,221
2	Health Care	Schedule 13	$12,341,700	$7,901,703	$4,439,997	($1,217,312)	($1,214,503)	($2,810)	$11,124,388	$6,687,200	$4,437,188
3	Group Life Insurance	Schedule 14	$930,683	$579,702	$350,981	($92,905)	($92,745)	($160)	$837,778	$486,957	$350,821
4	Thrift Plan	Schedule 15	$3,865,292	$2,489,542	$1,375,749	($407,946)	($406,993)	($954)	$3,457,345	$2,082,550	$1,374,796
5	FAS 112 / ASC 712	Schedule 16	($572,522)	($333,759)	($238,762)	$572,522	$333,759	$238,762	($0)	($0)	($0)
6	Service Company Rents	Schedule 17	$17,062,952	$13,985,369	$3,077,583	($6,995,280)	($6,644,381)	($350,899)	$10,067,672	$7,340,988	$2,726,684
7	Joint Facilities	Schedule 18	$1,579,848	$1,018,396	$561,452	$100,328	$106,159	($5,831)	$1,680,176	$1,124,555	$555,621
8	Uninsured Claims	Schedule 19	$1,648,059	$801,565	$846,495	($124,043)	($123,909)	($134)	$1,524,017	$677,655	$846,361
9	Insurance Premium	Schedule 20	$2,926,210	$2,097,226	$828,984	($286,481)	($286,481)	$0	$2,639,729	$1,810,745	$828,984
10	Regulatory Assessment Fees	Schedule 21	$6,862,284	$4,964,621	$1,897,662	($678,167)	($678,167)	$0	$6,184,116	$4,286,454	$1,897,662
11	Uncollectible Accounts	Schedule 22	$12,978,156	$8,952,665	$4,025,491	($3,294,644)	($4,987,981)	$1,693,337	$9,683,512	$3,964,684	$5,718,828
12	Postage	Schedule 23	$3,780,429	$2,460,952	$1,319,478	($24,107)	($16,697)	($7,410)	$3,756,323	$2,444,255	$1,312,068
13	Strike Contingency	Schedule 24	$8,194	$8,194	$0	$0	$0	$0	$8,194	$8,194	$0
14	Environmental Response Fund	Schedule 25	$3,078,000	$3,078,000	$0	$0	$0	$0	$3,078,000	$3,078,000	$0
15	Paperless Bill Credit	Schedule 26	$0	$0	$0	$816,516	$551,281	$265,235	$816,516	$551,281	$265,235
16	PBOP	Schedule 27	$7,914,078	$5,421,584	$2,492,494	($740,588)	($740,588)	$0	$7,173,490	$4,680,995	$2,492,494
17	Pension	Schedule 28	$22,239,834	$14,856,485	$7,383,350	($2,190,304)	($2,190,304)	$0	$20,049,530	$12,666,181	$7,383,350
18	Energy Efficiency Program	Schedule 29	$97,169,672	$73,467,743	$23,701,929	($97,169,672)	($73,467,743)	($23,701,929)	$0	$0	$0
19	Other Operating and Maintenance Expenses	Schedule 30	$86,785,496	$59,391,324	$27,394,172	($23,893,332)	($22,373,643)	($1,519,689)	$62,892,164	$37,017,681	$25,874,483
20	Storm Cost Recovery	Schedule 31	$7,338,972	$7,338,972	$0	($27,840)	($27,840)	$0	$7,311,132	$7,311,132	$0
21	Gas Commodity OM	Schedule 32	$0	$0	$0	$1,132,067	$0	$1,132,067	$1,132,067	$0	$1,132,067
22	NEP IFA Credit	Schedule 33	($138,452,360)	($138,452,360)	$0	$138,452,360	$138,452,360	$0	$0	$0	$0
23	Wheeling	Schedule 34	$179,791,010	$179,791,010	$0	($179,791,010)	($179,791,010)	$0	$0	$0	$0
24	Energy Innovation Hub	Schedule 35	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	Gas Business Enablement	Schedule 36	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Electric Operations	Schedule 37	$0	$0	$0	$0	$0	$0	$0	$0	$0
27	Gas Operations	Schedule 38	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	Customer Affordability Program	Schedule 39	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	Sub Total		$420,054,545	$304,575,180	$115,479,365	($192,323,257)	($164,238,756)	($28,084,501)	$227,731,287	$140,336,424	$87,394,863
30											
31	Purchased Power/ Purchased Gas	Schedule 40	$440,524,701	$304,255,398	$136,269,302	($440,524,701)	($304,255,398)	($136,269,302)	$0	$0	$0
32											
33	Sub Total		$440,524,701	$304,255,398	$136,269,302	($440,524,701)	($304,255,398)	($136,269,302)	$0	$0	$0
34											
35	TOTAL		$860,579,245	$608,830,578	$251,748,667	($632,847,958)	($468,494,154)	($164,353,804)	$227,731,287	$140,336,424	$87,394,863
			($0)	($0)	$0	$0	($0)	$0	$0	$0	$0

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Summary (ELECTRIC & GAS)

		Schedule Reference	Test Year Ended June 30, 2017(as Adjusted)			Proforma Adjustments			Rate Year Ending August 31, 2019		
			Total	Electric	Gas	Total	Electric	Gas	Total	Electric	Gas
			(a) = (b) + (c)	(b)	(c)	(d) = (e) + (f)	(e)	(f)	(g) = (h) + (i)	(h) = (b) + (e)	(i) = (c) + (f)
	Operation & Maintenance Expenses:										
1	Labor	Schedule 12	$74,315,139	$44,116,917	$30,198,221	$9,824,987	$6,692,369	$3,132,619	$84,140,126	$50,809,286	$33,330,840
2	Health Care	Schedule 13	$11,124,388	$6,687,200	$4,437,188	($392,792)	($295,776)	($97,016)	$10,731,596	$6,391,424	$4,340,172
3	Group Life Insurance	Schedule 14	$837,778	$486,957	$350,821	$148,107	$73,691	$74,416	$985,884	$560,647	$425,237
4	Thrift Plan	Schedule 15	$3,457,345	$2,082,550	$1,374,796	$458,489	$315,923	$142,566	$3,915,834	$2,398,472	$1,517,362
5	FAS 112 / ASC 712	Schedule 16	($0)	($0)	($0)	$0	$0	$0	($0)	($0)	($0)
6	Service Company Rents	Schedule 17	$10,067,672	$7,340,988	$2,726,684	$7,585,117	$5,776,023	$1,809,094	$17,652,789	$13,117,011	$4,535,777
7	Joint Facilities	Schedule 18	$1,680,176	$1,124,555	$555,621	$77,792	$52,067	$25,725	$1,757,968	$1,176,621	$581,346
8	Uninsured Claims	Schedule 19	$1,524,017	$677,655	$846,361	$955,618	$1,162,517	($206,899)	$2,479,635	$1,840,172	$639,463
9	Insurance Premium	Schedule 20	$2,639,729	$1,810,745	$828,984	$373,090	$280,149	$92,940	$3,012,818	$2,090,894	$921,924
10	Regulatory Assessment Fees	Schedule 21	$6,184,116	$4,286,454	$1,897,662	$0	$0	$0	$6,184,116	$4,286,454	$1,897,662
11	Uncollectible Accounts	Schedule 22	$9,683,512	$3,964,684	$5,718,828	($2,164,572)	$157,586	($2,322,158)	$7,518,940	$4,122,270	$3,396,670
12	Postage	Schedule 23	$3,756,323	$2,444,255	$1,312,068	$173,918	$113,169	$60,749	$3,930,240	$2,557,424	$1,372,817
13	Strike Contingency	Schedule 24	$8,194	$8,194	$0	$379	$379	$0	$8,573	$8,573	$0
14	Environmental Response Fund	Schedule 25	$3,078,000	$3,078,000	$0	$0	$0	$0	$3,078,000	$3,078,000	$0
15	Paperless Bill Credit	Schedule 26	$816,516	$551,281	$265,235	$0	$0	$0	$816,516	$551,281	$265,235
16	PBOP	Schedule 27	$7,173,490	$4,680,995	$2,492,494	($3,582,582)	$134,937	($3,717,518)	$3,590,908	$4,815,932	($1,225,024)
17	Pension	Schedule 28	$20,049,530	$12,666,181	$7,383,350	($10,775,306)	($6,665,307)	($4,110,000)	$9,274,224	$6,000,874	$3,273,350
18	Energy Efficiency Program	Schedule 29	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	Other Operating and Maintenance Expenses	Schedule 30	$62,892,164	$37,017,681	$25,874,483	$1,589,701	$863,146	$726,555	$64,481,865	$37,880,827	$26,601,038
20	Storm Cost Recovery	Schedule 31	$7,311,132	$7,311,132	$0	($287,406)	($287,406)	$0	$7,023,726	$7,023,726	$0
21	Gas Commodity OM	Schedule 32	$1,132,067	$0	$1,132,067	($1,132,067)	$0	($1,132,067)	$0	$0	$0
22	NEP IFA Credit	Schedule 33	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Wheeling	Schedule 34	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Energy Innovation Hub	Schedule 35	$0	$0	$0	$287,379	$186,193	$101,186	$287,379	$186,193	$101,186
25	Gas Business Enablement	Schedule 36	$0	$0	$0	$3,329,316	$482,041	$2,847,275	$3,329,316	$482,041	$2,847,275
26	Electric Operations	Schedule 37	$0	$0	$0	$611,550	$611,550	$0	$611,550	$611,550	$0
27	Gas Operations	Schedule 38	$0	$0	$0	$1,032,482	$0	$1,032,482	$1,032,482	$0	$1,032,482
28	Customer Affordability Program	Schedule 39	$0	$0	$0	$906,337	$613,623	$292,714	$906,337	$613,623	$292,714
29	Sub Total		$227,731,287	$140,336,424	$87,394,863	$9,019,537	$10,266,874	($1,247,337)	$236,750,824	$150,603,298	$86,147,527
30											
31	Purchased Power/ Purchased Gas	Schedule 40	$0	$0	$0	$0	$0	$0	$0	$0	$0
32											
33	Sub Total		$0	$0	$0	$0	$0	$0	$0	$0	$0
34											
35	TOTAL		$227,731,287	$140,336,424	$87,394,863	$9,019,537	$10,266,874	($1,247,337)	$236,750,824	$150,603,298	$86,147,527
	Column Notes		$0	$0	$0	($0)	($0)	$0	$0	$0	$0
	(b Column (h)										
	(c Column (i)										

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Summary (ELECTRIC & GAS)

		Schedule Reference	Rate Year Ending August 31, 2019 Electric (a)	Adjustments to Reflect Conditions in Rate Year Electric (b)	Rate Year Ending August 31, 2020 Electric (c) = (a) + (b)	Adjustments to Reflect Conditions in Rate Year Electric (d)	Rate Year Ending August 31, 2021 Electric (e) = (c) + (d)
	Operation & Maintenance Expenses:						
1	Labor	Schedule 12	$50,809,286	$1,824,395	$52,633,681	$1,593,433	$54,227,114
2	Health Care	Schedule 13	$6,391,424	$229,452	$6,620,876	$200,613	$6,821,489
3	Group Life Insurance	Schedule 14	$560,647	$35,040	$595,688	$32,525	$628,212
4	Thrift Plan	Schedule 15	$2,398,472	$86,105	$2,484,577	$75,283	$2,559,860
5	FAS 112 / ASC 712	Schedule 16	($0)	$0	($0)	$0	($0)
6	Service Company Rents	Schedule 17	$13,117,011	$380,409	$13,497,420	$390,531	$13,887,951
7	Joint Facilities	Schedule 18	$1,176,621	$31,298	$1,207,920	$29,353	$1,237,272
8	Uninsured Claims	Schedule 19	$1,840,172	$48,949	$1,889,121	$45,906	$1,935,026
9	Insurance Premium	Schedule 20	$2,090,894	$55,618	$2,146,512	$52,160	$2,198,672
10	Regulatory Assessment Fees	Schedule 21	$4,286,454	$0	$4,286,454	$0	$4,286,454
11	Uncollectible Accounts	Schedule 22	$4,122,270	$156,855	$4,279,125	$50,426	$4,329,551
12	Postage	Schedule 23	$2,557,424	$68,027	$2,625,451	$63,798	$2,689,250
13	Strike Contingency	Schedule 24	$8,573	$228	$8,801	$214	$9,015
14	Environmental Response Fund	Schedule 25	$3,078,000	$0	$3,078,000	$0	$3,078,000
15	Paperless Bill Credit	Schedule 26	$551,281	$0	$551,281	$0	$551,281
16	PBOP	Schedule 27	$4,815,932	$0	$4,815,932	$0	$4,815,932
17	Pension	Schedule 28	$6,000,874	($1,158,292)	$4,842,582	($1,086,286)	$3,756,296
18	Energy Efficiency Program	Schedule 29	$0	$0	$0	$0	$0
19	Other Operating and Maintenance Expenses	Schedule 30	$37,880,827	$1,000,191	$38,881,018	$938,013	$39,819,031
20	Storm Cost Recovery	Schedule 31	$7,023,726	$0	$7,023,726	$0	$7,023,726
21	Gas Commodity OM	Schedule 32	$0	$0	$0	$0	$0
22	NEP IFA Credit	Schedule 33	$0	$0	$0	$0	$0
23	Wheeling	Schedule 34	$0	$0	$0	$0	$0
24	Energy Innovation Hub	Schedule 35	$186,193	($32,395)	$153,798	$0	$153,798
25	Gas Business Enablement	Schedule 36	$482,041	$29,312	$511,352	($16,493)	$494,859
26	Electric Operations	Schedule 37	$611,550	($39,550)	$572,000	$46,083	$618,083
27	Gas Operations	Schedule 38	$0	$0	$0	$0	$0
28	Customer Affordability Program	Schedule 39	$613,623	($70,367)	$543,256	($255,128)	$288,128
29	Sub Total		$150,603,298	$2,645,275	$153,248,572	$2,160,429	$155,409,002
30							
31	Purchased Power/ Purchased Gas	Schedule 40	$0	$0	$0	$0	$0
32							
33	Sub Total		$0	$0	$0	$0	$0
34							
35	TOTAL		$150,603,298	$2,645,275	$153,248,572	$2,160,429	$155,409,002
	Column Notes		$0	$0	$0	($0)	$0
	(a) Column (h)						

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Summary (ELECTRIC & GAS)

		Schedule Reference	Rate Year Ending August 31, 2019 Gas (a)	Adjustments to Reflect Conditions in Rate Year Gas (b)	Rate Year Ending August 31, 2020 Gas (c) = (a) + (b)	Adjustments to Reflect Conditions in Rate Year Gas (d)	Rate Year Ending August 31, 2021 Gas (e) = (c) + (d)
	Operation & Maintenance Expenses:						
1	Labor	Schedule 12	$33,330,840	$1,411,867	$34,742,707	$1,089,746	$35,832,453
2	Health Care	Schedule 13	$4,340,172	$184,023	$4,524,195	$142,060	$4,666,255
3	Group Life Insurance	Schedule 14	$425,237	$29,341	$454,578	$25,320	$479,898
4	Thrift Plan	Schedule 15	$1,517,362	$64,336	$1,581,698	$49,665	$1,631,363
5	FAS 112 / ASC 712	Schedule 16	($0)	$0	($0)	$0	($0)
6	Service Company Rents	Schedule 17	$4,535,777	$219,840	$4,755,618	($260)	$4,755,358
7	Joint Facilities	Schedule 18	$581,346	$15,464	$596,810	$14,502	$611,313
8	Uninsured Claims	Schedule 19	$639,463	$17,010	$656,472	$15,952	$672,425
9	Insurance Premium	Schedule 20	$921,924	$24,441	$946,365	$22,328	$968,693
10	Regulatory Assessment Fees	Schedule 21	$1,897,662	$0	$1,897,662	$0	$1,897,662
11	Uncollectible Accounts	Schedule 22	$3,396,670	$111,079	$3,507,749	$109,234	$3,616,983
12	Postage	Schedule 23	$1,372,817	$36,517	$1,409,334	$34,247	$1,443,580
13	Strike Contingency	Schedule 24	$0	$0	$0	$0	$0
14	Environmental Response Fund	Schedule 25	$0	$0	$0	$0	$0
15	Paperless Bill Credit	Schedule 26	$265,235	$0	$265,235	$0	$265,235
16	PBOP	Schedule 27	($1,225,024)	$0	($1,225,024)	$0	($1,225,024)
17	Pension	Schedule 28	$3,273,350	($782,995)	$2,490,355	($732,618)	$1,757,736
18	Energy Efficiency Program	Schedule 29	$0	$0	$0	$0	$0
19	Other Operating and Maintenance Expenses	Schedule 30	$26,601,038	$704,127	$27,305,166	$659,247	$27,964,413
20	Storm Cost Recovery	Schedule 31	$0	$0	$0	$0	$0
21	Gas Commodity OM	Schedule 32	$0	$0	$0	$0	$0
22	NEP IFA Credit	Schedule 33	$0	$0	$0	$0	$0
23	Wheeling	Schedule 34	$0	$0	$0	$0	$0
24	Energy Innovation Hub	Schedule 35	$101,186	($17,605)	$83,581	$0	$83,581
25	Gas Business Enablement	Schedule 36	$2,847,275	$664,720	$3,511,995	$153,248	$3,665,243
26	Electric Operations	Schedule 37	$0	$0	$0	$0	$0
27	Gas Operations	Schedule 38	$1,032,482	($76,782)	$955,700	$0	$955,700
28	Customer Affordability Program	Schedule 39	$292,714	$2,518	$295,232	($138,649)	$156,583
29	Sub Total		$86,147,527	$2,607,902	$88,755,428	$1,444,023	$90,199,451
30							
31	Purchased Power/ Purchased Gas	Schedule 40	$0	$0	$0	$0	$0
32							
33	Sub Total		$0	$0	$0	$0	$0
34							
35	TOTAL		$86,147,527	$2,607,902	$88,755,428	$1,444,023	$90,199,451
	Column Notes		$0	$0	$0	$0	$0
	(a) Column (i)						

The Narragansett Electric Company d/b/a National Grid
Adjustments to Operating Expenses
Normalizing Adjustments to Other O & M Expenses (ELECTRIC & GAS)

		Test Year Ended June 30, 2017 (Per Books)	IFA	Vegetation Management (ISR)	Inspection & Maintenance (ISR)	Parent Company Initiative	Gas Business Enablement (GBE)	Storms	Gas Cost Recovery (GCR)	Other	Total Normalizing Adjustments	Test Year Ended June 30, 2017 (as Adjusted)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j) sum (b through i)	(k) = (a)+(j)
1	Test Year Amounts that are Specifically Adjusted:											
2												
3												
4												
5	Operating & Maintenance Expense											
6	Labor	$90,778,557	($8,107,062)	($277,467)	($391,633)	$0	$0	($1,012,529)	($829,823)	($5,844,904)	($16,463,419)	$74,315,139
7	Health Care	$12,341,700	($1,079,373)	$0	($53,188)	$0	$0	($53,705)	$0	($31,047)	($1,217,312)	$11,124,388
8	Group Life Insurance	$930,683	($79,187)	$0	($5,379)	($4,236)	$0	($1,384)	$0	($2,719)	($92,905)	$837,778
9	Thrift Plan	$3,865,292	($340,078)	$0	($14,936)	$0	$0	($14,021)	$0	($38,912)	($407,946)	$3,457,345
10	FAS 112 / ASC 712	($572,522)	$45,592	$0	$2,857	$0	$0	$10,407	$0	$513,666	$572,522	$0
11	Service Company Rents	$17,062,952	($2,543,016)	$0	$0	$0	$0	$0	$0	($4,452,264)	($6,995,280)	$10,067,672
12	Joint Facilities	$1,579,848	$0	$0	$0	$0	$0	$0	$0	$100,328	$100,328	$1,680,176
13	Uninsured Claims	$1,648,059	($109,494)	$0	($5,235)	($4,180)	$0	($2,690)	$0	($2,444)	($124,043)	$1,524,017
14	Insurance Premium	$2,926,210	($286,481)	$0	$0	$0	$0	$0	$0	$0	($286,481)	$2,639,729
15	Regulatory Assessment Fees	$6,862,284	($678,167)	$0	$0	$0	$0	$0	$0	$0	($678,167)	$6,184,116
16	Uncollectible Accounts	$12,978,156	$0	$0	$0	$0	$0	$0	$0	($3,294,644)	($3,294,644)	$9,683,512
17	Postage	$3,780,429	($2,997)	$0	$0	($7)	$0	$0	$0	($21,103)	($24,107)	$3,756,323
18	Strike Contingency	$8,194	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,194
19	Environmental Response Fund	$3,078,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,078,000
20	Paperless Bill Credit	$0	$0	$0	$0	$0	$0	$0	$0	$816,516	$816,516	$816,516
21	PBOP	$7,914,078	($740,588)	$0	$0	$0	$0	$0	$0	$0	($740,588)	$7,173,490
22	Pension	$22,239,834	($2,029,396)	$0	$0	$0	$0	$0	$0	($160,908)	($2,190,304)	$20,049,530
23	Energy Efficiency Program	$97,169,672	$0	$0	$0	$0	$0	$0	$0	($97,169,672)	($97,169,672)	$0
24	Other Operating and Maintenance Expenses	$86,785,496	($8,913,604)	($8,736,983)	($110,171)	($1,231,649)	($1,511,923)	$525,543	($258,832)	($3,655,714)	($23,893,332)	$62,892,164
25	Storm Cost Recovery	$7,338,972	$0	$0	$0	$0	$0	$0	$0	($27,840)	($27,840)	$7,311,132
26	Gas Commodity OM	$0	$0	$0	$0	$0	$0	$0	($43,411)	$1,175,478	$1,132,067	$1,132,067
27	NEP IFA Credit	($138,452,360)	$138,452,360	$0	$0	$0	$0	$0	$0	$0	$138,452,360	$0
28	Wheeling	$179,791,010	$0	$0	$0	$0	$0	$0	$0	($179,791,010)	($179,791,010)	$0
29	Energy Innovation Hub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	Gas Business Enablement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	Electric Operations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	Gas Operations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
33	Customer Affordability Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
34	Sub Total Operating & Maintenance Expense	$420,054,545	$113,588,510	($9,014,450)	($577,685)	($1,240,072)	($1,511,923)	($548,378)	($1,132,067)	($291,887,193)	($192,323,257)	$227,731,287
35												
36	Purchased Power/ Purchased Gas	$440,524,701	$0	$0	$0	$0	$0	$0	$0	($440,524,701)	($440,524,701)	$0
37												
38	Sub Total	$440,524,701	$0	$0	$0		$0	$0	$0	($440,524,701)	($440,524,701)	$0
39												
40	TOTAL	$860,579,245	$113,588,510	($9,014,450)	($577,685)		($1,511,923)	($548,378)	($1,132,067)	($732,411,894)	($632,847,958)	$227,731,287
	Check Totals	$860,579,245	$113,588,510	($9,014,450)	($577,685)	($1,240,071)	($1,511,923)	($548,380)	($1,132,067)	($732,411,893)	($632,847,958)	$227,731,287
	Difference	$0	$0	$0	$0	$0	$0	$1	$0	($1)	$0	$0

Column Notes
(a) Page 1, Column (a)

Line Notes
6(b) Schedule 12 Page 5, Lines 2(a) to 4(a)
6(c) Schedule 12 Page 5, Line 5(a)
6(d) Schedule 12 Page 5, Line 6(a) to 8(a)
6(g) Schedule 12 Page 5, Line 21(a) to 23(a)
6(h) Schedule 12 Page 5, Line 28(a) to 30(a)
6(i) Schedule 12 Page 5, Line 9(a) to 20(a) + Line 24(a) + Lines 25(a) to 27(a)
7(b) Schedule 13, Page 5 Lines 2(a) through 4(a)
7(d) Schedule 13, Page 5 Lines 6(a) through 8(a)
7(g) Schedule 13, Page 5 Lines 10(a) through 12(a)
8(b) Schedule 14, Page 5 Lines 2(a) through 4(a)
8(d) Schedule 14, Page 5 Lines 6(a) through 8(a)
8(e) Schedule 14, Page 5 Lines 10(a)
8(g) Schedule 14, Page 5 Lines 12(a) through 14(a)
9(b) Schedule 15, Page 5 Lines 2(a) through 4(a)
9(d) Schedule 15, Page 5 Lines 6(a) through 8(a)
9(g) Schedule 15, Page 5 Lines 12(a) through 14(a)
9(i) Schedule 15, Page 5 Lines 10(a)
10(b) Schedule 16, Page 5 Lines 2(a) through 4(a)
10(d) Schedule 16, Page 5 Lines 6(a) through 8(a)
10(g) Schedule 16, Page 5 Lines 10(a) through 12(a)
10(i) Schedule 16, Page 5 Lines 14(a) through 16(a)
11(b) Schedule 17, Page 5 Lines 7(a) through 8(a)
11(i) Schedule 17, Page 5 Lines 2(a) through 5(a)
13(b) Schedule 19, Page 5 Lines 2(a) through 4(a)
13(d) Schedule 19, Page 5 Lines 5(a) through 7(a)
13(e) Schedule 19, Page 5 Line 8(a)
13(g) Schedule 19, Page 5 Lines 9(a) through 11(a)
14(b) Schedule 20, Page 5 Lines 2(a) through 3(a)
15(b) Schedule 21, Page 5 Lines 2(a)
16(i) Schedule 22, Page 5 Lines 4(a)
17(b) Schedule 23, Page 5 Lines 2(a) through 4(a)
17(i) Schedule 23, Page 5 Lines 8(a) through 11(a)
20(i) Schedule 26, Page 5 Line 3(a)
21(b) Schedule 27, Page 5 Lines 2(a) through 4(a)
22(b) Schedule 28, Page 5 Lines 2(a) through 4(a)
22(i) Schedule 28, Page 5 Line 8(a)
23(i) Schedule 29, Page 5 Lines 2(a) through 3(a)
24(b) Schedule 30, Page 6 Lines 2(b) through 17(b)
24(c) Schedule 30, Page 6 Lines 2(d) through 17(d)
24(d) Schedule 30, Page 6 Lines 2(e) through 17(e)
24(e) Schedule 30, Page 6 Lines 2(f) through 17(f)
24(f) Schedule 30, Page 7 Lines 2(b) through 17(b)
24(g) Schedule 30, Page 6 Lines 2(g) through 17(g)
24(h) Schedule 30, Page 7 Lines 2(c) through 17(c)
24(i) Schedule 30, Page 6 Lines 2(c) through 17(c) + Page 6 Lines 2(h) through 17(h) + Page 7 Lines 2(d) through 17(d)
25(i) Schedule 31, Page 5 Lines 2(a)
26(h) - 26(i) Schedule 32 Page 5, Line 2(a) to Line 14(a)
27(b) Schedule 33 Page 5, Line 9(b)
28(i) Schedule 34 Page 5, Line 2(a) to Line 3(a)

The Narragansett Electric Company d/b/a National Grid
Adjustments to Electric Operating Expenses
Normalizing Adjustments to O & M Expenses (ELECTRIC)

		Test Year Ended June 30, 2017 (Per Books)	IFA	Vegetation Management (ISR)	Inspection & Maintenance (ISR)	Parent Company Initiative	Storms	Other	Total Normalizing Adjustments	Test Year Ended June 30, 2017 (as Adjusted)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) sum (b through g)	(i) = (a) + (i)
1	Test Year Amounts that are Specifically Adjusted:									
2										
3										
4										
5	Operating & Maintenance Expense									
6	Labor	$54,756,249	($8,107,062)	($277,467)	($391,633)	$0	($1,012,529)	($850,640.47)	($10,639,332)	$44,116,917
7	Health Care	$7,901,703	($1,079,373)	$0	($53,188)	$0	($53,705)	($28,237)	($1,214,503)	$6,687,200
8	Group Life Insurance	$579,702	($79,187)	$0	($5,379)	($4,236)	($1,384)	($2,559)	($92,745)	$486,957
9	Thrift Plan	$2,489,542	($340,078)	$0	($14,936)	$0	($14,021)	($37,958)	($406,993)	$2,082,550
10	FAS 112 / ASC 712	($333,759)	$45,592	$0	$2,857	$0	$10,407	$274,904	$333,759	$0
11	Service Company Rents	$13,985,369	($2,543,016)	$0	$0	$0	$0	($4,101,365)	($6,644,381)	$7,340,988
12	Joint Facilities	$1,018,396	$0	$0	$0	$0	$0	$106,159	$106,159	$1,124,555
13	Uninsured Claims	$801,565	($109,494)	$0	($5,235)	($4,180)	($2,690)	($2,311)	($123,909)	$677,655
14	Insurance Premium	$2,097,226	($286,481)	$0	$0	$0	$0	$0	($286,481)	$1,810,745
15	Regulatory Assessment Fees	$4,964,621	($678,167)	$0	$0	$0	$0	$0	($678,167)	$4,286,454
16	Uncollectible Accounts	$8,952,665	$0	$0	$0	$0	$0	($4,987,981)	($4,987,981)	$3,964,684
17	Postage	$2,460,952	($2,997)	$0	$0	($7)	$0	($13,693)	($16,697)	$2,444,255
18	Strike Contingency	$8,194	$0	$0	$0	$0	$0	$0	$0	$8,194
19	Environmental Response Fund	$3,078,000	$0	$0	$0	$0	$0	$0	$0	$3,078,000
20	Paperless Bill Credit	$0	$0	$0	$0	$0	$0	$551,281	$551,281	$551,281
21	PBOP	$5,421,584	($740,588)	$0	$0	$0	$0	$0	($740,588)	$4,680,995
22	Pension	$14,856,485	($2,029,396)	$0	$0	$0	$0	($160,908)	($2,190,304)	$12,666,181
23	Energy Efficiency Program	$73,467,743	$0	$0	$0	$0	$0	($73,467,743)	($73,467,743)	$0
24	Other Operating and Maintenance Expenses	$59,391,324	($8,913,604)	($8,736,983)	($110,171)	($1,231,649)	$525,543	($3,906,780)	($22,373,643)	$37,017,681
25	Storm Cost Recovery	$7,338,972	$0	$0	$0	$0	$0	($27,840)	($27,840)	$7,311,132
26	Gas Commodity OM	$0	$0	$0	$0	$0	$0	$0	$0	$0
27	NEP IFA Credit	($138,452,360)	$138,452,360	$0	$0	$0	$0	$0	$138,452,360	$0
28	Wheeling	$179,791,010	$0	$0	$0	$0	$0	($179,791,010)	($179,791,010)	$0
29	Energy Innovation Hub	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	Gas Business Enablement	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	Electric Operations	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	Gas Operations	$0	$0	$0	$0	$0	$0	$0	$0	$0
33	Customer Affordability Program	$0	$0	$0	$0	$0	$0	$0	$0	$0
34	Sub Total Operating & Maintenance Expense	$304,575,180	$113,588,510	($9,014,450)	($577,685)	($1,240,072)	($548,378)	($266,446,681)	($164,238,756)	$140,336,424
35										
36	Purchased Power/ Purchased Gas	$304,255,398	$0	$0	$0	$0	$0	($304,255,398)	($304,255,398)	$0
37										
38	Sub Total	$304,255,398	$0	$0	$0	$0	$0	($304,255,398)	($304,255,398)	$0
39										
40	TOTAL	$608,830,578	$113,588,510	($9,014,450)	($577,685)	($1,240,072)	($548,378)	($570,702,080)	($468,494,154)	$140,336,424
	Check Totals	$608,830,578	$113,588,510	($9,014,450)	($577,685)	($1,240,071)	($548,380)	($570,702,078)	($468,494,154)	$140,336,424
	Difference	$0	$0	$0	$0	$0	$1	($1)	$0	$0

Column Notes

Line Notes

6(b) Schedule 12 Page 5, Lines 2(b) to 4(b)
6(c) Schedule 12 Page 5, Line 5(b)
6(d) Schedule 12 Page 5, Line 6(b) to 8(b)
6(f) Schedule 12 Page 5, Line 21(b) to 23(b)
6(g) Schedule 12 Page 5, Line 9(b) to 20(b) + Line 24(b) + Lines 25(b) to 27(b)
7(b) Schedule 13, Page 5 Lines 2(b) through 4(b)
7(d) Schedule 13, Page 5 Lines 6(b) through 8(b)
7(f) Schedule 13, Page 5 Lines 10(b) through 12(b)
8(b) Schedule 14, Page 5 Lines 2(b) through 4(b)
8(d) Schedule 14, Page 5 Lines 6(b) through 8(b)
8(e) Schedule 14, Page 5 Lines 10(b)
8(f) Schedule 14, Page 5 Lines 12(b) through 14(b)
9(b) Schedule 15, Page 5 Lines 2(b) through 4(b)
9(d) Schedule 15, Page 5 Lines 6(b) through 8(b)
9(f) Schedule 15, Page 5 Lines 12(b) through 14(b)
9(g) Schedule 15, Page 5 Lines 10(b)
10(b) Schedule 16, Page 5 Lines 2(b) through 4(b)
10(d) Schedule 16, Page 5 Lines 6(b) through 8(b)
10(f) Schedule 16, Page 5 Lines 10(b) through 12(b)
10(g) Schedule 16, Page 5 Lines 14(b) through 16(b)
11(b) Schedule 17, Page 5 Lines 7(b) through 8(b)
11(g) Schedule 17, Page 5 Lines 2(b) through 5(b)
13(b) Schedule 19, Page 5 Lines 2(b) through 4(b)
13(d) Schedule 19, Page 5 Lines 5(b) through 7(b)
13(e) Schedule 19, Page 5 Line 8(b)
13(f) Schedule 19, Page 5 Lines 9(b) through 11(b)
14(b) Schedule 20, Page 5 Lines 2(b) through 3(b)
15(b) Schedule 21, Page 5 Lines 2(b)
16(g) Schedule 22, Page 5 Lines 4(b)
17(b) Schedule 23, Page 5 Lines 2(b) through 4(b)
17(g) Schedule 23, Page 5 Lines 8(b) through 11(b)
20(g) Schedule 26, Page 5 Line 3(b)
21(b) Schedule 27, Page 5 Lines 2(b) through 4(b)
22(b) Schedule 28, Page 5 Lines 2(b) through 4(b)
22(g) Schedule 28, Page 5 Line 8(b)
23(g) Schedule 29, Page 5 Lines 2(b) through 3(b)
24(b) Schedule 30, Page 6 Lines 2(b) through 17(b)
24(c) Schedule 30, Page 6 Lines 2(d) through 17(d)
24(d) Schedule 30, Page 6 Lines 2(e) through 17(e)
24(e) Schedule 30, Page 6 Lines 2(f) through 17(f)
24(f) Schedule 30, Page 6 Lines 2(g) through 17(g)
24(g) Schedule 30, Page 6, Lines 2(c) through 17(c) + Lines 2(h) through 17(h)
25(g) Schedule 31, Page 5 Lines 2(a)
27(b) Schedule 33 Page 5, Line 9(b)
28(g) Schedule 34 Page 5, Line 2(a) to Line 3(a)

The Narragansett Electric Company d/b/a National Grid
Adjustments to Gas Operating Expenses
Normalizing Adjustments to O & M Expenses (GAS)

		Test Year Ended June 30, 2017 (Per Books)	Gas Business Enablement (GBE)	Gas Cost Recovery (GCR)	Other	Total Normalizing Adjustments	Test Year Ended June 30, 2017 (as Adjusted)
		(c)	(b)	(c)	(d)	(e) = (b) + (c) + (d)	(f) = (c) + (e)
1	Test Year Amounts that are Specifically Adjusted:						
2							
3							
4							
5	Operating & Maintenance Expense						
6	Labor	$36,022,308	$0	($829,823)	($4,994,264)	($5,824,087)	$30,198,221
7	Health Care	$4,439,997	$0	$0	($2,810)	($2,810)	$4,437,188
8	Group Life Insurance	$350,981	$0	$0	($160)	($160)	$350,821
9	Thrift Plan	$1,375,749	$0	$0	($954)	($954)	$1,374,796
10	FAS 112 / ASC 712	($238,762)	$0	$0	$238,762	$238,762	$0
11	Service Company Rents	$3,077,583	$0	$0	($350,899)	($350,899)	$2,726,684
12	Joint Facilities	$561,452	$0	$0	($5,831)	($5,831)	$555,621
13	Uninsured Claims	$846,495	$0	$0	($134)	($134)	$846,361
14	Insurance Premium	$828,984	$0	$0	$0	$0	$828,984
15	Regulatory Assessment Fees	$1,897,662	$0	$0	$0	$0	$1,897,662
16	Uncollectible Accounts	$4,025,491	$0	$0	$1,693,337	$1,693,337	$5,718,828
17	Postage	$1,319,478	$0	$0	($7,410)	($7,410)	$1,312,068
18	Strike Contingency	$0	$0	$0	$0	$0	$0
19	Environmental Response Fund	$0	$0	$0	$0	$0	$0
20	Paperless Bill Credit	$0	$0	$0	$265,235	$265,235	$265,235
21	PBOP	$2,492,494	$0	$0	$0	$0	$2,492,494
22	Pension	$7,383,350	$0	$0	$0	$0	$7,383,350
23	Energy Efficiency Program	$23,701,929	$0	$0	($23,701,929)	($23,701,929)	$0
24	Other Operating and Maintenance Expenses	$27,394,172	($1,511,923)	($258,832)	$251,065	($1,519,689)	$25,874,483
25	Storm Cost Recovery	$0	$0	$0	$0	$0	$0
26	Gas Commodity OM	$0	$0	($43,411)	$1,175,478	$1,132,067	$1,132,067
27	NEP IFA Credit	$0	$0	$0	$0	$0	$0
28	Wheeling	$0	$0	$0	$0	$0	$0
29	Energy Innovation Hub	$0	$0	$0	$0	$0	$0
30	Gas Business Enablement	$0	$0	$0	$0	$0	$0
31	Electric Operations	$0	$0	$0	$0	$0	$0
32	Gas Operations	$0	$0	$0	$0	$0	$0
33	Customer Affordability Program	$0	$0	$0	$0	$0	$0
34	Sub Total Operating & Maintenance Expense	$115,479,365	($1,511,923)	($1,132,067)	($25,440,512)	($28,084,501)	$87,394,863
35							
36	Purchased Power/ Purchased Gas	$136,269,302	$0	$0	($136,269,302)	($136,269,302)	$0
37							
38	Sub Total	$136,269,302	$0	$0	($136,269,302)	($136,269,302)	$0
39							
40	TOTAL	$251,748,667	($1,511,923)	($1,132,067)	($161,709,815)	($164,353,804)	$87,394,863
	Check Totals	$251,748,667	($1,511,923)	($1,132,067)	($161,709,814)	($164,353,804)	$87,394,863
	Difference	$0	$0	$0	($0)	($0)	($0)

Line Notes

6(c)	Schedule 12 Page 5, Line 28(c) to 30(c)
6(d)	Schedule 12 Page 5, Line 6(c) to 8(c)
10(d)	Schedule 16, Page 5 Lines 14(c) through 16(c)
11(d)	Schedule 17, Page 5 Lines 2(c) through 5(c)
16(d)	Schedule 22, Page 5 Lines 4(c)
17(d)	Schedule 23, Page 5 Lines 8(c) through 11(c)
20(d)	Schedule 26, Page 5 Line 3(c)
23(d)	Schedule 29, Page 5 Lines 2(c) through 3(c)
24(b)	Schedule 30, Page 7 Lines 2(b) through 17(b)
24(c)	Schedule 30, Page 7 Lines 2(c) through 17(c)
24(d)	Schedule 30, Page 7 Lines 2(d) through 17(d)
26(c)	Schedule 32 Page 5, Line 2(a) to Line 14(a)
26(d)	Schedule 32 Page 5, Line 2(a) to Line 14(a)

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 3

The Narragansett Electric Company d/b/a National Grid
Calculation Of Inflation
Occurring Between The Test Year And The Rate Year

Calculation of Inflation Rate:	GDP-CTPI [1]	CPI-U [2]		Line
				1
Index - Midpoint of Test Year June 2017	112.4	242.7		2
				3
Index - Midpoint of Rate Year Aug 2019	117.5	254.2		4
				5
Increase in Index From Midpoint Of The Test Year				6
To The Midpoint of Rate Year				7
Inflation Factor %	**4.52%**	**4.73%**	**4.63%**	8
				9
Source: Moody's Analytics	2.26%	2.37%		10
				11
				12
	GDPIP	CPI		13
Index - Midpoint of Rate Year Aug 2019	117.5	254.2		14
				15
Index - Midpoint of Rate Year Aug 2020	120.4	261.3		16
				17
Increase in Index From Midpoint Of The Test Year				18
To The Midpoint of Rate Year				19
Inflation Factor %	**2.50%**	**2.82%**	**2.66%**	20
				21
Source: Moody's Analytics				22
				23
	GDPIP	CPI		24
Index - Midpoint of Rate Year Aug 2019	120.4	261.3		25
				26
Index - Midpoint of Rate YearAug 2020	123.2	268.0		27
				28
Increase in Index From Midpoint Of The Test Year				29
To The Midpoint of Rate Year				30
Inflation Factor %	**2.32%**	**2.54%**	**2.43%**	31

[1] Gross Domestic Product Chain-type Index

[2] LL URBAN Consumer Price Index

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/ 4780
Witness: Little

Compliance Attachment 2

Schedule 4-ELEC

Amortization of Regulatory Deferrals– Electric

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 4-ELEC
Page 1 of 2

The Narragansett Electric Company d/b/a National Grid
Amortization of Regulatory Deferrals - Electric
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2021

		Test Year Ended June 30, 2017	Normalizing Adjustments	Adjusted Balance June 30, 2017	Proforma Adjustments	Rate Year Ending August 31, 2019	Reflect Condition in Rate Year	Rate Year Ending August 31, 2020	Reflect Condition in Rate Year	Rate Year Ending August 31, 2021
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Rate Case Expenses	$8,454	($8,454)	$0	$471,908	$471,908	$0	$471,908	$0	$471,908
2										
3	Total	$8,454	($8,454)	$0	$471,908	$471,908	$0	$471,908	$0	$471,908

Line Notes
1 (d) Page 2, Line 7
1-3 Column (a) per Company Books
1-3 Column (c) = Column (a) + Column (b)
1-3 Column (e) = Column (c) + Column (d)
1-3 Column (g) = Column (e) + Column (f)
1-3 Column (i) = Column (g) + Column (h)

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 4-ELEC
Page 2 of 2

The Narragansett Electric Company d/b/a National Grid
Rate Case Expenses - Electric
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2021

		Amount
1	Rate Case Expense for Narragansett Electric Company - Electric Segment	$1,415,724
2		
3	Number of Years to be Normalized	3
4		
5	Annual Normalized Rate Case Expenses Recovery	$471,908

Line Notes
1 Based on response to RR-PUC-39 submitted on July 13, 2018

Consultant	Description of Service	Actual to Date	Estimated Remainder	Electric only	Allocated 67.64%	Total
		(a)	(b)	(c) = (a)+(b)	) = ((a)+(b*32.36	(e) = (c)+(d)
Gannett Fleming, Inc.	Depreciation Study	$46,495	$27,405		$49,986	$49,986
Howard S. Gorman - HSG Group, Inc.	Allocated Cost of Service Study - Electric	$68,000	$22,000	$90,000		$90,000
Scott Madden Inc.	ROE/Cost of Capital Structure	$108,649	$11,473		$81,251	$81,251
Keegan & Werlin	Legal	$232,908	$23,264		$173,275	$173,275
Hinckley Allen	Legal	$260,085	$300,000		$378,842	$378,842
Barclay Damon	Legal	$132,473	$4,000		$92,310	$92,310
Towers Watson	Compensation Study	$27,807	$0		$18,809	$18,809
WarRoom Document Solutions	Printing - Electric	$48,271	$21,000	$69,271		$69,271
A-1 Court Reports, Inc.	Other - Electric	$3,872	$2,200	$6,072		$6,072
Division of Public Utilities and Carriers	Rate Case Assessment	$450,908	$5,000	$455,908		$455,908
Total		$1,379,468	$416,342	$621,251	$794,473	$1,415,724

(a) Per Company's Cost Allocation Code G-316

SAP Alloc. Code	Company Description	3 Pt. Allocation %
G-316	Narragansett Electric Company	67.64%
G-316	Narragansett Gas Company	32.36%
	Total	100.00%

3 Rate case expected to be filed in 3 years

5 Line 1 divided by Line 3.

Compliance Attachment 2

Schedule 4-GAS

Amortization of Regulatory Deferrals – Gas

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 4-GAS
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The Narragansett Electric Company d/b/a National Grid
Amortization of Regulatory Deferrals - Gas
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2021

		Test Year Ended June 30, 2017	Normalizing Adjustments	Adjusted Balance June 30, 2017	Proforma Adjustments	Rate Year Ending August 31, 2019	Reflect Condition in Rate Year	Rate Year Ending August 31, 2020	Reflect Condition in Rate Year	Rate Year Ending August 31, 2021
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Advantage System Amortization	$705,953	($262)	$705,691	($705,691)	$0	$0	$0	$0	$0
2	Rate Case Expense Amortization	$0	$0	$0	$267,216	$267,216	$0	$267,216	$0	$267,216
3	Environmental Cost Amortization	$0	$1,310,000	$1,310,000	$0	$1,310,000	$0	$1,310,000	$0	$1,310,000
4	Total	$705,953	$1,309,738	$2,015,691	($438,475)	$1,577,216	$0	$1,577,216	$0	$1,577,216

Line Notes
1 (d) It is the amortization from "Advantage System Book Value 2012 ~ 2017", the balance at the beginning of the Rate Year 1 is zero, no amortization in rate year
2 (d) Page 2, Line 5
3 (d) As approved on RIPUC Docket No. 3401
1-4 Column (a) per Company Books
1-4 Column (c) = Column (a) + Column (b)
1-4 Column (e) = Column (c) + Column (d)
1-4 Column (g) = Column (e) + Column (f)
1-4 Column (i) = Column (g) + Column (h)

The Narragansett Electric Company d/b/a National Grid
Rate Case Expenses - Gas
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2021

		Amount
1	Rate Case Expense for Narragansett Electric Company - Gas Segment	$801,648
2		
3	Number of Years to be Normalized	3
4		
5	Annual Normalized Rate Case Expenses Recovery	$267,216

Line Notes
1 Based on response to RR-PUC-39 submitted on July 13, 2018

Consultant	Description of Service	Actual to Date	Estimated Remainder	Gas only	Allocated 32.36%	Total
		(a)	(b)	(c) = (a)+(b)	(d) = ((a)+(b*32.36%	(e) = (c)+(d)
Gannett Fleming, Inc.	Depreciation Study	$46,495	$27,405		$23,914	$23,914
Paul Normand - Management Applications Consulting, Inc.	Allocated Cost of Service Study - Gas	$43,706	$15,765	$59,471		$59,471
Scott Madden Inc.	ROE/Cost of Capital Structure	$108,649	$11,473		$38,871	$38,871
Keegan & Werlin	Legal	$232,908	$23,264		$82,897	$82,897
Hinckley Allen	Legal	$260,085	$300,000		$181,244	$181,244
Barclay Damon	Legal	$132,473	$4,000		$44,163	$44,163
Towers Watson	Compensation Study	$27,807	$0		$8,998	$8,998
WarRoom Document Solutions	Printing - Gas	$20,688	$9,000	$29,688		$29,688
A-1 Court Reports, Inc.	Other - Gas	$1,660	$1,000	$2,660		$2,660
Division of Public Utilities and Carriers	Rate Case Assessment	$324,742	$5,000	$329,742		$329,742
Total		$1,199,213	$396,907	$421,561	$380,087	$801,648

(a) Per Company's Cost Allocation Code G-316

SAP Alloc. Code	Company Description	3 Pt. Allocation %
G-316	Narragansett Electric Company	67.64%
G-316	Narragansett Gas Company	32.36%
	Total	100.00%

3 Rate case expected to be filed in 3 years

5 Line 1 divided by Line 3.

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/ 4780
Witness: Little

Compliance Attachment 2

Schedule 5-ELEC

Amortization of Intangibles– Electric

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 5-ELEC
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The Narragansett Electric Company d/b/a National Grid
Amortization of Intangibles - Electric
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2020

		Test Year Ended June 30, 2017 (a)	Normalizing Adjustments (b)	Adjusted Test Year June 30, 2017 (c)	Proforma Adjustments (d)	Rate Year Ending August 31, 2019 (e)	Reflect Condition in Rate Year (f)	Rate Year Ending August 31, 2020 (g)	Reflect Condition in Rate Year (h)	Rate Year Ending August 31, 2021 (i)
1	Amortization	$62,962	($62,962)	$0	$0	$0	$0	$0	$0	$0

Column Notes
(a) Per Company Books
(b) The intangible assets are recovered through the Renewable Energy Growth Program and excluded from the general rate case
(c) Column (a) plus Column (b)
(e) Column (c) plus Column (d)
(g) Column (e) plus Column (f)
(i) Column (g) plus Column (h)

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/ 4780
Witness: Little

Compliance Attachment 2

Schedule 5-GAS

Amortization of Intangibles – Gas

The Narragansett Electric Company d/b/a National Grid
Amortization of Intangibles - Gas
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2021

		Test Year Ended June 30, 2017 (a)	Normalizing Adjustments (b)	Adjusted Test Year June 30, 2017 (c)	Proforma Adjustments (d)	Rate Year 1 August 31, 2019 (e)	Reflect Condition in Rate Year (f)	Rate Year 2 August 31, 2020 (g)	Reflect Condition in Rate Year (h)	Rate Year Ending August 31, 2021 (i)
1	Amortization	$1,874,224	$106,546	$1,980,770	(1,554,586)	426,184	$0	426,184	$0	426,184

Column Notes

(a) Per Company Books

(b) The following software was written off at Mar 31, 2017 for accounting purpose, it is still in use and should be amortized for rate case purpose

	Cost	9,991,374
	Acc. Amortization	(7,523,135)

Refer to the schedule below, the software was amortized over 271 months before the being written off. The annual amortization is:

	Monthly Depreciation	A below	$35,515
	3 month Amortization for test year	A * 3	106,546
(e)	Annual Amortization	A * 12	426,184

Power plan report - 1604 for intangible assets as of March 2017

asset_id	description	init_life	remaining_life	gl_post_mo_yr	beg_asset_dollars	depr_reserve	Month_depr_expense
44763949	- Consultant AM/FM	271	97.45	1-Mar-17	$578,232	$372,436	$2,134
44763956	LA30397AM/FM - ITS I	271	48.95	1-Mar-17	$90,981	$76,942	$293
44763960	LAS30398AMFM - INTE	271	48.95	1-Mar-17	$285,234	$241,219	$918
44763961	MIS303980AFM - MISC	271	48.95	1-Mar-17	$110,722	$93,636	$356
44763966	SF303980AMFM - SOFT	271	48.95	1-Mar-17	$101,890	$86,167	$328
44763971	SF303990AMFM - AM/F	271	60.95	1-Mar-17	$2,698,329	$2,139,257	$9,326
44763993	TRL30397AMFM - TRA	271	48.95	1-Mar-17	$6,846	$5,789	$22
44763995	AF303980AMFM - AFU	271	48.95	1-Mar-17	$32,749	$27,695	$105
44763996	CN30396AM/FM - CON	271	48.95	1-Mar-17	$793,743	$671,259	$2,554
44763998	CN30397AM/FM - CON	271	48.95	1-Mar-17	$124,561	$105,340	$401
96815952	SF303000AMFM - AM/F	271	72.95	1-Mar-17	$3,096,677	$2,275,633	$11,411
96815957	SF303010AMFM - AM/F	271	84.95	1-Mar-17	$2,071,410	$1,427,760	$7,667
					$9,991,374	$7,523,135	$35,515
							A

(c) Column (a) + Column (b)

(d) Column (e) - Column (c)

(e) All other intangibles are fully amortized, only AM/FM Software needs to be amortized, refer to (b) for calcualtion

(g) Column (e) + Column (f)

(i) Column (g) + Column (h)

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/ 4780
Witness: Little

Compliance Attachment 2

Schedule 6-ELEC

Depreciation– Electric

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
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Schedule 6-ELEC
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The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Electric
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

Line No.	Description		Reference	Amount
			(a)	(b)
1	Total Company Rate Year Distribution Depreciation Expense		Sum of Page 2, Line 16 and Line 17	$50,128,332
2	Test Year Depreciation Expense		Per Company Books	$69,031,187
3	Less : Test Year IFA related Depreciation Expense		Page 4, Line 30, Column (c)	($19,814,202)
4	Less: ARO and other adjustments		Page 4, Line 30, Column (b) + Column (d)	($55,610)
5	Adjusted Total Company Test Year Distribution Depreciation Expense		Sum of Line 2 through Line 4	$49,161,375
6	Depreciation Expense Adjustment		Line 1 - Line 5	$966,957
7				
8				Per Book
9	Test Year Depreciation Expense 12 Months Ended 06/30/17:			Amount
10	Total Distribution Utility Plant 06/30/17		Page 4, Line 28, Column (e)	$2,141,474,644
11	Less Non Depreciable Plant		Page 4, Line 26, Column (e)	($627,567,742)
12	Depreciable Utility Plant 6/30/17		Line 10 + Line 11	$1,513,906,902
13				
14	Plus: Added Plant 2 Mos Ended 08/31/17		Schedule 11-ELEC, Page 6, Line 7	$12,473,833
15	Less: Streetlights retired in the 2 Mos Ended 08/31/17		Per Company Books	($1,057,011)
16	Less: Retired Plant 2 Months Ended 08/31/17	1/	Line 14 x Retirement Rate	($3,699,739)
17	Depreciable Utility Plant 08/31/17		Line 12 + Line 14 + Line 16	$1,521,623,985
18				
19	Average Depreciable Plant from 06/30/17 to 08/31/17		(Line 12 + Line 17)/2	$1,517,765,443
20				
21	Composite Book Rate %		As Approved in R.I.P.U.C. Docket No. 4323	3.40%
22				
23	Book Depreciation Reserve 06/30/17		Page 5, Line 69, Column (e)	$652,405,159
24	Plus: Book Depreciation Expense excluding Streetlight Retirement		1/6 of (Line 19 excl. Line 15 x Line 21)	$8,603,666
25	Less: Streetlights retired in the 2 Mos Ended 08/31/17 and Dep. for 2 Mos		1/12 of (Line 15 x SL Dep Rate)	($1,307.36)
26	Less: Net Cost of Removal/(Salvage)	2/	Line 14 x Cost of Removal Rate	($1,281,063)
27	Less: Retired Plant		Line 16	($3,699,739)
28	Book Depreciation Reserve 08/31/17		Sum of Line 23 through Line 27	$656,026,715
29				
30	Depreciation Expense 12 Months Ended 08/31/18			
31	Total Utility Plant 08/31/17		Line 10 + Line 14 + Line 15 + Line 16	$2,149,191,727
32	Less Non Depreciable Plant		Line 11	($627,567,742)
33	Depreciable Utility Plant 08/31/17		Line 31 + Line 32	$1,521,623,985
34				
35	Plus: Plant Added in 12 Months Ended 08/31/18		Schedule 11-ELEC, Page 6, Line 14	$74,843,000
36	Less: Plant Retired in 12 Months Ended 08/31/18	1/	Line 35 x Retirement rate	($22,198,434)
37	Depreciable Utility Plant 08/31/18		Sum of Line 33 through Line 36	$1,574,268,551
38				
39	Average Depreciable Plant for 12 Months Ended 08/31/18		(Line 33 + Line 37)/2	$1,547,946,268
40				
41	Composite Book Rate %		As Approved in R.I.P.U.C. Docket No. 4323	3.40%
42				
43	Book Depreciation Reserve 08/31/17		Line 28	$656,026,715
44	Plus: Book Depreciation 08/31/18		Line 39 x Line 41	$52,630,173
45	Less: Net Cost of Removal/(Salvage)	2/	Line 35 x Cost of Removal Rate	($7,686,376)
46	Less: Retired Plant		Line 36	($22,198,434)
47	Book Depreciation Reserve 08/31/18		Sum of Line 43 through Line 46	$678,772,079

1/	3 year average retirement over plant addition in service FY 15 ~ FY17	29.66%	Retirements
2/	3 year average Cost of Removal over plant addition in service FY 15 ~ FY17	10.27%	COR

The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Electric
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

Line No.	Description		Reference	Amount
			(a)	(b)
1	**Rate Year Depreciation Expense 12 Months Ended 08/31/19:**			
2	Total Utility Plant 08/31/18		Page 1, Line 31 + Line 35 + Line 36	$2,201,836,293
3	Less Non-Depreciable Plant		Page 1, Line 11	($627,567,742)
4	Depreciable Utility Plant 08/31/18		Line 2 + Line 3	$1,574,268,551
5				
6	Plus: Added Plant 12 Months Ended 08/31/19		Schedule 11-ELEC, Page 6, Line 38	$77,541,000
7	Less: Depreciable Retired Plant	1/	Line 6 x Retirement rate	($22,998,661)
8				
9	Depreciable Utility Plant 08/31/19		Sum of Line 4 through Line 7	$1,628,810,891
10				
11	Average Depreciable Plant for Rate Year Ended 08/31/19		(Line 4 + Line 9)/2	$1,601,539,721
12				
13	Proposed Composite Rate %		Page 4, Line 18, Columnumn (f)	3.15%
14				
15	Book Depreciation Reserve 08/31/18		Page 1, Line 47	$678,772,079
16	Plus: Book Depreciation Expense		Line 11 x Line 13	$50,375,341
17	Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-ELECTRIC, Part VI, Page 6	($247,009)
18	Less: Net Cost of Removal/(Salvage)	2/	Line 6 x Cost of Removal Rate	($7,963,461)
19	Less: Retired Plant		Line 7	($22,998,661)
20	Book Depreciation Reserve 08/31/19		Sum of Line 15 through Line 19	$697,938,290
21				
22	**Rate Year Depreciation Expense 12 Months Ended 08/31/20:**			
23	Total Utility Plant 08/31/19		Line 2 + Line 6 + Line 7	$2,256,378,633
24	Less Non-Depreciable Plant		Page 1, Line 11	($627,567,742)
25	Depreciable Utility Plant 08/31/19		Line 23 + Line 24	$1,628,810,891
26				
27	Plus: Added Plant 12 Months Ended 08/31/20		Schedule 11-ELEC, Page 5, Line 15(i)	$2,000,000
28	Less: Depreciable Retired Plant	1/	Line 27 x Retirement rate	($593,200)
29				
30	Depreciable Utility Plant 08/31/20		Sum of Line 25 through Line 28	$1,630,217,691
31				
32	Average Depreciable Plant for Rate Year Ended 08/31/20		(Line 25 + Line 30)/2	$1,629,514,291
33				
34	Proposed Composite Rate %		Page 4, Line 18, Columnumn (f)	3.15%
35				
36	Book Depreciation Reserve 08/31/20		Line 20	$697,938,290
37	Plus: Book Depreciation Expense		Line 32 x Line 34	$51,255,262
38	Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-ELECTRIC, Part VI, Page 6	($247,009)
39	Less: Net Cost of Removal/(Salvage)	2/	Line 27 x Cost of Removal Rate	($205,400)
40	Less: Retired Plant		Line 28	($593,200)
41	Book Depreciation Reserve 08/31/20		Sum of Line 36 through Line 40	$748,147,943
42				
43	**Rate Year Depreciation Expense 12 Months Ended 08/31/21:**			
44	Total Utility Plant 08/31/20		Line 23 + Line 27 + Line 28	$2,257,785,433
45	Less Non-Depreciable Plant		Page 1, Line 11	($627,567,742)
46	Depreciable Utility Plant 08/31/20		Line 44 + Line 45	$1,630,217,691
47				
48	Plus: Added Plant 12 Months Ended 08/31/21		Schedule 11-ELEC, Page 5, Line 15(l)	$2,000,000
49	Less: Depreciable Retired Plant	1/	Line 48 x Retirement rate	($593,200)
50				
51	Depreciable Utility Plant 08/31/21		Sum of Line 46 through Line 49	$1,631,624,491
52				
53	Average Depreciable Plant for Rate Year Ended 08/31/21		(Line 46 + Line 51)/2	$1,630,921,091
54				
55	Proposed Composite Rate %		Page 4, Line 18, Columnumn (f)	3.14543%
56				
57	Book Depreciation Reserve 08/31/20		Line 41	$748,147,943
58	Plus: Book Depreciation Expense		Line 53 x Line 55	$51,299,512
59	Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-ELECTRIC, Part VI, Page 6	($247,009)
60	Less: Net Cost of Removal/(Salvage)	2/	Line 48 x Cost of Removal Rate	($205,400)
61	Less: Retired Plant		Line 49	($593,200)
62	Book Depreciation Reserve 08/31/21		Sum of Line 57 through Line 61	$798,401,846

1/	3 year average retirement over plant addition in service FY 15 ~ FY17	29.66%	Retirements
2/	3 year average Cost of Removal over plant addition in service FY 15 ~ FY17	10.27%	COR

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
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The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Electric
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

Line No.	Account No.	Account Title	Test Year June 30, 2017 1/ (a)	ARO Adjustment (b)	Transmission Plant June 30, 2017 (c)	Other Adjustments June 30, 2017 (d)	Adjusted Balance (e)	Proposed Rate (f)	Test Year Depreciation (g) = (e) x (f)
		Intangible Plant							
1	303.00	Intangible Cap Software	$440,739	$0	$0	($440,739)	($0)	0.00%	$0
2									
3		Total Intangible Plant	$440,739	$0	$0	($440,739)	($0)		$0
4									
5		Production Plant							
6									
7	330.00	Land Hydro	$6,989	$0	$0	$0	$6,989	0.00%	$0
8	331.00	Struct & Improvements	$1,993,757	$0	$0	$0	$1,993,757	0.00%	$0
9	332.00	Reservoirs Dams And Water	$1,125,689	$0	$0	$0	$1,125,689	0.00%	$0
10									
11		Total Production Plant	$3,126,434	$0	$0	$0	$3,126,434		$0
12									
13		TransmissionPlant							
14									
15	350.00	Land&Land Rights	$9,121,773	$0	($9,121,773)	$0	$0	0.00%	$0
16	352.00	Structures And Improvements	$5,796,211	$0	($5,796,211)	$0	$0	0.94%	$0
17	353.00	Transmission Station Equipment	$296,170,454	$0	($296,170,454)	$0	$0	2.43%	$0
18	353.10	Sta Equip Poll Contl Facility	$52,233	$0	($52,233)	$0	$0	2.43%	$0
19	354.00	Towers And Fixtures Transmission	$1,554,741	$0	($1,554,741)	$0	$0	7.44%	$0
20	355.00	Poles And Fixtures Transmission	$328,207,728	$0	($328,207,728)	$0	$0	3.13%	$0
21	356.00	Transmsn Conductr New	$158,524,302	$0	($158,524,302)	$0	$0	3.60%	$0
22	356.10	Overhead Conductors And Devices	$58,973	$0	($58,973)	$0	$0	3.60%	$0
23	356.20	Conductor And Devices	$19,503	$0	($19,503)	$0	$0	3.60%	$0
24	357.10	Ug Transmission Manholes & Handholes	$228,385	$0	($228,385)	$0	$0	0.92%	$0
25	357.20	Ug Transmission Conduit	$4,601,701	$0	($4,601,701)	$0	$0	0.92%	$0
26	358.00	Underground Conductors And Devices	$29,948,930	$0	($29,948,930)	$0	$0	1.68%	$0
27	359.00	Roads And Trails	$492,182	$0	($492,182)	$0	$0	0.82%	$0
28	359.10	1/ Elect Equip ARO	$67,114	$0	($67,114)	$0	$0	0.00%	$0
29									
30		Total Transmission Plant	$834,844,229	$0	($834,844,229)	$0	$0		$0
31									
32		Distribution Plant							
33									
34	360.00	Land & Land Rights New	$364,996	$0	($364,996)	$0	$0	0.00%	$0
35	362.00	Station Equipment	$20,752,711	$0	($20,752,711)	$0	$0	2.32%	$0
36	365.00	Overhead Conductors and Devices	$1,571,576	$0	($1,571,576)	$0	$0	3.02%	$0
37	367.10	Underground Conductors and Devices	$83,518,730	$0	($83,518,730)	$0	$0	2.52%	$0
38	360.00	Land & Land Rights New	$12,874,490	$0	$0	$0	$12,874,490	0.00%	$0
39	360.10	Land Structures & Dist	$95,396	$0	$0	$0	$95,396	0.00%	$0
40	361.00	Struct & Improvements	$10,144,741	$0	$0	$0	$10,144,741	1.36%	$137,968
41	362.00	Station Equipment	$253,879,227	$0	$0	$0	$253,879,227	2.19%	$5,559,955
42	362.10	Station Equip Pollution	$71,597	$0	$0	$0	$71,597	2.19%	$1,568
43	362.55	Station Equipment - Energy Management System	$663,280	$0	$0	$0	$663,280	6.70%	$44,440
44	364.00	Poles, Towers And Fixtures	$237,808,052	$0	$0	$106,800	$237,914,852	4.27%	$10,158,964
45	365.00	Oh Conduct-Smart Grid	$307,943,917	$0	$0	$107,388	$308,051,305	2.65%	$8,163,360
46	366.10	Underground Manholes A	$23,368,987	$0	$0	$0	$23,368,987	1.33%	$310,808
47	366.20	Underground Conduit	$48,513,051	$0	$0	$0	$48,513,051	1.55%	$751,952
48	367.10	Underground Conductors	$173,786,203	$0	$0	$22,742	$173,808,945	3.42%	$5,944,266
49	368.10	Line Transformers - Stations	$10,674,398	$0	$0	$0	$10,674,398	2.76%	$294,613
50	368.20	Line Transformers - Bare Cost	$101,452,162	$0	$0	$0	$101,452,162	3.14%	$3,180,525
51	368.30	Line Transformers - Install Cost	$77,639,022	$0	$0	$62,731	$77,701,753	3.22%	$2,501,996
52	369.10	Overhead Services	$83,071,609	$0	$0	$95,006	$83,166,615	5.04%	$4,191,597
53	369.20	Underground Services C	$1,691,919	$0	$0	$0	$1,691,919	4.87%	$82,396
54	369.21	Underground Services C	$22,141,702	$0	$0	$9,071	$22,150,773	4.87%	$1,078,743
55	370.10	Meters - Bare Cost - Domestic	$26,411,207	$0	$0	($45,090)	$26,366,117	5.61%	$1,479,139
56	370.20	Meters - Install Cost - Domestic	$10,115,911	$0	$0	($89,809)	$10,026,102	5.81%	$582,517
57	370.30	Meters - Bare Cost - Large	$11,492,790	$0	$0	$0	$11,492,790	5.69%	$653,940
58	370.35	Meters - Install Cost - Large	$9,186,534	$0	$0	$0	$9,186,534	5.13%	$471,269
59	371.00	Installation On Custom	$119,825	$0	$0	$0	$119,825	3.61%	$4,326
60	373.10	Oh Steetlighting	$33,900,724	$0	$0	($10,229,598)	$23,671,126	1.46%	$345,598
61	373.20	Ug Streetlighting	$19,619,246	$0	$0	($3,606,259)	$16,012,987	1.52%	$243,397
62	374.00	1/ Elect Equip ARO	$569,213	($569,213)	$0	$0	$0	0.00%	$0
63									
64		Total Distribution Plant	$1,583,443,215	($569,213)	($106,208,013)	($13,567,018)	$1,463,098,971		$46,183,339

Column Notes:
(a) Per Company books
(d) Line 1, Line 56 and Line 57, exclude assets related to ReGrowth Program
(d) Line 44, 45, 48, 51, 52, 54, Company retirement adjustments
(d) Line 60 and Line 61, streetlight retirement adjustments
(e) Sum of Columns (a) through (d)
(f) Proposed Depreciation Rate based on Depreciation Study, refer to Schedule NWA-1-ELECTRIC, Part VI, Page 4 and Page 5

Line Notes:
3 Sum of Line 1 through Line 2
11 Sum of Line 7 through Line 9
30 Sum of Line 15 through Line 28
49~51 Changes made in depreciation rates based on settlement
64 Sum of Line 34 through Line 62
1/ Asset Retirement Obligations (AROs) are legal obligations that may exist in connection with the Company's retirement of a tangible long-lived asset. AROs are excluded from general rate case.

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
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The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Electric
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

Line No.	Account No.	Account Title	Test Year June 30, 2017 1/ (a)	ARO Adjustment (b)	Transmission Plant (c)	Other Adjustments June 30, 2017 (d)	Adjusted Balance (e)	Proposed Rate (f)	Test Year Depreciation (g) = (e) x (f)
		General Plant							
1	389.00	Land And Land Rights	$975,638	$0	($133,226)	$0	$842,411	0.00%	$0
2	390.00	Struct And Improvement Electric	$39,627,533	$0	($5,411,261)	$0	$34,216,272	2.28%	$780,131
3	391.00	Office Furn &Fixt Electric (Fully Dep)	$35,491	$0	($4,846)	$0	$30,645	0.00%	$29,542
4	391.00	Office Furn &Fixt Electric	$477,469	$0	($65,200)	$0	$412,269	6.67%	$27,498
5	393.00	Stores Equipment	$108,185	$0	($14,773)	$0	$93,412	5.00%	$4,671
6	394.00	General Plant Tools Shop	$2,240,705	$0	($305,975)	$0	$1,934,730	5.00%	$96,736
7	395.00	General Plant Laboratory (Fully Dep)	$333,809	$0	($45,582.66)	$0	$288,227	0.00%	$0
8	395.00	General Plant Laboratory (Fully Dep)	$1,420,854	$0	($194,022)	$0	$1,226,832	6.67%	$81,830
9	397.00	Communication Equipment	$6,181,769	$0	($844,139)	$0	$5,337,629	5.00%	$266,881
10	397.10	Communication Equipment Site Specific	$2,931,182	$0	($400,262)	$0	$2,530,920	3.90%	$98,706
11	397.50	Communication Equipment Network	$57,326	$0	($7,828)	$0	$49,498	5.00%	$2,475
12	398.00	General Plant Miscellaneous	$817,849	$0	($111,680)	$0	$706,169	6.67%	$47,101
13	399.00	Other Tangible Property	$14,459	$0	($1,974)	$0	$12,484	0.00%	$0
14	399.10	1/ ARO	$641,843	($554,198)	($87,646)	$0	$0	0.00%	$0
15									
16		Total General Plant	$55,864,110	($554,198)	($7,628,415)	$0	$47,681,498		$1,435,572
17									
18		Grand Total - All Categories	$2,477,718,727	($1,123,411)	($948,680,657)	($14,007,757)	$1,513,906,902	3.15%	$47,618,911
19									
20		Other Utility Plant Assets							
21									
22	105.00	Property For Future Use	$15,028,555				$15,028,555		
23	107	Construction Work in Progress	$96,433,650				$96,433,650		
24	114.00	Goodwill	$516,105,537				$516,105,537		
25									
26		Total of Other Utility Plant Assets	$627,567,742				$627,567,742		
27									
28		Total Electric Plant in Service	$3,105,286,469	($1,123,411)	($948,680,657)	($14,007,757)	$2,141,474,644		
29									
30		Test Year Depreciation Expense per books	$69,031,187	($130,581)	($19,814,202)	$74,971	$49,161,375		
31									
32		Accumulated Reserve	$768,535,818	($524,582)	($102,931,100)	($12,674,976)	$652,405,159		

Column Notes:
(a) Per Company books
(e) Sum of Columns (a) through (d)
(f) Proposed Depreciation Rate based on Depreciation Study, refer to Schedule NWA-1-ELECTRIC, Part VI, Page 5

Line Notes:
16 Sum of Line 1 through Line 14
18 Sum Lines (Page 3 Line 3, 11, 30, 64, and Page 4 Line 16)
18 Column (d), reflects adjustments for Retirements and Streetlight Sale not recorded on books as of June 30, 2017 and capital recovered through Renewable Energy Growth Program
26 Sum of Line 22 through Line 24
28 Sun of Line 18 and Line 26
30 Column (d), excluding depreciation of ReGrowth as well as the Company's retirement adjustments
32 Page 5, Line 69
1/ Asset Retirement Obligations (AROs) are legal obligations that may exist in connection with the Company's retirement of a tangible long-lived asset. AROs are excluded from general rate case.

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
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The Narragansett Electric Company d/b/a National Grid
Accumulated Depreciation - Electric
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

Line No.	Account No.	Account Title	Test Year 1/ June 30, 2017	ARO Adjustments	Transmission Plant	Other Adjustments	Adjusted Balance
			(a)	(b)	(c)	(d)	(e) = sum of (a) throu (d)
		Intangible Plant					
1	303.00	Intangible Cap Softwa	$91,821	$0	$0	($91,821)	$0
2							
3		Total Intangible Plant	$91,821	$0	$0	($91,821)	$0
4							
5		Production Plant					
6							
7	330.00	Land Hydro		$0	$0	$0	$0
8	331.00	Struct & Improvements	$1,993,757	$0	$0	$0	$1,993,757
9	332.00	Reservoirs Dams And Wa	$1,125,689	$0	$0	$0	$1,125,689
10							
11		Total Production Plant	$3,119,445	$0	$0	$0	$3,119,445
12							
13		TransmissionPlant					
14							
15	350.00	Land&Land Rights	($411,776)	$0	$411,776	$0	$0
16	352.00	Structures And Improvements	$3,510,381	$0	($3,510,381)	$0	$0
17	353.00	Transmission Station Equipment	$36,611,570	$0	($36,611,570)	$0	$0
18	354.00	Towers And Fixtures Transmission	$457,963	$0	($457,963)	$0	$0
19	355.00	Poles And Fixtures Transmission	$32,395,149	$0	($32,395,149)	$0	$0
20	356.00	Overhead Conductors And Devices	$5,975,934	$0	($5,975,934)	$0	$0
21	357.00	Underground Conduit	$3,203,223	$0	($3,203,223)	$0	$0
22	358.00	Underground Conductors And Devices	$17,053,879	$0	($17,053,879)	$0	$0
23	359.00	Roads And Trails	$526,621	$0	($526,621)	$0	$0
24	359.10	1/ Elect Equip ARO	$38,264	$0	($38,264)	$0	$0
25							
26		Total Transmission Plant	$99,361,208	$0	($99,361,208)	$0	$0
27							
28		Distribution Plant					
29							
32	360.00	Land & Land Rights New	$0		$0	$0	$0
33	362.00	Station Equipment	$206,606		($206,606)	$0	$0
34	365.00	Overhead Conductors and Devices	$5,641		($5,641)	$0	$0
35	367.10	Underground Conductors and Devices	$986,903		($986,903)	$0	$0
36	360.00	Land & Land Rights New	($23,760)	$0	$0	$23,760	$0
37	361.00	Struct & Improvements	$5,099,639	$0	$0	$0	$5,099,639
38	362.00	Station Equipment	$51,252,395	$0	$0	$0	$51,252,395
39	364.00	Poles, Towers And Fixtures	$107,271,672	$0	$0	$252,795	$107,524,467
40	365.00	Oh Conduct-Smart Grid	$127,305,163	$0	$0	$205,013	$127,510,176
41	366.00	Underground Manholes A	$33,879,330	$0	$0	$1,970	$33,881,300
42	367.00	Underground Conductors	$67,149,720	$0	$0	$265,309	$67,415,029
43	368.00	Transformer Stations	$117,261,728	$0	$0	$164,657	$117,426,385
44	369.00	Overhead Services	$40,962,172	$0	$0	$348,340	$41,310,512
45	370.00	Meters - Bare Cost - Domestic	$46,012,216	$0	$0	($9,143)	$46,003,073
46	371.00	Installation On Custom	$9,506	$0	$0	$0	$9,506
47	373.00	Oh Steetlighting	$51,025,715	$0	$0	($13,835,857)	$37,189,858
48	374.00	1/ Elect Equip ARO	$197,371	($197,371)	$0	$0	$0
49							
50		Total Distribution Plant	$648,602,015	($197,371)	($1,199,150)	($12,583,156)	$634,622,339
51							
52		General Plant					
53							
54	389.00	Land And Land Rights	$0	$0	$0	$0	$0
55	390.00	Struct And Improvement Electric	$10,151,568	$0	($1,386,228)	$0	$8,765,340
56	391.00	Office Furn &Fixt Elec	$1,714	$0	($234)	$0	$1,480
57	393.00	Stores Equipment	$34,864	$0	($4,761)	$0	$30,103
58	394.00	General Plant Tools Shop	$564,934	$0	($77,143)	$0	$487,790
59	395.00	General Plant Laboratory	$2,660	$0	($363)	$0	$2,297
60	395.10	Conservation Lab Equipment	$667,352	$0	($91,129)	$0	$576,223
61	397.00	Communication Equipment	$66,944	$0	($9,141)	$0	$57,803
62	397.10	Communication Equipment Site Specific	$5,490,323	$0	($749,720)	$0	$4,740,603
63	398.00	General Plant Miscellaneous	$706	$0	($96)	$0	$609
64	399.00	Other Tangible Property	$1,304	$0	($178)	$0	$1,126
65	399.10	1/ ARO	$378,960	($327,212)	($51,748)	$0	$0
66							
67		Total General Plant	$17,361,328	($327,212)	($2,370,742)	$0	$14,663,374
68							
69		Grand Total - All Categories	$768,535,818	($524,582)	($102,931,100)	($12,674,976)	$652,405,159

Column Notes:
(a) Per Company's books
(b) Adjustment for Assets Retirement Obligation which is not actual investment of the company
(c) Exclude transmission related items
(d) Exclude accumulated depreciation of ReGrowth Assets which is recovered through a separate mechanism
(d) Sum of Columns (a) through (c)

Line Notes:
11 Sum of Line 7 through Line 9
26 Sum of Line 15 through Line 24
50 Sum of Line 30 through Line 48
67 Sum of Line 54 through Line 65
69 Sum of Line 3, 11, 26, 50, and 67

1/ Asset Retirement Obligations (AROs) are legal obligations that may exist in connection with the Company's retirement of a tangible long-lived asset. AROs are excluded from general rate case.

Compliance Attachment 2

Schedule 6-GAS

Depreciation – Gas

The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Gas
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

Line No	Description		Reference	Amount
				(a)
1	Total Company Rate Year Depreciation		Sum of Page 2, Line 16 and Line 17	$39,136,909
2	Total Company Test Year Depreciation		Per Company Books	$33,311,851
3	Less: Reserve adjustments		Page 4, Line 29, Col (b) + Col (c)	($15,649)
4	Adjusted Total Company Test Year Depreciation Expense		Line 2 + Line 3	$33,296,202
5	**Depreciation Expense Adjustment**		Line 1 - Line 4	$5,840,707
6				
7				Per Book
8	Test Year Depreciation Expense 12 Months Ended 06/30/17:			Amount
9	Total Gas Utility Plant 06/30/17		Page 4, Line 27, Col (d)	$1,405,994,678
10	Less Non Depreciable Plant		Sum of Page 3, Line 5, Col (d) and Page 4, Line 25, Col (e)	($308,514,725)
11	Depreciable Utility Plant 06/30/17		Line 9 + Line 10	$1,097,479,953
12				
13	Plus: Added Plant 2 Mos Ended 08/31/17		Schedule 11-GAS, Page 3, Line 4	$19,592,266
14	Less: Retired Plant 2 Months Ended 08/31/17	1/	Line 13 x Retirement Rate	($1,345,989)
15	Depreciable Utility Plant 08/31/17		Line 11 + Line 13 + Line 14	$1,115,726,231
16				
17	Average Depreciable Plant for Year Ended 08/31/17		(Line 11 + Line 15)/2	$1,106,603,092
18				
19	Composite Book Rate %		As Approved in R.I.P.U.C. Docket No. 4323	3.38%
20				
21	Book Depreciation Reserve 06/30/17		Page 5, Line 72, Col (d)	$357,576,825
22	Plus: Book Depreciation Expense		Line 17 x Line 20	$6,233,864
23	Less: Net Cost of Removal/(Salvage)	2/	Line 13 x Cost of Removal Rate	($1,014,879)
24	Less: Retired Plant		Line 14	($1,345,989)
25	Book Depreciation Reserve 08/31/17		Sum of Line 21 through Line 24	$361,449,821
26				
27	Depreciation Expense 12 Months Ended 08/31/18			
28	Total Utility Plant 08/31/17		Line 9 + Line 13 + Line 14	$1,424,240,956
29	Less Non Depreciable Plant		Line 10	($308,514,725)
30	Depreciable Utility Plant 08/31/17		Line 28 + Line 29	$1,115,726,231
31				
32	Plus: Plant Added in 12 Months Ended 08/31/18		Schedule 11-GAS, Page 3, Line 11	$115,710,016
33	Less: Plant Retired in 12 Months Ended 08/31/18		Line 32 x Retirement rate	($7,949,278)
34	Depreciable Utility Plant 08/31/18		Sum of Line 30 through Line 33	$1,223,486,969
35				
36	Average Depreciable Plant for 12 Months Ended 08/31/18		(Line 30 + Line 34)/2	$1,169,606,600
37				
38	Composite Book Rate %		As Approved in R.I.P.U.C. Docket No. 4323	3.38%
39				
40	Book Depreciation Reserve 08/31/17		Line 25	$361,449,821
41	Plus: Book Depreciation 08/31/18		Line 36 x Line 38	$39,532,703
42	Less: Net Cost of Removal/(Salvage)		Line 32 x Cost of Removal Rate	($5,993,779)
43	Less: Retired Plant		Line 33	($7,949,278)
44	Book Depreciation Reserve 08/31/18		Sum of Line 40 through Line 43	$387,039,467

1/	3 year average retirement over plant addition in service FY 15 ~ FY17	6.87%	Retirements
2/	3 year average Cost of Removal over plant addition in service FY 15 ~ FY17	5.18%	COR

The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Gas
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2021

Line No	Description		Reference	Amount
1	**Rate Year Depreciation Expense 12 Months Ended 08/31/19:**			
2	Total Utility Plant 08/31/18		Page 1, Line 28 + Line 32 + Line 33	$1,532,001,694
3	Less Non-Depreciable Plant		Page 1, Line 10	($308,514,725)
4	Depreciable Utility Plant 08/31/18		Line 2 + Line 3	$1,223,486,969
5				
6	Plus: Added Plant 12 Months Ended 08/31/19		Schedule 11-GAS, Page 3, Line 35	$114,477,000
7	Less: Depreciable Retired Plant	1/	Line 6 x Retirement rate	($7,864,570)
8				
9	Depreciable Utility Plant 08/31/19		Sum of Line 4 through Line 7	$1,330,099,399
10				
11	Average Depreciable Plant for Rate Year Ended 08/31/19		(Line 4 + Line 9)/2	$1,276,793,184
12				
13	Proposed Composite Rate %		Page 4, Line 17, Col (e)	3.05%
14				
15	Book Depreciation Reserve 08/31/18		Page 1, Line 44	$387,039,467
16	Plus: Book Depreciation Expense		Line 11 x Line 13	$38,950,409
17	Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-GAS, Part VI, Page 6	$186,500
18	Less: Net Cost of Removal/(Salvage)	2/	Line 6 x Cost of Removal Rate	($5,929,909)
19	Less: Retired Plant		Line 7	($7,864,570)
20	Book Depreciation Reserve 08/31/19		Sum of Line 15 through Line 19	$412,381,898
21				
22	**Rate Year Depreciation Expense 12 Months Ended 08/31/20:**			
23	Total Utility Plant 08/31/19		Line 2 + Line 6 + Line 7	$1,638,614,124
24	Less Non-Depreciable Plant		Page 1, Line 10	($308,514,725)
25	Depreciable Utility Plant 08/31/19		Line 23 + Line 24	$1,330,099,399
26				
27	Plus: Added Plant 12 Months Ended 08/31/20		Schedule 11-GAS, Page 5, Line 11(i)	$21,017,630
28	Less: Depreciable Retired Plant	1/	Line 27 x Retirement rate	($1,443,911)
29				
30	Depreciable Utility Plant 08/31/20		Sum of Line 25 through Line 28	$1,349,673,118
31				
32	Average Depreciable Plant for Rate Year Ended 08/31/20		(Line 25 + Line 30)/2	$1,339,886,258
33				
34	Proposed Composite Rate %		Page 4, Line 17, Col (e)	3.05%
35				
36	Book Depreciation Reserve 08/31/20		Line 20	$412,381,898
37	Plus: Book Depreciation Expense		Line 32 x Line 34	$40,875,154
38	Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-GAS, Part VI, Page 6	$186,500
39	Less: Net Cost of Removal/(Salvage)	2/	Line 27 x Cost of Removal Rate	($1,088,713)
40	Less: Retired Plant		Line 28	($1,443,911)
41	Book Depreciation Reserve 08/31/20		Sum of Line 37 through Line 40	$450,910,927
42				
43	**Rate Year Depreciation Expense 12 Months Ended 08/31/21:**			
44	Total Utility Plant 08/31/20		Line 23 + Line 27 + Line 28	$1,658,187,843
45	Less Non-Depreciable Plant		Page 1, Line 10	($308,514,725)
46	Depreciable Utility Plant 08/31/20		Line 44 + Line 45	$1,349,673,118
47				
48	Plus: Added Plant 12 Months Ended 08/31/21		Schedule 11-GAS, Page 5, Line 11(l)	$21,838,436
49	Less: Depreciable Retired Plant	1/	Line 48 x Retirement rate	($1,500,301)
50				
51	Depreciable Utility Plant 08/31/21		Sum of Line 46 through Line 49	$1,370,011,253
52				
53	Average Depreciable Plant for Rate Year Ended 08/31/21		(Line 46 + Line 51)/2	$1,359,842,185
54				
55	Proposed Composite Rate %		Page 4, Line 17, Col (e)	3.05%
56				
57	Book Depreciation Reserve 08/31/20		Line 41	$450,910,927
58	Plus: Book Depreciation Expense		Line 53 x Line 55	$41,483,938
59	Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-GAS, Part VI, Page 6	$186,500
60	Less: Net Cost of Removal/(Salvage)	2/	Line 48 x Cost of Removal Rate	($1,131,231)
61	Less: Retired Plant		Line 49	($1,500,301)
62	Book Depreciation Reserve 08/31/21		Sum of Line 57 through Line 61	$489,949,834

1/	3 year average retirement over plant addition in service FY 15 ~ FY17	6.87%	Retirements
2/	3 year average Cost of Removal over plant addition in service FY 15 ~ FY17	5.18%	COR

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
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The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Gas
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

	Account No.	Account Title	Test Year June 30, 2017	1/ ARO Adjustment	Adjustments June 30, 2017	Adjusted Balance	Proposed Rate	Depreciation Expense
			(a)	(b)	(c)	(d) = (a) + (b) + (c)	(e)	(f) = (d) x (e)
		Intangible Plant						
1	302.00	Franchises And Consents	$213,499	$0	$0	$213,499	0.00%	$0
2	303.00	Misc. Intangible Plant	$25,427	$0	$0	$25,427	0.00%	$0
3	303.01	Misc. Int Cap Software	$19,833,570	$0	$9,991,374	$29,824,944	0.00%	$0
4								
5		Total Intangible Plant	$20,072,496	$0	$9,991,374	$30,063,870		$0
6								
7		Production Plant						
8								
9	304.00	Production Land Land Rights	$364,912	$0	$0	$364,912	0.00%	$0
10	305.00	Prod. Structures & Improvements	$2,693,397	$0	$0	$2,693,397	15.05%	$405,356
11	307.00	Production Other Power	$46,159	$0	$0	$46,159	7.16%	$3,305
12	311.00	Production LNG Equipme	$3,167,445	$0	$0	$3,167,445	11.40%	$361,089
13	320.00	Prod. Other Equipment	$1,106,368	$0	$0	$1,106,368	6.69%	$74,016
14								
15		Total Production Plant	$7,378,281	$0	$0	$7,378,281		$843,766
16								
17		Storage Plant						
18								
19	360.00	Stor Land & Land Rights	$261,151	$0	$0	$261,151	0.00%	$0
20	361.03	Storage Structures Improvements	$3,385,049	$0	$0	$3,385,049	0.99%	$33,512
21	362.04	Storage Gas Holders	$4,606,338	$0	$0	$4,606,338	0.04%	$1,843
22	363.00	Stor. Purification Equipment	$13,891,210	$0	$0	$13,891,210	3.37%	$468,134
23								
24		Total Storage Plant	$22,143,748	$0	$0	$22,143,748		$503,488
25								
26		Distribution Plant						
27								
28	374.00	Dist. Land & Land Rights	$956,717	$0	$0	$956,717	0.00%	$0
29	375.00	Gas Dist Station Structure	$10,642,632	$0	$0	$10,642,632	1.15%	$122,390
30	376.00	Distribution Mains	$46,080,760	$0	$0	$46,080,760	3.61%	$1,663,515
31	376.03	Dist. River Crossing Main	$695,165	$0	$0	$695,165	3.61%	$25,095
32	376.04	Mains - Steel And Other - Sl	$4,190	$0	$0	$4,190	0.00%	$0
33	376.06	Dist. District Regulator	$14,213,837	$0	$0	$14,213,837	3.61%	$513,120
34	376.11	Gas Mains Steel	$57,759,572	$0	$0	$57,759,572	3.31%	$1,908,954
35	376.12	Gas Mains Plastic	$382,797,443	$0	$0	$382,797,443	2.70%	$10,316,391
36	376.13	Gas Mains Cast Iron	$5,556,209	$0	$0	$5,556,209	8.39%	$465,888
37	376.14	Gas Mains Valves	$222,104	$0	$0	$222,104	3.61%	$8,018
38	376.15	Propane Lines	$0	$0	$0	$0	3.61%	$0
39	376.16	Dist. Cathodic Protect	$1,569,576	$0	$0	$1,569,576	3.61%	$56,662
40	376.17	Dist. Joint Seals	$63,067,055	$0	$0	$63,067,055	4.63%	$2,920,005
41	377.00	T&D Compressor Sta Equipment	$248,656	$0	$0	$248,656	1.07%	$2,661
42	377.62 1/	5360-Tanks ARO	$299	($299)	$0	$0	0.00%	$0
43	378.10	Gas Measur & Reg Sta Equipment	$19,586,255	$0	$0	$19,586,255	2.08%	$407,394
44	378.55	Gas M&Reg Sta Eqp RTU	$372,772	$0	$0	$372,772	6.35%	$23,671
45	379.00	Dist. Measur. Reg. Gs	$11,033,164	$0	$0	$11,033,164	2.22%	$244,936
46	379.01	Dist. Meas. Reg. Gs Eq	$1,399,586	$0	$0	$1,399,586	0.00%	$0
47	380.00	Gas Services All Sizes	$331,205,854	$0	$0	$331,205,854	3.05%	$10,101,779
48	381.10	Sml Meter& Reg Bare Co	$26,829,565	$0	$0	$26,829,565	1.76%	$472,200
49	381.30	Lrg Meter& Reg Bare Co	$15,779,214	$0	$0	$15,779,214	1.76%	$277,714
50	381.40	Meters	$9,332,227	$0	$0	$9,332,227	0.96%	$89,589
51	382.00	Meter Installations	$675,201	$0	$0	$675,201	3.66%	$24,712
52	382.20	Sml Meter& Reg Installation	$43,145,998	$0	$0	$43,145,998	3.66%	$1,579,144
53	382.30	Lrg Meter&Reg Installation	$2,524,025	$0	$0	$2,524,025	3.66%	$92,379
54	383.00	Dist. House Regulators	$937,222	$0	$0	$937,222	0.67%	$6,279
55	384.00	T&D Gas Reg Installs	$1,216,551	$0	$0	$1,216,551	1.56%	$18,978
56	385.00	Industrial Measuring And Regulating Station Equipment	$540,187	$0	$0	$540,187	4.18%	$22,580
57	385.01	Industrial Measuring And Regulating Station Equipment	$255,921	$0	$0	$255,921	0.00%	$0
58	386.00	Other Property On Customer Premises	$271,765	$0	$0	$271,765	0.23%	$625
59	386.02	Dist. Consumer Prem Equipment	$110,131	$0	$0	$110,131	0.00%	$0
60	387.00	Dist. Other Equipment	$930,079	$0	$0	$930,079	2.15%	$19,997
61	388.00 1/	ARO	$5,736,827	($5,736,827)	$0	$0	0.00%	$0
62								
63		Total Distribution Plant	$1,055,696,761	($5,737,126)	$0	$1,049,959,635		$31,384,677

Column Notes:
(a) Per Company Books
(e) Proposed Depreciation Rate based on Depreciation Study, refer to Schedule NWA-1-GAS, Part VI, Page 4 and Page 5

Line Notes:
1-3 Column (e) zero as intangibles are not included in the Depreciation Study, refer to Schedule 5-GAS for Amortization of Intangibles
5 Sum of Line 1 through Line 3
15 Sum of Line 9 through Line 13
24 Sum of Line 19 through Line 23
34~36 Changes made in depreciation rates based on settlement
47 Change made in depreciation rate based on settlement
63 Sum of Line 28 through Line 61

1/ Asset Retirement Obligations (AROs) are legal obligations that may exist in connection with the Company's retirement of a tangible long-lived asset. AROs are excluded from general rate case.

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 6-GAS
Page 4 of 5

The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Gas
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

	Account No.	Account Title	Test Year June 30, 2017 (a)	1/ ARO Adjustment (b)	Adjustments June 30, 2017 (c)	Adjusted Balance (d) = (a) + (b) + (c)	Proposed Rate (e)	Depreciation Expense (f) = (d) x (e)
1		General Plant						
2								
3	389.01	General Plant Land Lan	$285,357	$0	$0	$285,357	0.00%	$0
4	390.00	Structures And Improvements	$7,094,532	$0	$0	$7,094,532	3.12%	$221,349
5	391.01	Gas Office Furniture & Fixture	$274,719	$0	$0	$274,719	6.67%	$18,324
6	394.00	General Plant Tools Shop (Fully Dep)	$26,487	$0	$0	$26,487	0.00%	$0
7	394.00	General Plant Tools Shop	$5,513,613	$0	$0	$5,513,613	5.00%	$275,681
8	395.00	General Plant Laboratory	$221,565	$0	$0	$221,565	6.67%	$14,778
9	397.30	Communication Radio Site Specific	$387,650	$0	$0	$387,650	5.00%	$19,383
10	397.42	Communication Equip Tel Site	$63,481	$0	$0	$63,481	20.00%	$12,696
11	398.10	Miscellaneous Equipment (Fully Dep)	$1,341,386	$0	$0	$1,341,386	0.00%	$0
12	398.10	Miscellaneous Equipment	$2,789,499	$0	$0	$2,789,499	6.67%	$186,060
13	399.10 1/	ARO	$342,146	($342,146)	$0	$0	0.00%	$0
14								
15		Total General Plant	$18,340,436	($342,146)	$0	$17,998,289		$748,271
16								
17		Grand Total - All Categories	$1,123,631,722	($6,079,273)	$9,991,374	$1,127,543,823	3.05%	$33,480,202
18								
19		Other Utility Plant Assets						
20								
21	105.00	Prop For Future Use	$0			$0		
22	107	Construction Work in Progress	$43,392,799			$43,392,799		
23	114.00	Goodwill	$235,058,056			$235,058,056		
24								
25		Total of Other Utility Plant Assets	$278,450,855			$278,450,855		
26								
27		Total Gas Plant in Service	$1,402,082,577	($6,079,273)	$9,991,374	$1,405,994,678		
28								
29		Test Year Depreciation Expense per books	$33,311,851	($33,752)	$18,103	$33,296,202		
30								
31		Accumulated Reserve	$362,334,719	($5,387,893)	$629,999	$357,576,825		

Column Notes:
(a) Per Company Books
(e) Proposed Depreciation Rate based on Depreciation Study, refer to Schedule NWA-1-GAS, Part VI, Page 5

Line Notes
15 Sum of Line 3 through Line 13
17 Sum Lines (Page 3 Line 5, 15, 24, 63, and Page 4 Line 15)
25 Sum of Line 21 through Line 23
27 Sum of Line 17 and Line 25
29 Column (d), the Company's retirement adjustments
31 Page 5, Line 72

1/ Asset Retirement Obligations (AROs) are legal obligations that may exist in connection with the Company's retirement of a tangible long-lived asset. AROs are excluded from general rate case.

The Narragansett Electric Company d/b/a National Grid
Accumulated Depreciation - Gas
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

	Account No.		Account Title	Test Year June 30, 2017	1/ ARO Adjustment	Adjustments June 30, 2017	Adjusted Balance
				(a)	(b)	(c)	(d) = (a) + (b) + (c)
	Intangible Plant						
1	302.00		Franchises And Consents		$0	$0	$0
2	303.00		Misc. Intangible Plant		$0	$0	$0
3	303.01		Misc. Int Cap Software	$19,833,570	$0	$7,629,681	$27,463,251
4			Total Intangible Plant	$19,833,570	$0	$7,629,681	$27,463,251
5							
6	Production Plant						
7	304.00		Production Land Land Rights		$0	$0	$0
8	305.00		Prod. Structures & Improvements	$2,521,832	$0	$0	$2,521,832
9	307.00		Production Other Power	$55,325	$0	$0	$55,325
10	311.00		Production LNG Equipme	($1,427,606)	$0	$0	($1,427,606)
11	320.00		Prod. Other Equipment	($134,510)	$0	$0	($134,510)
12			Total Production Plant	$1,015,041	$0	$0	$1,015,041
13							
14	Storage Plant						
15	360.00		Stor Land & Land Rights		$0	$0	$0
16	361.03		Storage Structures Improvements	$2,429,540	$0	$0	$2,429,540
17	362.04		Storage Gas Holders	$4,646,257	$0	$0	$4,646,257
18	363.00		Stor. Purification Equipment	$5,726,431	$0	$0	$5,726,431
19			Total Storage Plant	$12,802,228	$0	$0	$12,802,228
20							
21	Distribution Plant						
22	374.00		Dist. Land & Land Righ	$0	$0	$0	$0
23	375.00		Gas Dist Station Structure	$6,988,174	$0	$0	$6,988,174
24	376.00		Distribution Mains	$29,845,037	$0	$0	$29,845,037
25	376.03		Dist. River Crossing Mains	$757,637	$0	$0	$757,637
26	376.04		Mains - Steel And Other - Sl	($7,662)	$0	$0	($7,662)
27	376.06		Dist. District Regulat	$2,915,625	$0	$0	$2,915,625
28	376.11		Gas Mains Steel	$25,081,627	$0	$0	$25,081,627
29	376.12		Gas Mains Plastic	$71,556,611	$0	$0	$71,556,611
30	376.13		Gas Mains Cast Iron	$113,413	$0	$0	$113,413
31	376.14		Gas Mains Valves		$0	$0	$0
32	376.15		Propane Lines	($56,661)	$0	$0	($56,661)
33	376.16		Dist. Cathodic Protect	$116,586	$0	$0	$116,586
34	376.17		Dist. Joint Seals	$10,813,050	$0	$0	$10,813,050
35	377.00		T&D Compressor Sta Equipment	$731,711	$0	$0	$731,711
36	377.62	1/	5360-Tanks ARO	$65	($65)	$0	$0
37	378.10		Gas Measur & Reg Sta Equipment	$5,277,579	$0	$0	$5,277,579
38	378.55		Gas M&Reg Sta Eqp RTU		$0	$0	$0
39	379.00		Dist. Measur. Reg. Gs	$3,446,717	$0	$0	$3,446,717
40	379.01		Dist. Meas. Reg. Gs Eq	$1,399,586	$0	$0	$1,399,586
41	380.00		Gas Services All Sizes	$148,606,388	$0	$383,120	$148,989,508
42	381.10		Sml Meter& Reg Bare Co	$13,106,230	$0	$0	$13,106,230
43	381.30		Lrg Meter& Reg Bare Co	$5,656,855	$0	$0	$5,656,855
44	381.40		Meters	$7,845,181	$0	$0	$7,845,181
45	382.00		Meter Installations	$1,454,329	$0	$0	$1,454,329
46	382.20		Sml Meter& Reg Instl C	$3,518,207	$0	$0	$3,518,207
47	382.30		Lrg Meter&Reg Instl C	$586,420	$0	$0	$586,420
48	383.00		Dist. House Regulators	$725,254	$0	$0	$725,254
49	384.00		T&D Gas Reg Installs	$610,349	$0	$0	$610,349
50	385.00		Industrial Measuring And Regulating Station Equipment	$78,827	$0	$0	$78,827
51	385.01		Industrial Measuring And Regulating Station Equipment	$255,921	$0	$0	$255,921
52	386.00		Other Property On Customer Premises	$284,088	$0	$0	$284,088
53	386.02		Dist. Consumer Prem Equipment	$110,131	$0	$0	$110,131
54	387.00		Dist. Other Equipment	$540,701	$0	$0	$540,701
55	388.00	1/	ARO	$5,068,067	($5,068,067)	$0	$0
56			Total Distribution Plant	$347,426,043	($5,068,132)	$383,120	$342,741,031
57							
58	General Plant						
59	389.01		General Plant Land and Land Right	($246,879)	$0	$246,879	$0
60	390.00		Structures And Improvements	$515,639	$0	$0	$515,639
61	391.01		Gas Office Furn & Fix	($1,284,707)	$0	$0	($1,284,707)
62	394.00		General Plant Tools Sh	$128,517	$0	$0	$128,517
63	395.00		General Plant Laborato	$147,585	$0	$0	$147,585
64	397.30		Commun Radio Site Spe	$838,919	$0	$0	$838,919
65	397.42		Commun Equip Tel Site	$20,409	$0	$0	$20,409
66	398.10		Power And Supervisory	$652,163	$0	$0	$652,163
67	399.10	1/	ARO	$319,761	($319,761)	$0	$0
68			Total General Plant	$1,091,407	($319,761)	$246,879	$1,018,525
69							
70			Grand Total - All Categories	$382,168,289	($5,387,893)	$8,259,680	$385,040,076
71							
72			Grand Total - Exclude Intangibles	$362,334,719	($5,387,893)	$629,999	$357,576,825

Column Notes:
(a) Per Company's books
(b) Adjustment for Assets Retirement Obligation which is not actual invetment of the company
(d) Sum of (a) through (c)

Line Notes:
41(c) Retirement adjustments
59(c) No accumulated depreciation for Land and Land Right
70 Sum of Line 4, 12, 19, 56, and 68
72 Sum of Line 12, 19, 56, and 68

1/ Asset Retirement Obligations (AROs) are legal obligations that may exist in connection with the Company's retirement of a tangible long-lived asset. AROs are excluded from general rate case.

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/ 4780
Witness: Little

Compliance Attachment 2

Schedule 7-ELEC

Municipal Taxes– Electric

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 7-ELEC
Page 1 of 9

The Narragansett Electric Company d/b/a National Grid
Municipal Taxes - Electric
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

		Test Year Ended June 30, 2017	Normalizing Adjustments to Test Year	Test Year Ended June 30, 2017 (as Adjusted)	Proforma Adjustments	Rate Year Ending August 31, 2019
		(a)	(b)	(a) + (b) =(c)	(d)	(e)
1	Narragansett Electric Company	$49,702,787	(20,023,313)	$29,679,474	$850,784	$30,530,258
2						
3	Total Municipal Taxes	$49,702,787	($20,023,313)	$29,679,474	$850,784	$30,530,258

Column Notes

(a) Per Company Books
(b) Page 8, Line 12 + Page 9, Line 6
(d) Column (e) - Column (c)
(e) Page 6, Line 43(n)

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 7-ELEC
Page 2 of 9

The Narragansett Electric Company d/b/a National Grid
Municipal Taxes - Electric
For the Rate Year 1 Ending August 31, 2020 and the Rate Year Ending August 31, 2021

		Rate Year Ending August 31, 2019	Proforma Adjustments	Rate Year Ending August 31, 2020	Proforma Adjustments	Rate Year Ending August 31, 2021
		(a)	(b)	(a) + (b) =(c)	(d)	(e)
1	Narragansett Electric Company	$30,530,258	$0	$30,530,258	$0	$30,530,258
2						
3	Total Municipal Taxes	$30,530,258	$0	$30,530,258	$0	$30,530,258

Column Notes

(a) Per Company Books
(b) Line 1(a) * Page 7, Line 6(e)
(d) Line 1(c) * Page 7, Line 6(e)
(e) Line 1 (c) + Line 1(d)

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 7-ELEC
Page 3 of 9

The Narragansett Electric Company d/b/a National Grid
Municipal Taxes - Electric - Personal Property
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019
Pro Forma Test Year

	Town	Total Assessment as of 12/31/16	IFA Related Assessment as of 12/31/2016	Net Distribution Assessment as of 12/31/16	2017 Actual Mill Rate	Distribution Municipal Taxes Pro Forma Tax Year 2017	Distribution Water/ Sewer Tax Year 2017	Total Distribution Municipal Taxes Pro Forma Tax Year 2017	Distribution Rebills to Third Parties Pro Forma Tax Year 2017	Net Distribution Municipal Taxes Pro Forma Tax Year 2017	Three Year Average Percentage Increase in Distribution Property Taxes	Distribution Municipal Tax Expense Pro Forma Tax Year 2018	Distribution Municipal Tax Expense Pro Forma Tax Year 2019	Total Distribution Municipal Taxes Pro Forma RY
	(a)	(b)	(c)	(b) - (c) = (d)	(e)	(d) * (e) = (f)	(g)	(f) + (g) = (h)	(i)	(h) - (i) = (j)	(k)	(j) * (1+(k)) = (l)	(l) * (1+(k)) = (m)	((l)/12*4)+((m)/12*8)= (n)
1	Albion Fire District	$ 3,473,004	$ 1,113,696	$ 2,359,308	3.00	$ 7,078	$ -	$ 7,078	$ -	$ 7,078	3.3%	$ 7,314	$ 7,558	$ 7,477.08
2	Central Coventry Fire District	9,718,175	6,663	9,711,512	3.08	29,911	-	29,911	-	29,911	3.3%	30,910	31,942	31,598
3	Chepachet Fire District - minimum	811	-	811	0.97	5	-	5	-	5	3.3%	5	5	5
4	City of Central Falls	3,906,302	-	3,906,302	73.11	285,590	-	285,590	-	285,590	3.3%	295,126	304,980	301,695
5	City of Cranston	49,005,313	18,808,600	30,196,713	34.41	1,039,069	-	1,039,069	-	1,039,069	3.3%	1,073,764	1,109,617	1,097,666
6	City of East Providence	19,302,830	1,365,766	17,937,064	55.24	990,843	-	990,843	-	990,843	3.3%	1,023,928	1,058,117	1,046,721
7	City of Newport	20,813,482	-	20,813,482	15.55	323,650	-	323,650	-	323,650	3.3%	334,456	345,624	341,902
8	City of Pawtucket	23,553,520	5,595,355	17,958,165	52.09	935,441	-	935,441	-	935,441	3.3%	966,676	998,953	988,194
9	City of Providence	199,668,496	25,635,812	174,032,684	55.80	9,711,024	-	9,711,024	-	9,711,024	3.3%	10,035,279	10,370,361	10,258,667
10	City of Warwick	113,873,763	73,918,380	39,955,383	40.48	1,617,394	-	1,617,394	-	1,617,394	3.3%	1,671,399	1,727,208	1,708,605
11	City of Woonsocket	22,226,800	9,089,819	13,136,981	46.58	611,921	-	611,921	-	611,921	3.3%	632,353	653,467	646,429
12	Coventry Fire District	2,891,470	1,982	2,889,488	4.86	14,043	-	14,043	-	14,043	3.3%	14,512	14,996	14,835
13	Cumberland Fire District	31,840,521	7,395,829	24,444,692	1.92	46,909	-	46,909	-	46,909	3.3%	48,476	50,094	49,555
14	Exeter Fire District	4,526,790	718,903	3,807,887	1.77	6,740	-	6,740	-	6,740	3.3%	6,965	7,198	7,120
15	Harmony FD	6,158,909	-	6,158,909	1.81	11,148	-	11,148	-	11,148	3.3%	11,520	11,905	11,776
16	Harrisville Fire District	33,987,783	31,245,857	2,741,926	2.53	6,937	-	6,937	-	6,937	3.3%	7,169	7,408	7,328
17	Hope Valley/Wyoming Fire District	5,927,260	656,797	5,270,463	1.12	5,903	-	5,903	-	5,903	3.3%	6,100	6,304	6,236
18	Hopkins Hill Fire District	2,429,543	1,666	2,427,877	3.38	8,194	-	8,194	-	8,194	3.3%	8,468	8,750	8,656
19	Lime Rock Fire District	7,111,389	2,280,424	4,830,965	2.20	10,628	-	10,628	-	10,628	3.3%	10,983	11,350	11,227
20	Lonsdale Fire District	1,819,193	583,364	1,235,829	3.15	3,893	-	3,893	-	3,893	3.3%	4,023	4,157	4,112
21	Manville Fire District	1,323,049	424,265	898,784	1.47	1,321	-	1,321	-	1,321	3.3%	1,365	1,411	1,396
22	Nasonville Fire District	24,629,150	22,642,222	1,986,928	1.63	3,239	-	3,239	-	3,239	3.3%	3,347	3,459	3,421
23	North Tiverton Fire District	4,335,015	822,970	3,512,045	0.98	3,442	-	3,442	-	3,442	3.3%	3,557	3,675	3,636
24	Oakland-Mapleville Fire District	11,962,740	10,997,660	965,080	2.42	2,335	-	2,335	-	2,335	3.3%	2,413	2,494	2,467
25	Pascoag Fire District	6,761,059	6,215,618	545,441	2.03	1,107	-	1,107	-	1,107	3.3%	1,144	1,182	1,170
26	Providence Water Supply Board	52,877,607	18,808,600	34,069,007	-	17,933	-	17,933	-	17,933	3.3%	18,532	19,151	18,945
27	Quinnville Fire District	330,762	106,066	224,696	1.48	333	-	333	-	333	3.3%	344	355	351
28	Richmond-Carolina Fire District	2,315,160	8,587	2,306,573	1.03	2,376	-	2,376	-	2,376	3.3%	2,455	2,537	2,510
29	Saylesville Fire District	2,480,717	795,497	1.685.220	3.15	5,308	-	5,308	-	5,308	3.3%	5,486	5,669	5,608
30	Stone Bridge Fire District	3,882,321	737,030	3,145,291	0.50	1,573	-	1,573	-	1,573	3.3%	1,625	1,679	1,661
31	Town of Barrington	6,040,216	-	6,040,216	20.00	120,804	-	120,804	-	120,804	3.3%	124,838	129,006	127,617
32	Town of Bristol	8,868,600	138,752	8,729,848	14.92	130,249	-	130,249	-	130,249	3.3%	134,598	139,093	137,595
33														
34	Total for All Towns	$ 688,041,750	$ 240,116,180	$ 447,925,570		$ 15,956,341	$ -	$ 15,956,341	$ -	$ 15,956,341		$ 16,489,130	$ 17,039,708	$ 16,856,182

Column Notes
(k) Page 7, Column 6(e)

Line Notes
26(f) Charges not taxed based on property value.

THE NARRAGANSETT ELECTRIC COMPANY
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The Narragansett Electric Company d/b/a National Grid
Municipal Taxes - Electric - Personal Property
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019
Pro Forma Test Year

	Town	Total Assessment as of 12/31/16	IFA Related Assessment as of 12/31/2016	Net Distribution Assessment as of 12/31/16	2017 Actual Mill Rate	Distribution Municipal Taxes Pro Forma Tax Year 2017	Distribution Water/Sewer Tax Year 2017	Total Distribution Municipal Taxes Pro Forma Tax Year 2017	Distribution Rebills to Third Parties Pro Forma Tax Year 2017	Net Distribution Municipal Taxes Pro Forma Tax Year 2017	Three Year Average Percentage Increase in Distribution Municipal Taxes	Distribution Municipal Tax Expense Pro Forma Tax Year 2018	Distribution Municipal Tax Expense Pro Forma Tax Year 2019	Total Distribution Municipal Taxes Pro Forma RY
	(a)	(b)	(c)	(b) - (c) = (d)	(e)	(d) * (e) = (f)	(g)	(f) + (g) = (h)	(i)	(h) - (i) = (j)	(k)	(j) * (1+(k)) = (l)	(l) * (1+(k)) = (m)	((l)/12*4)+((m)/12*8)= (n)
1	Town of Burrillville	70,369,059	64,692,116	5,676,943	17.56	99,687	-	99,687	-	99,687	3.3%	103,016	106,455	105,309
2	Town of Charlestown	11,291,883	2,409,330	8,882,553	9.59	85,184	-	85,184	-	85,184	3.3%	88,028	90,967	89,988
3	Town of Coventry	17,006,800	11,660	16,995,140	25.29	429,722	-	429,722	-	429,722	3.3%	444,071	458,898	453,956
4	Town of Cumberland	31,840,521	7,395,829	24,444,692	29.53	721,852	-	721,852	-	721,852	3.3%	745,955	770,862	762,560
5	Town of East Greenwich	10,048,885	3,916,964	6,131,921	23.66	145,081	-	145,081	-	145,081	3.3%	149,926	154,932	153,263
6	Town of Exeter	4,526,790	718,903	3,807,887	16.23	61,802	-	61,802	-	61,802	3.3%	63,866	65,998	65,287
7	Town of Foster	3,872,294	-	3,872,294	31.98	123,836	-	123,836	-	123,836	3.3%	127,971	132,244	130,820
8	Town of Glocester	6,158,909	-	6,158,909	39.46	243,031	-	243,031	-	243,031	3.3%	251,145	259,531	256,736
9	Town of Hopkinton	7,224,200	1,296,418	5,927,782	20.07	118,971	-	118,971	-	118,971	3.3%	122,943	127,048	125,680
10	Town of Jamestown	7.094.141	-	7,094,141	8.66	61,435	-	61.435	-	61.435	3.3%	63,487	65,606	64,900
11	Town of Johnston	87.358,420	51,745,388	35,613,032	59.71	2,126,454	-	2,126,454	-	2,126,454	3.3%	2,197,457	2,270,831	2,246,373
12	Town of Lincoln	16,538,115	5,303,313	11,234,802	34.39	386,365	-	386,365	-	386,365	3.3%	399,266	412,597	408.153
13	Town of Little Compton	2,750,261	-	2,750,261	11.68	32,123	-	32,123	-	32,123	3.3%	33,196	34,304	33,935
14	Town of Middletown	9,401,897	11	9,401,886	15.42	144,977	-	144,977	-	144,977	3.3%	149,818	154,820	153.153
15	Town of Narragansett	20,098,513	12,545,688	7,552,825	15.84	119,637	-	119,637	-	119,637	3.3%	123,631	127,760	126,384
16	Town of New Shoreham	9,929,665	9,929,665	-	5.86	-		-	-	-	3.3%	-	-	-
17	Town of North Kingstown	35,573,920	7,300,250	28,273,670	18.59	525,608	-	525,608	-	525,608	3.3%	543,158	561,294	555,249
18	Town of North Providence	7,600,411	853,272	6,747,139	68.11	459,548	-	459,548	-	459,548	3.3%	474,892	490,749	485,463
19	Town of North Smithfield	132,207,210	120,064,959	12,142,251	41.95	509,380	-	509,380	-	509,380	3.3%	526,388	543,964	538,105
20	Town of Portsmouth	11,990,388	2,005,830	9,984,558	15.42	153,962	-	153,962	-	153,962	3.3%	159,103	164,415	162,644
21	Town of Richmond	4,630,320	17,175	4,613,145	20.80	95,953	-	95,953	-	95,953	3.3%	99,157	102,468	101,365
22	Town of Scituate	9,110,940	545	9,110,395	40.04	364,798	-	364,798	-	364,798	3.3%	376,979	389,567	385,371
23	Town of Smithfield	59,426,840	35,596,545	23,830,295	60.74	1,447,452	-	1,447,452	-	1,447,452	3.3%	1,495,783	1,545,728	1,529,080
24	Town of South Kingstown	21,902,869	5,227,844	16,675,025	15.31	255,295	-	255,295	-	255,295	3.3%	263,819	272,628	269,692
25	Town of Tiverton	7,881,843	1,496,309	6,385,534	19.05	121,644	-	121,644	-	121,644	3.3%	125,706	129,904	128,504
26	Town of Warren	6,699,409	785,592	5,913,817	18.81	111,239	-	111,239	-	111,239	3.3%	114,953	118,792	117,512
27	Town of West Greenwich	6,201,405	14,130	6,187,275	33.85	209,439	-	209,439	-	209,439	3.3%	216,433	223,659	221,250
28	Town of West Warwick	24,718,480	12,882,400	11,836,080	41.78	494,511	-	494,511	-	494,511	3.3%	511,023	528,087	522,399
29	Town of Westerly	16,504,078	108,419	16,395,659	11.59	190,026	6,763	196,788	-	196,788	3.3%	203,359	210,149	207,886
30	Union Fire District	21,902,869	5,227,844	16,675,025	0.86	14,341	-	14,341	-	14,341	3.3%	14,819	15,314	15,149
31	West Glocester Fire District	2,053,781	-	2,053,781	1.65	3,389	-	3,389	-	3,389	3.3%	3,502	3,619	3.580
32	Western Coventry Fire District	2,429,540	1.666	2,427,874	1.62	3.933	-	3,933	-	3.933	3.3%	4,064	4,200	4.155
33														
34	Total for All Towns	$ 686,344,656	$ 351,548,065	$ 334,796,591		$ 9,860,673	$ 6,763	$ 9,867,436	$ -	$ 9,867,436		$ 10,196,914	$ 10,537,393	$ 10,423,900

Column Notes
(k) Page 7, Column 6(e)

THE NARRAGANSETT ELECTRIC COMPANY
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RIPUC Docket Nos. 4770/4780
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The Narragansett Electric Company d/b/a National Grid
Municipal Taxes - Electric - Real Property
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019
Pro Forma Test Year

	Town	Total Assessment as of 12/31/16	IFA Related Assessment as of 12/31/2016	Net Distribution Assessment as of 12/31/16	2017 Actual Mill Rate	Distribution Municipal Taxes Pro Forma Tax Year 2017	Distribution Water/ Sewer Tax Year 2017	Total Distribution Municipal Taxes Pro Forma Tax Year 2017	Distribution Rebills to Third Parties Pro Forma Tax Year 2017	Net Distribution Municipal Taxes Pro Forma	Three Year Average Percentage Increase in Distribution	Distribution Municipal Tax Expense Pro Forma Tax Year 2018	Distribution Municipal Tax Expense Pro Forma Tax Year 2019	Total Distribution Municipal Taxes Pro Forma RY
	(a)	(b)	(c)	(b) - (c) = (d)	(e)	(d) * (e) = (f)	(g)	(f) + (g) = (h)	(i)	(h) - (i) = (j)	(k)	(j) * (1+(k)) = (l)	(l) * (1+(k)) = (m	((l)/12*4)+((m)/12*8)= (n)
1	Albion Fire District	$ 4,178,200	$ 1,339,832	$ 2,838,368	1.78	$ 5,052	$ -	$ 5,052	$ -	$ 5,052	3.3%	$ 5,221	$ 5,395	$ 5,337.21
2	Albion Fire District - minimum	4,800	1,539	3,261	1.78	30	-	30	-	30	3.3%	31	32	31.69
3	Ashaway Fire District	1,034,300	185,610	848,690	1.31	1,112	-	1,112	-	1,112	3.3%	1,149	1,187	1,174
4	Bradford Fire District	10,300	68	10,232	0.79	8	-	8	-	8	3.3%	8	9	9
5	Central Coventry Fire District	1,345,200	922	1,344,278	3.08	4,140	-	4,140	-	4,140	3.3%	4,279	4,421	4,374
6	Charlestown Fire District	224,700	47,944	176,756	0.57	100	-	100	-	100	3.3%	103	107	106
7	Chepachet Fire District	2,033,000	-	2,033,000	0.97	1,962	-	1,962	-	1,962	3.3%	2,027	2,095	2,072
8	City of Central Falls	194,100	-	194,100	39.67	7,700	-	7,700	-	7,700	3.3%	7,957	8,223	8,134
9	City of Cranston - Commercial/Industrial	25,938,800	9,955,503	15,983,297	34.41	549,985	-	549,985	-	549,985	3.3%	568,349	587,327	581,001
10	City of Cranston- Residential	229,900	88,237	141,663	22.94	3,250	-	3,250	-	3,250	3.3%	3,358	3,470	3,433
11	City of East Providence	1,618,700	114,531	1,504,169	24.76	37,243	-	37,243	-	37,243	3.3%	38,487	39,772	39,344
12	City of Newport - Commercial	4,163,400	-	4,163,400	15.55	64,741	-	64,741	-	64,741	3.3%	66,903	69,136	68,392
13	City of Newport - Residential	75,200	-	75,200	11.21	843	-	843	-	843	3.3%	871	900	891
14	City of Pawtucket	9,571,053	2,273,692	7,297,361	34.88	254,532	-	254,532	-	254,532	3.3%	263,031	271,814	268,886
15	City of Providence - Commercial	29,411,972	3,776,258	25,635,714	36.70	940,831	-	940,831	39,869	900,962	3.3%	931,045	962,133	951,770
16	City of Providence - Residential	24,700	3,171	21,529	31.96	688	-	688	-	688	3.3%	711	735	727
17	City of Warwick - Commercial/Industrial	14,485,800	9,403,104	5,082,696	30.36	154,311	-	154,311	-	154,311	3.3%	159,463	164,788	163,013
18	City of Warwick - Residential	18,600	12,074	6,526	20.24	132	-	132	-	132	3.3%	137	141	140
19	City of Woonsocket	2,707,000	1,107,048	1,599,952	36.93	59,086	-	59,086	-	59,086	3.3%	61,059	63,098	62,418
20	Coventry Fire District	141,100	97	141,003	3.24	457	-	457	-	457	3.3%	472	488	483
21	Cumberland Fire District	1,088,200	252,764	835,436	1.92	1,603	-	1,603	-	1,603	3.3%	1,657	1,712	1,694
22	Dunns Corner Fire District	97,200	639	96,561	0.45	43	-	43	-	43	3.3%	45	46	45.90
23	Exeter Fire District	368,100	58,458	309,642	1.77	548	-	548	-	548	3.3%	566	585	579
24	Harrisville Fire District	924,400	849,825	74,575	2.53	189	-	189	-	189	3.3%	195	201	199
25	Hope Valley/Wyoming Fire District	42,000	7,537	34,463	1.12	39	-	39	-	39	3.3%	40	41	41
26	Lime Rock Fire District	1,379,200	442,271	936,929	2.20	2,061	-	2,061	-	2,061	3.3%	2,130	2,201	2,177
27	Lime Rock Fire District - minimum	5,700	1,828	3,872	2.20	15	-	15	-	15	3.3%	16	16	16
28	Lonsdale Fire District	67,300	21,581	45,719	1.90	87	-	87	-	87	3.3%	90	93	92
29	Manville Fire District	36,400	11,672	24,728	1.47	36	-	36	-	36	3.3%	38	39	38
30	Nasonville Fire District	777,600	714,868	62,732	1.63	102	-	102	-	102	3.3%	106	109	108
31	Nasonville Fire District - minimum	3,800	3,493	307	1.63	20	-	20	-	20	3.3%	21	21	21
32	North Tiverton Fire District	1,689,400	320,720	1,368,680	0.98	1,341	-	1,341	-	1,341	3.3%	1,386	1,432	1,417
33	Oakland-Mapleville Fire District	51,900	47,713	4,187	1.95	8	-	8	-	8	3.3%	8	9	9
34	Pascoag Fire District	2,478,800	2,278,826	199,974	2.03	406	-	406	-	406	3.3%	420	434	429
35	Pascoag Fire District - minimum	2,500	2,298	202	2.03	40	-	40	-	40	3.3%	41	43	42
36	Portsmouth Water and Fire District	1,061,700	177,608	884,092	0.22	195	-	195	-	195	3.3%	201	208	205
37	Portsmouth Water and Fire District - minimum	15,700	2,626	13,074	0.22	8	-	8	-	8	3.3%	8	9	8
38	Quinnville Fire District	24,000	22,064	1,936	1.48	3	-	3	-	3	3.3%	3	3	3
39														
40	Total for All Towns	$ 107,524,725	$ 33,526,423	$ 73,998,302		$ 2,092,947	$ -	$ 2,092,947	$ 39,869	$ 2,053,078		$ 2,121,631	$ 2,192,474	$ 2,168,860

Column Notes
(k) Page 7, Column 6(e)

The Narragansett Electric Company d/b/a National Grid
Municipal Taxes - Electric - Real Property
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019
Pro Forma Test Year

	Town	Total Assessment as of 12/31/16	IFA Related Assessment as of 12/31/2016	Net Distribution Assessment as of 12/31/16	2017 Actual Mill Rate	Distribution Municipal Taxes Pro Forma Tax Year 2017	Distribution Water/Sewer Tax Year 2017	Total Distribution Municipal Taxes Pro Forma Tax Year 2017	Distribution Rebills to Third Parties Pro Forma Tax Year 2017	Net Distribution Municipal Taxes Pro Forma Tax Year 2017	Three Year Average Percentage Increase in Distribution Municipal Taxes	Distribution Municipal Tax Expense Pro Forma Tax Year 2018	Distribution Municipal Tax Expense Pro Forma Tax Year 2019	Total Distribution Municipal Taxes Pro Forma RY
	(a)	(b)	(c)	(b) - (c) = (d)	(e)	(d) * (e) = (f)	(g)	(f) + (g) = (h)	(i)	(h) - (i) = (j)	(k)	(j) * (1+(k)) = (l)	(l) * (1+(k)) = (m)	((l)/12*4)+((m)/12*8)= (n)
1	Saylesville Fire District	621,700	199,362	422,338	1.98	836	-	836	-	836	3.3%	864	893	883
2	Saylesville Fire District - minimum	800	257	543	1.98	20	-	20	-	20	3.3%	21	21	21
3	Stone Bridge Fire District	110,200	20,921	89,279	0.50	45	-	45	-	45	3.3%	46	48	47
4	Town of Barrington	344,500	-	344,500	20.00	6,890	-	6,890	-	6,890	3.3%	7,120	7,358	7,279
5	Town of Bristol	1.376.800	21.541	1.355.259	14.92	20.220	-	20.220	-	20.220	3.3%	20.896	21.593	21.361
6	Town of Burrillville	4.238.100	3.896.196	341.904	17.56	6.004	-	6.004	-	6.004	3.3%	6.204	6.411	6.342
7	Town of Burrillville - minimum	900	827	73	17.39	30	-	30	-	30	3.3%	31	32	32
8	Town of Charlestown	224,700	47,944	176,756	9.59	1,695	-	1,695	-	1,695	3.3%	1,752	1,810	1,791
9	Town of Coventry	3,087,500	2,117	3,085,383	25.29	78,014	-	78,014	-	78,014	3.3%	80,619	83,311	82,413
10	Town of Cumberland	1,088,200	252,764	835,436	15.21	12,707	-	12,707	-	12,707	3.3%	13,131	13,570	13,424
11	Town of East Greenwich	6,064,600	2,363,926	3,700,674	23.66	87,558	-	87,558	-	87,558	3.3%	90,482	93,503	92,496
12	Town of Exeter	368,100	58,458	309,642	16.23	5,025	-	5,025	-	5,025	3.3%	5,193	5,367	5,309
13	Town of Foster	3,289,000	-	3,289,000	23.25	76,469	-	76,469	-	76,469	3.3%	79,023	81,661	80,782
14	Town of Glocester	2.907.700	-	2.907.700	23.67	68.825	-	68.825	-	68.825	3.3%	71.123	73.498	72.707
15	Town of Hopkinton	1,076,300	193,147	883,153	20.07	17,725	-	17,725	-	17,725	3.3%	18,317	18,928	18,724
16	Town of Jamestown	750,600	-	750,600	8.66	6,500	142	6,643	-	6,643	3.3%	6,864	7,094	7,017
17	Town of Johnston	3,609,562	2,138,067	1,471,495	27.49	40,451	-	40,451	-	40,451	3.3%	41,802	43,198	42,733
18	Town of Lincoln	6,385,100	2,047,524	4,337,576	26.72	115,900	-	115,900	-	115,900	3.3%	119,770	123,769	122,436
19	Town of Lincoln -minimum	300	96	204	26.35	10	-	10	-	10	3.3%	10	11	11
20	Town of Middletown - Commerical	4,186,700	5	4,186,695	20.44	85,576	1,697	87,273	-	87,273	3.3%	90,187	93,199	92,195
21	Town of Middletown - Residential	350,700	0	350,700	15.42	5,408	-	5,408	-	5,408	3.3%	5,588	5,775	5,713
22	Town of Narraqansett	253.700	158.362	95.338	15.84	1.510	-	1.510	-	1.510	3.3%	1.561	1.613	1.595
23	Town of North Kingstown	7,682,200	1,576,491	6,105,709	18.59	113,505	-	113,505	-	113,505	3.3%	117,295	121,212	119,906
24	Town of North Providence	1,812,200	203,449	1,608,751	26.14	42,053	-	42,053	-	42,053	3.3%	43,457	44,908	44,424
25	Town of North Smithfield	14,416,400	13,092,361	1,324,039	18.66	24,704	-	24,704	-	24,704	3.3%	25,529	26,381	26,097
26	Town of Portsmouth	1,035,300	173,192	862,108	15.42	13,294	-	13,294	-	13,294	3.3%	13,738	14,196	14,043
27	Town of Scituate	495,900	30	495,870	22.59	11,202	-	11,202	-	11,202	3.3%	11,576	11,962	11,833
28	Town of Smithfield	1,273,300	762,704	510,596	18.40	9,395	-	9,395	-	9,395	3.3%	9,709	10,033	9,925
29	Town of South Kingstown	1,180,900	281,861	899,039	15.31	13,764	-	13,764	-	13,764	3.3%	14,224	14,699	14,541
30	Town of Tiverton	1.989.500	377.692	1.611.808	19.05	30.705	-	30.705	-	30.705	3.3%	31.730	32.790	32.437
31	Town of Warren	3.227.600	378.478	2.849.122	18.81	53.592	-	53.592	-	53.592	3.3%	55.381	57.231	56.614
32	Town of West Greenwich	1,053,300	2,400	1,050,900	22.55	23,698	-	23,698	-	23,698	3.3%	24,489	25,307	25,034
33	Town of West Warwick	1,036,200	540,031	496,169	32.12	15,937	-	15,937	-	15,937	3.3%	16,469	17,019	16,836
34	Town of Westerly	2,221,300	14,592	2,206,708	11.59	25,576	560	26,135	-	26,135	3.3%	27,008	27,910	27,609
35	Union Fire District	1,180,900	281,861	899,039	0.86	773	-	773	-	773	3.3%	799	826	817
36	West Glocester Fire District	985,230	-	985,230	1.65	1,626	-	1,626	-	1,626	3.3%	1,680	1,736	1,717
37	Westerly Fire District	2,111,700	13,872	2,097,828	0.65	1,364	-	1,364	-	1,364	3.3%	1,409	1,456	1,440
38	Westerly Fire District - minimum	2,100	14	2,086	0.65	3	-	3	-	3	3.3%	3	3	3
39	Western Coventry Fire District	1.596.300	1.094	1.595.206	1.62	2.584	-	2.584	-	2.584	3.3%	2.671	2.760	2.730
40														
41	Total for All Towns	$ 83,636,092	$ 29,101,635	$ 54,534,457		$ 1,021,193	$ 2,399	$ 1,023,592	$ -	$ 1,023,592		$ 1,057,770	$ 1,093,090	$ 1,081,317
42														
43	**Grand Total**	**$ 1,565,547,223**	**$ 654,292,303**	**$ 911,254,920**		**$ 28,931,155**	**$ 9,162**	**$ 28,940,317**	**$ 39,869**	**$ 28,900,448**		**$ 29,865,445**	**$ 30,862,664**	**$ 30,530,258**
44														
45	Composite Mill Rate for Year				31.76									

Column Notes
(k) Page 7, Column 6(e)

Line Notes
45(e) Line 45(h)/Line 45(d)

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
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The Narragansett Electric Company d/b/a National Grid
Municipal Taxes - Electric
For the Test Year Ended June 30, 2017
Growth Rate

Line		12 Months Ended 6/30/2017	Total Property Taxes	IFA Related Expenses	Adjusted Municipal Taxes	Percentage Inc/(Dec)
1	Three Year Average Municipal Tax Expense Growth Rate:	(a)	(b)	(c)	(b) - (c) = (d)	(e)
2		2017	$ 49,149,953	$ 18,373,163	$ 30,776,790	-2.7%
3		2016	$ 47,654,474	$ 16,025,070	$ 31,629,404	-6.0%
4		2015	$ 49,682,964	$ 16,041,524	$ 33,641,441	18.7%
5		2014	$ 37,420,246	$ 9,077,147	$ 28,343,100	
6	Three Year Average Percentage Increase in Property Taxes					**3.3%**

Column Notes

(b)-(d) Per Company Books

Line Notes

2(e) (Col (d) Line 2 - Col (d) Line 3) / Col (d) Line 3
3(e) (Col (d) Line 3 - Col (d) Line 4) / Col (d) Line 4
4(e) (Col (d) Line 4- Col (d) Line 5) / Col (d) Line 5
6(e) (Sum of Lines 2(e),3(e) and 4(e))/3

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
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The Narragansett Electric Company d/b/a National Grid
Municipal Taxes - Electric
For the Test Year Ended June 30, 2017
Normalizing Adjustments

Line	Items for Removal	Total	Transmission	Distribution	6 Months Amortization Applicable to Test Year ended June 30, 2017
	(a)	(b)	(c)	(b)-(c)=(d)	(d)/12*6= (e)
1	Add (Less) Correcting entry for assets associated with wrong parcels				
2	Tax Year 2017-2018				
3	Chepachet Fire District, Gas Parcels recorded in Electric Municipal Taxes	$ (1,948)	$ -	$ (1,948)	$ (974)
4	Town of Gloucester, Gas Parcels recorded in Electric Municipal Taxes	(145)	-	(145)	($73)
5	Town of Smithfield, Electric Parcels recorded in Gas Municipal Taxes	826	495	331	$166
6	Tax Year 2016-2017				
7	Town of Cumberland, Electric Parcels recorded in Gas Municipal Taxes	6,101	1,417	4,684	2,342
8	Town of Smithfield, Electric Parcels recorded in Gas Municipal Taxes	826	495	331	166
9	North Tiverton FD, Gas Parcels recorded in Electric Municipal Taxes	(4)	(1)	(3)	(2)
10	Pascoag FD, Gas Parcels recorded in Electric Municipal Taxes	(266)	(244)	(21)	(11)
11					
12	Total for Normalizing Adjustment	**$ 5,391**	**$ 2,162**	**$ 3,229**	**$ 1,614**

Column Notes
(b)-(d) Per Company Books

Line Notes
12 Sum of Lines 3 to 10

THE NARRAGANSETT ELECTRIC COMPANY
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The Narragansett Electric Company d/b/a National Grid
Municipal Taxes - Electric
For the Test Year Ended June 30, 2017
Normalizing Adjustments

Line	Items for Removal (a)	Total (b)	Transmission (c)	Distribution (b)-(c)=(d)
1	Reduction for IFA	$ (18,149,081)	$ (18,149,081)	$ -
2	Out of Period adjustment	(552,833)		(552,833)
3	Reduction for estimated Municipal Tax impact for BITS assets	(1,323,013)	(1,323,013)	-
4	Total for Normalizing Adjustment	**$ (20,024,927)**	**$ (19,472,094)**	**$ (552,833)**

Line Notes

1 Workpaper 1 Page 1 Line 15(a)
2 Per Company Books
3 Per Company Books
4 Sum of Line 1 - Line 3

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/ 4780
Witness: Little

Compliance Attachment 2

Schedule 7-GAS

Municipal Taxes – Gas

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
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The Narragansett Electric Company d/b/a National Grid
Municipal Taxes -Gas
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

		Test Year Ended June 30, 2017 (Per Books)	Normalizing Adjustments to Test Year	Test Year Ended June 30, 2017 (as Adjusted)	Proforma Adjustments	Rate Year Ending August 31, 2019
		(a)	(b)	(a) + (b) =(c)	(d)	(e)
1	Narragansett Electric Company	$22,542,352	($453,318)	$22,089,035	$4,780,420	$26,869,455
2						
3	Total Municipal Taxes	$22,542,352	($453,318)	$22,089,035	$4,780,420	$26,869,455

Column Notes

(a) Per Company Books
(b) Page 7, Line 6(c)
(d) Column (e) - Column (c)
(e) Page 4, Line 26(j)

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
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The Narragansett Electric Company d/b/a National Grid
Municipal Taxes - Gas
For the Rate Year 2 Ending August 31, 2020 and the Rate Year 3 Ending August 31, 2021

		Rate Year Ending August 30, 2019	Proforma to Rate Year	Rate Year Ending August 31, 2020	Proforma to Rate Year	Rate Year Ending August 31, 2021
		(a)	(b)	(a) + (b) =(c)	(d)	(e)
1	Narragansett Electric Company	$26,869,455	$0	$26,869,455	$0	$26,869,455
2						
3	Total Municipal Taxes	$26,869,455	$0	$26,869,455	$0	$26,869,455

Column Notes

(a) Page 1, Line 3(e)
(b) Line 1(a) * Page 5, Line 6(c)
(d) Line 1(c) * Page 5, Line 6(c)
(e) Line 1 (c) + Line 1(d)

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
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The Narragansett Electric Company d/b/a National Grid
Municipal Taxes Gas - Personal Property
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019
Pro Forma Test Year

	Town	Total Assessment as of 12/31/16	2017 Actual Mill Rate	Municipal Taxes Pro Forma Tax Year 2017	Water/Sewer Pro Forma Tax Year 2017	Total Municipal Taxes Pro Forma Tax Year 2017	Three Year Average Percentage Increase in Municipal Taxes	Municipal Tax Expense Pro Forma Tax Year 2018	Municipal Tax Expense Pro Forma Tax Year 2019	Total Municipal Taxes Pro Forma RY
	(a)	(b)	(c)	(b) * (c) = (d)	(e)	(d) + (e) = (f)	(g)	(f) * (1+(g)) = (h)	(h) * (1+(g)) = (i)	((h)/12*4)+((i)/12*8)= (j)
1	Albion Fire District	$ 1,657,806	3.00	$ 4,973	$ -	$ 4,973	11.3%	$ 5,536	$ 6,162	$ 5,953
2	Central Coventry Fire District	5,295,055	3.08	16,309	-	16,309	11.3%	18,153	20,207	19,522
3	Chepachet Fire District	2,052,968	0.97	1,981	-	1,981	11.3%	2,205	2,455	2,371
4	City of Central Falls	4,270,752	73.11	312,235	-	312,235	11.3%	347,552	386,863	373,759
5	City of Cranston	40,338,559	34.41	1,388,050	-	1,388,050	11.3%	1,545,053	1,719,814	1,661,560
6	City of East Providence	42,780,560	55.24	2,363,198	-	2,363,198	11.3%	2,630,500	2,928,037	2,828,858
7	City of Newport	30,426,936	15.55	473,139	-	473,139	11.3%	526,656	586,226	566,369
8	City of Pawtucket	10,166,600	52.09	529,578	-	529,578	11.3%	589,479	656,155	633,930
9	City of Providence	132,538,496	55.80	7,395,648	-	7,395,648	11.3%	8,232,172	9,163,315	8,852,934
10	City of Warwick	61,018,284	40.48	2,470,020	-	2,470,020	11.3%	2,749,405	3,060,391	2,956,729
11	City of Woonsocket	10,293,700	46.58	479,481	-	479,481	11.3%	533,715	594,083	573,960
12	Coventry Fire District	1,470,140	4.86	7,145	-	7,145	11.3%	7,953	8,853	8,553
13	Cumberland Fire District	28,869,013	1.92	55,400	-	55,400	11.3%	61,666	68,641	66,316
14	Exeter Fire District	5,913,220	1.77	10,466	-	10,466	11.3%	11,650	12,968	12,529
15	Hope Valley/Wyoming Fire District	19,790	1.12	22	-	22	11.3%	25	27	27
16	Hopkins Hill Fire District	1,134,654	3.38	3,829	-	3,829	11.3%	4,263	4,745	4,584
17	Lime Rock Fire District	3,394,556	2.20	7,468	-	7,468	11.3%	8,313	9,253	8,940
18	Lonsdale Fire District	868,375	3.15	2,735	-	2,735	11.3%	3,045	3,389	3,274
19	Manville Fire District	631,545	1.47	928	-	928	11.3%	1,033	1,150	1,111
20	North Tiverton Fire District	2,288,307	0.98	2,243	-	2,243	11.3%	2,496	2,779	2,684
21	Pascoag Fire District	3,377,691	2.03	6,857	-	6,857	11.3%	7,632	8,496	8,208
22	Quinnville Fire District	157,886	1.48	234	-	234	11.3%	260	290	280
23	Saylesville Fire District	7,894,316	3.15	24,867	-	24,867	11.3%	27,680	30,811	29,767
24	Stone Bridge Fire District	1,728,635	0.50	864	-	864	11.3%	962	1,071	1,035
25	Town of Barrington	20,375,383	20.00	407,508	-	407,508	11.3%	453,601	504,908	487,806
26	Town of Bristol	11,361,500	14.92	169,514	-	169,514	11.3%	188,687	210,030	202,916
27	Town of Burrillville	3,377,691	17.56	59,312	-	59,312	11.3%	66,021	73,489	71,000
28	Town of Coventry	7,942,580	25.29	200,828	-	200,828	11.3%	223,544	248,829	240,401
29	Town of Cumberland	28,869,013	29.53	852,502	-	852,502	11.3%	948,929	1,056,262	1,020,484
30	Town of East Greenwich	7,997,799	23.66	189,228	-	189,228	11.3%	210,632	234,456	226,515
31	Town of Exeter	5,913,220	16.23	95,972	-	95,972	11.3%	106,827	118,910	114,882
32	Town of Glocester	2,434	39.46	96	-	96	11.3%	107	119	115
33	Town of Hopkinton	91,770	20.07	1,842	-	1,842	11.3%	2,050	2,282	2,205
34	Town of Johnston	12,723,070	59.71	759,695	-	759,695	11.3%	845,624	941,272	909,390
35	Town of Lincoln	7,894,316	34.39	271,486	-	271,486	11.3%	302,193	336,374	324,981
36	Town of Middletown	12,042,051	15.42	185,688	-	185,688	11.3%	206,692	230,071	222,278
37	Town of Narragansett	5,225,482	15.84	82,772	-	82,772	11.3%	92,134	102,555	99,081
38	Town of North Kingstown	19,714,010	18.59	366,483	-	366,483	11.3%	407,936	454,078	438,698
39	Town of North Providence	15,315,263	68.11	1,043,123	-	1,043,123	11.3%	1,161,110	1,292,444	1,248,666
40	Town of North Smithfield	1,044,140	41.95	43,803	-	43,803	11.3%	48,757	54,272	52,434
41	Town of Portsmouth	3,082,573	15.42	47,533	-	47,533	11.3%	52,910	58,894	56,900
42	Town of Richmond	39,580	20.80	823	-	823	11.3%	916	1,020	985
43	Town of Scituate	224,330	40.04	8,983	-	8,983	11.3%	9,999	11,130	10,753
44	Town of Smithfield	6,011,280	60.74	365,125	-	365,125	11.3%	406,425	452,395	437,072
45	Town of South Kingstown	4,430,050	15.31	67,824	-	67,824	11.3%	75,496	84,035	81,189
46	Town of Tiverton	4,576,615	19.05	87,185	-	87,185	11.3%	97,046	108,023	104,364
47	Town of Warren	6,102,739	18.81	114,793	-	114,793	11.3%	127,777	142,230	137,412
48	Town of West Greenwich	229,623	33.85	7,773	-	7,773	11.3%	8,652	9,631	9,304
49	Town of West Warwick	8,935,260	41.78	373,315	-	373,315	11.3%	415,541	462,543	446,876
50	Town of Westerly	16,292,723	11.59	188,833	6,680	195,513	11.3%	217,627	242,243	234,038
51	Union Fire District	4,430,050	0.86	3,810	-	3,810	11.3%	4,241	4,720	4,561
52	Western Coventry Fire District	1,134,650	1.62	1,838	-	1,838	11.3%	2,046	2,277	2,200
53										
54	Total for All Towns	$ 613,967,038		$ 21,555,354	$ 6,680	$ 21,562,034		$ 24,000,922	$ 26,715,672	$ 25,810,756

Column Notes
(g) Page 5, Column 6(c)

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The Narragansett Electric Company d/b/a National Grid
Municipal Taxes Gas - Real Property
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019
Pro Forma Test Year

	Town	Total Assessment as of 12/31/16	2017 Actual Mill Rate	Municipal Taxes Pro Forma Tax Year 2017	Water/Sewer Pro Forma Tax Year 2017	Total Municipal Taxes Pro Forma Tax Year 2017	Three Year Average Percentage Increase in Muncipal Taxes	Municipal Tax Expense Pro Forma Tax Year 2018	Municipal Tax Expense Pro Forma Tax Year 2019	Total Muncipal Taxes Pro Forma RY
	(a)	(b)	(c)	(b) * (c) = (d)	(e)	(d) + (e) = (f)	(g)	(f) * (1+(g)) = (h)	(h) * (1+(g)) = (i)	((h)/12*4)+((i)/12*8)= (j)
1	Bradford Fire District	$ 1,400	0.79	$ 1	-	$ 1	11.3%	$ 1	$ 1	$ 1
2	City of East Providence	667,800	24.76	16,535	-	16,535	11.3%	18,405	20,487	19,793
3	City of Pawtucket	1,186,700	34.88	41,392	-	41,392	11.3%	46,074	51,285	49,548
4	City of Providence	17,113,300	36.70	628,058	-	628,058	11.3%	699,098	778,173	751,815
5	City of Woonsocket	167,000	36.93	6,167	-	6,167	11.3%	6,865	7,641	7,383
6	Cumberland Fire District	8,113,300	1.92	15,569	-	15,569	11.3%	17,330	19,291	18,637
7	Exeter Fire District	706,000	1.77	1,250	-	1,250	11.3%	1,391	1,548	1,496
8	Manville Fire District - minimum	2,600	1.47	30	-	30	11.3%	33	37	36
9	North Tiverton Fire District	4,100	0.98	4	-	4	11.3%	4	5	5
10	Pascoag Fire District	767,000	2.03	1,557	-	1,557	11.3%	1,733	1,929	1,864
11	Portsmouth Water and Fire District	177,400	0.22	39	-	39	11.3%	43	48	47
12	Town of Burrillville	767,000	17.56	13,469	-	13,469	11.3%	14,992	16,688	16,122
13	Town of Cumberland	8,113,300	15.21	123,403	-	123,403	11.3%	137,361	152,898	147,719
14	Town of Exeter	706,000	16.23	11,458	-	11,458	11.3%	12,754	14,197	13,716
15	Town of Lincoln	2,600	26.72	69	-	69	11.3%	77	86	83
16	Town of Middletown	106,900	20.44	2,185	-	2,185	11.3%	2,432	2,707	2,616
17	Town of Portsmouth	177,400	15.42	2,736	-	2,736	11.3%	3,045	3,389	3,275
18	Town of Smithfield	224,100	18.40	4,123	-	4,123	11.3%	4,590	5,109	4,936
19	Town of Tiverton	7,800	19.05	149	-	149	11.3%	165	184	178
20	Town of Warren	666,300	18.81	12,533	-	12,533	11.3%	13,951	15,529	15,003
21	Town of Westerly	291,200	11.59	3,375	135	3,510	11.3%	3,907	4,349	4,202
22	Westerly Fire District	289,800	0.65	188	-	188	11.3%	210	233	225
23										
24	Total for All Towns	$ 40,259,000		$ 884,291	$ 135	$ 884,426		$ 984,464	$ 1,095,817	$ 1,058,699
25										
26	**Grand Total**	**$ 654,226,038**	-	**$ 22,439,645**	**$ 6,815**	**$ 22,446,460**		**$ 24,985,386**	**$ 27,811,489**	**$ 26,869,455**
27										
28	Composite Mill Rate for Year		34.31							

Column Notes
(g) Page 5, Column 6(c)

Line Notes
28(c) Line 26(f) / Line 26(b)

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
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The Narragansett Electric Company d/b/a National Grid
Municipal Taxes - Gas
For the Test Year Ended June 30, 2017
Growth Rate

Line	Three Year Average Municipal Tax Expense Growth Rate:	12 Months Ended June 30, 2017	Municipal Taxes	Percentage Inc/(Dec)
1		(a)	(b)	(c)
2		2017	$ 22,091,730	7.7%
3		2016	20,515,689	23.8%
4		2015	16,566,064	2.4%
5		2014	16,176,329	
6	Three Year Average Percentage Increase in Municipal Taxes			**11.3%**

Line Notes

2(b) Per Company Books
3(b) Per Company Books
4(b) Per Company Books
5(b) Per Company Books
2(c) (Col (b) Line 2 - Col (b) Line 3) / Col (b) Line 3
3(c) (Col (b) Line 3 - Col (b) Line 4) / Col (b) Line 4
4(c) (Col (b) Line 4- Col (b) Line 5) / Col (b) Line 5
6(c) (Sum of Lines 2(c),3(c) and 4(c))/3

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
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The Narragansett Electric Company d/b/a National Grid
Municipal Taxes - Gas
For the Test Year Ended June 30, 2017
Normalizing Adjustments

Line	Items for Removal	Amount	6 Months Amortization Applicable to Test Year ended June 30, 2017
	(a)	(b)	(b)/12*6= (c)
1	Correcting entry for assets associated with wrong parcels for prior year	($450,622)	($450,622)
2	Tax Year 2017-2018		
3	Chepachet Fire District, Gas Parcels recorded in Electric Municipal Taxes	$ 1,948	$ 974
4	Town of Gloucester, Gas Parcels recorded in Electric Municipal Taxes	145	73
5	Town of Smithfield, Electric Parcels recorded in Gas Municipal Taxes	(826)	(413)
6	Tax Year 2016-2017		
7	Town of Cumberland, Electric Parcels recorded in Gas Municipal Taxes	(6,101)	(3,050)
8	Town of Smithfield, Electric Parcels recorded in Gas Municipal Taxes	(826)	(413)
9	North Tiverton FD, Gas Parcels recorded in Electric Municipal Taxes	4	2
10	Pascoag FD, Gas Parcels recorded in Electric Municipal Taxes	266	133
11			
12	Total for Normalizing Adjustment	**$ (456,013)**	**$ (453,318)**

Column Notes
(b) Per Company Books

Line Notes
12 Sum of Lines 3 to 10

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/ 4780
Witness: Little

Compliance Attachment 2

Schedule 8

Payroll Taxes

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 8
Page 1 of 8

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Payroll Taxes

		Test Year Ended June 30, 2017 (Per Books)			Normalizing Adjustments			Test Year Ended June 30, 2017 (as Adjusted)		
		Total	Electric	Gas	Total	Electric	Gas	Total	Electric	Gas
		(a) = (b) + (c)	(b)	(c)	(d) = (e) + (f)	(e)	(f)	(g) = (h) + (i)	(h) = (b) + (e)	(i) = (c) + (f)
	Provider Company:									
1	Narragansett Electric Company	$1,080,722	$4,242,306	($3,161,584)	($100,816)	($3,864,645)	$3,763,829	$979,906	$377,661	$602,245
2	National Grid USA Service Company	$5,646,749	$3,816,827	$1,829,922	($552,786)	($551,205)	($1,581)	$5,093,963	$3,265,621	$1,828,342
3	All Other Companies	$127,000	$89,579	$37,420	($20,058)	($20,058)	$0	$106,941	$69,521	$37,420
4	Total	$6,854,470	$8,148,712	($1,294,241)	($673,660)	($4,435,908)	$3,762,248	$6,180,811	$3,712,803	$2,468,007
		$0	$0	$0	($0)	$0	$0	$0	$0	$0

Column Notes
(b)-(c) Per Company Books

Line Notes
1(e)-(f) Sum of Page 5, Lines 2, 3, 6, and 7
2(e)-(f) Sum of Page 5, Lines 4, 8, and 10
3(e)-(f) Sum of Page 5, Lines 5, 9, and 11

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Payroll Taxes

		Test Year Ended June 30, 2017 (as Adjusted)			Proforma Adjustments			Rate Year Ending August 31, 2019		
		Total	Electric	Gas	Total	Electric	Gas	Total	Electric	Gas
		(a) = (b) + (c)	(b)	(c)	(d) = (e) + (f)	(e)	(f)	(g) = (h) + (i)	(h) = (b) + (e)	(i) = (c) + (f)
	Provider Company:									
1	Narragansett Electric Company	$979,906	$377,661	$602,245	$312,735	$212,164	$100,571	$1,292,642	$589,825	$702,816
2	National Grid USA Service Company	$5,093,963	$3,265,621	$1,828,342	$307,810	$219,214	$88,596	$5,401,773	$3,484,835	$1,916,937
3	All Other Companies	$106,941	$69,521	$37,420	$13,556	$10,341	$3,215	$120,498	$79,862	$40,636
4	Total	$6,180,811	$3,712,803	$2,468,007	$634,101	$441,719	$192,382	$6,814,912	$4,154,522	$2,660,389
		$0	$0	$0	$0	$0	$0	$0	$0	$0

Column Notes

(b)-(c) Page 1, Columns (h)-(i)
(e)-(f) Page 5, Lines 19(b) through 21(c)

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Payroll Taxes

		Rate Year Ending August 31, 2019	Adjustments to Reflect Conditions in Rate Year Ending August 31, 2020	Rate Year Ending August 31, 2020	Adjustments to Reflect Conditions in Rate Year Ending August 31, 2021	Rate Year Ending August 31, 2021
		Electric	Electric	Electric	Electric	Electric
		(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) + (d)
	Provider Company:					
1	Narragansett Electric Company	$589,825	$52,376	$642,201	$40,881	$683,083
2	National Grid USA Service Company	$3,484,835	$53,976	$3,538,811	$42,309	$3,581,120
3	All Other Companies	$79,862	$2,529	$82,392	$1,965	$84,356
4	Total	$4,154,522	$108,881	$4,263,404	$85,155	$4,348,558
		$0	$0	$0	$0	$0

Column Notes

(a) Page 2, Column (h)
(b) Page 5, Lines 29(b) through 31(b)
(d) Page 5, Lines 38(b) through 40(b)

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Payroll Taxes

		Rate Year Ending August 31, 2019	Adjustments to Reflect Conditions in Rate Year Ending August 31, 2020	Rate Year Ending August 31, 2020	Adjustments to Reflect Conditions in Rate Year Ending August 31, 20121	Rate Year Ending August 31, 2021
		Gas	Gas	Gas	Gas	Gas
		(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) + (d)
	Provider Company:					
1	Narragansett Electric Company	$702,816	$39,306	$742,123	$29,314	$771,437
2	National Grid USA Service Company	$1,916,937	$34,081	$1,951,019	$25,408	$1,976,426
3	All Other Companies	$40,636	$1,230	$41,865	$910	$42,775
4	Total	$2,660,389	$74,617	$2,735,007	$55,631	$2,790,638
		$0	$0	$0	$0	$0

Column Notes

(a) Page 2, Column (i)
(b) Page 5, Lines 29(c) through 31(c)
(d) Page 5, Lines 38(c) through 40(c)

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Payroll Taxes

		Explanation of Adjustments:	Provider Company	Total	Electric	Gas
				(a) = (b) + (c)	(b)	(c)
1	Page 1	Adjustments: (to normalize Historic Year):				
2		Out of period FUTA segment reclass	Narragansett Electric Company	$0	($3,763,829)	$3,763,829
3		(IFA) Integrated Facilities Agreement	Narragansett Electric Company	($579,499)	($579,499)	$0
4		(IFA) Integrated Facilities Agreement	National Grid USA Service Company	($521,379)	($521,379)	$0
5		(IFA) Integrated Facilities Agreement	All Other Companies	($12,237)	($12,237)	$0
6		Less IFA related to out of period FUTA segment reclass	Narragansett Electric Company	$514,139	$514,139	$0
7		Inspection & Maintenance	Narragansett Electric Company	($24,521)	($24,521)	$0
8		Inspection & Maintenance	National Grid USA Service Company	($213)	($213)	$0
9		Inspection & Maintenance	All Other Companies	($4,268)	($4,268)	$0
10		Major Storm Normalization	National Grid USA Service Company	($24,694)	($24,694)	$0
11		Major Storm Normalization	All Other Companies	($3,554)	($3,554)	$0
12		RI Government Relations and Federal Affairs	Narragansett Electric Company	($10,935)	($10,935)	$0
13		RI Government Relations and Federal Affairs	National Grid USA Service Company	($6,500)	($4,920)	($1,581)
14						
15			TOTAL	($673,660)	($4,435,908)	$3,762,248
16						
17						
18	Page 2	Adjustments: (to reflect conditions in the Rate Year 8/30/19)				
19		To increase costs for:				
20						
21		Recalculated Payroll Tax Expense Adjustment	Narragansett Electric Company	$312,735	$212,164	$100,571
22			National Grid USA Service Company	$307,810	$219,214	$88,596
23			All Other Companies	$13,556	$10,341	$3,215
24						
25			TOTAL	$634,101	$441,719	$192,382
26						
27						
28	Page 3 and 4	Adjustments: (to reflect conditions in the Rate Year Ending 8/30/20)				
29		To increase costs for:				
30						
31		Recalculated Payroll Tax Expense Adjustment	Narragansett Electric Company	$91,682	$52,376	$39,306
32			National Grid USA Service Company	$88,057	$53,976	$34,081
33			All Other Companies	$3,759	$2,529	$1,230
34						
35			TOTAL	$183,499	$108,881	$74,617
36						
37	Page 3 and 4	Adjustments: (to reflect conditions in the Rate Year Ending 8/30/21)				
38		To increase costs for:				
39						
40		Recalculated Payroll Tax Expense Adjustment	Narragansett Electric Company	$70,195	$40,881	$29,314
41			National Grid USA Service Company	$67,716	$42,309	$25,408
42			All Other Companies	$2,874	$1,965	$910
43						
44			TOTAL	$140,786	$85,155	$55,631

Line Notes

21(b) Page 6, Line 25(a)
21(c) Page 6, Line 25(b)
22(b) Page 6, Line 25(c)
22(c) Page 6, Line 25(d)
23(c) Page 6, Line 25(e)
23(c) Page 6, Line 25(f)
31(b) Page 6, Line 52(a)
31(c) Page 6, Line 52(b)
32(b) Page 6, Line 52(c)
32(c) Page 6, Line 52(d)
33(b) Page 6, Line 52(e)
33(c) Page 6, Line 52(f)
40(b) Page 6, Line 79(a)
40(c) Page 6, Line 79(b)
41(b) Page 6, Line 79(c)
41(c) Page 6, Line 79(d)
42(b) Page 6, Line 79(e)
42(c) Page 6, Line 79(f)

The Narragansett Electric Company d/b/a National Grid
Payroll Taxes
Rate Year Ending August 31, 2019, August 31, 2020 and August 31, 2021

	Description	Total	Electric	Gas
		(a) = (b) + (c)	(b)	(c)
1	Test Year Payroll Tax Expense	$6,854,470	$8,148,712	($1,294,241)
2	Out of period FUTA segment reclass	$0	($3,763,829)	$3,763,829
3	Inspection & Maintenance	($29,002)	($29,002)	$0
4	(IFA) Integrated Facilities Agreement	($1,113,114)	($1,113,114)	$0
5	Less IFA related to out of period FUTA segment reclass	$514,139	$514,139	$0
6	Major Storm Normalizing Adjustment	($28,247)	($28,247)	$0
7	RI Government Relations and Federal Affairs	($17,436)	($15,855)	($1,581)
8	Adjusted Test Year Payroll Tax Expense	$6,180,811	$3,712,803	$2,468,007
9	Rate Year O&M Salaries and Wages - Percentage Change		15.17%	10.37%
10	Payroll Tax Expense Adjustment	$819,165	$563,232	$255,932
11	Adjustment for SS-FICA, FUTA, SUTA, and EMAC salary caps	($185,064)	($121,513)	($63,550)
12	Recalculated Payroll Tax Expense Adjustment	**$634,101**	**$441,719**	**$192,382**
13	**Rate Year Expense**	**$6,814,912**	**$4,154,522**	**$2,660,389**
14				
15				

16		Narragansett Electric Company - Electric	Narragansett Electric Company - Gas	National Grid Service Company - Electric	National Grid Service Company - Gas	Other Affiliates - Electric	Other Affiliates - Gas	Total Electric	Total Gas	Percentage Increase / (Decrease) Electric	Percentage Increase / (Decrease) Gas
17	Source	Schedule 12, Page 6	Schedule 12, Page 7	Schedule 12, Page 8	Schedule 12, Page 9	Schedule 12, Page 10	Schedule 12, Page 11				
18		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (a) + (c) + (e)	(h) = (b) + (d) + (f)	(i)	(j)
19	Test Year O&M Wages	$20,424,581	$15,941,589	$22,568,253	$13,739,056	$1,124,084	$517,576	$44,116,918	$30,198,221		
20	Rate Year O&M Wages	$24,404,424	$17,424,303	$25,215,342	$15,349,511	$1,189,520	$557,026	$50,809,287	$33,330,840		
21	Difference	$3,979,843	$1,482,714	$2,647,090	$1,610,455	$65,436	$39,450	$6,692,369	$3,132,619	15.17%	10.37%
22											
23	Allocation of Payroll Tax Expense	$1,995,476	$1,390,767	$2,061,783	$1,225,162	$97,264	$44,460	$4,154,522	$2,660,389		
24											
25	**Rate Year Expense**	$1,783,312	$1,290,196	$1,842,569	$1,136,566	$86,922	$41,245	**$3,712,803**	**$2,468,007**	**$6,180,811**	
26	**Recalculated Payroll Tax Expense Adjustment**	**$212,164**	**$100,571**	**$219,214**	**$88,596**	**$10,341**	**$3,215**	**$441,719**	**$192,382**	**$634,101**	
27											
28											
29											
30											
31											

32	Description	Total	Electric	Gas
33		(a) = (b) + (c)	(b)	(c)
34				
35	Rate Year Expense	$6,814,912	$4,154,522	$2,660,389
36	Rate Year 2020 O&M Salaries and Wages - Percentage Change		3.59%	4.24%
37	Payroll Tax Expense Adjustment	$261,948	$149,147	$112,801
38	Adjustment for SS-FICA, FUTA, SUTA, and EMAC salary caps	($78,449)	($40,266)	($38,183)
39	Recalculated Payroll Tax Expense Adjustment	**$183,499**	**$108,881**	**$74,617**
40	**Rate Year 2020 Expense**	**$6,998,410**	**$4,263,404**	**$2,735,007**
41				
42				

43		Narragansett Electric Company - Electric	Narragansett Electric Company - Gas	National Grid Service Company - Electric	National Grid Service Company - Gas	Other Affiliates - Electric	Other Affiliates - Gas	Total Electric	Total Gas	Percentage Increase / (Decrease) Electric	Percentage Increase / (Decrease) Gas
44	Source	Schedule 12, Page 6	Schedule 12, Page 7	Schedule 12, Page 8	Schedule 12, Page 9	Schedule 12, Page 10	Schedule 12, Page 11				
45		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (a) + (c) + (e)	(h) = (b) + (d) + (f)	(i)	(j)
46	Rate Year O&M Wages	$24,404,424	$17,424,303	$25,215,342	$15,349,511	$1,189,520	$557,026	$50,809,287	$33,330,840		
47	Rate Year 2020 O&M Wages	$25,318,731	$18,301,520	$26,092,188	$15,868,577	$1,222,762	$572,610	$52,633,682	$34,742,707		
48	Difference	$914,307	$877,217	$876,846	$519,066	$33,242	$15,584	$1,824,395	$1,411,867	3.59%	4.24%
49											
50	Allocation of Payroll Tax Expense	$2,050,854	$1,440,728	$2,113,505	$1,249,202	$99,045	$45,077	$4,263,404	$2,735,007		
51											
52	**Rate Year 2020 Expense**	$1,998,478	$1,401,421	$2,059,529	$1,215,121	$96,516	$43,847	**$4,154,522**	**$2,660,389**	**$6,814,912**	
53	**Recalculated Payroll Tax Expense Adjustment**	**$52,376**	**$39,306**	**$53,976**	**$34,081**	**$2,529**	**$1,230**	**$108,881**	**$74,617**	**$183,499**	
54											
55											
56											
57											
58											

59	Description	Total	Electric	Gas
60		(a) = (b) + (c)	(b)	(c)
61				
62	Rate Year 2020 Expense	$6,998,410	$4,263,404	$2,735,007
63	Rate Year 2021 O&M Salaries and Wages - Percentage Change		3.03%	3.14%
64	Payroll Tax Expense Adjustment	$215,060	$129,181	$85,879
65	Adjustment for SS-FICA, FUTA, SUTA, and EMAC salary caps	($74,274)	($44,026)	($30,248)
66	Recalculated Payroll Tax Expense Adjustment	**$140,786**	**$85,155**	**$55,631**
67	**Rate Year 2021 Expense**	**$7,139,196**	**$4,348,558**	**$2,790,638**
68				
69				

70		Narragansett Electric Company - Electric	Narragansett Electric Company - Gas	National Grid Service Company - Electric	National Grid Service Company - Gas	Other Affiliates - Electric	Other Affiliates - Gas	Total Electric	Total Gas	Percentage Increase / (Decrease) Electric	Percentage Increase / (Decrease) Gas
71	Source	Schedule 12, Page 6	Schedule 12, Page 7	Schedule 12, Page 8	Schedule 12, Page 9	Schedule 12, Page 10	Schedule 12, Page 11				
72		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (a) + (c) + (e)	(h) = (b) + (d) + (f)	(i)	(j)
73	Rate Year 2020 O&M Wages	$25,318,731	$18,301,520	$26,092,188	$15,868,577	$1,222,762	$572,610	$52,633,682	$34,742,707		
74	Rate Year 2021 O&M Wages	$26,033,577	$18,881,321	$26,942,463	$16,365,202	$1,251,075	$585,930	$54,227,115	$35,832,453		
75	Difference	$714,846	$579,801	$850,275	$496,625	$28,312	$13,320	$1,593,433	$1,089,746	3.03%	3.14%
76											
77	Allocation of Payroll Tax Expense	$2,087,674	$1,470,480.69	$2,160,559	$1,274,525	$100,326	$45,632	$4,348,558	$2,790,638		
78											
79	**Rate Year 2021 Expense**	$2,046,792	$1,441,167	$2,118,250	$1,249,117	$98,361	$44,723	**$4,263,404**	**$2,735,007**	**$6,998,410**	
80	**Recalculated Payroll Tax Expense Adjustment**	**$40,881**	**$29,314**	**$42,309**	**$25,408**	**$1,965**	**$910**	**$85,155**	**$55,631**	**$140,786**	

The Narragansett Electric Company d/b/a National Grid
Payroll Taxes - Electric
Rate Year Ending August 31, 2019, August 31, 2020 and August 31, 2021

	Description	Payroll Tax Expense Breakdown	Test Year Payroll Tax Expense	Breakdown of Payroll Tax Expense Adjustment	Percent of Rate Year 2019 Payroll Subject to Tax Increase	Recalculated Rate Year 2019 Payroll Tax Expense Adjustment	Breakdown of Rate Year 2020 Payroll Tax Expense Adjustment	Percent of Rate Year 2020 Payroll Subject to Tax Increase	Recalculated Rate Year 2020 Payroll Tax Expense Adjustment	Breakdown of Rate Year 2021 Payroll Tax Expense Adjustment	Percent of Rate Year 2021 Payroll Subject to Tax Increase	Recalculated Rate Year 2021 Payroll Tax Expense Adjustment
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	SS portion of FICA	76.26%	$2,831,507	$429,540	78.00%	$335,041	$113,745	70.96%	$80,713	$98,518	61.67%	$60,756
2	Medicare portion of FICA	17.84%	$662,207	$100,457	100.00%	$100,457	$26,602	100.00%	$26,602	$23,040	100.00%	$23,040
3	FICA	94.10%	$3,493,715	$529,997		$435,498	$140,346		$107,315	$121,558		$83,796
4												
5	FUTA	0.63%	$23,551	$3,573	0.91%	$33	$946	-0.40%	($4)	$819	-0.34%	($3)
6												
7	SUTA	3.89%	$144,363	$21,900	1.02%	$223	$5,799	-0.07%	($4)	$5,023	-0.05%	($3)
8												
9	Oth Inc Tax-St Tax Ma	0.32%	$11,969	$1,816	0.98%	$18	$481	-0.16%	($1)	$416	-0.13%	($1)
10	NY Metropolitan Commuter Tax	1.06%	$39,206	$5,948	100.00%	$5,948	$1,575	100.00%	$1,575	$1,364	100.00%	$1,364
11	Other Payroll Taxes	0.00%	$0	$0	100.00%	$0	$0	100.00%	$0	$0	100.00%	$0
12	Other	1.38%	$51,174	$7,763		$5,965	$2,056		$1,574	$1,781		$1,364
13												
14	Total Payroll Tax Expense	100.00%	$3,712,803	$563,232		$441,719	$149,147		$108,881	$129,181		$85,155

Column Notes:

(a) Per Company books
(b) Page 6, Line 7(b) x Column (a)
(c) Page 6, Line 9(b) x Column (a)
(d) Per Company books
(e) Column (c) x Column (d)
(f) Page 6, Line 36(b) x Column (a)
(g) Per Company books
(h) Column (f) x Column (g)
(i) Page 6, Line 63(b) x Column (a)
(j) Per Company books
(k) Column (i) x Column (j)

FICA = Federal Insurance Contributions Act.
FUTA = Federal Unemployment Tax Act.
SUTA = State Unemployment Tax Act

The Narragansett Electric Company d/b/a National Grid
Payroll Taxes - Gas
Rate Year Ending August 31, 2019, August 31, 2020 and August 31, 2021

	Description	Payroll Tax Expense Breakdown	Test Year Payroll Tax Expense	Breakdown of Payroll Tax Expense Adjustment	Percent of Rate Year 2019 Payroll Subject to Tax Increase	Recalculated Rate Year 2019 Payroll Tax Expense Adjustment	Breakdown of Rate Year 2020 Payroll Tax Expense Adjustment	Percent of Rate Year 2020 Payroll Subject to Tax Increase	Recalculated Rate Year 2020 Payroll Tax Expense Adjustment	Breakdown of Rate Year 2021 Payroll Tax Expense Adjustment	Percent of Rate Year 2021 Payroll Subject to Tax Increase	Recalculated Rate Year 2021 Payroll Tax Expense Adjustment
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	SS portion of FICA	77.01%	$1,900,561	$197,088	73.02%	$143,914	$86,865	61.36%	$53,301	$66,134	59.58%	$39,403
2	Medicare portion of FICA	18.01%	$444,486	$46,093	100.00%	$46,093	$20,315	100.00%	$20,315	$15,467	100.00%	$15,467
3	FICA	95.02%	$2,345,047	$243,181		$190,007	$107,181		$73,616	$81,601		$54,869
4												
5	FUTA	0.58%	$14,363	$1,489	0.72%	$11	$656	-0.42%	($3)	$500	-0.43%	($2)
6												
7	SUTA	3.23%	$79,714	$8,266	0.89%	$74	$3,643	-0.06%	($2)	$2,774	-0.08%	($2)
8												
9	Other Income Taxes -State Tax MA	0.28%	$6,849	$710	0.84%	$6	$313	-0.15%	($0)	$238	-0.17%	($0)
10	NY Metropolitan Commuter Tax	0.89%	$22,034	$2,285	100.00%	$2,285	$1,007	100.00%	$1,007	$767	100.00%	$767
11	Other Payroll Taxes	0.00%	$0	$0	100.00%	$0	$0	100.00%	$0	$0	100.00%	$0
12	Other	1.17%	$28,883	$2,995		$2,291	$1,320		$1,007	$1,005		$766
13												
14	Total Payroll Tax Expense	100.00%	$2,468,007	$255,932		$192,382	$112,801		$74,617	$85,879		$55,631

Column Notes:

(a) Per Company books
(b) Page 6, Line 7(c) x Column (a)
(c) Page 6, Line 9(c) x Column (a)
(d) Per Company books
(e) Column (c) x Column (d)
(f) Page 6, Line 36(c) x Column (a)
(g) Per Company books
(h) Column (f) x Column (g)
(i) Page 6, Line 63(c) x Column (a)
(j) Per Company books
(k) Column (i) x Column (j)

FICA = Federal Insurance Contributions Act
FUTA = Federal Unemployment Tax Act
SUTA = State Unemployment Tax Act

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/ 4780
Witness: Little

Compliance Attachment 2

Schedule 9

Other Tax and Gross Receipts Tax

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 9
Page 1 of 5

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Taxes Other Than Income Taxes - Other Taxes and Gross Receipts Tax

		Test Year Ended June 30, 2017 (Per Books)			Normalizing Adjustments			Test Year Ended June 30, 2017 (as Adjusted)		
		Total	Electric	Gas	Total	Electric	Gas	Total	Electric	Gas
		(a) = (b) + (c)	(b)	(c)	(d) = (e) + (f)	(e)	(f)	(g) = (h) + (i)	(h)	(i)
	Taxes Other Than Income Taxes:									
1	Narragansett Electric Company	$17,353	$13,187	$4,166	$0	$0	$0	$17,353	$13,187	$4,166
2	National Grid USA Service Company	$634,409	$421,111	$213,298	$0	$0	$0	$634,409	$421,111	$213,298
3	All Other Companies	$0	$0	$0	$0	$0	$0	$0	$0	$0
4	Total Other Taxes	$651,762	$434,298	$217,464	$0	$0	$0	$651,762	$434,298	$217,464
	Check	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Gross Receipts Tax:									
5	Narragansett Electric Company	$43,734,959	$32,568,650	$11,166,309	($43,734,959)	($32,568,650)	($11,166,309)	$0	$0	$0
6	National Grid USA Service Company	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	All Other Companies	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Total Gross Receipts Tax	$43,734,959	$32,568,650	$11,166,309	($43,734,959)	($32,568,650)	($11,166,309)	$0	$0	$0
	Check	$0	$0	$0	$0	$0	$0	$0	$0	$0

Column Notes
(b) and (c) Per Company Books
(e) Page 5, Line 2 to Line 10, Column (b)
(f) Page 5, Line 2 to Line 10, Column (c)
(h) Column (b) + Column (e)
(i) Column (c) + Column (f)

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Taxes Other Than Income Taxes - Other Taxes and Gross Receipts Tax

		Test Year Ended June 30, 2017 (as Adjusted)			Proforma Adjustments			Rate Year Ending August 31, 2019		
		Total	Electric	Gas	Total	Electric	Gas	Total	Electric	Gas
		(a) = (b) + (c)	(b)	(c)	(d) = (e) + (f)	(e)	(f)	(g) = (h) + (i)	(h)	(i)
	Taxes Other Than Income Taxes:									
1	Narragansett Electric Company	$17,353	$13,187	$4,166	$803	$611	$193	$18,157	$13,797	$4,359
2	National Grid USA Service Company	$634,409	$421,111	$213,298	$29,373	$19,497	$9,876	$663,782	$440,609	$223,173
3	All Other Companies	$0	$0	$0	$0	$0	$0	$0	$0	$0
4	Total Other Taxes	$651,762	$434,298	$217,464	$30,177	$20,108	$10,069	$681,939	$454,406	$227,533
	Check	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Gross Receipts Tax:									
5	Narragansett Electric Company	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	National Grid USA Service Company	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	All Other Companies	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Total Gross Receipts Tax	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Check	$0	$0	$0	$0	$0	$0	$0	$0	$0

Column Notes
(b) Page 1, Column (h)
(c) Page 1, Column (i)
(h) Column (b) + Column (e)
(i) Column (c) + Column (f)

Line Notes
1(e) Page 5, Line 20(b)
2(e) Page 5, Line 21(b)
3(e) Page 5, Line 22(b)
1(f) Page 5, Line 20(c)
2(f) Page 5, Line 21(c)
3(f) Page 5, Line 22(c)

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Taxes Other Than Income Taxes - Other Taxes and Gross Receipts Tax
Electric

		Rate Year Ending August 31, 2019	Reflect Conditions in Rate Year Ending August 31, 2020	Rate Year Ending August 31, 2020	Reflect Conditions in the Rate Year Ending August 31, 2021	Rate Year Ending August 31, 2021
		Electric	Electric	Electric	Electric	Electric
		(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) + (d)
	Taxes Other Than Income Taxes:					
1	Narragansett Electric Company	$13,797	$367	$14,164	$344	$14,509
2	National Grid USA Service Company	$440,609	$11,720	$452,329	$10,992	$463,321
3	All Other Companies	$0	$0	$0	$0	$0
4	Total Other Taxes	$454,406	$12,087	$466,493	$11,336	$477,829
	Check	$0	$0	$0	$0	$0
	Gross Receipts Tax:					
5	Narragansett Electric Company	$0	$0	$0	$0	$0
6	National Grid USA Service Company	$0	$0	$0	$0	$0
7	All Other Companies	$0	$0	$0	$0	$0
8	Total Gross Receipts Tax	$0	$0	$0	$0	$0
	Check	$0	$0	$0	$0	$0

Column Notes
(a) Page 2, Column (h)

Line Notes
1(b) Page 5, Line 30(b)
2(b) Page 5, Line 31(b)
3(b) Page 5, Line 32(b)
1(d) Page 5, Line 40(b)
2(d) Page 5, Line 41(b)
3(d) Page 5, Line 42(b)
8 Flow through tax, zero balance

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Taxes Other Than Income Taxes - Other Taxes and Gross Receipts Tax
Gas

		Rate Year Ending August 31, 2019	Reflect Conditions in the Rate Year Ending August 31, 2020	Rate Year Ending August 31, 2020	Reflect Conditions in the Rate Year Ending August 31, 2021	Rate Year Ending August 31, 2021
		Gas	Gas	Gas	Gas	Gas
		(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) + (d)
	Provider Company:					
1	Narragansett Electric Company	$4,359	$116	$4,475	$109	$4,584
2	National Grid USA Service Company	$223,173	$5,936	$229,110	$5,567	$234,677
3	All Other Companies	$0	$0	$0	$0	$0
4	Total Other Taxes	$227,533	$6,052	$233,585	$5,676	$239,261
	Check	$0	$0	$0	$0	$0
	Provider Company:					
1	Narragansett Electric Company	$0	$0	$0	$0	$0
2	National Grid USA Service Company	$0	$0	$0	$0	$0
3	All Other Companies	$0	$0	$0	$0	$0
4	Total Gross Receipts Tax	$0	$0	$0	$0	$0
	Check	$0	$0	$0	$0	$0

Column Notes
(a) Page 2, Column (i)

Line Notes
1(b) Page 5, Line 30(c)
2(b) Page 5, Line 31(c)
3(b) Page 5, Line 32(c)
1(d) Page 5, Line 40(c)
2(d) Page 5, Line 41(c)
3(d) Page 5, Line 42(c)

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Taxes Other Than Income Taxes - Other Taxes and Gross Receipts Tax

		Explanation of Adjustments:	Provider Company	Total	Electric	Gas
				(a) = (b) + (c)	(b)	(c)
1	Page 1	Taxes Other Than Income Taxes Adjustments: (to normalize Historic Year)				
2				$0	$0	$0
3				$0	$0	$0
4				$0	$0	$0
5		TOTAL Taxes Other Than Income Taxes Normalization Adjustments		$0	$0	$0
6						
7		Gross Receipts Tax Adjustments: (to normalize Historic Year)				
8			Narragansett Electric Company	($43,734,959)	($32,568,650)	($11,166,309)
9			National Grid USA Service Company	$0	$0	$0
10			All Other Companies	$0	$0	$0
11		TOTAL Gross Receipts Tax Normalization Adjustments		($43,734,959)	($32,568,650)	($11,166,309)
12						
13						
14						
15	Page 2	Adjustments: (to reflect conditions in the Rate Year 8/31/2019)				
16						
17		General inflation %				
18		4.63%				
19						
20			Narragansett Electric Company	$803	$611	$193
21			National Grid USA Service Company	$29,373	$19,497	$9,876
22			All Other Companies	$0	$0	$0
23						
24			TOTAL	$30,177	$20,108	$10,069
25						
26						
27	Page 3 and Page 4	Adjustments: (to reflect conditions in the Rate Year 8/31/2020)				
28						
29		General inflation %				
30		2.66%	Narragansett Electric Company	$483	$367	$116
31			National Grid USA Service Company	$17,657	$11,720	$5,936
32			All Other Companies	$0	$0	$0
33						
34			TOTAL	$18,140	$12,087	$6,052
35						
36						
37	Page 3 and Page 4	Adjustments: (to reflect conditions in the Rate Year 8/31/2021)				
38						
39		General inflation %				
40		2.43%	Narragansett Electric Company	$453	$344	$109
41			National Grid USA Service Company	$16,559	$10,992	$5,567
42			All Other Companies	$0	$0	$0
43						
44			TOTAL	$17,012	$11,336	$5,676

Line Notes

8-10 (b) Negative Page 1, Line 5 through Line 7, Column (b)
8-10 (c) Negative Page 1, Line 5 through Line 7, Column (c)
20(b) Page 2, Line 1(b) x General Inflation Rate
21(b) Page 2, Line 2(b) * General Inflation Rate
22(b) Page 2, Line 3(b) * General Inflation Rate
20(c) Page 2, Line 1(c) * General Inflation Rate
21(c) Page 2, Line 2(c) * General Inflation Rate
22(c) Page 2, Line 3(c) * General Inflation Rate
30(b) Page 3, Line 1(a) * General Inflation Rate
31(b) Page 3, Line 2(a) * General Inflation Rate
32(b) Page 3, Line 3(a) * General Inflation Rate
30(c) Page 4, Line 1(a) * General Inflation Rate
31(c) Page 4, Line 2(a) * General Inflation Rate
32(c) Page 4, Line 3(a) * General Inflation Rate
40(b) Page 3, Line 1(c) * General Inflation Rate
41(b) Page 3, Line 2(c) * General Inflation Rate
42(b) Page 3, Line 3(c) * General Inflation Rate
40(c) Page 4, Line 1(c) * General Inflation Rate
41(c) Page 4, Line 2(c) * General Inflation Rate
42(c) Page 4, Line 3(c) * General Inflation Rate

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/ 4780
Witness: Little

Compliance Attachment 2

Schedule 10-ELEC

Income Taxes– Electric

The Narragansett Electric Company d/b/a National Grid
Electric Income Tax Expense
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

		Reference	Rate Year Ending August 31, 2019	Revenue Increase Effect	Rate Year Ending August 31, 2019 with Revenue Increase
			(a)	(b)	(c)
1	Revenues	Schedule 1-ELEC	$279,091,943	$12,038,936	$291,130,879
2	Expenses	Schedule 1-ELEC	($236,474,851)	($156,855)	($236,631,706)
3	Pre-tax operating income before interest		$42,617,092	$11,882,081	$54,499,173
4					
5	Synchronized Interest Expense				
6	Rate Base	Schedule 11-ELEC	$729,509,971		$729,509,971
7	Weighted Debt Component	2.24%	2.24%	2.24%	2.24%
8	Synchronized Interest Expense		$16,341,023		$16,341,023
9					
10	Pre-tax income- State		$26,276,068	$11,882,081	$38,158,150
11	State statutory tax rate	0.00%	0.00%	0.00%	0.00%
12	Normalized State income tax expense		$0	$0	$0
13					
14	Pre-tax income- State		$26,276,068	$11,882,081	$38,158,150
15	Normalized State income tax expense		$0	$0	$0
16	Pre-tax income- Federal		$26,276,068	$11,882,081	$38,158,150
17	Federal statutory tax rate	21.00%	21.00%	21.00%	21.00%
18	Normalized Federal income tax expense		$5,517,974	$2,495,237	$8,013,211
19	Effective combined statutory tax rate	21.00%	21.00%	21.00%	21.00%
20	Excess Deferred Tax		($5,066,000)	$0	($5,066,000)
21	Deferred income tax deficiency from Docket 4065		$650,000	$0	$650,000
22	Amortization of Investment Tax Credits		($4,540)	$0	($4,540)
23	ITC Basis Reduction Depreciation		$15,210	$0	$15,210
24	Equity AFUDC		$0	$0	$0
25	AFUDC Amortization		$44,446	$0	$44,446
26	Normalized State income tax expense		$0	$0	$0
27	Normalized Federal income tax expense		$5,517,974	$2,495,237	$8,013,211
28	Normalized Federal plus State income tax expense revised		$1,157,091	$2,495,237	$3,652,328
29					
30	After-tax income		$41,460,001	$9,386,844	$50,846,845

Line Notes

1	Schedule 1-ELEC, Page 1, Line 1(e) through 1(g)	17	Federal income tax rate
2	Schedule 1-ELEC, Page 1, Line 25(e) through 25(g)	18	Line 16 x Line 17
3	Line 1 + Line 2	19	Line 11 + Line 17 - (Line 11 x Line 17)
6	Schedule 11-ELEC, Page 1, Line 24(c)	20 & 21	Per Tax Dept
7	Schedule 1-ELEC, Page 4, Line 1(c) + Line 3(c)	22	Page 4, Line 7
8	Line 6 x Line 7	23	Per Tax Dept
10	Line 3 - Line 8	24	Per Tax Dept
11	State income tax rate for utilities	25	Per Tax Dept
12	Line 10 x Line 11	26	Equals Line 12
14	Equals Line 10	27	Equals Line 18
15	Less Line 12	28	Sum of Lines 21 through 27
16	Line 14 + Line 15	30	Line 3 - Line 28

The Narragansett Electric Company d/b/a National Grid
Electric Income Tax Expense
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2020

		Reference	Rate Year Ending August 31, 2020	Revenue Increase Effect	Rate Year Ending August 31, 2020 with Revenue Increase
			(a)	(b)	(c)
1	Revenues	Schedule 1-ELEC	$291,130,879	$3,870,311	$295,001,190
2	Expenses	Schedule 1-ELEC	($240,293,355)	($50,426)	($240,343,781)
3	Pre-tax operating income before interest		$50,837,523	$3,819,885	$54,657,408
4					
5	Synchronized Interest Expense				
6	Rate Base	Schedule 11-ELEC	$731,597,435		$731,597,435
7	Weighted Debt Component	2.24%	2.24%	2.24%	2.24%
8	Synchronized Interest Expense		$16,387,783		$16,387,783
9					
10	Pre-tax income- State		$34,449,741	$3,819,885	$38,269,626
11	State statutory tax rate	0.00%	0.00%	0.00%	0.00%
12	Normalized State income tax expense		$0	$0	$0
13					
14	Pre-tax income- State		$34,449,741	$3,819,885	$38,269,626
15	Normalized State income tax expense		$0	$0	$0
16	Pre-tax income- Federal		$34,449,741	$3,819,885	$38,269,626
17	Federal statutory tax rate	21.00%	21.00%	21.00%	21.00%
18	Normalized Federal income tax expense		$7,234,446	$802,176	$8,036,621
19	Effective combined statutory tax rate	21.00%	21.00%	21.00%	21.00%
20	Excess Deferred Tax		(5,066,000)	$0	($5,066,000)
21	Deferred income tax deficiency from Docket 4065		$650,000	$0	$650,000
22	Amortization of Investment Tax Credits		$0	$0	$0
23	ITC Basis Reduction Depreciation		$0	$0	$0
24	Equity AFUDC		$0	$0	$0
25	AFUDC Amortization		$44,446	$0	$44,446
26	Normalized State income tax expense		$0	$0	$0
27	Normalized Federal income tax expense		$7,234,446	$802,176	$8,036,621
28	Normalized Federal plus State income tax expense revised		$2,862,891	$802,176	$3,665,067
29					
30	After-tax income		$47,974,632	$3,017,709	$50,992,341

Line Notes

1	Schedule 1-ELEC, Page 2, Line 1(c) through 1(e)	17	Federal income tax rate
2	Schedule 1-ELEC, Page 2 Line 25(c) through 25(e)	18	Line 16 x Line 17
3	Line 1 + Line 2	19	Line 11 + Line 17 - (Line 11 x Line 17)
6	Schedule 11-ELEC, Page 1, Line 24(d)	20 & 21	Per Tax Dept
7	Schedule 1-ELEC, Page 4, Line 1(c) + Line 3(c)	22	Per Tax Dept
8	Line 6 x Line 7	23	Per Tax Dept
10	Line 3 - Line 8	24	Per Tax Dept
11	State income tax rate for utilities	25	Per Tax Dept
12	Line 10 x Line 11	26	Equals Line 12
14	Equals Line 10	27	Equals Line 18
15	Less Line 12	28	Sum of Lines 21 through 27
16	Line 14 + Line 15	30	Line 3 - Line 28

The Narragansett Electric Company d/b/a National Grid
Electric Income Tax Expense
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2021

		Reference	Rate Year Ending August 31, 2021	Revenue Increase Effect	Rate Year Ending August 31, 2021 with Revenue Increase
			(a)	(b)	(c)
1	Revenues	Schedule 1-ELEC	$295,001,190	$2,546,157	$297,547,347
2	Expenses	Schedule 1-ELEC	($242,590,217)	($33,174)	($242,623,390)
3	Pre-tax operating income before interest		$52,410,973	$2,512,983	$54,923,956
4					
5	Synchronized Interest Expense				
6	Rate Base	Schedule 11-ELEC	$734,837,218		$734,837,218
7	Weighted Debt Component	2.24%	2.24%	2.24%	2.24%
8	Synchronized Interest Expense		$16,460,354		$16,460,354
9					
10	Pre-tax income- State		$35,950,619	$2,512,983	$38,463,603
11	State statutory tax rate	0.00%	0.00%	0.00%	0.00%
12	Normalized State income tax expense		$0	$0	$0
13					
14	Pre-tax income- State		$35,950,619	$2,512,983	$38,463,603
15	Normalized State income tax expense		$0	$0	$0
16	Pre-tax income- Federal		$35,950,619	$2,512,983	$38,463,603
17	Federal statutory tax rate	21.00%	21.00%	21.00%	21.00%
18	Normalized Federal income tax expense		$7,549,630	$527,726	$8,077,357
19	Effective combined statutory tax rate	21.00%	21.00%	21.00%	21.00%
20	Excess Deferred Tax		(5,066,000)	$0	($5,066,000)
21	Deferred income tax deficiency from Docket 4065		$650,000	$0	$650,000
22	Amortization of Investment Tax Credits		$0	$0	$0
23	ITC Basis Reduction Depreciation		$0	$0	$0
24	Equity AFUDC		$0	$0	$0
25	AFUDC Amortization		$44,446	$0	$44,446
26	Normalized State income tax expense		$0	$0	$0
27	Normalized Federal income tax expense		$7,549,630	$527,726	$8,077,357
28	Normalized Federal plus State income tax expense revised		$3,178,076	$527,726	$3,705,802
29					
30	After-tax income		$49,232,897	$1,985,257	$51,218,154

Line Notes

1	Schedule 1-ELEC, Page 3, Line 1(c) through 1(e)	17	Federal income tax rate
2	Schedule 1-ELEC, Page 3, Line 25(c) through 25(e)	18	Line 16 x Line 17
3	Line 1 + Line 2	19	Line 11 + Line 17 - (Line 11 x Line 17)
6	Schedule 11-ELEC, Page 1, Line 24(e)	20 & 21	Per Tax Dept
7	Schedule 1-ELEC, Page 4, Line 1(c) + Line 3(c)	22	Per Tax Dept
8	Line 6 x Line 7	23	Per Tax Dept
10	Line 3 - Line 8	24	Per Tax Dept
11	State income tax rate for utilities	25	Per Tax Dept
12	Line 10 x Line 11	26	Equals Line 12
14	Equals Line 10	27	Equals Line 18
15	Less Line 12	28	Sum of Lines 21 through 27
16	Line 14 + Line 15	30	Line 3 - Line 28

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 10-ELEC
Page 4 of 5

The Narragansett Electric Company d/b/a National Grid
Amortization of Investment Tax Credits
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

		Total
1	Rate Year Investment Tax Credits	($7,151)
2	Less: Related IFA Expenses	$2,611
3	Rate Year Investment Tax Credits Adjustment	($4,540)

Line Notes

1 Page 5, Line 14
2 Line 5 times 36.52% IFA plant allocator
3 Line 5 + Line 6

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
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Schedule 10-ELEC
Page 5 of 5

The Narragansett Electric Company d/b/a National Grid
Amortization of Investment Tax Credits
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

		Amortization
1	September 2018	($1,907)
2	October 2018	($1,907)
3	November 2018	($1,907)
4	December 2018	($230)
5	January 2019	($150)
6	February 2019	($150)
7	March 2019	($150)
8	April 2019	($150)
9	May 2019	($150)
10	June 2019	($150)
11	July 2019	($150)
12	August 2019	($150)
13		
14	**Total**	($7,151)

Line Notes

1-12 Per Tax Department
14 Sum of Line 1 thru Line 12

Compliance Attachment 2

Schedule 10-GAS

Income Taxes – Gas

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 10-GAS
Page 1 of 3

The Narragansett Electric Company d/b/a National Grid
Gas Income Tax Expense
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

		Reference	Rate Year Ending August 31, 2019	Revenue Increase Effect	Rate Year Ending August 31, 2019 with Revenue Increase
			(a)	(b)	(c)
1	Revenues	Schedule 1-GAS	$212,811,375	$5,823,471	$218,634,846
2	Expenses	Schedule 1-GAS	($157,080,397)	($111,079)	($157,191,476)
3	Pre-tax operating income before interest		$55,730,978	$5,712,392	$61,443,370
4					
5	Synchronized Interest Expense				
6	Rate Base	Schedule 11-GAS	$760,564,795		$760,564,795
7	Weighted Debt Component	2.42%	2.42%	2.42%	2.42%
8	Synchronized Interest Expense		$18,405,668		$18,405,668
9					
10	Pre-tax income- State		$37,325,310	$5,712,392	$43,037,702
11	State statutory tax rate	0.00%	0.00%	0.00%	0.00%
12	Normalized State income tax expense		$0	$0	$0
13					
14	Pre-tax income- State		$37,325,310	$5,712,392	$43,037,702
15	Normalized State income tax expense		$0	$0	$0
16	Pre-tax income- Federal		$37,325,310	$5,712,392	$43,037,702
17	Federal statutory tax rate	21.00%	21.00%	21.00%	21.00%
18	Normalized Federal income tax expense		$7,838,315	$1,199,602	$9,037,917
19	Effective combined statutory tax rate	21.00%	21.00%	21.00%	21.00%
20	Excess Deferred Tax		(1,998,000)	$0	($1,998,000)
21	Equity AFUDC		$0	$0	$0
22	AFUDC Amortization		$23,070	$0	$23,070
23	Normalized State income tax expense		$0	$0	$0
24	Normalized Federal income tax expense		$7,838,315	$1,199,602	$9,037,917
25	Normalized Federal plus State income tax expense revised		$5,863,385	$1,199,602	$7,062,987
26					
27	After-tax income		$49,867,593	$4,512,790	$54,380,383

Line Notes

1	Schedule 1-GAS, Page 1, Line 1(e) through 1(g)	16	Line 14 + Line 15
2	Schedule 1-GAS, Page 1, Line 25(e) through 25(g)	17	Federal income tax rate
3	Line 1 + Line 2	18	Line 16 x Line 17
6	Schedule 11-GAS, Page 1, Line 36(c)	19	Line 11 + Line 17 - (Line 11 x Line 17)
7	Schedule 1-GAS, Page 4, Line 1(c) + Line 3(c)	20	Per Tax Dept
8	Line 6 x Line 7	21	Per Tax Dept
10	Line 3 - Line 8	22	Per Tax Dept
11	State income tax rate	23	Equals Line 12
12	Line 10 x Line 11	24	Equals Line 18
14	Equals Line 10	25	Sum of Lines 21 through 25
15	Less Line 12	27	Line 3 - Line 25

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
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Schedule 10-GAS
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The Narragansett Electric Company d/b/a National Grid
Gas Income Tax Expense
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2020

		Reference	Rate Year Ending August 31, 2020	Revenue Increase Effect	Rate Year Ending August 31, 2020 with Revenue Increase
			(a)	(b)	(c)
1	Revenues	Schedule 1-GAS	$218,634,846	$5,726,761	$224,361,607
2	Expenses	Schedule 1-GAS	($161,739,605)	($109,234)	($161,848,840)
3	Pre-tax operating income before interest		$56,895,241	$5,617,527	$62,512,767
4					
5	Synchronized Interest Expense				
6	Rate Base	Schedule 11-GAS	$773,284,603		$773,284,603
7	Weighted Debt Component	2.42%	2.42%	2.42%	2.42%
8	Synchronized Interest Expense		$18,713,487		$18,713,487
9					
10	Pre-tax income- State		$38,181,753	$5,617,527	$43,799,280
11	State statutory tax rate	0.00%	0.00%	0.00%	0.00%
12	Normalized State income tax expense		$0	$0	$0
13					
14	Pre-tax income- State		$38,181,753	$5,617,527	$43,799,280
15	Normalized State income tax expense		$0	$0	$0
16	Pre-tax income- Federal		$38,181,753	$5,617,527	$43,799,280
17	Federal statutory tax rate	21.00%	21.00%	21.00%	21.00%
18	Normalized Federal income tax expense		$8,018,168	$1,179,681	$9,197,849
19	Effective combined statutory tax rate	21.00%	21.00%	21.00%	21.00%
20	Excess Deferred Tax		(1,998,000)	$0	($1,998,000)
21	Equity AFUDC		$0	$0	$0
22	AFUDC Amortization		$23,070	$0	$23,070
23	Normalized State income tax expense		$0	$0	$0
24	Normalized Federal income tax expense		$8,018,168	$1,179,681	$9,197,849
25	Normalized Federal plus State income tax expense revised		$6,043,238	$1,179,681	$7,222,918
26					
27	After-tax income		$50,852,003	$4,437,846	$55,289,849

Line Notes

1	Schedule 1-GAS, Page 2, Line 1(c) through 1(e)	16	Line 14 + Line 15
2	Schedule 1-GAS, Page 2, Line 23(c) through 23(e)	17	Federal income tax rate
3	Line 1 + Line 2	18	Line 16 x Line 17
6	Schedule 11-GAS, Page 1, Line 36(d)	19	Line 11 + Line 17 - (Line 11 x Line 17)
7	Schedule 1-GAS, Page 4, Line 1(c) + Line 3(c)	20	Per Tax Dept
8	Line 6 x Line 7	21	Per Tax Dept
10	Line 3 - Line 8	22	Per Tax Dept
11	State income tax rate	23	Equals Line 12
12	Line 10 x Line 11	24	Equals Line 18
14	Equals Line 10	25	Sum of Lines 21 through 25
15	Less Line 12	27	Line 3 - Line 25

The Narragansett Electric Company d/b/a National Grid
Gas Income Tax Expense
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2021

		Reference	Rate Year Ending August 31, 2021	Revenue Increase Effect	Rate Year Ending August 31, 2021 with Revenue Increase
			(a)	(b)	(c)
1	Revenues	Schedule 1-GAS	$224,361,607	$3,362,798	$227,724,405
2	Expenses	Schedule 1-GAS	($163,852,572)	($64,143)	($163,916,716)
3	Pre-tax operating income before interest		$60,509,035	$3,298,655	$63,807,690
4					
5	Synchronized Interest Expense				
6	Rate Base	Schedule 11-GAS	$788,686,880		$788,686,880
7	Weighted Debt Component	2.42%	2.42%	2.42%	2.42%
8	Synchronized Interest Expense		$19,086,222		$19,086,222
9					
10	Pre-tax income- State		$41,422,812	$3,298,655	$44,721,467
11	State statutory tax rate	0.00%	0.00%	0.00%	0.00%
12	Normalized State income tax expense		$0	$0	$0
13					
14	Pre-tax income- State		$41,422,812	$3,298,655	$44,721,467
15	Normalized State income tax expense		$0	$0	$0
16	Pre-tax income- Federal		$41,422,812	$3,298,655	$44,721,467
17	Federal statutory tax rate	21.00%	21.00%	21.00%	21.00%
18	Normalized Federal income tax expense		$8,698,791	$692,718	$9,391,508
19	Effective combined statutory tax rate	21.00%	21.00%	21.00%	21.00%
20	Excess Deferred Tax		(1,998,000)	$0	($1,998,000)
21	Equity AFUDC		$0	$0	$0
22	AFUDC Amortization		$23,070	$0	$23,070
23	Normalized State income tax expense		$0	$0	$0
24	Normalized Federal income tax expense		$8,698,791	$692,718	$9,391,508
25	Normalized Federal plus State income tax expense revised		$6,723,860	$692,718	$7,416,578
26					
27	After-tax income		$53,785,175	$2,605,937	$56,391,112

Line Notes

1	Schedule 1-GAS, Page 3, Line 1(c) - 1(e)	16	Line 14 + Line 15
2	Schedule 1-GAS, Page 3, Line 23(c) - 23(e)	17	Federal income tax rate
3	Line 1 + Line 2	18	Line 16 x Line 17
6	Schedule 11-GAS, Page 1, Line 36(e)	19	Line 11 + Line 17 - (Line 11 x Line 17)
7	Schedule 1, Page 4, Line 1(c) + Line 3(c)	20	Per Tax Dept
8	Line 6 x Line 7	21	Per Tax Dept
10	Line 3 - Line 8	22	Per Tax Dept
11	State income tax rate	23	Equals Line 12
12	Line 10 x Line 11	24	Equals Line 18
14	Equals Line 10	25	Sum of Lines 21 through 25
15	Less Line 12	27	Line 3 - Line 25

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/ 4780
Witness: Little

Compliance Attachment 2

Schedule 11-ELEC

Rate Base– Electric

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
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The Narragansett Electric Company d/b/a National Grid
Distribution Rate Base Calculation - Electric
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

	Description	Test Year Ended June 30, 2017 (Per Books - 5 Quarter Average) (a)	Adjustments (b)	5 Quarter Average Rate Year Ending August 31, 2019 (c)	Rate Year Ending August 31, 2020 (d)	Rate Year Ending August 31, 2021 (e)
1	Utility Plant In Service	$1,503,289,331	$98,250,392	$1,601,539,723	$1,602,539,723	$1,604,539,723
2						
3	Property Held for Future Use	$2,496,405	$0	$2,496,405	$2,496,405	$2,496,405
4	Less: Contribution in Aid of Construction	($101,521)	$104,277	$2,756	$2,756	$2,756
5	Less: Accumulated Depreciation	$656,218,763	$32,136,421	$688,355,184	$688,470,384	$688,563,184
6						
7	Net Plant	$849,668,494	$66,009,694	$915,678,188	$916,562,988	$918,470,188
8						
9	Materials and Supplies	$4,750,549	($1,256,873)	$3,493,676	$3,403,498	$3,327,193
10	Prepayments	$742,480	($742,479)	$0	$0	$0
11	Loss on Reacquired Debt	$1,934,554	($533,340)	$1,401,214	$1,244,585	$1,112,052
12	Cash Working Capital	$4,975,475	$12,946,603	$17,922,078	$17,922,078	$17,922,078
13	Unamortized Interest Rate Lock	$2,439,092	($801,086)	$1,638,006	$1,237,463	$898,542
14	Unamortized Debt Issuance Costs $550M	$1,113,997	($212,054)	$901,943	$795,916	$706,200
15	Unamortized Debt Issuance Costs $250M	$945,261	($79,025)	$866,236	$826,723	$793,290
16	Unamortized Debt Issuance Costs $350M	$0	$577,476	$577,476	$511,041	$454,826
17	Subtotal	$16,901,408	$9,899,222	$26,800,630	$25,941,303	$25,214,181
18						
19	Accumulated Deferred FIT	$183,859,681	$19,680,525	$203,540,205	$201,385,915	$199,252,781
20	Accumulated Deferred FIT -Loss on Reacquired Debt	$677,094	($137,021)	$540,073	$509,711	$479,349
21	Customer Deposits	$9,956,664	($1,068,096)	$8,888,568	$9,011,230	$9,115,021
22	Subtotal	$194,493,439	$18,475,408	$212,968,847	$210,906,856	$208,847,151
23						
24	Rate Base	$672,076,463	$57,433,508	$729,509,971	$731,597,435	$734,837,218

Column Notes
(a) Page 2, Column (f)
(b) Column (c) - Column (a)

Line Notes
1(c) Page 6, Line 34
1(d) Page 7, Line 16
1(e) Page 7, Line 33
2(c) - (e) Line 1(a)
4(c) Page 10, Line 46(a)
4(d) Page 10, Line 48(a)
4(e) Page 10, Line 50(a)
5(c) Page 8, Line 30
5(d) Page 9, Line 16
5(e) Page 9, Line 33
7(a) - (e) Line 1 + Line 3 - Line 4 - Line 5
9(c) Page 10, Line 46(b)
9(d) Page 10, Line 48(b)
9(e) Page 10, Line 50(b)
11(c) Page 10, Line 46(d)
11(d) Page 10, Line 48(d)
11(e) Page 10, Line 50(d)
12(c) - (e) Schedule 4, Page 1 Line 23
13(c) Page 10, Line 46(f)
13(d) Page 10, Line 48(f)
13(e) Page 10, Line 50(f)
14(c) Page 10, Line 46(g)
14(d) Page 10, Line 48(g)
14(e) Page 10, Line 50(g)
15(c) Page 10, Line 46(h)
15(d) Page 10, Line 48(h)
15(e) Page 10, Line 50(h)
16(c) Page 10, Line 46(i)
16(d) Page 10, Line 48(i)
16(e) Page 10, Line 50(i)
17(a) - (e) Sum of Lines 9 - 16
19(c) Page 11, Line 24(b)
19(d) Page 12, Line 16(b)
19(e) Page 12, Line 31(b)
20 (c)- (e) Line 11 * 35%
21(c) Page 10, Line 46(e)
21(d) Page 10, Line 48(e)
21(e) Page 10, Line 50(e)
22(a) - (e) Sum of Lines 19 - 21
24(a) - (e) Line 7 + Line 17 - Line 22

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
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The Narragansett Electric Company d/b/a National Grid
Test Year Rate Base - Distribution
Five Quarter Average

	Description	June 2016 (a)	September 2016 (b)	Quarter Ending December 2016 (c)	March 2017 (d)	June 2017 (e)	Five Quarter Average (f)
1	Utility Plant in Service	$1,483,904,318	$1,487,785,788	$1,490,507,033	$1,525,211,443	$1,529,038,072	$1,503,289,331
2							
3	Property Held for Future Use	$2,496,405	$2,496,405	$2,496,405	$2,496,405	$2,496,405	$2,496,405
4	Less: Contribution in Aid of Construction	$2,756	$2,756	$2,756	($518,630)	$2,756	($101,521)
5	Less: Accumulated Depreciation	$656,628,902	$656,147,751	$654,105,202	$661,928,361	$652,283,601	$656,218,763
6							
7	Net Plant in Service	$829,769,065	$834,131,685	$838,895,480	$866,298,116	$879,248,120	$849,668,494
8							
9	Plus:						
10	Materials and Supplies	$5,204,452	$4,879,444	$4,525,831	$5,510,606	$3,632,412	$4,750,549
11	Prepayments	$630,356	$907,230	$1,444,668	$1,054,315	($324,172)	$742,480
12	Loss on Reacquired Debt	$1,907,920	$1,882,220	$1,854,556	$2,318,694	$1,709,381	$1,934,554
13	Cash Working Capital	$4,975,475	$4,975,475	$4,975,475	$4,975,475	$4,975,475	$4,975,475
14	Unamortized Interest Rate Lock	$2,623,958	$2,531,525	$2,439,092	$2,346,659	$2,254,226	$2,439,092
15	Unamortized Debt Issuance Costs ($550M)	$1,162,933	$1,138,465	$1,113,997	$1,089,529	$1,065,062	$1,113,997
16	Unamortized Debt Issuance Costs ($250M 2012)	$963,498	$954,379	$945,261	$936,143	$927,024	$945,261
17	Subtotal	$17,468,592	$17,268,739	$17,298,880	$18,231,421	$14,239,408	$16,901,408
18							
19	Less:						
20	Accumulated Deferred FIT	$178,348,805	$193,417,512	$165,941,844	$184,975,771	$196,614,471	$183,859,681
21	Accumulated Deferred FIT - Loss on Reacquired Debt	$667,772	$658,777	$649,095	$811,543	$598,283	$677,094
22	Customer Deposits	$10,276,171	$10,375,796	$10,276,666	$10,154,831	$8,699,858	$9,956,664
23	Subtotal	$189,292,748	$204,452,085	$176,867,604	$195,942,145	$205,912,612	$194,493,439
24							
25	Rate Base	$657,944,909	$646,948,339	$679,326,756	$688,587,393	$687,574,916	$672,076,463

Column Notes
(a) Column(a) from Page 4 - Column(a) from Page 3
(b) Column(b) from Page 4 - Column(b) from Page 3
(c) Column(c) from Page 4 - Column(c) from Page 3
(d) Column(d) from Page 4 - Column(d) from Page 3
(e) Column(e) from Page 4 - Column(e) from Page 3

THE NARRAGANSETT ELECTRIC COMPANY
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The Narragansett Electric Company d/b/a National Grid
Test Year Rate Base - Integrated Facilities Agreement (IFA) and Block Island Transmission System
Five Quarter Average

	Description	June 2016 (a)	September 2016 (b)	Quarter Ending December 2016 (c)	March 2017 (d)	June 2017 (e)	Five Quarter Average (f)
1	Utility Plant in Service	$837,858,278	$837,980,360	$925,389,760	$943,635,963	$948,680,657	$898,709,004
2							
3	Property Held for Future Use	$12,531,903	$12,531,903	$12,531,903	$12,531,903	$12,531,903	$12,531,903
4	Less: Contribution in Aid of Construction	$0	$0	$0	$0	$0	$0
5	Less: Accumulated Depreciation	$98,171,448	$97,433,163	$96,405,529	$99,824,250	$102,899,605	$98,946,799
6							
7	Net Plant in Service	$752,218,732	$753,079,101	$841,516,133	$856,343,616	$858,312,955	$812,294,107
8							
9	Plus:						
10	Materials and Supplies	$3,099,585	$2,868,780	$2,720,358	$1,338,323	$2,684,191	$2,542,247
11	Prepayments	$367,547	$526,333	$836,202	$256,054	$475,210	$492,269
12	Loss on Reacquired Debt	$1,112,467	$1,091,978	$1,073,453	$563,126	$1,126,251	$993,455
13	Cash Working Capital	$2,870,239	$3,789,549	$2,681,655	$3,194,316	$2,514,043	$3,009,960
14	Unamortized Interest Rate Lock	$1,623,928	$1,566,724	$1,509,520	$1,452,316	$1,395,112	$1,509,520
14	Unamortized Debt Issuance Costs ($550M)	$816,103	$800,961	$785,818	$770,675	$710,105	$776,732
15	Unamortized Debt Issuance Costs ($250M 2012)	$641,436	$635,793	$630,149	$624,506	$618,863	$630,149
16	Subtotal	$10,531,305	$11,280,118	$10,237,155	$8,199,317	$9,523,775	$9,954,334
17							
18	Less:						
19	Accumulated Deferred FIT	$154,416,255	$156,079,291	$158,841,895	$168,039,168	$159,376,348	$159,350,591
20	Accumulated Deferred FIT - Loss on Reacquired Debt	$389,363	$382,192	$375,709	$197,094	$394,188	$347,709
21	Customer Deposits	$0	$0	$0	$0	$0	$0
23	Subtotal	$154,805,618	$156,461,483	$159,217,604	$168,236,262	$159,770,536	$159,698,301
24							
25	Rate Base	$607,944,420	$607,897,736	$692,535,685	$696,306,671	$708,066,194	$662,550,141

Column Notes
(a) - (e) Per Company Books

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
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The Narragansett Electric Company d/b/a National Grid
Test Year Rate Base - Total Distribution and IFA
Five Quarter Average

	Description	Quarter Ending June 2016 (a)	September 2016 (b)	December 2016 (c)	March 2017 (d)	June 2017 (e)	Five Quarter Average (f)
1	Utility Plant in Service	$2,321,762,596	$2,325,766,148	$2,415,896,793	$2,468,847,406	$2,477,718,729	$2,401,998,334
2							
3	Property Held for Future Use	$15,028,308	$15,028,308	$15,028,308	$15,028,308	$15,028,308	$15,028,308
4	Less: Contribution in Aid of Construction	$2,756	$2,756	$2,756	($518,630)	$2,756	($101,521)
5	Less: Accumulated Depreciation	$754,800,350	$753,580,914	$750,510,731	$761,752,611	$755,183,206	$755,165,562
6							
7	Net Plant in Service	$1,581,987,798	$1,587,210,786	$1,680,411,614	$1,722,641,733	$1,737,561,075	$1,661,962,601
8							
9	Plus:						
10	Materials and Supplies	$8,304,037	$7,748,224	$7,246,188	$6,848,929	$6,316,603	$7,292,796
11	Prepayments	$997,903	$1,433,564	$2,280,870	$1,310,370	$151,039	$1,234,749
12	Loss on Reacquired Debt	$3,020,387	$2,974,198	$2,928,009	$2,881,820	$2,835,632	$2,928,009
13	Cash Working Capital	$7,845,714	$8,765,024	$7,657,130	$8,169,791	$7,489,518	$7,985,435
14	Unamortized Interest Rate Lock	$4,247,886	$4,098,249	$3,948,612	$3,798,975	$3,649,338	$3,948,612
15	Unamortized Interest Rate Lock $550M	$1,979,036	$1,939,426	$1,899,815	$1,763,818	$1,724,208	$1,861,261
16	Unamortized Debt Issuance Costs $550M	$1,604,933	$1,590,172	$1,575,410	$1,515,504	$1,500,743	$1,557,352
17	Subtotal	$27,999,897	$28,548,857	$27,536,035	$26,289,207	$23,667,080	$26,808,215
18							
19	Less:						
20	Accumulated Deferred FIT	$332,765,060	$349,496,803	$324,783,739	$353,014,939	$355,990,819	$343,210,272
21	Accumulated Deferred FIT - Loss on Reacquired Debt	$1,057,135	$1,040,969	$1,024,803	$1,008,637	$992,471	$1,024,803
22	Customer Deposits	$10,276,171	$10,375,796	$10,276,666	$10,154,831	$8,699,858	$9,956,664
23	Subtotal	$344,098,367	$360,913,568	$336,085,208	$364,178,406	$365,683,148	$354,191,740
24							
25	Rate Base	$1,265,889,328	$1,254,846,074	$1,371,862,441	$1,384,752,533	$1,395,545,007	$1,334,579,077

Column Notes
(a) - (e) Per Company Books

The Narragansett Electric Company d/b/a National Grid
Adjustments to Rate Base
Analysis of Test Year through Rate Year Capital Investment

			FY18		FY19										
			4/1/17 - 6/30/17	7/1/17 - 3/31/18	4/1/18 - 8/31/18	9/1/18 - 3/31/19	FY20 4/1/19 - 8/31/19	Rate Year 1 9/1/18 - 8/31/19	FY20 9/1/19 - 3/31/20	FY21 4/1/20 - 8/31/20	Rate Year 2 9/1/19 - 8/31/20	FY21 9/1/20 - 3/31/21	FY22 4/1/21- 8/31/21	Rate Year 3 9/1/20 - 8/31/21	FY22 9/1/21 - 8/31/22
			(a)	(b)	(c)	(d)	(e)	(f)=(d)+(e)	(g)	(h)	(i)=(g)+(h)	(j)	(k)	(l)=(j)+(k)	(m)
	Distribution														
1	FY 2018 Approved ISR Plan		$18,710,750	$56,132,250	$31,184,583	$43,658,417	$31,184,583	$74,843,000							
2															
3															
4															
5	Total Distribution		$18,710,750	$56,132,250	$31,184,583	$43,658,417	$31,184,583	$74,843,000	$0	$0	$0	$0	$0	$0	$0
6															
7	**General Plant**														
8	Facilities		$0	$0	$0	$1,542,917	$1,102,083	$2,645,000	$1,166,667	$833,333	$2,000,000	$1,166,667	$833,333	$2,000,000	$2,000,000
9	IS Costs		$0	$0	$35,000	$53,000	$0	$53,000	$0	$0	$0	$0	$0	$0	$0
10	Fleet/Inventory Mgmt		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	Total General		$0	$0	$35,000	$1,595,917	$1,102,083	$2,698,000	$1,166,667	$833,333	$2,000,000	$1,166,667	$833,333	$2,000,000	$2,000,000
12	Amount Applicable to Transmission	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Amount Applicable to Distribution		$0	$0	$35,000	$1,595,917	$1,102,083	$2,698,000	$1,166,667	$833,333	$2,000,000	$1,166,667	$833,333	$2,000,000	$2,000,000
14															
15	Distribution and General		$18,710,750	$56,132,250	$31,219,583	$45,254,333	$32,286,667	$77,541,000	$1,166,667	$833,333	$2,000,000	$1,166,667	$833,333	$2,000,000	$2,000,000

Line Notes
5(a) - (m) Sum of Lines 1-4
8 Per Company Books
9(c) RI Elec Only Physical Security Replacements - FY18
9(d) RI Elec Only Physical Security Replacements - FY18
15(a) - (m) Sum of Line 5 + Line 13

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The Narragansett Electric Company d/b/a National Grid
Rate Base Adjustments
Plant in Service

	Description	Period	Distribution Plant In Service
		(a)	(b)
1	Balance at June 30, 2017		$1,529,038,072
2	Less: ARO		($1,123,411)
3	Less: Other Capital Adjustments		($14,007,757)
4	Adjusted Balance at June 30, 2017		$1,513,906,904
5			
6			
7	Plus: Plant Additions 2 months ending 8/31/17		$12,473,833
8	Less: Streetlight Retirement in 2 months ending 8/31/17		($1,057,011)
9	Less: Plant Retirements 2 months ending 8/31/17		($3,699,739)
10	Net Increase		$7,717,083
11			
12	Balance at August 31, 2017		$1,521,623,987
13			
14	Plus: Plant Additions 12 Months Ended 8/31/18		$74,843,000
15	Less: Plant Retirements 12 Months Ended 08/31/18		($22,198,434)
16	Net Increase		$52,644,566
17			
18	Balance at August 31, 2018		$1,574,268,553
19			
20			
21		09/30/18 1/	$1,578,813,748
22		10/31/18 1/	$1,583,358,943
23		11/30/18 1/	$1,587,904,138
24		12/31/18 1/	$1,592,449,333
25		01/31/19 1/	$1,596,994,528
26		02/28/19 1/	$1,601,539,723
27		03/31/19 1/	$1,606,084,918
28		04/30/19 1/	$1,610,630,113
29		05/31/19 1/	$1,615,175,308
30		06/30/19 1/	$1,619,720,503
31		07/31/19 1/	$1,624,265,698
32		08/31/19 1/	$1,628,810,893
33			
34	Rate Year Plant in Service - 5 Quarter Average		$1,601,539,723
35			
36	1/ Adjustment Detail:		
37	Plant Detail 12 Months Ended 8/31/19		
38	Plant Additions 12 Months Ended 8/31/19		$77,541,000
39	Plant Retirements 12 Months Ended 8/31/19		($22,998,661)
40	Net Increase / (Decrease)		$54,542,339
41			
42	Monthly Increase / (Decrease)		$4,545,195

Line Notes

1	Page 2, Line 1(e)
2	Schedule 6-ELEC Page 4, Line 18(b)
3	Schedule 6-ELEC Page 4, Line 18(d)
4	Sum of Lines 1- 3
7	Schedule 6-ELEC Page 1, Line 14(b)
8	Schedule 6-ELEC Page 1, Line 15(b)
9	Schedule 6-ELEC Page 1, Line 16(b)
10	Sum of Lines 7-9
12	Line 4 + Line 10
14	Schedule 6-ELEC Page 1, Line 34(b)
15	Schedule 6-ELEC Page 1, Line 35(b)
16	Line 14 + Line 15
18	Line 12 + Line 16
21	Line 18 + Line 42
22-32	Prior Month Balance + Line 42
34	Average of Lines 18, 23, 26, 29, and 32
38	Schedule 6-ELEC Page 2, Line 6(b)
39	Schedule 6-ELEC Page 2, Line 7(b)
40	Line 38 + Line 38
42	Line 40 divided by 12

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The Narragansett Electric Company d/b/a National Grid
Plant Adjustments to Rate Base
Rate Year 1 Ending August 31, 2019 through Rate Year 3 Ending August 31, 2021
Electric Plant in Service Forecast

	Description	Period (a)		Distribution Plant in Service (b)
1	Balance at August 31, 2019			$1,628,810,893
2				
3	Balance as of:	09/30/19	1/	$1,628,928,126
4		10/31/19	1/	$1,629,045,359
5		11/30/19	1/	$1,629,162,593
6		12/31/19	1/	$1,629,279,826
7		01/31/20	1/	$1,629,397,059
8		02/28/20	1/	$1,629,514,293
9		03/31/20	1/	$1,629,631,526
10		04/30/20	1/	$1,629,748,759
11		05/31/20	1/	$1,629,865,993
12		06/30/20	1/	$1,629,983,226
13		07/31/20	1/	$1,630,100,459
14	Balance at August 31, 2020		1/	$1,630,217,693
15				
16	Rate Year 2 Plant in Service - 5 Quarter Average			$1,629,514,293
17				
18	Balance at August 31, 2020			$1,630,217,693
19				
20	Balance as of:	09/30/20	2/	$1,630,334,926
21		10/31/20	2/	$1,630,452,159
22		11/30/20	2/	$1,630,569,393
23		12/31/20	2/	$1,630,686,626
24		01/31/21	2/	$1,630,803,859
25		02/28/21	2/	$1,630,921,093
26		03/31/21	2/	$1,631,038,326
27		04/30/21	2/	$1,631,155,559
28		05/31/21	2/	$1,631,272,793
29		06/30/21	2/	$1,631,390,026
30		07/31/21	2/	$1,631,507,259
31	Balance at August 31, 2021		2/	$1,631,624,493
32				
33	Rate Year 3 Plant in Service - 5 Quarter Average			$1,630,921,093
34				
35	1/ Rate Year 2 ending 08/31/20 Adjustment Detail:			
36	Plant Additions 12 Months Ended 08/31/2020			$2,000,000
37	Plant Retirements 12 Months Ended 08/31/2020			($593,200)
38	Net Increase / (Decrease)			$1,406,800
39				
40				
41	Monthly Increase / (Decrease)			$117,233
42				
43	2/ Rate Year 3 ending 08/31/21 Adjustment Detail:			
44	Plant Additions 12 Months Ended 08/31/2021			$2,000,000
45	Plant Retirements 12 Months Ended 08/31/2021			($593,200)
46	Net Increase / (Decrease)			$1,406,800
47				
48				
49	Monthly Increase / (Decrease)			$117,233

Line Notes

1	Page 6, Line 32
3	Line 1 + Line 41
4-14	Prior Month Balance + Line 41
16	Average of Lines 1, 5, 8, 11, and 14
18	Line 14
20	Line 18 + Line 49
21-31	Prior Month Balance + Line 49
33	Average of Lines 18, 22, 25, 28, and 31
36	Schedule 6-ELEC Page 2, Line 27(b)
37	Schedule 6-ELEC Page 2, Line 28(b)
38	Line 36 + Line 37
41	Line 38 divided by 12
44	Schedule 6-ELEC Page 2, Line 48(b)
45	Schedule 6-ELEC Page 2, Line 49(b)
46	Line 44+ Line 45
49	Line 46 divided by 12

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The Narragansett Electric Company d/b/a National Grid
Rate Base Adjustments
Accumulated Depreciation

	Description	Period	Accumulated Depreciation
		(a)	(b)
1	Balance at June 30, 2017		$652,405,159
2			
3	Depreciation Expense 07/01/2017 - 08/31/2017		$8,603,666
4	Less: Streetlights retired in the 2 Mos Ended 08/31/17 and Dep. for 2		($1,307)
5	Less: Net Cost of Removal / (Salvage)		($1,281,063)
6	Less: Retirements		($3,699,739)
7	Net Increase		$3,621,557
8			
9	Balance at August 31, 2017		$656,026,715
10			
11	Depreciation Expense 09/01/17 - 08/31/18		$52,630,173
12	Less: Net Cost of Removal / (Salvage)		($7,686,376)
13	Less: Retirements		($22,198,434)
14	Net Increase / (Decrease)		$22,745,363
15			
16	Balance at August 31, 2018		$678,772,079
17			
18		09/30/18 1/	$680,369,263
19		10/31/18 1/	$681,966,447
20		11/30/18 1/	$683,563,631
21		12/31/18 1/	$685,160,816
22		01/31/19 1/	$686,758,000
23		02/28/19 1/	$688,355,184
24		03/31/19 1/	$689,952,368
25		04/30/19 1/	$691,549,553
26		05/31/19 1/	$693,146,737
27		06/30/19 1/	$694,743,921
28		07/31/19 1/	$696,341,105
29	Balance at August 31, 2019	1/	$697,938,290
30			
31	Rate Year Accumulated Depreciation - Five Quarter Average		$688,355,184
32			
33	1/ Rate Year Ended 8/31/19 Depreciation Reserve Detail:		
34	Depreciation Expense		$50,375,341
35	Plus: Unrecovered Reserve Adjustment		($247,009)
36	Net Cost of Removal / (Salvage)		($7,963,461)
37	Less: Retirements		($22,998,661)
38	Net Increase / (Decrease)		$19,166,211
39			
40	Monthly Increase / (Decrease)		$1,597,184

Line Notes

1	Schedule 6-ELEC Page 1, Line 23(b)
3	Schedule 6-ELEC Page 1, Line 24(b)
4	Schedule 6-ELEC Page 1, Line 25(b)
5	Schedule 6-ELEC Page 1, Line 25(b)
6	Schedule 6-ELEC Page 1, Line 26(b)
7	Sum of Lines 3-6
8	Line 1 + Line 7
11	Schedule 6-ELEC Page 1, Line 43(b)
12	Schedule 6-ELEC Page 1, Line 44(b)
13	Schedule 6-ELEC Page 1, Line 45(b)
14	Sum of Lines 11-13
16	Line 9 + Line 14
18	Line 16 + Line 40
19-29	Prior Month Balance + Line 340
31	Average of Lines 16, 20, 23, 26, and 29
34	Schedule 6-ELEC Page 2, Line 16(b)
35	Schedule 6-ELEC Page 2, Line 17(b)
36	Schedule 6-ELEC Page 2, Line 18(b)
37	Schedule 6-ELEC Page 2, Line 19(b)
38	Sum of Lines 33-36
40	Line 37 divided by 12

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The Narragansett Electric Company d/b/a National Grid
Accumulated Depreciation Adjustments To Rate Base
Rate Year 1 Ending August 31, 2019 through Rate Year 3 Ending August 31, 2021

		Description	Period		Accumulated Depreciation
			(a)		(b)
1		Balance @ August 31, 2019			$697,938,290
2					
3		Balance as of:	09/30/19	1/	$702,122,427
4			10/31/19	1/	$706,306,565
5			11/30/19	1/	$710,490,703
6			12/31/19	1/	$714,674,841
7			01/31/20	1/	$718,858,978
8			02/28/20	1/	$723,043,116
9			03/31/20	1/	$727,227,254
10			04/30/20	1/	$731,411,392
11			05/31/20	1/	$735,595,530
12			06/30/20	1/	$739,779,667
13			07/31/20	1/	$743,963,805
14		Balance @ August 31, 2020		1/	$748,147,943
15					
16		Rate Year 2 Accumulated Depreciation - 5 Quarter Average			$723,043,116
17					
18		Balance @ August 31, 2020			$748,147,943
19					
20		Balance as of:	09/30/20	2/	$752,335,768
21			10/31/20	2/	$756,523,593
22			11/30/20	2/	$760,711,419
23			12/31/20	2/	$764,899,244
24			01/31/21	2/	$769,087,069
25			02/28/21	2/	$773,274,895
26			03/31/21	2/	$777,462,720
27			04/30/21	2/	$781,650,545
28			05/31/21	2/	$785,838,370
29			06/30/21	2/	$790,026,196
30			07/31/21	2/	$794,214,021
31		Balance @ August 31, 2021		2/	$798,401,846
32					
33		Rate Year 3 Accumulated Depreciation - 5 Quarter Average			$773,274,895
34					
35	1/	Rate Year 2 Ended 08/31/20 Depreciation Reserve Detail:			
36		Depreciation Expense 09/01/19 - 08/31/20			$51,255,262
37		Plus: Unrecovered Reserve Adjustment			($247,009)
38		Net Cost of Removal / (Salvage)			($205,400)
39		Less: Retirements			($593,200)
40		Net Increase / (Decrease)			$50,209,653
41					
42		Monthly Increase / (Decrease)			$4,184,138
43					
44	2/	Rate Year 3 Ended 08/31/21 Depreciation Reserve Detail:			
45		Depreciation Expense 09/01/20 - 08/31/21			$51,299,512
46		Plus: Unrecovered Reserve Adjustment			($247,009)
47		Net Cost of Removal / (Salvage)			($205,400)
48		Less: Retirements			($593,200)
49		Net Increase / (Decrease)			$50,253,903
50					
51		Monthly Increase / (Decrease)			$4,187,825

Line Notes

1	Page 8, Line 28
3	Line 1 + Line 42
4-14	Prior Month Balance + Line 42
16	Average of Lines 1, 5, 8, 11, and 14
18	Line 14
20	Line 18 + Line 51
21-31	Prior Month Balance + Line 51
33	Average of Lines 18, 22, 25, 28, and 31
36	Schedule 6-ELEC Page 2 Line 37(b)
37	Schedule 6-ELEC Page 2 Line 38(b)
38	Schedule 6-ELEC Page 2 Line 39(b)
39	Schedule 6-ELEC Page 2 Line 40(b)
40	Sum of Lines 36-39
42	Line 40 divided by 12
45	Schedule 6-ELEC Page 2 Line 58(b)
46	Schedule 6-ELEC Page 2 Line 59(b)
47	Schedule 6-ELEC Page 2 Line 60(b)
48	Schedule 6-ELEC Page 2 Line 61(b)
49	Sum of Lines 45-48
51	Line 49 divided by 12

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The Narragansett Electric Company d/b/a National Grid
Rate Base Adjustments
Other Rate Base Adjustments For 12 months ending August 31, 2019

	Description	Period	CIAC	Materials and Supplies	Prepayments	Loss on Reacquired Debt	Customer Deposits	Unamort Lock	$550M Unamort Issuance Costs	$250M Unamort Issuance Costs	$350M Unamort Issuance Costs
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Distribution Only Balance @ June 30, 2017		$2,756	$3,632,412	($324,172)	$1,709,381	$8,699,858	$2,254,226	$1,065,062	$927,024	$0
2											
3	Total Increase/(Decrease)		$0	($83,241)	$206,918	$0	$113,226	($369,732)	($97,871)	($36,473)	$0
4											
5	Distribution Only Balance @ June 30, 2018		$2,756	$3,549,171	($117,253)	$1,709,381	$8,813,084	$1,884,494	$967,190	$890,551	$0
6											
7		07/31/18	$2,756	$3,542,234	($100,010)	$1,485,554	$8,822,520	$1,853,683	$959,034	$887,512	$613,249
8		08/31/18	$2,756	$3,535,297	($82,767)	$1,473,505	$8,831,955	$1,822,872	$950,878	$884,472	$608,139
9		09/30/18	$2,756	$3,528,360	($65,524)	$1,461,457	$8,841,391	$1,792,061	$942,722	$881,433	$603,028
10		10/31/18	$2,756	$3,521,423	($48,280)	$1,449,408	$8,850,826	$1,761,250	$934,567	$878,394	$597,918
11		11/30/18	$2,756	$3,514,487	($31,037)	$1,437,360	$8,860,262	$1,730,439	$926,411	$875,354	$592,807
12		12/31/18	$2,756	$3,507,550	($13,794)	$1,425,311	$8,869,697	$1,699,628	$918,255	$872,315	$587,697
13		01/31/19	$2,756	$3,500,613	$3,449	$1,413,263	$8,879,133	$1,668,817	$910,099	$869,275	$582,587
14		02/28/19	$2,756	$3,493,676	$20,692	$1,401,214	$8,888,568	$1,638,006	$901,943	$866,236	$577,476
15		03/31/19	$2,756	$3,486,740	$37,936	$1,389,166	$8,898,004	$1,607,195	$893,787	$863,196	$572,366
16		04/30/19	$2,756	$3,479,803	$55,179	$1,377,118	$8,907,439	$1,576,384	$885,631	$860,157	$567,255
17		05/31/19	$2,756	$3,472,866	$72,422	$1,365,069	$8,916,875	$1,545,573	$877,475	$857,118	$562,145
18		06/30/19	$2,756	$3,465,929	$72,422	$1,353,021	$8,926,310	$1,514,762	$869,319	$854,078	$557,034
19		07/31/19	$2,756	$3,458,992	$89,665	$1,340,972	$8,935,746	$1,483,951	$861,163	$851,039	$551,924
20		08/31/19	$2,756	$3,452,056	$0	$1,328,924	$8,945,182	$1,453,140	$853,007	$847,999	$546,814
21		09/30/19	$2,756	$3,445,119	$0	$1,316,875	$8,954,617	$1,422,329	$844,851	$844,960	$541,703
22		10/31/19	$2,756	$3,438,182	$0	$1,304,827	$8,964,053	$1,391,518	$836,695	$841,920	$536,593
23		11/30/19	$2,756	$3,431,245	$0	$1,292,778	$8,973,488	$1,360,707	$828,539	$838,881	$531,482
24		12/31/19	$2,756	$3,424,308	$0	$1,280,730	$8,982,924	$1,329,896	$820,383	$835,842	$526,372
25		01/31/20	$2,756	$3,417,372	$0	$1,268,682	$8,992,359	$1,299,085	$812,227	$832,802	$521,262
26		02/29/20	$2,756	$3,410,435	$0	$1,256,633	$9,001,795	$1,268,274	$804,071	$829,763	$516,151
27		03/31/20	$2,756	$3,403,498	$0	$1,244,585	$9,011,230	$1,237,463	$795,916	$826,723	$511,041
28		04/30/20	$2,756	$3,396,561	$0	$1,232,536	$9,020,666	$1,206,652	$787,760	$823,684	$505,930
29		05/31/20	$2,756	$3,389,624	$0	$1,220,488	$9,030,101	$1,175,841	$779,604	$820,644	$500,820
30		06/30/20	$2,756	$3,382,688	$0	$1,208,439	$9,039,537	$1,145,030	$771,448	$817,605	$495,710
31		07/31/20	$2,756	$3,375,751	$0	$1,196,391	$9,048,972	$1,114,219	$763,292	$814,566	$490,599
32		08/31/20	$2,756	$3,368,814	$0	$1,184,342	$9,058,408	$1,083,408	$755,136	$811,526	$485,489
33		09/30/20	$2,756	$3,361,877	$0	$1,172,294	$9,067,843	$1,052,597	$746,980	$808,487	$480,378
34		10/31/20	$2,756	$3,354,941	$0	$1,160,246	$9,077,279	$1,021,786	$738,824	$805,447	$475,268
35		11/30/20	$2,756	$3,348,004	$0	$1,148,197	$9,086,714	$990,975	$730,668	$802,408	$470,158
36		12/31/20	$2,756	$3,341,067	$0	$1,136,149	$9,096,150	$960,164	$722,512	$799,368	$465,047
37		01/31/21	$2,756	$3,334,130	$0	$1,124,100	$9,105,585	$929,353	$714,356	$796,329	$459,937
38		02/28/21	$2,756	$3,327,193	$0	$1,112,052	$9,115,021	$898,542	$706,200	$793,290	$454,826
39		03/31/21	$2,756	$3,320,257	$0	$1,100,003	$9,124,457	$867,731	$698,044	$790,250	$449,716
40		04/30/21	$2,756	$3,313,320	$0	$1,087,955	$9,133,892	$836,920	$689,888	$787,211	$444,605
41		05/31/21	$2,756	$3,306,383	$0	$1,075,906	$9,143,328	$806,109	$681,732	$784,171	$439,495
42		06/30/21	$2,756	$3,299,446	$0	$1,063,858	$9,152,763	$775,298	$673,576	$781,132	$434,385
43		07/31/21	$2,756	$3,292,509	$0	$1,051,809	$9,162,199	$744,487	$665,420	$778,092	$429,274
44		08/31/21	$2,756	$3,285,573	$0	$1,039,761	$9,171,634	$713,676	$657,265	$775,053	$424,164
45											
46	Rate Year 1 Amounts - Five Quarter Average		$2,756	$3,493,676	$0	$1,401,214	$8,888,568	$1,638,006	$901,943	$866,236	$577,476
47											
48	Rate Year 2 Amounts - Five Quarter Average		$2,756	$3,403,498	$0	$1,244,585	$9,011,230	$1,237,463	$795,916	$826,723	$511,041
49											
50	Rate Year 3 Amounts - Five Quarter Average		$2,756	$3,327,193	$0	$1,112,052	$9,115,021	$898,542	$706,200	$793,290	$454,826
51											
52	Changes:										
53	Total Increase/(Decrease)		$0	($128,866)	$320,331	($223,827)	$113,226	($369,732)	($97,871)	($36,473)	($61,325)
54											
55	Percentage Applicable to IFA		0.00%	35.40%	35.40%	35.40%	0.00%	0.00%	0.00%	0.00%	0.00%
56											
57	Less Amount Applicable to IFA		$0	$45,625	($113,413)	79,246	$0	$0	$0	$0	$0
58											
59	Total Distribution Only Increase/(Decrease)		$0	($83,241)	$206,918	(144,581)	$113,226	($369,732)	($97,871)	($36,473)	($61,325)
60											
61	Monthly Change		$0	(6,937)	17,243	(12,048)	9,436	(30,811)	(8,156)	(3,039)	($5,110)

Line Notes

1(a)	Page 2, Line 4(e)	7-44	Prior Month Balance + Line 61
1(b)	Page 2, Line 10(e)	46	Average of Lines 8, 11, 14, 17, and 20
1(c)	Page 2, Line 11(e)	48	Average of Lines 21, 24, 27, 30, and 33
1(d)	Page 2, Line 12(e)	50	Average of Lines 32, 35, 38, 41, and 44
1(e)	Page 2, Line 22(e)	53(b) - (e)	Adjustment based on average annual change for the prior 3 years
1(f)	Page 2, Line 14(e)	53(f)	Workpaper 3 Page 3, Line 10(a)-(l)
1(g)	Page 2, Line 15(e)	53(g)	Workpaper 3 Page 7, Line 9(c)-20(c) + Page 12 Lines 9(i)-20(i)
1(h)	Page 2, Line 16(e)	53(h)	Workpaper 3 Page 17, Line 8(g) to Line 19(g)
3	Line 59	53(i)	Workpaper 3 Page 22, Line 4 x 12
3(i)	Amortization does not begin until August 2018	55	Per Company Books
7(i)	Amortization does not begin until August 2018	57	Line 53 x Line 55
		59	Line 53 + Line 57
		61	Line 59 divided by 12

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The Narragansett Electric Company d/b/a National Grid
Rate Base Adjustments
Five Quarter Average Ending June 30, 2017 through Rate Year 3 Ending August 31, 2019
Accumulated Deferred Tax Forecast

		Description	Period or Amount		Accumulated Deferred Income Tax
			(a)		(b)
1		Balance at June 30, 2017			$196,614,471
2		Impact of Federal Tax Reform on June 30, 2017 balance			($1,147,243)
3		Increase/(Decrease) 2 Month Ended		1/	$2,580,654
4					
5		Balance at August 31, 2017			$198,047,882
6					
7		Increase/(Decrease) 12 Month Ended		2/	$5,847,765
8					
9		Balance at August 31, 2018			$203,895,647
10					
11		Balance as of:	09/30/18	3/	$203,836,407
12			10/31/18	3/	$203,777,166
13			11/30/18	3/	$203,717,926
14			12/31/18	3/	$203,658,686
15			01/31/19	3/	$203,599,446
16			02/28/19	3/	$203,540,205
17			03/31/19	3/	$203,480,965
18			04/30/19	3/	$203,421,725
19			05/31/19	3/	$203,362,484
20			06/30/19	3/	$203,303,244
21			07/31/19	3/	$203,244,004
22		Balance at August 31, 2019		3/	$203,184,764
23					
24		Rate Year 1 Accumulated Deferred Income Tax - Five Quarter Average			$203,540,205
25					
26			Book	Tax	Difference
27			(a)	(b)	(c)
28	1/	2 Months Ending 08/30/17			
29		Depreciation	$8,602,358	$16,781,928	$8,179,570
30		Income Tax Rate			31.55%
31		2 Month Change to Accumulated Deferred Taxes			$2,580,654
32		Net Operating Loss Utilization			$0
33		Proration Adjustment			$0
34		Net Annual Change			$2,580,654
35					
36	2/	12 Months Ended 08/31/18:			
37		Depreciation	$52,630,173	$74,165,596	$21,535,423
38		Income Tax Rate			27.15%
39		Annual Change to Accumulated Deferred Taxes			$5,847,765
40		Net Operating Loss Utilization			$0
41		Proration Adjustment			$0
42		Net Annual Change			$5,847,765
43					
44	3/	12 Months Ended 08/31/19:			
45		Depreciation	$50,375,341	$72,926,482	$22,551,141
46		Income Tax Rate			21.00%
47		Annual Change to Accumulated Deferred Taxes			$4,735,740
48		Net Operating Loss Utilization			$0
49		Proration Adjustment			($380,623)
50		Net Annual Change			$4,355,117
51		Net of Amortization of Excess Deferred Tax		($4,080,912)	($5,066,000)
52		Monthly Change to Accumulated Deferred Taxes			($59,240)

Line Notes

1	Page 2, Line 20 + Line 21
3	Line 34(c)
5	Line 1 + Line 3
7	Line 42(c)
9	Line 5 + Line 7
11	Line 9(b) + Line 52(c)
12-22	Prior Month Balance + Line 52(c)
24	Average of Lines 9, 13, 16, 19, and 22
29(a)	Schedule 6-ELEC Page 1, Line 24(b) + Schedule 6-ELEC Page 1, Line 25(b)
29(b)	Page 14 Line 3(b)
30	Per Tax Dept
31	Line 29 x Line 30
33	Page 13 Line 3
34	Sum of Lines 31-33
37(a)	Schedule 6-ELEC Page 1, Line 43(b)
37(b)	Page 14 Line 3(c)
38	Per Tax Dept
39	Line 37 x Line 38
41	Page 13 Line 3(c)
42	Sum of Lines 39-41
45(a)	Schedule 6-ELEC Page 2, Line 16(b)
45(b)	Page 14 Line 3(d)
46	Per Tax Dept
47	Sum of Lines 47-49
49	Page 13, Line 3(d)
50	Sum of Lines 47-49
52	Line 50 divided by 12

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The Narragansett Electric Company d/b/a National Grid
Rate Base Adjustments
Five Quarter Average Ending June 30, 2017 through Rate Year 3 Ending August 31, 2019
Accumulated Deferred Tax Forecast

	Description	Period or Amount (a)		Accumulated Deferred Income Tax (b)
1	Balance at August 31, 2019			$203,565,387
2				
3	Balance as of:	09/30/19	1/	$203,202,141
4		10/31/19	1/	$202,838,896
5		11/30/19	1/	$202,475,651
6		12/31/19	1/	$202,112,405
7		01/31/20	1/	$201,749,160
8		02/29/20	1/	$201,385,915
9		03/31/20	1/	$201,022,669
10		04/30/20	1/	$200,659,424
11		05/31/20	1/	$200,296,179
12		06/30/20	1/	$199,932,934
13		07/31/20	1/	$199,569,688
14	Balance @ August 31, 2020		1/	$199,206,443
15				
16	Rate Year 2 Accumulated Deferred Income Tax - Five Quarter Average			$201,385,915
17				
18	Balance as of:	09/30/20	2/	$199,769,327
19		10/31/20	2/	$199,666,017
20		11/30/20	2/	$199,562,708
21		12/31/20	2/	$199,459,399
22		01/31/21	2/	$199,356,090
23		02/28/21	2/	$199,252,781
24		03/31/21	2/	$199,149,472
25		04/30/21	2/	$199,046,163
26		05/31/21	2/	$198,942,854
27		06/30/21	2/	$198,839,545
28		07/31/21	2/	$198,736,235
29	Balance @ August 31, 2021		2/	$198,632,926
30				
31	Rate Year 3 Accumulated Deferred Income Tax - Five Quarter Average			$199,252,781
32				
33		Book	Tax	Difference
34		(a)	(b)	(c)
35	1/ 12 Months Ended 08/31/20:			
36	Depreciation	$51,255,262	$45,851,846	($5,403,416)
37	Income Tax Rate			21.00%
38	Annual Change to Accumulated Deferred Taxes			($1,134,717)
39	Net Operating Loss Utilization			$2,507,967
40	Proration Adjustment			($666,193)
41	Net Annual Change			$707,056
42	Amortization of Excess DIT			($5,066,000)
43	Monthly Change to Accumulated Deferred Taxes			($363,245)
44				
45	2/ 12 Months Ended 08/31/21:			
46	Depreciation	$51,299,512	$43,468,954	($7,830,558)
47	Income Tax Rate			21.00%
48	Annual Change to Accumulated Deferred Taxes			($1,644,417)
49	Net Operating Loss Utilization			$9,804,674
50	Proration Adjustment			($4,333,966)
51	Net Annual Change			$3,826,291
52	Amortization of Excess DIT			($5,066,000)
53	Monthly Change to Accumulated Deferred Taxes			($103,309)

Line Notes

1	Page 11, Line 22(b)
3	Line 1(b) + Line 43(c)
4-14	Prior Month Balance + Line 43(c)
16	Average of Lines 1, 5, 8, 11, and 14
18	Line 14(b) + Line 53(c)
19-29	Prior Month Balance + Line 53(c)
31	Average of Lines 14, 20, 23, 26, and 29
36(a)	Schedule 6-ELEC Page 2, Line 37(b)
36(b)	Page 14, Line 3(e)
37	Per Tax Dept
38	Line 36 x Line 37
39	Per Tax Dept
40	Page 13, Line 3(e)
41	Sum of Lines 38-40
43	Line 41 divided by 12
46(a)	Schedule 6-ELEC Page 2, Line 58(b)
46(b)	Page 14, Line 3(f)
47	Per Tax Dept
48	Line 46 x Line 47
49	Per Tax Dept
50	Page 13, Line 3(f)
51	Sum of Lines 48-50
53	Line 51 divided by 12

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Proration Adjustment
Test Year through Rate Year 3

	Description	2 Months Ending August 31, 2017 (a)	12 Months Ending August 31, 2018 (b)	Rate Year 1 Ending August 31, 2019 (c)	Rate Year 2 Ending August 31, 2020 (d)	Rate Year 3 Ending August 31, 2021 (e)
1	Proration Adjustment	$0	$0	($380,623)	$666,193	$4,333,966
2						
3	Total	$0	$0	($380,623)	$666,193	$4,333,966
4						
5						
6	NOTE: Proration is not applicable to actual ADIT					
7						
8						
9						
10						
11						
12						
13	**Deferred Tax Subject to Proration**					
14	Book Depreciation	$8,602,358	$52,630,173	$50,375,341	$51,255,262	$51,299,512
15	Bonus Depreciation	($4,778,726)	($2,392,332)	$0	$0	
16	Remaining MACRS Tax Depreciation	($7,805,758)	($46,659,851)	($47,021,426)	($45,182,813)	($42,799,921)
17						
18	Cumulative Book / Tax Timer	($3,982,125)	$3,577,990	$3,353,915	$6,072,449	$8,499,591
19	Effective Tax Rate	32%	27%	21%	21%	21%
20	Deferred Tax Reserve	($1,274,280)	$966,057	$704,322	$1,275,214	$1,784,914
21						
22	**Net Operating Loss Utilization**					
23						
24	Net Operating Loss Utilization				($11,942,698)	($46,688,922)
25	Effective Tax Rate			21%	21%	21%
26	Deferred Tax Reserve			$0	($2,507,967)	($9,804,674)
27						
28	Total Accumulated Deferred Income Taxes Subject to Proration	$0	$0	$704,322	($1,232,752)	($8,019,759)
29						
30		Number of Days in Month (a)	Proration Percentage (b)			
31						
32	Proration Calculation					
33	September	30	92%	$0	$0	$53,869	($94,286)	($613,383)
34	October	31	83%	$0	$0	$48,884	($85,561)	($556,623)
35	November	30	75%	$0	$0	$44,060	($77,117)	($501,693)
36	December	31	67%	$0	$0	$39,075	($68,392)	($444,932)
37	January	31	58%	$0	$0	$34,090	($59,667)	($388,171)
38	February	28	50%	$0	$0	$29,588	($51,787)	($336,903)
39	March	31	42%	$0	$0	$24,603	($43,062)	($280,142)
40	April	30	34%	$0	$0	$19,779	($34,618)	($225,212)
41	May	31	25%	$0	$0	$14,794	($25,893)	($168,452)
42	June	30	17%	$0	$0	$9,970	($17,450)	($113,522)
43	July	31	8%	$0	$0	$4,985	($8,725)	($56,761)
44	August	31	0%	$0	$0	$0	$0	$0
45	Total			$0	$0	$323,699	($566,559)	($3,685,794)
46						
47	Deferred Tax Without Proration			$0	$0	$704,322	($1,232,752)	($8,019,759)
48	Proration Adjustment			$0	$0	($380,623)	$666,193	$4,333,966

Line Notes

1	Line 48(b)	18	Sum of Lines 14-16
14(a)	Page 11, Line 29(a)	19	Per Tax Dept
14(b)	Page 11, Line 37(a)	20	Line 18 x Line 19
14(c)	Page 11, Line 45(a)	24(d)	Page 12, Line 39(c) divided by 35%
14(d)	Page 12, Line 36(a)	24(e)	Page 12, Line 49(c) divided by 35%
14(e)	Page 12, Line 46(a)	25	Per Tax Dept
15(a)	Page 15, Line 1(c)	28	Line 20 + Line 26
15(b)	Page 15, Line 4(c)	33-44	Line 28 x Percent in Col B
15(c)	Page 15, Line 7(c)	45	Sum of Lines 33-44
15(d)	Page 15, Line 10(c)	47	Line 28
15(e)	Page 15, Line 13(c)	48	Line 45 - Line 47
16(a)	Page 15, Line 2(d)		
16(b)	Page 15, Line 2(e) + Line 5(e)		
16(c)	Page 15, Line 2(f) + Line 5(f) + Line 8(f)		
16(d)	Page 15, Line 2(g) + Line 5(g) + Line 8(g) + Line 11(g)		
16(e)	Page 15, Line 2(h) + Line 5(h) + Line 8(h) + Line 11(h)+ Line 14(h)		

The Narragansett Electric Company d/b/a National Grid
Federal Tax Depreciation
Test Year through Rate Year 3
Estimated Additions

	Description	Test Year Ending June 30, 2017 (a)	2 Months Ending August 31, 2017 (b)	12 Months Ending August 31, 2018 (c)	Rate Year 1 Ending August 31, 2019 (d)	Rate Year 2 Ending August 31, 2020 (e)	Rate Year 3 Ending August 31, 2021 (f)
1	Narragansett Electric Tax Depreciation of Embedded Plant	$30,311,226	$16,781,928	$74,165,596	$72,926,482	$45,851,846	$43,468,954
2							
3	Total	$30,311,226	$16,781,928	$74,165,596	$72,926,482	$45,851,846	$43,468,954

Line Notes
1(a) Per Tax Dept
1(b) Page 15, Line 16(d)
1(c) Page 15, Line 16(e)
1(d) Page 15, Line 16(f)
1(e) Page 15, Line 16(g)
1(f) Page 15, Line 16(h)

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The Narragansett Electric Company d/b/a National Grid
Federal Tax Depreciation
Summary

	Narragansett Electric Company	Capital Additions	Capital Repairs Current Deduct	Yr 1 Bonus	Total Tax Depreciation and Repairs Deduction				
					2 Months Ending August 31, 2017	12 Months Ending August 31, 2018	Rate Year 1 Ending August 31, 2019	Rate Year 2 Ending August 31, 2020	Rate Year 2 Ending August 31, 2021
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(b)
1	Tax Depreciation on Existing Plant				$7,626,556	$44,251,489	$40,495,216	$36,853,608	$34,980,126
2	Capital Repairs/Bonus 2 Months Ending August 31, 2017	$12,473,833	$2,916,382	$4,778,726	$7,695,108				
3	MACRS 2 Months Ending August 31, 2017				$179,202	$344,976	$319,076	$295,182	$273,009
4	Cost of Removal Test 2 Months Ending August 31,2017				$1,281,063				
5	Capital Repairs/Bonus 12 Months Ending August 31, 2018	$74,843,000	$17,427,037	$2,392,332		$19,819,369			
6	MACRS 12 Months Ending August 31, 2018					$2,063,386	$3,972,156	$3,673,928	$3,398,810
7	Cost of Removal Test 2 Months Ending August 31,2018					$7,686,376			
8	Capital Repairs/Bonus 12 Months Ending August 31, 2019	$77,541,000	$17,941,595	$0			$17,941,595		
9	MACRS 12 Months Ending August 31, 2019						$2,234,978	$4,302,481	$3,979,452
10	Cost of Removal Test 2 Months Ending August 31,2019						$7,963,461		
11	Capital Repairs/Bonus 12 Months Ending August 31, 2020	$2,000,000	$463,633	$0				$463,633	
12	MACRS 12 Months Ending August 31, 2020							$57,614	$110,910
13	Cost of Removal Test 2 Months Ending August 31,2020							$205,400	
14	Capital Repairs/Bonus 12 Months Ending August 31, 2021	$2,000,000	$463,633	$0					$463,633
15	MACRS 12 Months Ending August 31, 2021								$57,614
16	Cost of Removal Test 2 Months Ending August 31,2021								$205,400
17	Total	$168,857,833	$39,212,281	$7,171,058	$16,781,928	$74,165,596	$72,926,482	$45,851,846	$43,468,954

Line Note

(d) - (l Per Tax Dept
2(a) Page 16, Line 1(a)
2(b) Page 16, Line 5(a)
2(c) Page 16, Line 16(a)
2(d) Sum of Line 1(b) & Line 1(c)
3(d) Page 16, Line 24(a)
3(e) Page 16, Line 24(b)
3(f) Page 16, Line 24(c)
3(g) Page 16, Line 24(d)
3(h) Page 16, Line 24(e)
4(d) Page 16, Line 26(a)
5(a) Page 17, Line 1(a)
5(b) Page 17. Line 5(a)
5(c) Page 17. Line 16(a)
5(e) Line 4(b) + Line 4(c)
6(e) Page 17, Line 24(a)
6(f) Page 17, Line 24(b)
6(g) Page 17, Line 24(c)
6(h) Page 17, Line 24(d)
7(e) Page 17, Line 26(a)
8(a) Page 18, Line 1(a)
8(b) Page 18, Line 5(a)
8(c) Page 18, Line 16(a)
8(f) Line 7(b) + 7(c)
9(f) Page 18, Line 25(a)
9(g) Page 18, Line 25(b)
9(h) Page 18, Line 25(c)
10(f) Page 18, Line 27(a)
11(a) Page 19, Line 1(a)
11(b) Page 19, Line 5(a)
11(c) Page 19, Line 16(a)
11(g) Line 10(b) + 10(c)
12(g) Page 19, Line 25(a)
12(h) Page 19, Line 25(b)
13(g) Page 19, Line 27(a)
14(a) Page 20, Line 1(a)
14(b) Page 20, Line 5(a)
14(c) Page 20, Line 16(a)
14(h) Line 13(b) + Line 13(c)
16(h) Page 20, Line 27(a)

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Calculation of Tax Depreciation and Repairs Deduction
On Capital Investment for the 2 Months Ending August 31, 2017

		Reference	2 Months Ending August 31, 2017 (a)	12 Months Ending August 31, 2018 (b)	Rate Year 1 Ending August 31, 2019 (c)	Rate Year 2 Ending August 31, 2020 (d)	Rate Year 2 Ending August 31, 2021 (e)
	Capital Repairs Deduction						
1	Plant Additions	Page 6, Line 7	$12,473,833				
2							
3	Plant Eligible tfor Capital Repairs Deduction		$12,473,833				
4	Capital Repairs Deduction Rate	Per Tax Department	23.38%				
5	Capital Repairs Deduction	Line 3 * Line 4	$2,916,382				
6							
7	Bonus Depreciation						
8	Plant Additions	Line 1	$12,473,833				
9	Less Capital Repairs Deduction	Line 5	$2,916,382				
10	Plant Additions Net of Capital Repairs Deduction	Line 8 - Line 9	$9,557,451				
11	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	100.00%				
12	Plant Eligible for Bonus Depreciation	Line 10 * Line 11	$9,557,451				
13	Bonus Depreciation Rate	Per Tax Department	50.00%				
14							
15							
16	Total Bonus Depreciation Rate	Line 12 * Line 13	$4,778,726				
17							
18	Remaining Tax Depreciation						
19	Plant Additions	Line 1	$12,473,833				
20	Less Capital Repairs Deduction	Line 5	($2,916,382)				
21	Less Bonus Depreciation	Line 14	($4,778,726)				
22	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Sum of Line 17 through 19	$4,778,726	$4,778,726	$4,778,726	$4,778,726	$4,778,726
23	20 YR MACRS Tax Depreciation Rates		3.750%	7.219%	6.677%	6.177%	5.713%
24	Remaining Tax Depreciation	Line 20 * Line 21	$179,202	$344,976	$319,076	$295,182	$273,009
25							
26	Cost of Removal	Schedule 6-ELEC Page 1, Line 25(b)	$1,281,063				
27							
28	Total Tax Depreciation and Repairs Deduction	Line 5 + Line 14 + Line 22 + Line 24	$9,155,372	$344,976	$319,076	$295,182	$273,009

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The Narragansett Electric Company d/b/a National Grid
Calculation of Tax Depreciation and Repairs Deduction
On Capital Investment for the 12 Months Ending August 31, 2018

		Reference	12 Months Ending August 31, 2018 (a)	Rate Year 1 Ending August 31, 2019 (b)	Rate Year 2 Ending August 31, 2020 (c)	Rate Year 2 Ending August 31, 2021 (d)
	Capital Repairs Deduction					
1	Plant Additions	Page 6, Line 14	$74,843,000			
2						
3	Plant Eligible tfor Capital Repairs Deduction		$74,843,000			
4	Capital Repairs Deduction Rate	Per Tax Department	23.28%			
5	Capital Repairs Deduction	Line 3 * Line 4	$17,427,037			
6						
7	Bonus Depreciation					
8	Plant Additions	Line 1	$74,843,000			
9	Less Capital Repairs Deduction	Line 5	$17,427,037			
10	Plant Additions Net of Capital Repairs Deduction	Line 8 - Line 9	$57,415,963			
11	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	8.33%			
12	Plant Eligible for Bonus Depreciation	Line 10 * Line 11	$4,784,664			
13	Bonus Depreciation Rate	Per Tax Department	50.00%			
14		8 months 2018 @ 40%	0.00%			
15		Sum of Lines 13 + 14	50.00%			
16	Total Bonus Depreciation Rate	Line 12 * Line 13	$2,392,332			
17						
18	Remaining Tax Depreciation					
19	Plant Additions	Line 1	$74,843,000			
20	Less Capital Repairs Deduction	Line 5	($17,427,037)			
21	Less Bonus Depreciation		($2,392,332)			
22	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 8 - Line 9	$55,023,631	$55,023,631	$55,023,631	$55,023,631
23	20 YR MACRS Tax Depreciation Rates		3.750%	7.219%	6.677%	6.177%
24	Remaining Tax Depreciation	Line 11 * Line 12	$2,063,386	$3,972,156	$3,673,928	$3,398,810
25						
26	Cost of Removal	Schedule 6-ELEC Page 1, Line 44(b)	$7,686,376			
27						
28	Total Tax Depreciation and Repairs Deduction	Line 5 + Line 14 + Line 22 + Line 24	$29,569,131	$3,972,156	$3,673,928	$3,398,810

THE NARRAGANSETT ELECTRIC COMPANY
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The Narragansett Electric Company d/b/a National Grid
Calculation of Tax Depreciation and Repairs Deduction
On Capital Investment for the 12 Months Ending August 31, 2019

		Reference	Rate Year 1 Ending August 31, 2019 (a)	Rate Year 2 Ending August 31, 2020 (b)	Rate Year 2 Ending August 31, 2021 (c)
	Capital Repairs Deduction				
1	Plant Additions	Page 6, Line 38	$77,541,000		
2					
3	Plant Eligible for Capital Repairs Deduction		$77,541,000		
4	Capital Repairs Deduction Rate	Per Tax Department	23.14%		
5	Capital Repairs Deduction	Line 3 * Line 4	$17,941,595		
6					
7	Bonus Depreciation				
8	Plant Additions	Line 1	$77,541,000		
9	Less Capital Repairs Deduction	Line 5	$17,941,595		
10	Plant Additions Net of Capital Repairs Deduction	Line 8 - Line 9	$59,599,405		
11	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	0.00%		
12	Plant Eligible for Bonus Depreciation	Line 10 * Line 11	$0		
13	Bonus Depreciation Rate	4 months 2018 @ 40% (40%*4/12)	13.33%		
14		8 months 2019 @ 30% (30%*8/12)	20.00%		
15		Sum of Lines 13 + 14	33.33%		
16	Total Bonus Depreciation Rate	Line 12 * Line 13	$0		
17					
18					
19	Remaining Tax Depreciation				
20	Plant Additions	Line 1	$77,541,000		
21	Less Capital Repairs Deduction	Line 5	($17,941,595)		
22	Less Bonus Depreciation	Line 14	$0		
23	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 8 - Line 9	$59,599,405	$59,599,405	$59,599,405
24	20 YR MACRS Tax Depreciation Rates		3.750%	7.219%	6.677%
25	Remaining Tax Depreciation	Line 11 * Line 12	$2,234,978	$4,302,481	$3,979,452
26					
27	Cost of Removal	Schedule 6-ELEC Page 2, Line 18(b)	$7,963,461		
28					
29	Total Tax Depreciation and Repairs Deduction	Line 5 + Line 13 + Line 15	$28,140,034	$4,302,481	$3,979,452

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The Narragansett Electric Company d/b/a National Grid
Calculation of Tax Depreciation and Repairs Deduction
On Capital Investment for the 12 Months Ending August 31, 2020

		Reference	Rate Year 2 Ending August 31, 2020 (a)	Rate Year 2 Ending August 31, 2021 (b)
	Capital Repairs Deduction			
1	Plant Additions	Page 7, Line 36	$2,000,000	
2				
3	Plant Eligible for Capital Repairs Deduction		$2,000,000	
4	Capital Repairs Deduction Rate	Per Tax Department	23.18%	
5	Capital Repairs Deduction	Line 3 * Line 4	$463,633	
6				
7	Bonus Depreciation			
8	Plant Additions	Line 1	$2,000,000	
9	Less Capital Repairs Deduction	Line 5	$463,633	
10	Plant Additions Net of Capital Repairs Deduction	Line 8 - Line 9	$1,536,367	
11	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	0.00%	
12	Plant Eligible for Bonus Depreciation	Line 10 * Line 11	$0	
13	Bonus Depreciation Rate	4 months 2019 @ 30% (30%*4/12)	10.00%	
14		8 months 2020 @ 00% (00%*8/12)	0.00%	
15		Sum of Lines 13 + 14	10.00%	
16	Total Bonus Depreciation Rate	Line 12 * Line 13	$0	
17				
18				
19	Remaining Tax Depreciation			
20	Plant Additions	Line 1	$2,000,000	
21	Less Capital Repairs Deduction	Line 5	($463,633)	
22	Less Bonus Depreciation	Line 14	$0	
23	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 8 - Line 9	$1,536,367	$1,536,367
24	20 YR MACRS Tax Depreciation Rates		3.750%	7.219%
25	Remaining Tax Depreciation	Line 11 * Line 12	$57,614	$110,910
26				
27	Cost of Removal	Schedule 6-ELEC Page 2, Line 39(b)	$205,400	
28				
29	Total Tax Depreciation and Repairs Deduction	Line 5 + Line 13 + Line 15	$726,647	$110,910

THE NARRAGANSETT ELECTRIC COMPANY
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The Narragansett Electric Company d/b/a National Grid
Calculation of Tax Depreciation and Repairs Deduction
On Capital Investment for the 12 Months Ending August 31, 2021

		Reference	Rate Year 2 Ending August 31, 2021 (a)
	Capital Repairs Deduction		
1	Plant Additions	Page 7, Line 44	$2,000,000
2			
3	Plant Eligible for Capital Repairs Deduction		$2,000,000
4	Capital Repairs Deduction Rate	Per Tax Department	23.18%
5	Capital Repairs Deduction	Line 3 * Line 4	$463,633
6			
7	Bonus Depreciation		
8	Plant Additions	Line 1	$2,000,000
9	Less Capital Repairs Deduction	Line 5	$463,633
10	Plant Additions Net of Capital Repairs Deduction	Line 8 - Line 9	$1,536,367
11	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	100.00%
12	Plant Eligible for Bonus Depreciation	Line 10 * Line 11	$1,536,367
13	Bonus Depreciation Rate		0.00%
14			
15			
16	Total Bonus Depreciation Rate	Line 12 * Line 13	$0
17			
18			
19	Remaining Tax Depreciation		
20	Plant Additions	Line 1	$2,000,000
21	Less Capital Repairs Deduction	Line 5	($463,633)
22	Less Bonus Depreciation	Line 14	$0
23	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 8 - Line 9	$1,536,367
24	20 YR MACRS Tax Depreciation Rates		3.750%
25	Remaining Tax Depreciation	Line 11 * Line 12	$57,614
26			
27	Cost of Removal	Schedule 6-ELEC Page 2, Line 60(b)	$205,400
28			
29	Total Tax Depreciation and Repairs Deduction	Line 5 + Line 13 + Line 15	$726,647

Compliance Attachment 2

Schedule 11-GAS

Rate Base – Gas

THE NARRAGANSETT ELECTRIC COMPANY
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The Narragansett Electric Company d/b/a National Grid
Rate Base Summary
Five Quarter Average Ending June 30, 2017 through Rate Year Ending August 31, 2021

	Description	Five Quarter Average Ending June 30, 2017 (a)	Adjustments (b)	Rate Year 1 Ending August 31, 2019 (c)	Rate Year Ending August 31, 2020 (d)	Rate Year Ending August 31, 2021 (e)
1	Gas Plant In Service	$1,092,141,316	$214,715,738	$1,306,857,054	$1,328,015,869	$1,349,443,902
2	Normalizing Adjustment: Smallworld GIS[1]	$3,996,550	$0	$3,996,550	$3,996,550	$3,996,550
3	Gas Plant In Service	$1,096,137,866	$214,715,738	$1,310,853,604	$1,332,012,419	$1,353,440,451
4						
5	Construction Work In Progress	$49,783,414	($5,570,043)	$44,213,371	$45,444,229	$46,739,869
6						
7	Less: Accumulated Depreciation	$389,907,868	$37,266,066	$427,173,934	$428,191,816	$429,895,395
8	Normalizing Adjustment: Smallworld GIS[1]	$2,987,945	$0	$2,987,945	$3,414,129	$3,840,314
9	Test Year Adjusted Accumulated Depreciation	$392,895,813	$37,266,066	$430,161,879	$431,605,945	$433,735,709
10						
11	Less: Contribution in Aid of Construction	$38	($984)	($946)	($2,250)	($3,622)
12						
13	Net Plant	$753,025,429	$171,880,612	$924,906,042	$945,852,952	$966,448,234
14						
15	Additions:					
16	Materials and Supplies	$3,941,353	($1,261,179)	$2,680,174	$2,159,157	$1,610,719
17	Prepaid Expenses, Excluding Taxes	$393,734	($189,233)	$204,501	$276,014	$351,290
18	Deferred Debits	$411,653	($411,653)	$0	$0	$0
19	Cash Working Capital	$8,974,216	($2,301,262)	$6,672,954	$6,672,954	$6,672,954
20	Unamortized Interest Lock expense $550M	$1,068,051	($350,778)	$717,273	$555,375	$393,477
21	Unamortized Issuance Costs $300M	$406,500	($37,950)	$368,550	$351,035	$333,519
22	Unamortized Issuance Costs $250M	$81,303	($54,906)	$26,397	$4,434	$0
23	Unamortized Issuance Costs $200M	$274,996	($23,064)	$251,932	$241,287	$230,642
24	Unamortized Issuance Costs $350M	$0	$454,825	$454,825	$406,525	$358,225
25	Unamortized Issuance Costs Mortgage Bonds	$103,899	($49,670)	$54,229	$31,304	$8,379
26	Total Additions	$15,655,704	($4,224,871)	$11,430,834	$10,698,085	$9,959,206
27						
28	Deductions:					
29	Accumulated Deferred FIT	$111,588,901	$44,052,946	$155,641,847	$165,481,552	$172,638,610
30	Merger Hold Harmless Adjustment	$22,255,350	($3,592,594)	$18,662,756	$16,576,053	$14,145,381
31	Customer Deposits	$2,342,658	($875,181)	$1,467,477	$1,208,830	$936,570
32	Total Deductions	$136,186,909	$39,585,171	$175,772,080	$183,266,434	$187,720,560
33						
34	Rate Base	$632,494,225	$128,070,571	$760,564,795	$773,284,603	$788,686,880
35						
36	Total Rate Base			$760,564,795	$773,284,603	$788,686,880

[1]Gas Information System

Column Notes
(a) Page 2 of 23 Column (f)
(b) (c) minus (a)

Line Notes
1(c) Page 3 of 23 Line 30 Column (b)
1(d) 1(c) plus Page 5 of 23, Lines 3(f), 8(f) and 11(i) times 50%
1(e) 1(d) plus Page 5 of 23, Line 11(l) times 50%
5(c) Page 8 of 23 Line 47 Column (a)
5(d) Page 8 of 23 Line 48 Column (a)
5(e) Page 8 of 23 Line 49 Column (a)
8(d) 8(c) plus Schedule 5-GAS Page 1 of 1 Column Notes (e)
8(e) 8(d) plus Schedule 5-GAS Page 1 of 1 Column Notes (e)
11(c) Page 8 of 23 Line 47 Column (b)
11(d) Page 8 of 23 Line 48 Column (b)
11(e) Page 8 of 23 Line 49 Column (b)
16(c) Page 8 of 23 Line 47 Column (c)
16(d) Page 8 of 23 Line 48 Column (c)
16(e) Page 8 of 23 Line 49 Column (c)
17(c) Page 8 of 23 Line 47 Column (d)
17(d) Page 8 of 23 Line 48 Column (d)
17(e) Page 8 of 23 Line 49 Column (d)
18(c) Page 8 of 23 Line 47 Column (e)
18(d) Page 8 of 23 Line 48 Column (e)
18(e) Page 8 of 23 Line 49 Column (e)
19(c) Cash Working Capital Page 1 of 29 Line 15 Column CWC Dollars
20(c) Page 8 of 23 Line 47 Column (g)
20(d) Page 8 of 23 Line 48 Column (g)
20(e) Page 8 of 23 Line 49 Column (g)
21(c) Page 8 of 23 Line 47 Column (h)
21(d) Page 8 of 23 Line 48 Column (h)
21(e) Page 8 of 23 Line 49 Column (h)
22(c) Page 8 of 23 Line 47 Column (i)
22(d) Page 8 of 23 Line 48 Column (i)
22(e) Page 8 of 23 Line 49 Column (i)
23(c) Page 8 of 23 Line 47 Column (j)
23(d) Page 8 of 23 Line 48 Column (j)
23(e) Page 8 of 23 Line 49 Column (j)
24(c) Page 8 of 23 Line 47 Column (k)
24(d) Page 8 of 23 Line 48 Column (k)
24(e) Page 8 of 23 Line 49 Column (k)
25(c) Page 8 of 23 Line 47 Column (l)
25(d) Page 8 of 23 Line 48 Column (l)
25(e) Page 8 of 23 Line 49 Column (l)
29(c) Page 11 of 23 Line 24 Column (c)
29(d) Page 12 of 23 Line 16 Column (c)
29(e) Page 12 of 23 Line 31 Column (c)
30(c) Page 9 of 23 Line 24 Column (c)
30(d) Page 10 of 23 Line 15 Column (c)
30(e) Page 10 of 23 Line 31 Column (c)
31(c) Page 8 of 23 Line 47 Column (f)
31(d) Page 8 of 23 Line 48 Column (f)
31(e) Page 8 of 23 Line 49 Column (f)

The Narragansett Electric Company d/b/a National Grid
Adjustments To Rate Base
Five-Quarter Average Ending June 31, 2017

	Description	Quarter Ending June 2016 (a)	September 2016 (b)	December 2016 (c)	March 2017 (d)	June 2017 (e)	Five Quarter Average (f)
1	Gas Plant In Service	$1,064,548,669	$1,082,547,975	$1,092,122,373	$1,103,935,113	$1,117,552,449 1/	$1,092,141,316
2	Normalizing Adjustment: Smallworld GIS	$0	$0	$0	$9,991,374	$9,991,374	$3,996,550
3	Test Year Adjusted Gas Plant in Service	$1,064,548,669	$1,082,547,975	$1,092,122,373	$1,113,926,487	$1,127,543,823	$1,096,137,866
4							
5	Construction Work In Progress	$45,838,370	$51,024,819	$59,381,840	$49,279,243	$43,392,799	$49,783,414
6							
7	Less: Accumulated Depreciation	$394,425,115	$394,671,874	$394,265,448	$388,553,414	$377,623,487	$389,907,868
8	Normalizing Adjustment: Smallworld GIS	$0	$0	$0	$7,523,135	$7,416,589	$2,987,945
9	Test Year Adjusted Accumulated Depreciation	$394,425,115	$394,671,874	$394,265,448	$396,076,549	$385,040,076	$392,895,813
10							
11	Less: Contribution in Aid of Construction	$38	$38	$38	$38	$38	$38
12							
13	Net Plant	$715,961,886	$738,900,882	$757,238,727	$767,129,143	$785,896,508	$753,025,429
14							
15	Additions:						
16	Materials and Supplies	$4,721,557	$4,722,950	$3,891,605	$3,297,430	$3,073,221	$3,941,353
17	Prepaid Expenses, Excluding Taxes	$172,681	$97,000	$853,452	$694,983	$150,553	$393,734
18	Deferred Debits	$764,498	$588,076	$411,653	$235,230	$58,807	$411,653
19	Cash Working Capital	$8,974,216	$8,974,216	$8,974,216	$8,974,216	$8,974,216	$8,974,216
20	Unamortized Interest Lock expense $550M	$1,149,000	$1,108,526	$1,068,051	$1,027,577	$987,102	$1,068,051
21	Unamortized Issuance Costs $300M	$415,258	$410,879	$406,500	$402,121	$397,742	$406,500
22	Unamortized Issuance Costs $250M	$93,973	$87,638	$81,303	$74,967	$68,632	$81,303
23	Unamortized Issuance Costs $200M	$280,318	$277,657	$274,996	$272,335	$269,674	$274,996
24	Unamortized Issuance Costs $350M	$0	$0	$0	$0	$0	$0
25	Unamortized Issuance Costs Mortgage Bonds	$115,362	$109,631	$103,899	$98,168	$92,437	$103,899
26	Total Additions	$16,686,863	$16,376,572	$16,065,675	$15,077,027	$14,072,384	$15,655,704
27							
28	Deductions:						
29	Accumulated Deferred FIT	$93,485,567	$91,026,451	$128,345,105	$122,162,393	$122,924,988	$111,588,901
30	Hold Harmless	$22,928,782	$22,610,421	$22,292,061	$21,912,516	$21,532,971	$22,255,350
32	Customer Deposits	$1,912,168	$3,005,416	$2,524,080	$2,359,458	$1,912,168	$2,342,658
33	Total Deductions	$118,326,517	$116,642,288	$153,161,246	$146,434,367	$146,370,127	$136,186,909
34							
35	Rate Base	$614,322,232	$638,635,166	$620,143,156	$635,771,804	$653,598,765	$632,494,225
36							
37	Total Rate Base						$632,494,225
38							
39				1/ Utility Plant		$1,123,631,722	
40				Asset Retirement Obligation (ARO)		($6,079,273)	
41				Net Utility Plant		$1,117,552,449	

Column Notes
(a) through (e) PER ESM Q1 filing RIPUC docket number 4708 schedule except as indicated in line notes
(f) ((a)+(b)+(c)+(d)+(e)) / 5

Line Notes
5(e) NECO FERC FORM 3Q JUNE 2017_FINAL page 201 Line 11 Column (d)
7(e) Schedule 6-GAS Page 5 of 5 Line 70 Column (d) less line 8 Column (e)
8(d) Schedule 5-GAS Page 1 of 1 Column Notes Acc. Amortization
8(e) 8(d) less Schedule 5-GAS Page 1 of 1 Column Notes (b) 3 month Amortization for test year
20(a) Workpaper 3 Page 5 of 27 Line 5 Column (a)
20(b) Workpaper 3 Page 5 of 27 Line 15 Column (c)
20(c) Workpaper 3 Page 5 of 27 Line 15 Column (f)
20(d) Workpaper 3 Page 5 of 27 Line 15 Column (i)
20(e) Workpaper 3 Page 5 of 27 Line 5 Column (l)
21(a) Workpaper 3 Page 9 of 27 Line 27 Column (b)
21(b) Workpaper 3 Page 9 of 27 Line 30 Column (b)
21(c) Workpaper 3 Page 9 of 27 Line 33 Column (b)
21(d) Workpaper 3 Page 9 of 27 Line 36 Column (b)
21(e) Workpaper 3 Page 9 of 27 Line 27 Column (c)
22(a) Workpaper 3 Page 14 of 27 Line 27 Column (h)
22(b) Workpaper 3 Page 14 of 27 Line 30 Column (h)
22(c) Workpaper 3 Page 14 of 27 Line 33 Column (h)
22(d) Workpaper 3 Page 14 of 27 Line 36 Column (h)
22(e) Workpaper 3 Page 14 of 27 Line 27 Column (i)
23(a) Workpaper 3 Page 19 of 27 Line 26 Column (f)
23(b) Workpaper 3 Page 19 of 27 Line 29 Column (f)
23(c) Workpaper 3 Page 19 of 27 Line 32 Column (f)
23(d) Workpaper 3 Page 19 of 27 Line 35 Column (f)
23(e) Workpaper 3 Page 19 of 27 Line 26 Column (g)
25(a) Workpaper 3 Page 27 of 27 Line 31 Column (j)
25(b) Workpaper 3 Page 27 of 27 Line 34 Column (j)
25(c) Workpaper 3 Page 27 of 27 Line 37 Column (j)
25(d) Workpaper 3 Page 27 of 27 Line 40 Column (j)
25(e) Workpaper 3 Page 27 of 27 Line 31 Column (k)
29(a) through (e) Per Tax Department
30(a) Page 21 of 23 Line 1 Column (e)
30(b) Page 21 of 23 Line 2 Column (e)
30(c) Page 21 of 23 Line 3 Column (e)
30(d) Page 21 of 23 Line 4 Column (e)
30(e) Page 21 of 23 Line 5 Column (e)
39 NECO FERC FORM 3Q JUNE 2017_FINAL page 201 Line 8 Column (d)
40 Schedule 6-GAS, Page 4 of 5 Line 17 Column (b)
ARO total in FY 2018 ESM Q1 differs from Ratebase-Depreciation-Gas

The Narragansett Electric Company d/b/a National Grid
Plant Adjustments to Rate Base
Test Year Ending June 31,2017 through Rate Year 1 Ending August 31, 2019
Gas Plant in Service Forecast

	Description	Period		Gas Plant in Service
		(a)		(b)
1	Balance at June 30, 2017			$1,127,543,823
2				
3	Subsequent 2 months			
4	Plus: Added Plant 2 Months Ended 08/31/2017			$19,592,266
5	Less: Retired Plant 2 Months Ended 08/31/2017			($1,345,989)
6	Depreciable Utility Plant 08/31/17			$18,246,278
7				
8	Balance at August 31, 2017			$1,145,790,101
9				
10	Activity prior to Rate Year 1			
11	Plus: Plant Additions 12 Months Ended 08/31/2018			$115,710,016
12	Less: Plant Retirements 12 Months Ended 08/31/2018		1/	($7,949,278)
13	Net Increase / (Decrease)			$107,760,738
14				
15	Balance at August 31, 2018			$1,253,550,839
16				
17	Balance as of:	09/30/18	2/	$1,262,435,208
18		10/31/18	2/	$1,271,319,577
19		11/30/18	2/	$1,280,203,947
20		12/31/18	2/	$1,289,088,316
21		01/31/19	2/	$1,297,972,685
22		02/28/19	2/	$1,306,857,054
23		03/31/19	2/	$1,315,741,423
24		04/30/19	2/	$1,324,625,792
25		05/31/19	2/	$1,333,510,162
26		06/30/19	2/	$1,342,394,531
27		07/31/19	2/	$1,351,278,900
28	Balance at August 31, 2019		2/	$1,360,163,269
29				
30	Rate Year Plant in Service - 5 Quarter Average			$1,306,857,054
31				
32	1/ 3 year average retirement over plant addition in service FY 15 ~ FY17			
33				
34	2/ Rate Year 1 ending 08/31/19 Adjustment Detail:			
35	Plant Additions 12 Months Ended 08/31/2019			$114,477,000
36	Plant Retirements 12 Months Ended 08/31/2019			($7,864,570)
37	Net Increase / (Decrease)			$106,612,430
38				
39	Monthly Increase / (Decrease)			$8,884,369

Line Notes

1(b)	Page 2 of 23 Line 1 Column (e)
4(b)	Schedule 6-GAS Page 1 of 5 Line 13 Column (a)
5(b)	Schedule 6-GAS Page 1 of 5 Line 14 Column (a)
11(b)	Schedule 6-GAS Page 1 of 5 Line 32 Column (a)
12(b)	Schedule 6-GAS Page 1 of 5 Line 33 Column (a)
35(b)	Schedule 6-GAS Page 2 of 5 Line 6 Column (a)
36(b)	Schedule 6-GAS Page 2 of 5 Line 7 Column (a)

The Narragansett Electric Company d/b/a National Grid
Plant Adjustments to Rate Base
Rate Year 1 Ending August 31, 2019 through Rate Year Ending August 31, 2021
Gas Plant in Service Forecast

	Description	Period		Gas Plant in Service
		(a)		(b)
1	Balance at August 31, 2019			$1,360,163,269
2				
3	Balance as of:	09/30/19	1/	$1,361,794,412
4		10/31/19	1/	$1,363,425,556
5		11/30/19	1/	$1,365,056,699
6		12/31/19	1/	$1,366,687,842
7		01/31/20	1/	$1,368,318,985
8		02/28/20	1/	$1,369,950,128
9		03/31/20	1/	$1,371,581,272
10		04/30/20	1/	$1,373,212,415
11		05/31/20	1/	$1,374,843,558
12		06/30/20	1/	$1,376,474,701
13		07/31/20	1/	$1,378,105,844
14	Balance at August 31, 2020		1/	$1,379,736,988
15				
16	Rate Year 2 Plant in Service - 5 Quarter Average			$1,369,950,128
17				
18	Balance at August 31, 2020			$1,379,736,988
19				
20	Balance as of:	09/30/20	2/	$1,381,431,832
21		10/31/20	2/	$1,383,126,677
22		11/30/20	2/	$1,384,821,521
23		12/31/20	2/	$1,386,516,366
24		01/31/21	2/	$1,388,211,211
25		02/28/21	2/	$1,389,906,055
26		03/31/21	2/	$1,391,600,900
27		04/30/21	2/	$1,393,295,745
28		05/31/21	2/	$1,394,990,589
29		06/30/21	2/	$1,396,685,434
30		07/31/21	2/	$1,398,380,278
31	Balance at August 31, 2021		2/	$1,400,075,123
32				
33	Rate Year 3 Plant in Service - 5 Quarter Average			$1,389,906,055
34				
35	1/ Rate Year ending 08/31/20 Adjustment Detail:			
36	Plant Additions 12 Months Ended 08/31/2020			$21,017,630
37	Plant Retirements 12 Months Ended 08/31/2020			($1,443,911)
38	Net Increase / (Decrease)			$19,573,719
39				
40				
41	Monthly Increase / (Decrease)			$1,631,143
42				
43	2/ Rate Year ending 08/31/21 Adjustment Detail:			
44	Plant Additions 12 Months Ended 08/31/2021			$21,838,436
45	Plant Retirements 12 Months Ended 08/31/2021			($1,500,301)
46	Net Increase / (Decrease)			$20,338,135
47				
48				
49	Monthly Increase / (Decrease)			$1,694,845

Line Notes
36(b) Schedule 6-GAS Page 2 of 5 Line 27 Column (a)
37(b) Schedule 6-GAS Page 2 of 5 Line 28 Column (a)
44(b) Schedule 6-GAS Page 2 of 5 Line 48 Column (a)
45(b) Schedule 6-GAS Page 2 of 5 Line 49 Column (a)

The Narragansett Electric Company d/b/a National Grid
Adjustments to Rate Base
Analysis of Test Year through Rate Year Capital Investment

		FY18		FY19		FY20	Rate Year 1	FY20	FY21	Rate Year 2	FY21	FY22	Rate Year 3
		04/01/17 - 06/30/17	07/01/17 - 03/31/18	04/01/18 - 08/31/18	09/01/18 - 03/31/19	04/01/19 - 08/31/19	09/01/18 - 08/31/19	09/01/19 - 03/31/20	04/01/20 - 08/31/20	09/01/19 - 08/31/20	09/01/20 - 03/31/21	04/01/21- 08/31/21	09/01/20 - 08/31/21
		(a)	(b)	(c)	(d)	(e)	(f)=(d)+(e)	(g)	(h)	(i)=(g)+(h)	(j)	(k)	(l)=(j)+(k)
	Distribution												
1	FY 2018 Approved ISR Plan	$21,037,000	$72,140,000	$38,823,750	$54,353,250	$38,823,750	$93,177,000			$0			$0
2	Gas Expansion	$0	$500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Growth (adj DIV 16-24)	$2,655,000	$15,376,199	$8,313,333	$11,638,667	$8,313,333	$19,952,000	$11,210,650	$9,056,980	$20,267,630	$11,121,216	$9,967,220	$21,088,436
4	Total Distribution	$23,692,000	$88,016,199	$47,137,083	$65,991,917	$47,137,083	$113,129,000	$11,210,650	$9,056,980	$20,267,630	$11,121,216	$9,967,220	$21,088,436
5													
6	General Plant												
7	Facilities	$0	$0	$0	$624,167	$445,833	$1,070,000	$437,500	$312,500	$750,000	$437,500	$312,500	$750,000
8	IS	$0	$149,000	$0	$278,000	$0	$278,000	$0	$0	$0	$0	$0	$0
9	Total General	$0	$149,000	$0	$902,167	$445,833	$1,348,000	$437,500	$312,500	$750,000	$437,500	$312,500	$750,000
10													
11	Distribution and General	$23,692,000	$88,165,199	$47,137,083	$66,894,083	$47,582,917	$114,477,000	$11,648,150	$9,369,480	$21,017,630	$11,558,716	$10,279,720	$21,838,436

Line Notes
2(b) FY18 gas expansion/Southern RI capacity/engineering not included in ISR
3 Per Company Books
7 Per Company Books
8(b) RI Gas Only Physical Security Replacements - FY18
8(d) RI Gas Only Physical Security Replacements - FY19

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
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The Narragansett Electric Company d/b/a National Grid
Accumulated Depreciation Adjustments To Rate Base
Test Year Ending June 31, 2017 through Rate Year 1 Ending August 31, 2019

		Description	Period		Accumulated Depreciation
			(a)		(b)
1		Balance at June 30, 2017			$385,040,076
2					
3		Depreciation Expense 07/01/2017 - 08/31/2017			$6,233,864
4		Less: Net Cost of Removal / (Salvage)			($1,014,879)
5		Less: Retirements			($1,345,989)
6		Net Increase / (Decrease)			$3,872,996
7					
8		Balance at August 31, 2017			$388,913,072
9					
10		Depreciation Expense 09/01/17 - 08/31/18			$39,532,703
11		Less: Net Cost of Removal / (Salvage)			($5,993,779)
12		Less: Retirements			($7,949,278)
13		Net Increase / (Decrease)			$25,589,646
14					
15		Balance at August 31, 2018			$414,502,719
16					
17		Balance as of:	09/30/18	1/	$416,614,588
18			10/31/18	1/	$418,726,457
19			11/30/18	1/	$420,838,326
20			12/31/18	1/	$422,950,196
21			01/31/19	1/	$425,062,065
22			02/28/19	1/	$427,173,934
23			03/31/19	1/	$429,285,803
24			04/30/19	1/	$431,397,672
25			05/31/19	1/	$433,509,542
26			06/30/19	1/	$435,621,411
27			07/31/19	1/	$437,733,280
28		Balance at August 31, 2019		1/	$439,845,149
29					
30		Rate Year Accumulated Depreciation - 5 Quarter Average			$427,173,934
31					
32					
33	1/	Rate Year Ended 08/31/19 Depreciation Reserve Detail:			
34		Depreciation Expense 09/01/18 - 08/31/19			$38,950,409
35		Plus: Unrecovered Reserve Adjustment			$186,500
36		Net Cost of Removal / (Salvage)			($5,929,909)
37		Less: Retirements			($7,864,570)
38		Net Increase / (Decrease)			$25,342,431
39					
40		Monthly Increase / (Decrease)			$2,111,869

Line Notes
1(b) Page 2 of 23 Line 9 Column (e)
3(b) Schedule 6-GAS Page 1 of 5 Line 22 Column (a)
4(b) Schedule 6-GAS Page 1 of 5 Line 23 Column (a)
5(b) Schedule 6-GAS Page 1 of 5 Line 24 Column (a)
10(b) Schedule 6-GAS Page 1 of 5 Line 41 Column (a)
11(b) Schedule 6-GAS Page 1 of 5 Line 42 Column (a)
12(b) Schedule 6-GAS Page 1 of 5 Line 43 Column (a)
34(b) Schedule 6-GAS Page 2 of 5 Line 16 Column (a)
35(b) Schedule 6-GAS Page 2 of 5 Line 17 Column (a)
36(b) Schedule 6-GAS Page 2 of 5 Line 18 Column (a)
37(b) Schedule 6-GAS Page 2 of 5 Line 19 Column (a)

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
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The Narragansett Electric Company d/b/a National Grid
Accumulated Depreciation Adjustments To Rate Base
Rate Year 1 Ending August 31, 2019 through Rate Year Ending August 31, 2021

		Description	Period (a)		Accumulated Depreciation (b)
1		Balance at August 31, 2019			$439,845,149
2					
3		Balance as of:	09/30/19	1/	$443,055,902
4			10/31/19	1/	$446,266,654
5			11/30/19	1/	$449,477,407
6			12/31/19	1/	$452,688,159
7			01/31/20	1/	$455,898,912
8			02/28/20	1/	$459,109,664
9			03/31/20	1/	$462,320,417
10			04/30/20	1/	$465,531,169
11			05/31/20	1/	$468,741,922
12			06/30/20	1/	$471,952,674
13			07/31/20	1/	$475,163,427
14		Balance at August 31, 2020		1/	$478,374,179
15					
16		DataYear 1 Accumulated Depreciation - 5 Quarter Average			$459,109,664
17					
18		Balance at August 31, 2020			$478,374,179
19					
20		Balance as of:	09/30/20	2/	$481,093,983
21			10/31/20	2/	$483,813,787
22			11/30/20	2/	$486,533,591
23			12/31/20	2/	$489,253,395
24			01/31/21	2/	$491,973,199
25			02/28/21	2/	$494,693,002
26			03/31/21	2/	$497,412,806
27			04/30/21	2/	$500,132,610
28			05/31/21	2/	$502,852,414
29			06/30/21	2/	$505,572,218
30			07/31/21	2/	$508,292,022
31		Balance at August 31, 2021		2/	$511,011,826
32					
33		Rate Year 3 Accumulated Depreciation - 5 Quarter Average			$494,693,002
34					
35	1/	Rate Year Ended 08/31/20 Depreciation Reserve Detail:			
36		Depreciation Expense 09/01/19 - 08/31/20			$40,875,154
37		Plus: Unrecovered Reserve Adjustment			$186,500
38		Net Cost of Removal / (Salvage)			($1,088,713)
39		Less: Retirements			($1,443,911)
40		Net Increase / (Decrease)			$38,529,030
41					
42		Monthly Increase / (Decrease)			$3,210,752
43					
44	2/	Rate Year Ended 08/31/21 Depreciation Reserve Detail:			
45		Depreciation Expense 09/01/20 - 08/31/21			$41,483,938
46		Plus: Unrecovered Reserve Adjustment			$186,500
47		Net Cost of Removal / (Salvage)			($1,131,231)
48		Less: Retirements			($7,901,560)
49		Net Increase / (Decrease)			$32,637,647
50					
51		Monthly Increase / (Decrease)			$2,719,804

Line Notes
36(b) Schedule 6-GAS Page 2 of 5 Line 37 Column (a)
37(b) Schedule 6-GAS Page 2 of 5 Line 38 Column (a)
38(b) Schedule 6-GAS Page 2 of 5 Line 39 Column (a)
39(b) Schedule 6-GAS Page 2 of 5 Line 40 Column (a)
45(b) Schedule 6-GAS Page 2 of 5 Line 58 Column (a)
46(b) Schedule 6-GAS Page 2 of 5 Line 59 Column (a)
47(b) Schedule 6-GAS Page 2 of 5 Line 60 Column (a)
48(b) Schedule 6-GAS Page 2 of 5 Line 61 Column (a)

The Narragansett Electric Company d/b/a National Grid
Adjustments To Rate Base
Five Quarter Average Ending June 30, 2017 through Rate Year Ending August 31, 2021
Other Rate Base Item Forecast

			CWIP	CIAC	Materials and Supplies	Prepaid Expenses	Deferred Debits	Customer Deposits	Unamort Interest Rate Lock	Unamort Debt Issuance $300M	Unamort Debt Issuance $250M	Unamort Debt Issuance $200M	Unamort Debt Issuance $350M	Unamort Debt Issuance Mortgage Bonds
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Balance at the of Test Year June 30, 2017		$43,392,799	$38	$3,073,221	$150,553	$58,807	$1,912,168	$987,102	$397,742	$68,632	$269,674	$0	$92,437
2														
3	Increase / (Decrease) 12 Months Ended	06/30/18	$0	($114)	($45,703)	$6,273	($58,807)	($272,260)	($161,898)	($17,515)	($25,341)	($10,645)	$0	($22,925)
4														
5	Balance at	06/30/18	$43,392,799	($76)	$3,027,518	$156,826	$0	$1,639,908	$825,205	$380,227	$43,291	$259,029	$0	$69,512
6														
7	Balance = prior month plus monthly change (from Row 52)													
8		07/31/18	$43,500,769	($191)	$2,981,815	$163,099	$0	$1,617,220	$811,713	$378,767	$41,179	$258,141	$483,000	$67,602
9		08/31/18	$43,608,739	($305)	$2,936,111	$169,372	$0	$1,594,531	$798,222	$377,308	$39,067	$257,254	$478,975	$65,691
10		09/30/18	$43,716,709	($420)	$2,890,408	$175,645	$0	$1,571,843	$784,730	$375,848	$36,955	$256,367	$474,950	$63,781
11		10/31/18	$43,824,679	($534)	$2,844,705	$181,918	$0	$1,549,155	$771,239	$374,388	$34,844	$255,480	$470,925	$61,871
12		11/30/18	$43,932,649	($648)	$2,799,002	$188,191	$0	$1,526,466	$757,747	$372,929	$32,732	$254,593	$466,900	$59,960
13		12/31/18	$44,040,619	($763)	$2,753,299	$194,464	$0	$1,503,778	$744,256	$371,469	$30,620	$253,706	$462,875	$58,050
14		01/31/19	$44,148,589	($877)	$2,707,596	$200,737	$0	$1,481,090	$730,764	$370,010	$28,508	$252,819	$458,850	$56,139
15		02/28/19	$44,256,559	($991)	$2,661,892	$207,010	$0	$1,458,401	$717,273	$368,550	$26,397	$251,932	$454,825	$54,229
16		03/31/19	$44,364,529	($1,106)	$2,616,189	$213,283	$0	$1,435,713	$703,781	$367,090	$24,285	$251,045	$450,800	$52,319
17		04/30/19	$44,472,499	($1,220)	$2,570,486	$219,556	$0	$1,413,025	$690,290	$365,631	$22,173	$250,158	$446,775	$50,408
18		05/31/19	$44,472,499	($1,220)	$2,570,486	$219,556	$0	$1,413,025	$676,798	$364,171	$20,061	$249,271	$442,750	$48,498
19		06/30/19	$44,580,469	($1,335)	$2,524,783	$225,829	$0	$1,390,336	$663,307	$362,712	$17,950	$248,384	$438,725	$46,587
20		07/31/19	$44,688,439	($1,449)	$2,479,080	$232,103	$0	$1,367,648	$649,815	$361,252	$15,838	$247,496	$434,700	$44,677
21		08/31/19	$44,796,409	($1,563)	$2,433,376	$238,376	$0	$1,344,960	$636,324	$359,792	$13,726	$246,609	$430,675	$42,767
22		09/30/19	$44,904,379	($1,678)	$2,387,673	$244,649	$0	$1,322,271	$622,832	$358,333	$11,614	$245,722	$426,650	$40,856
23		10/31/19	$45,012,349	($1,792)	$2,341,970	$250,922	$0	$1,299,583	$609,341	$356,873	$9,502	$244,835	$422,625	$38,946
24		11/30/19	$45,120,319	($1,906)	$2,296,267	$257,195	$0	$1,276,895	$595,849	$355,414	$7,391	$243,948	$418,600	$37,035
25		12/31/19	$45,228,289	($2,021)	$2,250,564	$263,468	$0	$1,254,206	$582,358	$353,954	$5,279	$243,061	$414,575	$35,125
26		01/31/20	$45,336,259	($2,135)	$2,204,861	$269,741	$0	$1,231,518	$568,866	$352,494	$3,167	$242,174	$410,550	$33,215
27		02/29/20	$45,444,229	($2,250)	$2,159,157	$276,014	$0	$1,208,830	$555,375	$351,035	$1,055	$241,287	$406,525	$31,304
28		03/31/20	$45,552,199	($2,364)	$2,113,454	$282,287	$0	$1,186,141	$541,883	$349,575	$0	$240,400	$402,500	$29,394
29		04/30/20	$45,660,169	($2,478)	$2,067,751	$288,560	$0	$1,163,453	$528,392	$348,115	$0	$239,513	$398,475	$27,483
30		05/31/20	$45,768,139	($2,593)	$2,022,048	$294,833	$0	$1,140,765	$514,901	$346,656	$0	$238,626	$394,450	$25,573
31		06/30/20	$45,876,109	($2,707)	$1,976,345	$301,106	$0	$1,118,076	$501,409	$345,196	$0	$237,739	$390,425	$23,663
32		07/31/20	$45,984,079	($2,821)	$1,930,642	$307,379	$0	$1,095,388	$487,918	$343,737	$0	$236,851	$386,400	$21,752
33		08/31/20	$46,092,049	($2,936)	$1,884,938	$313,652	$0	$1,072,700	$474,426	$342,277	$0	$235,964	$382,375	$19,842
34		09/30/20	$46,200,019	($3,050)	$1,839,235	$319,925	$0	$1,050,011	$460,935	$340,817	$0	$235,077	$378,350	$17,931
35		10/31/20	$46,307,989	($3,165)	$1,793,532	$326,198	$0	$1,027,323	$447,443	$339,358	$0	$234,190	$374,325	$16,021
36		11/30/20	$46,415,959	($3,279)	$1,747,829	$332,471	$0	$1,004,635	$433,952	$337,898	$0	$233,303	$370,300	$14,111
37		12/31/20	$46,523,929	($3,393)	$1,702,126	$338,744	$0	$981,946	$420,460	$336,439	$0	$232,416	$366,275	$12,200
38		01/31/21	$46,631,899	($3,508)	$1,656,422	$345,017	$0	$959,258	$406,969	$334,979	$0	$231,529	$362,250	$10,290
39		02/28/21	$46,739,869	($3,622)	$1,610,719	$351,290	$0	$936,570	$393,477	$333,519	$0	$230,642	$358,225	$8,379
40		03/31/21	$46,847,839	($3,736)	$1,565,016	$357,563	$0	$913,881	$379,986	$332,060	$0	$229,755	$354,200	$6,469
41		04/30/21	$46,955,809	($3,851)	$1,519,313	$363,836	$0	$891,193	$366,494	$330,600	$0	$228,868	$350,175	$4,559
42		05/31/21	$47,063,779	($3,965)	$1,473,610	$370,109	$0	$868,505	$353,003	$329,141	$0	$227,981	$346,150	$2,648
43		06/30/21	$47,171,749	($4,080)	$1,427,907	$376,382	$0	$845,816	$339,511	$327,681	$0	$227,094	$342,125	$738
44		07/31/21	$47,279,719	($4,194)	$1,382,203	$382,656	$0	$823,128	$326,020	$326,221	$0	$226,206	$338,100	($1,173)
45		08/31/21	$47,387,689	($4,308)	$1,336,500	$388,929	$0	$800,440	$312,528	$324,762	$0	$225,319	$334,075	($3,083)
46	Five Quarter Average:													
47	Rate Year 1 Amount		$44,213,371	($946)	$2,680,174	$204,501	$0	$1,467,477	$717,273	$368,550	$26,397	$251,932	$454,825	$54,229
48	Rate Year 2 Amount		$45,444,229	($2,250)	$2,159,157	$276,014	$0	$1,208,830	$555,375	$351,035	$4,434	$241,287	$406,525	$31,304
49	Rate Year 3 Amount		$46,739,869	($3,622)	$1,610,719	$351,290	$0	$936,570	$393,477	$333,519	$0	$230,642	$358,225	$8,379
50														
51	Changes:													
52	Annual		$1,295,640 1/	($1,373) 1/	($548,438) 1/	$75,276 1/	$0	($272,260) 1/	($161,898)	(17,515)	(25,341)	(10,645)	(48,300)	(22,925)
53	Monthly (as applied above)		$107,970	($114)	($45,703)	$6,273	$0	($22,688)	($13,491)	($1,460)	($2,112)	($887)	($4,025)	($1,910)
54														

1/ Balance ending June 30, (Per Company Books)

	CWIP	CIAC	Materials and Supplies	Prepaid Expenses	Customer Deposits
2015	$40,130,108	($38)	$4,170,097	$0	$2,456,688
2016	$41,016,062	($2,783)	$4,566,887	$172,681	$3,077,936
2017	$42,721,388	($2,783)	$3,073,221	$150,553	$1,912,168
Average Annual Change over 2 year period	$1,295,640	($1,373)	($548,438)	$75,276	($272,260)

Line Notes

1(a) Page 2 of 23 Line 5 Column (e)
1(b) Page 2 of 23 Line 11 Column (e)
1(c) Page 2 of 23 Line 16 Column (e)
1(d) Page 2 of 23 Line 17 Column (e)
1(e) Page 2 of 23 Line 18 Column (e)
1(f) Page 2 of 23 Line 32 Column (e)
1(g) Page 2 of 23 Line 20 Column (e)
1(h) Page 2 of 23 Line 21 Column (e)
1(i) Page 2 of 23 Line 22 Column (e)
1(j) Page 2 of 23 Line 23 Column (e)
1(k) Page 2 of 23 Line 24 Column (e)
1(l) Page 2 of 23 Line 25 Column (e)
5 Line 1 + Line 3
8(e) One month remaining expense
8(k) Amortization begins in August
47 Average of Lines 9, 12, 15, 18 and 21
48 Average of Lines 21, 24, 27, 30 and 33
49 Average of Lines 33, 36, 39, 42 and 45
52(g) Sum of Workpaper 3 Page 5 of 27 Line 43 Columns (a) through (l)
52(h) Sum of Workpaper 3 Page 9 of 27 Column (a) Lines 9 through 20
52(i) Sum of Workpaper 3 Page 14 of 27 Column (i) Lines 9 through 20
52(j) Sum of Workpaper 3 Page 19 of 27 Column (g) Lines 8 through 19
52(k) Sum of Workpaper 3 Page 24 of 27 Column (a) Lines 10 through 21
52(l) Sum of Workpaper 3 Page 27 of 27 Column (k) Lines 13 through 24

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The Narragansett Electric Company d/b/a National Grid
Merger Hold Harmless Rate Base Credit Adjustments To Rate Base
Test Year Ending June 31,2017 through Rate Year 1 Ending August 31, 2019

	Description	Period	Monthly Expense	Merger Hold Harmless Rate Base Credit
		(a)	(b)	(c)
1	Balance at June 30, 2017			$21,532,971
2				
3	Subsequent 2 months			($253,030)
4				
5	Balance at August 31, 2017			$21,279,942
6				
7				
8	Increase/(Decrease) 12 Months Ended	08/31/18		($1,674,988)
9				
10	Balance at August 31, 2018			$19,604,953
11		09/30/18	($146,116)	$19,458,837
12		10/31/18	($146,116)	$19,312,721
13		11/30/18	($146,116)	$19,166,605
14		12/31/18	($146,116)	$19,020,489
15		01/31/19	($167,950)	$18,852,539
16		02/28/19	($167,950)	$18,684,590
17		03/31/19	($167,950)	$18,516,640
18		04/30/19	($167,950)	$18,348,691
19		05/31/19	($167,950)	$18,180,741
20		06/30/19	($167,950)	$18,012,792
21		07/31/19	($167,950)	$17,844,842
22	Balance at August 31, 2019	08/31/19	($167,950)	$17,676,893
23				
24	Rate Year 1 Merger Hold Harmless - 5 Quarter Average			$18,662,756

Line Notes

1(c)	Page 21 of 23 Line 5 Column (e)
3(c)	Page 21 of 23 Line 6 Column (f) divide by 3 times 2
5(c)	Line 1 + Line 8
11(b)	Page 21 of 23 Line 10 Column (f) divide by 3 times 1
12(b)	Page 21 of 23 Line 11 Column (f) divide by 3 times 1
13(b)	Page 21 of 23 Line 11 Column (f) divide by 3 times 1
14(b)	Page 21 of 23 Line 11 Column (f) divide by 3 times 1
15(b)	Page 21 of 23 Line 12 Column (f) divide by 3 times 1
16(b)	Page 21 of 23 Line 12 Column (f) divide by 3 times 1
17(b)	Page 21 of 23 Line 12 Column (f) divide by 3 times 1
18(b)	Page 21 of 23 Line 13 Column (f) divide by 3 times 1
19(b)	Page 21 of 23 Line 13 Column (f) divide by 3 times 1
20(b)	Page 21 of 23 Line 13 Column (f) divide by 3 times 1
21(b)	Page 21 of 23 Line 14 Column (f) divide by 3 times 1
22(b)	Page 21 of 23 Line 14 Column (f) divide by 3 times 1

The Narragansett Electric Company d/b/a National Grid
Merger Hold Harmless Rate Base Credit Adjustments To Rate Base
Rate Year 1 Ending August 31, 2019 through Rate Year Ending August 31, 2021

	Description	Period	Monthly Expense	Merger Hold Harmless Rate Base Credit
		(a)	(b)	(c)
1	Balance at August 31, 2019			$17,676,893
2		09/30/19	($167,950)	$17,508,943
3		10/31/19	($167,950)	$17,340,994
4		11/30/19	($167,950)	$17,173,044
5		12/31/19	($167,950)	$17,005,095
6		01/31/20	($198,997)	$16,806,098
7		02/29/20	($198,997)	$16,607,100
8		03/31/20	($198,997)	$16,408,103
9		04/30/20	($198,997)	$16,209,106
10		05/31/20	($198,997)	$16,010,109
11		06/30/20	($198,997)	$15,811,112
12		07/31/20	($198,997)	$15,612,115
13	Balance at August 31, 2020	08/31/20	($198,997)	$15,413,118
14				
15	Rate Year 2 Merger Hold Harmless - 5 Quarter Average			$16,576,053
16				
17	Balance at August 31, 2020			$15,413,118
18		09/30/20	($198,997)	$15,214,120
19		10/31/20	($198,997)	$15,015,123
20		11/30/20	($198,997)	$14,816,126
21		12/31/20	($198,997)	$14,617,129
22		01/31/21	($223,582)	$14,393,547
23		02/28/21	($223,582)	$14,169,965
24		03/31/21	($223,582)	$13,946,383
25		04/30/21	($223,582)	$13,722,802
26		05/31/21	($223,582)	$13,499,220
27		06/30/21	($223,582)	$13,275,638
28		07/31/21	($223,582)	$13,052,056
29	Balance at August 31, 2021	08/31/21	($223,582)	$12,828,474
30				
31	Rate Year 3 Merger Hold Harmless - 5 Quarter Average			$14,145,381

Line Notes

1(c)	Page 9 of 23 Line 22 Column (c)
2(b)	Page 21 of 23 Line 14 Column (f) divide by 3 times 1
3(b)	Page 21 of 23 Line 15 Column (f) divide by 3 times 1
4(b)	Page 21 of 23 Line 15 Column (f) divide by 3 times 1
5(b)	Page 21 of 23 Line 15 Column (f) divide by 3 times 1
6(b)	Page 21 of 23 Line 16 Column (f) divide by 3 times 1
7(b)	Page 21 of 23 Line 16 Column (f) divide by 3 times 1
8(b)	Page 21 of 23 Line 16 Column (f) divide by 3 times 1
9(b)	Page 21 of 23 Line 17 Column (f) divide by 3 times 1
10(b)	Page 21 of 23 Line 17 Column (f) divide by 3 times 1
11(b)	Page 21 of 23 Line 17 Column (f) divide by 3 times 1
12(b)	Page 21 of 23 Line 18 Column (f) divide by 3 times 1
13(b)	Page 21 of 23 Line 18 Column (f) divide by 3 times 1
18(b)	Page 21 of 23 Line 18 Column (f) divide by 3 times 1
19(b)	Page 21 of 23 Line 19 Column (f) divide by 3 times 1
20(b)	Page 21 of 23 Line 19 Column (f) divide by 3 times 1
21(b)	Page 21 of 23 Line 19 Column (f) divide by 3 times 1
22(b)	Page 21 of 23 Line 20 Column (f) divide by 3 times 1
23(b)	Page 21 of 23 Line 20 Column (f) divide by 3 times 1
24(b)	Page 21 of 23 Line 20 Column (f) divide by 3 times 1
25(b)	Page 21 of 23 Line 21 Column (f) divide by 3 times 1
26(b)	Page 21 of 23 Line 21 Column (f) divide by 3 times 1
27(b)	Page 21 of 23 Line 21 Column (f) divide by 3 times 1
28(b)	Page 21 of 23 Line 22 Column (f) divide by 3 times 1
29(b)	Page 21 of 23 Line 22 Column (f) divide by 3 times 1

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The Narragansett Electric Company d/b/a National Grid
Accumulated Deferred Tax Forecast Rate Base Adjustments
Test Year Ending June 31,2017 through Rate Year 1 Ending August 31, 2019

		Description	Period or Amount			Accumulated Deferred Income Tax
			(a)	(b)		(c)
1		Balance at June 30, 2017				$122,924,988
2						
3		Increase/(Decrease) 2 Month Ended			1/	$5,298,607
4		Adjustment for decrease in federal tax rate				($75,170)
5		Balance at August 31, 2017				$128,148,424
6						
7		Increase/(Decrease) 12 Month Ended			2/	$20,453,237
8						
9		Balance at August 31, 2018				$148,601,661
10						
11		Balance as of:	09/30/18		3/	$149,775,025
12			10/31/18		3/	$150,948,390
13			11/30/18		3/	$152,121,754
14			12/31/18		3/	$153,295,118
15			01/31/19		3/	$154,468,483
16			02/28/19		3/	$155,641,847
17			03/31/19		3/	$156,815,211
18			04/30/19		3/	$157,988,576
19			05/31/19		3/	$159,161,940
20			06/30/19		3/	$160,335,305
21			07/31/19		3/	$161,508,669
22		Balance at August 31, 2019			3/	$162,682,033
23						
24		Rate Year 1 Accumulated Deferred Income Tax - Five Quarter Average				$155,641,847
25						
26			Book	Tax		Difference
27			(a)	(b)		(c)
28	1/	2 Months Ending 08/30/17				
29		Depreciation	$6,233,864	$23,028,180		$16,794,315
30		Income Tax Rate				31.55%
31		2 Month Change to Accumulated Deferred Taxes				$5,298,607
32		Net Operating Loss Utilization				$0
33		Proration Adjustment				$0
34		Net Annual Change				$5,298,607
35						
36	2/	12 Months Ended 08/31/18:				
37		Depreciation	$39,532,703	$114,855,349		$75,322,646
38		Income Tax Rate				27.15%
39		Annual Change to Accumulated Deferred Taxes				$20,453,237
40		Net Operating Loss Utilization				$0
41		Proration Adjustment				$0
42		Net Annual Change				$20,453,237
43						
44	3/	12 Months Ended 08/31/19:				
45		Depreciation	$38,950,409	$114,925,096		$75,974,687
46		Income Tax Rate				21.00%
47		Annual Change to Accumulated Deferred Taxes				$15,954,684
48		Net Operating Loss Utilization				$1,379,604
49		Proration Adjustment				($1,255,916)
50		Net Annual Change				$16,078,372
51		Excess DIT amortization				($1,998,000)
52		Monthly Change to Accumulated Deferred Taxes				$1,173,364

Column Notes
(b) Per Tax Department

Line Notes
1(c) Page 2 of 23 Line 29 Column (e)
29(a) Schedule 6-GAS Page 1 of 5 Line 22 Column (a)
29(b) Page 14 of 23 Line 3 Column (b)
37(a) Schedule 6-GAS Page 1 of 5 Line 41 Column (a)
37(b) Page 14 of 23 Line 3 Column (c)
45(a) Schedule 6-GAS Page 2 of 5 Line 16 Column (a)
45(b) Page 14 of 23 Line 3 Column (d)

The Narragansett Electric Company d/b/a National Grid
Accumulated Deferred Tax Forecast Rate Base Adjustments
Rate Year 1 Ending August 31, 2019 through Rate Year Ending August 31, 2021

		Description	Period or Amount (a)			Accumulated Deferred Income Tax (c)
1		Balance at August 31, 2019				$163,937,949
2						
3		Balance as of:	09/30/19		1/	$164,195,216
4			10/31/19		1/	$164,452,483
5			11/30/19		1/	$164,709,750
6			12/31/19		1/	$164,967,018
7			01/31/20		1/	$165,224,285
8			02/29/20		1/	$165,481,552
9			03/31/20		1/	$165,738,819
10			04/30/20		1/	$165,996,086
11			05/31/20		1/	$166,253,353
12			06/30/20		1/	$166,510,620
13			07/31/20		1/	$166,767,888
14		Balance at August 31, 2020			1/	$167,025,155
15						
16		Rae Year 2 Accumulated Deferred Income Tax - Five Quarter Average				$165,481,552
17						
18		Balance as of:	09/30/20		2/	$170,243,228
19			10/31/20		2/	$170,722,305
20			11/30/20		2/	$171,201,381
21			12/31/20		2/	$171,680,457
22			01/31/21		2/	$172,159,534
23			02/28/21		2/	$172,638,610
24			03/31/21		2/	$173,117,686
25			04/30/21		2/	$173,596,763
26			05/31/21		2/	$174,075,839
27			06/30/21		2/	$174,554,915
28			07/31/21		2/	$175,033,992
29		Balance at August 31, 2021			2/	$175,513,068
30						
31		Rate Year 3 Accumulated Deferred Income Tax - Five Quarter Average				$172,638,610
32						
33			Book	Tax		Difference
34			(a)	(b)		(c)
35	1/	12 Months Ended 08/31/20:				
36		Depreciation	$40,875,154	$57,821,237		$16,946,083
37		Income Tax Rate				21.00%
38		Annual Change to Accumulated Deferred Taxes				$3,558,677
39		Net Operating Loss Utilization				$4,265,526
40		Proration Adjustment				($2,738,997)
41		Net Annual Change				$5,085,206
42		Excess DIT amortization				($1,998,000)
43		Monthly Change to Accumulated Deferred Taxes				$257,267
44						
45	2/	12 Months Ended 08/31/21:				
46		Depreciation	$41,483,938	$58,200,613		$16,716,675
47		Income Tax Rate				21.00%
48		Annual Change to Accumulated Deferred Taxes				$3,510,502
49		Net Operating Loss Utilization				$9,978,651
50		Proration Adjustment				($5,742,237)
51		Net Annual Change				$7,746,916
52		Excess DIT amortization				($1,998,000)
53		Monthly Change to Accumulated Deferred Taxes				$479,076

Column Notes
(b) Per Tax Department

Line Notes
36(a) Schedule 6-GAS Page 2 of 5 Line 37 Column (a)
36(b) Page 14 of 23 Line 3 Column (e)
46(a) Schedule 6-GAS Page 2 of 5 Line 58 Column (a)
46(b) Page 14 of 23 Line 3 Column (f)

The Narragansett Electric Company d/b/a National Grid
Proration Adjustment
Test Year through Rate Year 3

	Description	2 Months Ending August 31, 2017 (a)	12 Months Ending August 31, 2018 (b)	Rate Year 1 Ending August 31, 2019 (c)	Rate Year Ending August 31, 2020 (d)	Rate Year Ending August 31, 2021 (e)
1	Proration Adjustment	$0	$0	$1,255,916	$2,738,997	$5,742,237
2						
3	Total	$0	$0	$1,255,916	$2,738,997	$5,742,237
4						
5						
6	NOTE: Proration is not applicable to actual ADIT					
7						
8	August 2018 Rate Calculation			# of Months		
9	Sep 2017 - 3/31/2018		31.55%	7		
10	4/1/2018 - 8/31/2018		21.00%	5		
11	Blended Rate		27.15%	12		
12						
13	Deferred Tax Subject to Proration					
14	Book Depreciation	$6,233,864	$39,532,703	$38,950,409	$40,875,154	$41,483,938
15	Bonus Depreciation	($4,187,029)	($2,060,682)	$0	$0	$0
16	Remaining MACRS Tax Depreciation	($6,608,062)	($40,547,235)	($43,447,540)	($44,698,174)	($44,565,053)
17						
18	Cumulative Book / Tax Timer	($4,561,227)	($3,075,214)	($4,497,131)	($3,823,020)	($3,081,114)
19	Effective Tax Rate	31.55%	27.15%	21.00%	21.00%	21.00%
20	Deferred Tax Reserve	($1,439,067)	($835,049)	($944,397)	($802,834)	($647,034)
21						
22	Net Operating Loss Utilization					
23						
24	Net Operating Loss Utilization			($6,569,542)	($20,312,027)	($47,517,386)
25	Effective Tax Rate			21.00%	21.00%	21.00%
26	Deferred Tax Reserve			($1,379,604)	($4,265,526)	($9,978,651)
27						
28	Total Accumulated Deferred Income Taxes Subject to Proration	$0	$0	($2,324,001)	($5,068,360)	($10,625,685)
29						
30		Days in Month	Proration Percentage			
31						
32	Proration Calculation					
33	September	30	92%	$0	$0	($177,749)	($387,649)	($812,695)
34	October	31	83%	$0	$0	($161,301)	($351,777)	($737,490)
35	November	30	75%	$0	$0	($145,383)	($317,062)	($664,712)
36	December	31	67%	$0	$0	($128,934)	($281,190)	($589,507)
37	January	31	58%	$0	$0	($112,486)	($245,318)	($514,303)
38	February	28	50%	$0	$0	($97,629)	($212,917)	($446,376)
39	March	31	42%	$0	$0	($81,181)	($177,045)	($371,171)
40	April	30	34%	$0	$0	($65,263)	($142,331)	($298,393)
41	May	31	25%	$0	$0	($48,815)	($106,459)	($223,188)
42	June	30	17%	$0	$0	($32,897)	($71,744)	($150,409)
43	July	31	8%	$0	$0	($16,448)	($35,872)	($75,205)
44	August	31	0%	$0	$0	$0	$0	$0
45	Total			$0	$0	($1,068,086)	($2,329,363)	($4,883,448)
46								
47	Deferred Tax Without Proration			$0	$0	($2,324,001)	($5,068,360)	($10,625,685)
48	Proration Adjustment			$0	$0	$1,255,916	$2,738,997	$5,742,237

Line Notes
14(a) Schedule 6-GAS Page 1 of 5 Line 22 Column (a)
14(b) Schedule 6-GAS Page 1 of 5 Line 41 Column (a)
14(c) Schedule 6-GAS Page 2 of 5 Line 16 Column (a)
14(d) Schedule 6-GAS Page 2 of 5 Line 37 Column (a)
14(e) Schedule 6-GAS Page 2 of 5 Line 58 Column (a)
15(a) Page 15 of 23 Line 2 Column (c) times -1
15(b) Page 15 of 23 Line 5 Column (c) times -1
15(c) Page 15 of 23 Line 8 Column (c) times -1
15(d) Page 15 of 23 Line 11 Column (c) times -1
16(a) Page 15 of 23; Line 1 Column (d) plus Line 3 Column (d)
16(b) Page 15 of 23; Line 1 Column (e) plus Line 3 Column (e) plus Line 6 Column (e)
16(c) Page 15 of 23; Line 1 Column (f) plus Line 3 Column (f) plus Line 6 Column (f) plus Line 9 Column (f)
16(d) Page 15 of 23; Line 1 Column (g) plus Line 3 Column (g) plus Line 6 Column (g) plus Line 9 Column (g) plus Line 12 Column (g)
16(e) Page 15 of 23; Line 1 Column (h) plus Line 3 Column (h) plus Line 6 Column (h) plus Line 9 Column (h) plus Line 12 Column (h) plus Line 15 Column (h)
18 Sum of Lines 14, 15 and 16
19 Per Tax Department
20 Line 18 times 19
24(c) Page 11 of 23 Line 48 Column (c) divided by Line 19 Column (c)
24(d) Page 12 of 23 Line 39 Column (c) divided by Line 19 Column (d)
24(e) Page 12 of 23 Line 49 Column (c) divided by Line 19 Column (e)
25 Per Tax Department
26 Line 25 times 24
28 Line 20 plus 26

The Narragansett Electric Company d/b/a National Grid
Federal Tax Depreciation
Test Year through Rate Year 3
Estimated Additions

	Description	Test Year Ending June 30, 2017 (a)	2 Months Ending August 31, 2017 (b)	12 Months Ending August 31, 2018 (c)	Rate Year 1 Ending August 31, 2019 (d)	Rate Year Ending August 31, 2020 (e)	Rate Year Ending August 31, 2021 (f)
1	Narragansett Gas Tax Depreciation of Embedded Plant	$30,237,950	$23,028,180	$114,855,349	$114,925,096	$57,821,237	$58,200,613
2							
3	Total	$30,237,950	$23,028,180	$114,855,349	$114,925,096	$57,821,237	$58,200,613

Line Notes
1(a) Per Tax Department
1(b) Page 15 of 23 Line 17 Column (d)
1(c) Page 15 of 23 Line 17 Column (e)
1(d) Page 15 of 23 Line 17 Column (f)
1(e) Page 15 of 23 Line 17 Column (g)
1(f) Page 15 of 23 Line 17 Column (h)

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The Narragansett Electric Company d/b/a National Grid
Federal Tax Depreciation
Summary

	Narragansett Electric Company	Capital Additions	Capital Repairs Current Deduct	Yr 1 Bonus	Total Tax Depreciation and Repairs Deduction				
					2 Months Ending August 31, 2017	12 Months Ending August 31, 2018	Rate Year 1 Ending August 31, 2019	Rate Year 2 Ending August 31, 2020	Rate Year 3 Ending August 31, 2021
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Tax Depreciation on Existing Plant				$6,451,048	$38,467,635	$37,911,627	$37,405,849	$37,132,672
2	Capital Repairs/Bonus 2 Months Ending August 31, 2017	$19,592,266	$11,218,210	$4,187,029	$15,405,238				
3	MACRS 2 Months Ending August 31, 2017				$157,014	$302,262	$279,568	$258,633	$239,205
4	Cost of Removal 2 Months Ending August 31,2017				$1,014,879				
5	Capital Repairs/Bonus 12 Months Ending August 31, 2018	$115,710,016	$66,253,652	$2,060,682		$68,314,334			
6	MACRS 12 Months Ending August 31, 2018					$1,777,338	$3,421,494	$3,164,610	$2,927,631
7	Cost of Removal 12 Months Ending August 31,2018					$5,993,779			
8	Capital Repairs/Bonus Rate Year 1 Ending August 31, 2019	$114,477,000	$65,547,648	$0			$65,547,648		
9	MACRS Rate Year 1 Ending August 31, 2019						$1,834,851	$3,532,210	$3,267,013
10	Cost of Removal Rate Year 1 Ending August 31,2019						$5,929,909		
11	Capital Repairs/Bonus Rate Year Ending August 31, 2020	$21,017,630	$12,034,349	$0				$12,034,349	
12	MACRS Rate Year Ending August 31, 2020							$336,873	$648,503
13	Cost of Removal RateYear Ending August 31,2020							$1,088,713	
14	Capital Repairs/Bonus Rate Year Ending August 31, 2021	$21,838,436	$12,504,329						$12,504,329
15	MACRS Rate Year Ending August 31, 2021								$350,029
16	Cost of Removal Rate Year Ending August 31,2021								$1,131,231
17	Total	$292,635,348	$167,558,188	$6,247,711	$23,028,180	$114,855,349	$114,925,096	$57,821,237	$58,200,613

Line Note

2(a) Page 16 of 23 Line 1 Column (a)
2(b) Page 16 of 23 Line 5 Column (a)
2(c) Page 16 of 23 Line 16 Column (a)
2(d) Sum of 2(b) plus 2(c)
3(d) Page 16 of 23 Line 24 Column (a)
3(e) Page 16 of 23 Line 24 Column (b)
3(f) Page 16 of 23 Line 24 Column (c)
3(g) Page 16 of 23 Line 24 Column (d)
3(h) Page 16 of 23 Line 24 Column (e)
4(d) Page 16 of 23 Line 26 Column (a)
5(a) Page 17 of 23 Line 1 Column (a)
5(b) Page 17 of 23 Line 5 Column (a)
5(c) Page 17 of 23 Line 16 Column (a)
5(e) Sum of 5(b) plus 5(c)
6(e) Page 17 of 23 Line 24 Column (a)
6(f) Page 17 of 23 Line 24 Column (b)
6(g) Page 17 of 23 Line 24 Column (c)
6(h) Page 17 of 23 Line 24 Column (d)
7(e) Page 17 of 23 Line 26 Column (a)
8(a) Page 18 of 23 Line 1 Column (a)
8(b) Page 18 of 23 Line 5 Column (a)
8(c) Page 18 of 23 Line 16 Column (a)
8(f) Sum of 8(b) plus 8(c)
9(f) Page 18 of 23 Line 24 Column (a)
9(g) Page 18 of 23 Line 24 Column (b)
9(h) Page 18 of 23 Line 24 Column (c)
10(f) Page 18 of 23 Line 26 Column (a)
11(a) Page 19 of 23 Line 1 Column (a)
11(b) Page 19 of 23 Line 5 Column (a)
11(c) Page 19 of 23 Line 16 Column (a)
11(g) Sum of 11(b) plus 11(c)
12(g) Page 19 of 23 Line 24 Column (a)
12(h) Page 19 of 23 Line 24 Column (b)
13(g) Page 19 of 23 Line 26 Column (a)
14(a) Page 20 of 23 Line 1 Column (a)
14(b) Page 20 of 23 Line 5 Column (a)
14(h) Sum of 14(b) plus 14(c)
15(h) Page 20 of 23 Line 24 Column (a)
16(h) Page 20 of 23 Line 26 Column (a)

The Narragansett Electric Company d/b/a National Grid
Calculation of Tax Depreciation and Repairs Deduction
On Capital Investment for the 2 Months Ending August 31, 2017

		Reference	2 Months Ending August 31, 2017 (a)	12 Months Ending August 31, 2018 (b)	Rate Year 1 Ending August 31, 2019 (c)	Rate Year 2 Ending August 31, 2020 (d)	Rate Year 3 Ending August 31, 2021 (e)
	Capital Repairs Deduction						
1	Plant Additions	Schedule 11-GAS Page 3 of 23 Line 4 Column (b)	$19,592,266				
2							
3	Plant Eligible for Capital Repairs Deduction		$19,592,266				
4	Capital Repairs Deduction Rate	Per Tax Department	57.26%				
5	Capital Repairs Deduction	Line 3 * Line 4	$11,218,210				
6							
7	Bonus Depreciation						
8	Plant Additions	Line 1	$19,592,266				
9	Less Capital Repairs Deduction	Line 5	$11,218,210				
10	Plant Additions Net of Capital Repairs Deduction	Line 8 - Line 9	$8,374,057				
11	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	100.00%				
12	Plant Eligible for Bonus Depreciation	Line 10 * Line 11	$8,374,057				
13							
14							
15	Bonus Depreciation Rate		50.00%				
16	Total Bonus Depreciation Rate	Line 12 * Line 15	$4,187,029				
17							
18	Remaining Tax Depreciation						
19	Plant Additions	Line 1	$19,592,266				
20	Less Capital Repairs Deduction	Line 5	($11,218,210)				
21	Less Bonus Depreciation	Line 14	($4,187,029)				
22	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Sum Lines 19 Through 21	$4,187,028	$4,187,028	$4,187,028	$4,187,028	$4,187,028
23	20 YR MACRS Tax Depreciation Rates	Per Tax Department	3.75%	7.219%	6.677%	6.177%	5.713%
24	Remaining Tax Depreciation	Line 23 * Line 24	$157,014	$302,262	$279,568	$258,633	$239,205
25							
26	Cost of Removal	Schedule 6-GAS Page 1 of 5 Line 23 Column (a) * -1	$1,014,879				
27							
28	Total Tax Depreciation and Repairs Deduction	Line 5 + Line 16 + Line 24 + Line 26	$16,577,131	$302,262	$279,568	$258,633	$239,205

The Narragansett Electric Company d/b/a National Grid
Calculation of Tax Depreciation and Repairs Deduction
On Capital Investment for the 12 Months Ending August 31, 2018

		Reference	12 Months Ending August 31, 2018 (a)	Rate Year 1 Ending August 31, 2019 (b)	Rate Year 2 Ending August 31, 2020 (c)	Rate Year 3 Ending August 31, 2021 (d)
	Capital Repairs Deduction					
1	Plant Additions	Schedule 11-GAS Page 3 of 23 Line 11 Column (b)	$115,710,016			
2						
3	Plant Eligible for Capital Repairs Deduction		$115,710,016			
4	Capital Repairs Deduction Rate	Per Tax Department	57.26%			
5	Capital Repairs Deduction	Line 3 * Line 4	$66,253,652			
6						
7	Bonus Depreciation					
8	Plant Additions	Line 1	$115,710,016			
9	Less Capital Repairs Deduction	Line 5	$66,253,652			
10	Plant Additions Net of Capital Repairs Deduction	Line 8 - Line 9	$49,456,364			
11	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	8.33%			
12	Plant Eligible for Bonus Depreciation	Line 10 * Line 11	$4,121,364			
13	Bonus Depreciation Rate (September 2017 - December 2017)	4 months 2017 @ 50% (50%*4/12)	50.00%			
14	Bonus Depreciation Rate (January 2018 - August 2018)	8 months 2018 @ 40% (40%*8/12)	0.00%			
15	Total Bonus Depreciation Rate	Line 13 + Line 14	50.00%			
16	Total Bonus Depreciation Rate	Line 12 * Line 15	$2,060,682			
17						
18	Remaining Tax Depreciation					
19	Plant Additions	Line 1	$115,710,016			
20	Less Capital Repairs Deduction	Line 5	($66,253,652)			
21	Less Bonus Depreciation	Line 16 * -1	($2,060,682)			
22	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciatic	Sum Lines 19 Through 21	$47,395,682	$47,395,682	$47,395,682	$47,395,682
23	20 YR MACRS Tax Depreciation Rates	Per Tax Department	3.75%	7.219%	6.677%	6.177%
24	Remaining Tax Depreciation	Line 23 * Line 24	$1,777,338	$3,421,494	$3,164,610	$2,927,631
25						
26	Cost of Removal	Schedule 6-GAS Page 1 of 5 Line 42 Column (a) * -1	$5,993,779			
27						
28	Total Tax Depreciation and Repairs Deduction	Line 5 + Line 16 + Line 24 + Line 26	$76,085,451	$3,421,494	$3,164,610	$2,927,631

The Narragansett Electric Company d/b/a National Grid
Calculation of Tax Depreciation and Repairs Deduction
On Capital Investment for the 12 Months Ending August 31, 2019

		Reference	Rate Year 1 Ending August 31, 2019 (a)	Rate Year Ending August 31, 2020 (b)	Rate Year Ending August 31, 2021 (c)
	Capital Repairs Deduction				
1	Plant Additions	Schedule 11-GAS Page 3 of 23 Line 35 Column (b)	$114,477,000		
2					
3	Plant Eligible for Capital Repairs Deduction		$114,477,000		
4	Capital Repairs Deduction Rate	Per Tax Department	57.26%		
5	Capital Repairs Deduction	Line 3 * Line 4	$65,547,648		
6					
7	Bonus Depreciation				
8	Plant Additions	Line 1	$114,477,000		
9	Less Capital Repairs Deduction	Line 5	$65,547,648		
10	Plant Additions Net of Capital Repairs Deduction	Line 8 - Line 9	$48,929,352		
11	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	0.00%		
12	Plant Eligible for Bonus Depreciation	Line 10 * Line 11	$0		
13	Bonus Depreciation Rate (September 2018 - December 2018)	4 months 2018 @ 40% (40%*4/12)	13.33%		
14	Bonus Depreciation Rate (January 2019 - August 2019)	8 months 2019 @ 30% (30%*8/12)	20.00%		
15	Bonus Depreciation Rate	Line 13 + Line 14	33.33%		
16	Total Bonus Depreciation Rate	Line 12 * Line 15	$0		
17					
18					
19	Remaining Tax Depreciation				
20	Plant Additions	Line 1	$114,477,000		
21	Less Capital Repairs Deduction	Line 5	($65,547,648)		
22	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Sum Lines 19 Through 21	$48,929,352	$48,929,352	$48,929,352
23	20 YR MACRS Tax Depreciation Rates	Per Tax Department	3.750%	7.219%	6.677%
24	Remaining Tax Depreciation	Line 23 * Line 24	$1,834,851	$3,532,210	$3,267,013
25					
26	Cost of Removal	Schedule 6-GAS Page 2 of 5 Line 18 Column (a) *s -1	$5,929,909		
27					
28	Total Tax Depreciation and Repairs Deduction	Line 5 + Line 16 + Line 24 + Line 26	$73,312,407	$3,532,210	$3,267,013

The Narragansett Electric Company d/b/a National Grid
Calculation of Tax Depreciation and Repairs Deduction
On Capital Investment for the 12 Months Ending August 31, 2020

		Reference	Rate Year Ending August 31, 2020 (a)	Rate Year Ending August 31, 2021 (b)
	Capital Repairs Deduction			
1	Plant Additions	Schedule 11-GAS Page 4 of 23 Line 36 Column (b)	$21,017,630	
2				
3	Plant Eligible for Capital Repairs Deduction		$21,017,630	
4	Capital Repairs Deduction Rate	Per Tax Department	57.26%	
5	Capital Repairs Deduction	Line 3 * Line 4	$12,034,349	
6				
7	Bonus Depreciation			
8	Plant Additions	Line 1	$21,017,630	
9	Less Capital Repairs Deduction	Line 5	$12,034,349	
10	Plant Additions Net of Capital Repairs Deduction	Line 8 - Line 9	$8,983,281	
11	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	0.00%	
12	Plant Eligible for Bonus Depreciation	Line 10 * Line 11	$0	
13	Bonus Depreciation Rate (September 2019 - December 2019)	4 months 2019 @ 30% (30%*4/12)	10.00%	
14	Bonus Depreciation Rate (January 2020 - August 2020)	8 months 2020 @ 00% (00%*8/12)	0.00%	
15	Bonus Depreciation Rate	Line 13 + Line 14	10.00%	
16	Total Bonus Depreciation Rate	Line 12 * Line 15	$0	
17				
18				
19	Remaining Tax Depreciation			
20	Plant Additions	Line 1	$21,017,630	
21	Less Capital Repairs Deduction	Line 5	($12,034,349)	
22	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Sum Lines 19 Through 21	$8,983,281	$8,983,281
23	20 YR MACRS Tax Depreciation Rates	Per Tax Department	3.750%	7.219%
24	Remaining Tax Depreciation	Line 23 * Line 24	$336,873	$648,503
25				
26	Cost of Removal	Schedule 6-GAS Page 2 of 5 Line 39 Column (a) * -1	$1,088,713	
27				
28	Total Tax Depreciation and Repairs Deduction	Line 5 + Line 13 + Line 15	$13,459,935	$648,503

The Narragansett Electric Company d/b/a National Grid
Calculation of Tax Depreciation and Repairs Deduction
On Capital Investment for the 12 Months Ending August 31, 2021

		Reference	Rate Year Ending August 31, 2021 (a)
	Capital Repairs Deduction		
1	Plant Additions	Schedule 11-GAS Page 4 of 23 Line 44 Column (b)	$21,838,436
2			
3	Plant Eligible for Capital Repairs Deduction		$21,838,436
4	Capital Repairs Deduction Rate	Per Tax Department	57.26%
5	Capital Repairs Deduction	Line 3 * Line 4	$12,504,329
6			
7	Bonus Depreciation		
8	Plant Additions	Line 1	$21,838,436
9	Less Capital Repairs Deduction	Line 5	$12,504,329
10	Plant Additions Net of Capital Repairs Deduction	Line 8 - Line 9	$9,334,107
11	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	0.00%
12	Plant Eligible for Bonus Depreciation	Line 10 * Line 11	$0
13			
14			
15	Bonus Depreciation Rate		0.00%
16	Total Bonus Depreciation Rate	Line 12 * Line 13	$0
17			
18			
19	Remaining Tax Depreciation		
20	Plant Additions	Line 1	$21,838,436
21	Less Capital Repairs Deduction	Line 5	($12,504,329)
22	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Sum Lines 19 Through 21	$9,334,107
23	20 YR MACRS Tax Depreciation Rates	Per Tax Department	3.750%
24	Remaining Tax Depreciation	Line 23 * Line 24	$350,029
25			
26	Cost of Removal	Schedule 6-GAS Page 2 of 5 Line 60 Column (a) * -1	$1,131,231
27			
28	Total Tax Depreciation and Repairs Deduction	Line 5 + Line 16 + Line 24 + Line 26	$13,985,589

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National Grid - RI Gas
Customer Hold Harmless Credit
Rate Base Impact

	Month	Year	Deferred FIT DFIT Balance	Unamortized Investment Tax Credit Balance	Hold Harmless Total	Deferred Federal Income Tax Change	ITC Change	Total Change
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	June	2016	$22,928,782	$0	$22,928,782	($318,361)	$0	($318,361)
2	September	2016	$22,610,421	$0	$22,610,421	($318,361)	$0	($318,361)
3	December	2016	$22,292,061	$0	$22,292,061	($318,361)	$0	($318,361)
4	March	2017	$21,912,516	$0	$21,912,516	($379,545)	$0	($379,545)
5	June	2017	$21,532,971	$0	$21,532,971	($379,545)	$0	($379,545)
6	September	2017	$21,153,427	$0	$21,153,427	($379,545)	$0	($379,545)
7	December	2017	$20,773,882	$0	$20,773,882	($379,545)	$0	($379,545)
8	March	2018	$20,335,534	$0	$20,335,534	($438,348)	$0	($438,348)
9	June	2018	$19,897,186	$0	$19,897,186	($438,348)	$0	($438,348)
10	September	2018	$19,458,837	$0	$19,458,837	($438,348)	$0	($438,348)
11	December	2018	$19,020,489	$0	$19,020,489	($438,348)	$0	($438,348)
12	March	2019	$18,516,640	$0	$18,516,640	($503,849)	$0	($503,849)
13	June	2019	$18,012,792	$0	$18,012,792	($503,849)	$0	($503,849)
14	September	2019	$17,508,943	$0	$17,508,943	($503,849)	$0	($503,849)
15	December	2019	$17,005,095	$0	$17,005,095	($503,849)	$0	($503,849)
16	March	2020	$16,408,103	$0	$16,408,103	($596,991)	$0	($596,991)
17	June	2020	$15,811,112	$0	$15,811,112	($596,991)	$0	($596,991)
18	September	2020	$15,214,120	$0	$15,214,120	($596,991)	$0	($596,991)
19	December	2020	$14,617,129	$0	$14,617,129	($596,991)	$0	($596,991)
20	March	2021	$13,946,383	$0	$13,946,383	($670,746)	$0	($670,746)
21	June	2021	$13,275,638	$0	$13,275,638	($670,746)	$0	($670,746)
22	September	2021	$12,604,892	$0	$12,604,892	($670,746)	$0	($670,746)
23	December	2021	$11,934,147	$0	$11,934,147	($670,746)	$0	($670,746)
24	March	2022	$11,216,530	$0	$11,216,530	($717,617)	$0	($717,617)
25	June	2022	$10,498,913	$0	$10,498,913	($717,617)	$0	($717,617)
26	September	2022	$9,781,296	$0	$9,781,296	($717,617)	$0	($717,617)
27	December	2022	$9,063,679	$0	$9,063,679	($717,617)	$0	($717,617)
28	March	2023	$8,310,658	$0	$8,310,658	($753,021)	$0	($753,021)
29	June	2023	$7,557,637	$0	$7,557,637	($753,021)	$0	($753,021)
30	September	2023	$6,804,616	$0	$6,804,616	($753,021)	$0	($753,021)
31	December	2023	$6,051,595	$0	$6,051,595	($753,021)	$0	($753,021)
32	March	2024	$5,270,123	$0	$5,270,123	($781,472)	$0	($781,472)
33	June	2024	$4,488,651	$0	$4,488,651	($781,472)	$0	($781,472)
34	September	2024	$3,707,179	$0	$3,707,179	($781,472)	$0	($781,472)
35	December	2024	$2,925,707	$0	$2,925,707	($781,472)	$0	($781,472)
36	March	2025	$2,103,962	$0	$2,103,962	($821,746)	$0	($821,746)
37	June	2025	$1,282,216	$0	$1,282,216	($821,746)	$0	($821,746)
38	September	2025	$460,470	$0	$460,470	($821,746)	$0	($821,746)
39	December	2025	($361,276)	$0	($361,276)	($821,746)	$0	($821,746)
40	March	2026	($859,326)	$0	($859,326)	($498,050)	$0	($498,050)
41	June	2026	($1,357,377)	$0	($1,357,377)	($498,050)	$0	($498,050)
42	September	2026	($1,855,427)	$0	($1,855,427)	($498,050)	$0	($498,050)
43	December	2026	($2,353,477)	$0	($2,353,477)	($498,050)	$0	($498,050)
44	March	2027	($2,394,903)	$0	($2,394,903)	($41,426)	$0	($41,426)
45	June	2027	($2,436,329)	$0	($2,436,329)	($41,426)	$0	($41,426)
46	September	2027	($2,477,755)	$0	($2,477,755)	($41,426)	$0	($41,426)
47	December	2027	($2,519,181)	$0	($2,519,181)	($41,426)	$0	($41,426)
48	March	2028	($2,445,890)	$0	($2,445,890)	$73,292	$0	$73,292
49	June	2028	($2,372,598)	$0	($2,372,598)	$73,292	$0	$73,292
50	September	2028	($2,299,307)	$0	($2,299,307)	$73,292	$0	$73,292
51	December	2028	($2,226,015)	$0	($2,226,015)	$73,292	$0	$73,292

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National Grid - RI Gas
Customer Hold Harmless Credit
Rate Base Impact

	Month	Year	Deferred FIT DFIT Balance	Unamortized Investment Tax Credit Balance	Hold Harmless Total	Deferred Federal Income Tax Change	ITC Change	Total Change
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	March	2029	($2,152,724)	$0	($2,152,724)	$73,291	$0	$73,291
2	June	2029	($2,079,433)	$0	($2,079,433)	$73,291	$0	$73,291
3	September	2029	($2,006,143)	$0	($2,006,143)	$73,291	$0	$73,291
4	December	2029	($1,932,852)	$0	($1,932,852)	$73,291	$0	$73,291
5	March	2030	($1,871,230)	$0	($1,871,230)	$61,621	$0	$61,621
6	June	2030	($1,809,609)	$0	($1,809,609)	$61,621	$0	$61,621
7	September	2030	($1,747,988)	$0	($1,747,988)	$61,621	$0	$61,621
8	December	2030	($1,686,367)	$0	($1,686,367)	$61,621	$0	$61,621
9	March	2031	($1,628,755)	$0	($1,628,755)	$57,611	$0	$57,611
10	June	2031	($1,571,144)	$0	($1,571,144)	$57,611	$0	$57,611
11	September	2031	($1,513,533)	$0	($1,513,533)	$57,611	$0	$57,611
12	December	2031	($1,455,922)	$0	($1,455,922)	$57,611	$0	$57,611
13	March	2032	($1,398,473)	$0	($1,398,473)	$57,449	$0	$57,449
14	June	2032	($1,341,024)	$0	($1,341,024)	$57,449	$0	$57,449
15	September	2032	($1,283,574)	$0	($1,283,574)	$57,449	$0	$57,449
16	December	2032	($1,226,125)	$0	($1,226,125)	$57,449	$0	$57,449
17	March	2033	($1,168,891)	$0	($1,168,891)	$57,234	$0	$57,234
18	June	2033	($1,111,657)	$0	($1,111,657)	$57,234	$0	$57,234
19	September	2033	($1,054,423)	$0	($1,054,423)	$57,234	$0	$57,234
20	December	2033	($997,190)	$0	($997,190)	$57,234	$0	$57,234
21	March	2034	($953,205)	$0	($953,205)	$43,984	$0	$43,984
22	June	2034	($909,221)	$0	($909,221)	$43,984	$0	$43,984
23	September	2034	($865,237)	$0	($865,237)	$43,984	$0	$43,984
24	December	2034	($821,253)	$0	($821,253)	$43,984	$0	$43,984
25	March	2035	($779,574)	$0	($779,574)	$41,678	$0	$41,678
26	June	2035	($737,896)	$0	($737,896)	$41,678	$0	$41,678
27	September	2035	($696,218)	$0	($696,218)	$41,678	$0	$41,678
28	December	2035	($654,540)	$0	($654,540)	$41,678	$0	$41,678
29	March	2036	($614,040)	$0	($614,040)	$40,500	$0	$40,500
30	June	2036	($573,539)	$0	($573,539)	$40,500	$0	$40,500
31	September	2036	($533,039)	$0	($533,039)	$40,500	$0	$40,500
32	December	2036	($492,539)	$0	($492,539)	$40,500	$0	$40,500
33	March	2037	($453,832)	$0	($453,832)	$38,707	$0	$38,707
34	June	2037	($415,126)	$0	($415,126)	$38,707	$0	$38,707
35	September	2037	($376,419)	$0	($376,419)	$38,707	$0	$38,707
36	December	2037	($337,713)	$0	($337,713)	$38,707	$0	$38,707
37	March	2038	($299,432)	$0	($299,432)	$38,281	$0	$38,281
38	June	2038	($261,151)	$0	($261,151)	$38,281	$0	$38,281
39	September	2038	($222,870)	$0	($222,870)	$38,281	$0	$38,281
40	December	2038	($184,589)	$0	($184,589)	$38,281	$0	$38,281
41	March	2039	($147,789)	$0	($147,789)	$36,800	$0	$36,800
42	June	2039	($110,988)	$0	($110,988)	$36,800	$0	$36,800
43	September	2039	($74,188)	$0	($74,188)	$36,800	$0	$36,800
44	December	2039	($37,387)	$0	($37,387)	$36,800	$0	$36,800
45	March	2040	($8,127)	$0	($8,127)	$29,260	$0	$29,260
46	June	2040	$21,133	$0	$21,133	$29,260	$0	$29,260
47	September	2040	$50,393	$0	$50,393	$29,260	$0	$29,260
48	December	2040	$79,653	$0	$79,653	$29,260	$0	$29,260
49	March	2041	$76,145	$0	$76,145	($3,508)	$0	($3,508)
50	June	2041	$72,636	$0	$72,636	($3,508)	$0	($3,508)
51	September	2041	$69,128	$0	$69,128	($3,508)	$0	($3,508)

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 11-GAS

National Grid - RI Gas
Customer Hold Harmless Credit
Rate Base Impact

	Month	Year	Deferred FIT DFIT Balance	Unamortized Investment Tax Credit Balance	Hold Harmless Total	Deferred Federal Income Tax Change	ITC Change	Total Change
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	December	2041	$65,619	$0	$65,619	($3,508)	$0	($3,508)
2	March	2042	$60,603	$0	$60,603	($5,016)	$0	($5,016)
3	June	2042	$55,587	$0	$55,587	($5,016)	$0	($5,016)
4	September	2042	$50,571	$0	$50,571	($5,016)	$0	($5,016)
5	December	2042	$45,555	$0	$45,555	($5,016)	$0	($5,016)
6	March	2043	$40,241	$0	$40,241	($5,314)	$0	($5,314)
7	June	2043	$34,928	$0	$34,928	($5,314)	$0	($5,314)
8	September	2043	$29,614	$0	$29,614	($5,314)	$0	($5,314)
9	December	2043	$24,300	$0	$24,300	($5,314)	$0	($5,314)
10	March	2044	$17,124	$0	$17,124	($7,177)	$0	($7,177)
11	June	2044	$9,947	$0	$9,947	($7,177)	$0	($7,177)
12	September	2044	$2,770	$0	$2,770	($7,177)	$0	($7,177)
13	December	2044	($4,406)	$0	($4,406)	($7,177)	$0	($7,177)
14	March	2045	($7,558)	$0	($7,558)	($3,152)	$0	($3,152)
15	June	2045	($10,709)	$0	($10,709)	($3,152)	$0	($3,152)
16	September	2045	($13,861)	$0	($13,861)	($3,152)	$0	($3,152)
17	December	2045	($17,013)	$0	($17,013)	($3,152)	$0	($3,152)
18	March	2046	($16,720)	$0	($16,720)	$292	$0	$292
19	June	2046	($16,428)	$0	($16,428)	$292	$0	$292
20	September	2046	($16,135)	$0	($16,135)	$292	$0	$292
21	December	2046	($15,843)	$0	($15,843)	$292	$0	$292
22	March	2047	($15,315)	$0	($15,315)	$528	$0	$528
23	June	2047	($14,787)	$0	($14,787)	$528	$0	$528
24	September	2047	($14,259)	$0	($14,259)	$528	$0	$528
25	December	2047	($13,731)	$0	($13,731)	$528	$0	$528
26	March	2048	($13,203)	$0	($13,203)	$528	$0	$528
27	June	2048	($12,675)	$0	($12,675)	$528	$0	$528
28	September	2048	($12,147)	$0	($12,147)	$528	$0	$528
29	December	2048	($11,619)	$0	($11,619)	$528	$0	$528
30	March	2049	($11,091)	$0	($11,091)	$528	$0	$528
31	June	2049	($10,563)	$0	($10,563)	$528	$0	$528
32	September	2049	($10,036)	$0	($10,036)	$528	$0	$528
33	December	2049	($9,508)	$0	($9,508)	$528	$0	$528
34	March	2050	($8,980)	$0	($8,980)	$528	$0	$528
35	June	2050	($8,452)	$0	($8,452)	$528	$0	$528
36	September	2050	($7,924)	$0	($7,924)	$528	$0	$528
37	December	2050	($7,396)	$0	($7,396)	$528	$0	$528
38	March	2051	($6,868)	$0	($6,868)	$528	$0	$528
39	June	2051	($6,340)	$0	($6,340)	$528	$0	$528
40	September	2051	($5,812)	$0	($5,812)	$528	$0	$528
41	December	2051	($5,284)	$0	($5,284)	$528	$0	$528
42	March	2052	($4,756)	$0	($4,756)	$528	$0	$528
43	June	2052	($4,228)	$0	($4,228)	$528	$0	$528
44	September	2052	($3,700)	$0	($3,700)	$528	$0	$528
45	December	2052	($3,173)	$0	($3,173)	$528	$0	$528
46	March	2053	($2,645)	$0	($2,645)	$528	$0	$528
47	June	2053	($2,117)	$0	($2,117)	$528	$0	$528
48	September	2053	($1,589)	$0	($1,589)	$528	$0	$528
49	December	2053	($1,061)	$0	($1,061)	$528	$0	$528
50	March	2054	($796)	$0	($796)	$265	$0	$265
51	June	2054	($530)	$0	($530)	$265	$0	$265

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/ 4780
Witness: Little

Compliance Attachment 2

Schedule 12

Labor

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Labor - Expense Type

		Test Year Ended June 30, 2017 (Per Books)			Normalizing Adjustments to Test Year			Test Year Ended June 30, 2017 (as Adjusted)		
		Total	Electric	Gas	Total	Electric	Gas	Total	Electric	Gas
		(a) = (b) + (c)	(b)	(c)	(d) = (e) + (f)	(e)	(f)	(g) = (h) + (i)	(h) = (b) + (e)	(i) = (c) + (f)
	Provider Company:									
1	Narragansett Electric Company	$38,831,791	$19,786,961	$19,044,830	($2,465,621)	$637,619	($3,103,241)	$36,366,170	$20,424,581	$15,941,589
2	National Grid USA Service Company	$50,101,582	$33,639,835	$16,461,747	($13,794,274)	($11,071,583)	($2,722,690)	$36,307,308	$22,568,252	$13,739,056
3	All Other Companies	$1,845,184	$1,329,452	$515,732	($203,524)	($205,368)	$1,844	$1,641,661	$1,124,084	$517,576
4	Total	$90,778,557	$54,756,249	$36,022,308	($16,463,419)	($10,639,332)	($5,824,087)	$74,315,139	$44,116,917	$30,198,221
5										
6										
7	Operation:									
8	Production Expenses	$0	$0	$0	($43,352)	($43,352)	$0	($43,352)	($43,352)	$0
9	Power Production Expenses	$40	$0	$40	($5)	$0	(5)	$35	$0	$35
10	Natural Gas Storage, Terminaling	$2,302,746	$0	$2,302,746	($957,714)	$0	(957,714)	$1,345,032	$0	$1,345,032
11	and Processing Exp.									
12	Transmission Expenses	$4,363,087	$4,357,614	$5,473	($5,457,804)	($5,451,987)	(5,817)	($1,094,717)	($1,094,373)	($344)
13	Regional Market Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Distribution Expenses	$27,782,414	$11,603,931	$16,178,484	($5,706,278)	$416,895	(6,123,173)	$22,076,136	$12,020,826	$10,055,310
15	Customer Accounts Expenses	$7,778,674	$4,595,462	$3,183,211	($1,002,876)	($616,967)	(385,909)	$6,775,798	$3,978,495	$2,797,303
16	Customer Service and	$1,328,073	$909,906	$418,167	($363,850)	($229,044)	(134,806)	$964,223	$680,862	$283,361
17	Informational Expenses									
18	Sales Expenses	$950,199	$408,619	$541,581	($662,158)	($449,967)	(212,191)	$288,042	($41,348)	$329,390
19	Administrative & General Expenses	$27,297,462	$19,729,562	$7,567,901	$440,807	($1,756,872)	2,197,679	$27,738,269	$17,972,690	$9,765,579
20	Sub Total	$71,802,695	$41,605,093	$30,197,602	($13,753,229)	($8,131,293)	(5,621,936)	$58,049,466	$33,473,799	$24,575,666
21										
22	Maintenance:									
23	Transmission Expenses	$1,084,676	$1,021,494	$63,182	($735,266)	($1,016,595)	281,329	$349,411	$4,899	$344,512
24	Distribution Expenses	$17,772,833	$12,016,514	$5,756,319	($1,946,898)	($1,464,013)	(482,886)	$15,825,934	$10,552,501	$5,273,433
25	Administrative & General Expenses	$118,353	$113,149	$5,205	($28,025)	($27,431)	(595)	$90,328	$85,718	$4,610
26	Sub Total	$18,975,863	$13,151,156	$5,824,706	($2,710,190)	($2,508,038)	($202,151)	$16,265,673	$10,643,118	$5,622,555
27										
28	TOTAL	$90,778,557	$54,756,249	$36,022,308	($16,463,419)	($10,639,332)	($5,824,087)	$74,315,139	$44,116,917	$30,198,221
		$0	$0	$0	$0	$0	$0	$0	$0	$0

Column Notes
(b)-(c) Per Company Books

Line Notes
1(e)-(f) Sum of Page 5, Lines 2, 6, 9, 12, 15, 18, 21, 25, and 28
2(e)-(f) Sum of Page 5, Lines 3, 5, 7, 10, 13, 16, 19, 22, 24, 26, and 29
3(e)-(f) Sum of Page 5, Lines 4, 8, 11, 14, 17, 20, 23, 27, and 30

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Labor - Expense Type

		Test Year Ended June 30, 2017 (as Adjusted)			Pro forma Adjustments			Rate Year Ending August 31, 2019		
		Total	Electric	Gas	Total	Electric	Gas	Total	Electric	Gas
		(a) = (b) + (c)	(b)	(c)	(d) = (e) + (f)	(e)	(f)	(g) = (h) + (i)	(h) = (b) + (e)	(i) = (c) + (f)
	Provider Company:									
1	Narragansett Electric Company	$36,366,170	$20,424,581	$15,941,589	$5,462,557	$3,979,843	$1,482,714	$41,828,727	$24,404,424	$17,424,303
2	National Grid USA Service Company	$36,307,308	$22,568,252	$13,739,056	$4,257,545	$2,647,090	$1,610,455	$40,564,853	$25,215,342	$15,349,511
3	All Other Companies	$1,641,661	$1,124,084	$517,576	$104,885	$65,436	$39,450	$1,746,546	$1,189,520	$557,026
4	Total	$74,315,139	$44,116,917	$30,198,221	$9,824,987	$6,692,369	$3,132,619	$84,140,126	$50,809,286	$33,330,840
5										
6										
7	Operation:									
8	Production Expenses	($43,352)	($43,352)	$0	($6,576)	($6,576)	$0	($49,928)	($49,928)	$0
9	Power Production Expenses	$35	$0	$35	$4	$0	$4	$39	$0	$39
10	Natural Gas Storage, Terminaling	$1,345,032	$0	$1,345,032	$139,527	$0	$139,527	$1,484,559	$0	$1,484,559
11	and Processing Exp.									
12	Transmission Expenses	($1,094,717)	($1,094,373)	($344)	($166,048)	($166,012)	($36)	($1,260,765)	($1,260,385)	($380)
13	Regional Market Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Distribution Expenses	$22,076,136	$12,020,826	$10,055,310	$2,866,603	$1,823,514	$1,043,090	$24,942,739	$13,844,339	$11,098,400
15	Customer Accounts Expenses	$6,775,798	$3,978,495	$2,797,303	$893,701	$603,523	$290,179	$7,669,499	$4,582,018	$3,087,481
16	Customer Service and	$964,223	$680,862	$283,361	$132,679	$103,284	$29,395	$1,096,902	$784,146	$312,756
17	Informational Expenses									
18	Sales Expenses	$288,042	($41,348)	$329,390	$27,897	($6,272)	$34,169	$315,939	($47,621)	$363,559
19	Administrative & General Expenses	$27,738,269	$17,972,690	$9,765,579	$3,739,423	$2,726,389	$1,013,034	$31,477,692	$20,699,079	$10,778,614
20	Sub Total	$58,049,466	$33,473,799	$24,575,666	$7,627,210	$5,077,848	$2,549,362	$65,676,676	$38,551,648	$27,125,028
21										
22	Maintenance:									
23	Transmission Expenses	$349,411	$4,899	$344,512	$36,481	$743	$35,738	$385,892	$5,642	$380,250
24	Distribution Expenses	$15,825,934	$10,552,501	$5,273,433	$2,147,815	$1,600,774	$547,041	$17,973,749	$12,153,275	$5,820,474
25	Administrative & General Expenses	$90,328	$85,718	$4,610	$13,481	$13,003	$478	$103,809	$98,721	$5,088
26	Sub Total	$16,265,673	$10,643,118	$5,622,555	$2,197,777	$1,614,521	$583,257	$18,463,451	$12,257,639	$6,205,812
27										
28	TOTAL	$74,315,139	$44,116,917	$30,198,221	$9,824,987	$6,692,369	$3,132,619	$84,140,126	$50,809,286	$33,330,840
		$0	$0	$0	$0	$0	$0	$0	$0	$0

Column Notes
(b)-(c) Page 1, Columns (h)-(i)
(e)-(f) Page 5, Lines 43(b) through 45(c)

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Labor - Expense Type

		Rate Year Ending August 31, 2019	Adjustments to Reflect Conditions in Rate Year	Rate Year Ending August 31, 2020	Adjustments to Reflect Conditions in Rate Year	Rate Year Ending August 31, 2021
		Electric	Electric	Electric	Electric	Electric
		(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) + (d)
	Provider Company:					
1	Narragansett Electric Company	$24,404,424	$914,307	$25,318,731	$714,846	$26,033,577
2	National Grid USA Service Company	$25,215,342	$876,846	$26,092,188	$850,275	$26,942,462
3	All Other Companies	$1,189,520	$33,242	$1,222,762	$28,312	$1,251,075
4	Total	$50,809,286	$1,824,395	$52,633,681	$1,593,433	$54,227,114
5						
6						
7	Operation:					
8	Production Expenses	($49,928)	($1,793)	($51,721)	($1,566)	($53,287)
9	Power Production Expenses	$0	$0	$0	$0	$0
10	Natural Gas Storage, Terminaling	$0	$0	$0	$0	$0
11	and Processing Exp.					
12	Transmission Expenses	($1,260,385)	($45,256)	($1,305,642)	($39,527)	($1,345,169)
13	Regional Market Expenses	$0	$0	$0	$0	$0
14	Distribution Expenses	$13,844,339	$497,105	$14,341,444	$434,173	$14,775,617
15	Customer Accounts Expenses	$4,582,018	$164,525	$4,746,543	$143,697	$4,890,240
16	Customer Service and	$784,146	$28,156	$812,302	$24,592	$836,894
17	Informational Expenses					
18	Sales Expenses	($47,621)	($1,710)	($49,330)	($1,493)	($50,824)
19	Administrative & General Expenses	$20,699,079	$743,236	$21,442,315	$649,145	$22,091,460
20	Sub Total	$38,551,648	$1,384,263	$39,935,911	$1,209,020	$41,144,932
21						
22	Maintenance:					
23	Transmission Expenses	$5,642	$203	$5,845	$177	$6,021
24	Distribution Expenses	$12,153,275	$436,384	$12,589,660	$381,140	$12,970,799
25	Administrative & General Expenses	$98,721	$3,545	$102,266	$3,096	$105,362
26	Sub Total	$12,257,639	$440,132	$12,697,770	$384,413	$13,082,183
27						
28	TOTAL	$50,809,286	$1,824,395	$52,633,681	$1,593,433	$54,227,114
		($0)	$0	($0)	$0	($0)

Column Notes

(a) Page 2, Column (h)
(b) Page 5, Lines 52(b) through 54(b)
(d) Page 5, Lines 61(b) through 63(b)

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Labor - Expense Type

		Rate Year Ending August 31, 2019	Adjustments to Reflect Conditions in Rate Year	Rate Year Ending August 31, 2020	Adjustments to Reflect Conditions in Rate Year	Rate Year Ending August 31, 2021
		Gas	Gas	Gas	Gas	Gas
		(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) + (d)
	Provider Company:					
1	Narragansett Electric Company	$17,424,303	$877,217	$18,301,520	$579,801	$18,881,321
2	National Grid USA Service Company	$15,349,511	$519,066	$15,868,577	$496,625	$16,365,202
3	All Other Companies	$557,026	$15,584	$572,610	$13,320	$585,930
4	Total	$33,330,840	$1,411,867	$34,742,707	$1,089,746	$35,832,453
5						
6						
7	Operation:					
8	Production Expenses	$0	$0	$0	$0	$0
9	Power Production Expenses	$39	$2	$41	$1	$42
10	Natural Gas Storage, Terminaling	$1,484,559	$62,885	$1,547,444	$48,537	$1,595,981
11	and Processing Exp.					
12	Transmission Expenses	($380)	($16)	($396)	($12)	($409)
13	Regional Market Expenses	$0	$0	$0	$0	$0
14	Distribution Expenses	$11,098,400	$470,119	$11,568,519	$362,860	$11,931,380
15	Customer Accounts Expenses	$3,087,481	$130,783	$3,218,264	$100,945	$3,319,209
16	Customer Service and	$312,756	$13,248	$326,004	$10,226	$336,229
17	Informational Expenses					
18	Sales Expenses	$363,559	$15,400	$378,959	$11,887	$390,846
19	Administrative & General Expenses	$10,778,614	$456,573	$11,235,187	$352,405	$11,587,592
20	Sub Total	$27,125,028	$1,148,994	$28,274,022	$886,848	$29,160,870
21						
22	Maintenance:					
23	Transmission Expenses	$380,250	$16,107	$396,357	$12,432	$408,789
24	Distribution Expenses	$5,820,474	$246,551	$6,067,025	$190,299	$6,257,324
25	Administrative & General Expenses	$5,088	$216	$5,304	$166	$5,470
26	Sub Total	$6,205,812	$262,873	$6,468,685	$202,898	$6,671,583
27						
28	TOTAL	$33,330,840	$1,411,867	$34,742,707	$1,089,746	$35,832,453
		$0	$0	$0	$0	$0

Column Notes

(a) Page 2, Column (h)
(b) Page 5, Lines 52(c) through 54(c)
(d) Page 5, Lines 61(c) through 63(c)

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 12
Page 5 of 11

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Labor - Expense Type

		Explanation of Adjustments:	Provider Company	Total (a)	Electric (b)	Gas (c)	
1	Page 1	Adjustments: (to normalize Historic Year)					
2		(IFA) Integrated Facilities Agreement	Narragansett Electric Company	($1,178,434)	($1,178,434)	$0	See IFA tab
3		(IFA) Integrated Facilities Agreement	National Grid USA Service Company	($6,844,426)	($6,844,426)	$0	See IFA tab
4		(IFA) Integrated Facilities Agreement	All Other Companies	($84,203)	($84,203)	$0	See IFA tab
5		Vegetation Management expense	National Grid USA Service Company	($277,467)	($277,467)	$0	Distribution Maintenance
6		Inspection & Maintenance	Narragansett Electric Company	($327,886)	($327,886)	$0	Labor spread
7		Inspection & Maintenance	National Grid USA Service Company	($2,827)	($2,827)	$0	Labor spread
8		Inspection & Maintenance	All Other Companies	($60,920)	($60,920)	$0	Labor spread
9		Elevate portion of Variable Pay paid at 160% of target; reduce to target	Narragansett Electric Company	($79,802)	($65,346)	($14,456)	See Variable Pay Adj by Reg Class tab
10		Elevate portion of Variable Pay paid at 160% of target; reduce to target	National Grid USA Service Company	($851,889)	($531,973)	($319,916)	See Variable Pay Adj by Reg Class tab
11		Elevate portion of Variable Pay paid at 160% of target; reduce to target	All Other Companies	($7,047)	($4,853)	($2,194)	See Variable Pay Adj by Reg Class tab
12		Normalize Union Variable Pay to target	Narragansett Electric Company	($119,783)	($15,657)	($104,125)	See Variable Pay Adj by Reg Class tab
13		Normalize Union Variable Pay to target	National Grid USA Service Company	($33,281)	($13,711)	($19,570)	See Variable Pay Adj by Reg Class tab
14		Normalize Union Variable Pay to target	All Other Companies	$3,612	($2,899)	$6,511	See Variable Pay Adj by Reg Class tab
15		Reclass Misc Pay (to)/from Affiliates	Narragansett Electric Company	$624,738	$473,880	$150,857	See Variable Pay Adj by Reg Class tab
16		Reclass Misc Pay (to)/from Affiliates	National Grid USA Service Company	($621,523)	($471,442)	($150,081)	See Variable Pay Adj by Reg Class tab
17		Reclass Misc Pay (to)/from Affiliates	All Other Companies	($3,214)	($2,438)	($776)	See Variable Pay Adj by Reg Class tab
18		Record IFA Impact of Miscellaneous Pay reclasses (to)/from Affiliates	Narragansett Electric Company	($64,727)	($64,727)	$0	See IFA tab
19		Record IFA Impact of Miscellaneous Pay reclasses (to)/from Affiliates	National Grid USA Service Company	$64,394	$64,394	$0	See IFA tab
20		Record IFA Impact of Miscellaneous Pay reclasses (to)/from Affiliates	All Other Companies	$333	$333	$0	See IFA tab
21		Major Storm Normalization	Narragansett Electric Company	($591,080)	($591,080)	$0	Distribution Maintenance
22		Major Storm Normalization	National Grid USA Service Company	($370,308)	($370,308)	$0	Distribution Maintenance
23		Major Storm Normalization	All Other Companies	($51,141)	($51,141)	$0	Distribution Maintenance
24		Standard Offer Service (SOS) Admin Costs	National Grid USA Service Company	($217,804)	($217,804)	$0	Administrative & General Expenses-o
25		Segment Reclassification	Narragansett Electric Company	$0	$2,562,849	($2,562,849)	See validation topsides tab
26		Segment Reclassification	National Grid USA Service Company	($0)	$646,585	($646,585)	See validation topsides tab
27		Segment Reclassification	All Other Companies	($0)	$752	($752)	See validation topsides tab
28		GCR Labor Adjustment	Narragansett Electric Company	($572,670)	$0	($572,670)	Natural Gas Storage
29		GCR Labor Adjustment	National Grid USA Service Company	($256,209)	$0	($256,209)	Natural Gas Storage
30		GCR Labor Adjustment	All Other Companies	($944)	$0	($944)	Natural Gas Storage
31		Service Company A&G Overhead Study Adjustment - Base Labor Union	National Grid USA Service Company	($429,740)	($270,274)	($159,466)	See tab Servco A&G Study
32		Service Company A&G Overhead Study Adjustment - Base Labor Non-Un	National Grid USA Service Company	($2,947,935)	($1,992,654)	($955,281)	See tab Servco A&G Study
33		Service Company A&G Overhead Study Adjustment - Variable Pay Union	National Grid USA Service Company	($10,825)	($5,942)	($4,883)	See tab Servco A&G Study
34		Service Company A&G Overhead Study Adjustment - Variable Pay Non-U	National Grid USA Service Company	($505,965)	($348,354)	($157,611)	See tab Servco A&G Study
35		Service Company A&G Overhead Study Adjustment - Overtime Union	National Grid USA Service Company	($68,746)	($40,506)	($28,240)	See tab Servco A&G Study
36		Service Company A&G Overhead Study Adjustment - Overtime Non-Unio	National Grid USA Service Company	($24,875)	($20,002)	($4,874)	See tab Servco A&G Study
37		RI Government Relations and Federal Affairs	Narragansett Electric Company	($155,978)	($155,981)	$2	Administrative & General Expenses-o
38		RI Government Relations and Federal Affairs	National Grid USA Service Company	($82,128)	($62,154)	($19,974)	Administrative & General Expenses-o
39		Exclude ReGrowth Program Costs	National Grid USA Service Company	($312,719)	($312,719)	$0	Administrative & General Expenses-o
40							
41			TOTAL	($16,463,419)	($10,639,332)	($5,824,087)	
42							
43	Page 2	Adjustments: (to reflect conditions in the Rate Year 8/31/2019)					
44							
45							
46		Adjustments to Rate Year	Narragansett Electric Company	$5,462,557	$3,979,843	$1,482,714	
47		Adjustments to Rate Year	National Grid USA Service Company	$4,257,545	$2,647,090	$1,610,455	
48		Adjustments to Rate Year	All Other Companies	$104,885	$65,436	$39,450	
49							
50			TOTAL	$9,824,987	$6,692,369	$3,132,619	
51							
52	Page 3 and Page 4	Adjustments: (to reflect conditions in the Rate Year 8/31/2020)					
53							
54							
55		Adjustments to Rate Year	Narragansett Electric Company	$1,791,524	$914,307	$877,217	
56		Adjustments to Rate Year	National Grid USA Service Company	$1,395,912	$876,846	$519,066	
57		Adjustments to Rate Year	All Other Companies	$48,826	$33,242	$15,584	
58							
59			TOTAL	$3,236,262	$1,824,395	$1,411,867	
60							
61	Page 3 and Page 4	Adjustments: (to reflect conditions in the Rate Year 8/31/2021)					
62							
63							
64		Adjustments to Rate Year	Narragansett Electric Company	$1,294,647	$714,846	$579,801	
65		Adjustments to Rate Year	National Grid USA Service Company	$1,346,900	$850,275	$496,625	
66		Adjustments to Rate Year	All Other Companies	$41,633	$28,312	$13,320	
67							
68			TOTAL	$2,683,179	$1,593,433	$1,089,746	

Line Notes
46(b) Page 6, Line 42
46(c) Page 7, Line 42
47(b) Page 8, Line 46
47(c) Page 9, Line 46
48(b) Page 10, Line 46
48(c) Page 11, Line 46
55(b) Page 6, Line 52
55(c) Page 7, Line 52
56(b) Page 8, Line 56
56(c) Page 9, Line 56
57(b) Page 10, Line 56
57(c) Page 11, Line 56
64(b) Page 6, Line 62
64(c) Page 7, Line 62
65(b) Page 8, Line 66
65(c) Page 9, Line 66
66(b) Page 10, Line 66
66(c) Page 11, Line 66

The Narragansett Electric Company d/b/a National Grid
The Narragansett Electric Company Employees Salary and Wages
Rate Year Ending August 31, 2019, August 31, 2020 and August 31, 2021

Line	Description	Rate	Portion of Year	Union	Non-Union	Rate Year Amount	Test Year Amount
		Electric	Electric	Electric	Electric	Electric	Electric
		(a)	(b)	(c)	(d)	(e)	(f)
1	Test Year Total Base Wages			$27,531,828	$4,870,224		$32,402,052
2	Less Test Year Capitalized Wages			$14,546,826	$2,756,069		$17,302,896
3	Test Year O&M Wages			$12,985,002	$2,114,155		$15,099,157
4	O&M Portion			47.16%	43.41%		46.60%
5							
6	Test Year O&M Variable Pay			$114,710	$495,523		$610,233
7	Test Year O&M Overtime Wages			$4,692,596	$22,595		$4,715,191
8	Total Test Year Narragansett Electric Company O&M Wages			$17,792,308	$2,632,273		$20,424,581
9							
10	Steady State Wages at 6/30/17 (excluding Temporary Employees)			$23,845,332	$4,733,253	$28,578,585	
11	Normalize employees serving the electric business from the gas segment			$5,895,635	$609,838	$6,505,473	
12	Test Year Temporary and Seasonal Employees			$466,499	$5,921	$472,420	
13	Incremental Full Time Equivalents			$1,593,548	$227,574	$1,821,122	
14	Vacancies			$1,490,756	$101,000	$1,591,756	
15	Total Steady State Wages at 06/30/17			$33,291,770	$5,677,586	$38,969,356	
16							
17	Weighted Union Wage Increases Effective 07/01/2017 through 06/30/2018	0.34%	100.00%	$113,192		$113,192	
18	Non-Union Wage Increase Effective 07/01/17 through 06/30/18 (12 Months)	3.64%	100.00%		$206,664	$206,664	
19							
20	Subtotal			$33,404,962	$5,884,250	$39,289,212	
21							
22	Weighted Union Wage Increases Effective 07/01/2018 through 06/31/2019	2.53%	100.00%	$845,146		$845,146	
23	Non-Union Wage Increase Effective 07/01/18 through 06/30/19 (12 Months)	3.25%	100.00%		$191,238	$191,238	
24							
25	Subtotal			$34,250,108	$6,075,488	$40,325,596	
26							
27	Weighted Union Wage Increases Effective 07/01/2019 through 08/31/2019	2.74%	16.99%	$159,443		$159,443	
28	Non-Union Wage Increase Effective 07/01/19 through 08/31/19 (2 Months)	3.00%	16.99%		$30,967	$30,967	
29							
30	Rate Year 8/31/2019 Total Base Wages			$34,409,551	$6,106,455	$40,516,006	
31							
32	Rate Year 8/31/2019 O&M Base Wages			$16,227,544	$2,650,812	$18,878,356	
33							
34	Test Year O&M Non-Financial Variable Pay			$114,710	$495,523.48	$610,233	
35	Test Year O&M Overtime Wages			$4,692,596	$22,595	$4,715,191	
36	Increase Through Rate Year			3.36%	7.55%		
37	Impact of O&M Non-Financial Variable Pay Increase Through Rate Year			$3,854	$37,412	$41,266	
38	Impact of O&M Overtime Wages Increase Through Rate Year			$157,671	$1,706	$159,377	
39							
40	Rate Year 8/31/2019 O&M Wages			$21,196,376	$3,208,048	$24,404,424	$24,404,424
41							
42	**Narragansett Electric Company Wage Adjustment 8/31/2019**						**$3,979,843**
43							
44	Incremental Full Time Equivalents 09/01/2019 through 8/31/2020			$326,691	$0	$326,691	
45	Incremental Full Time Equivalents, O&M portion			$154,067	$0	$154,067	
46							
47	Weighted Union Wage Increases Effective 09/01/2019 through 08/31/2020	3.11%	100.00%	$663,999		$663,999	
48	Non-Union Wage Increase Effective 09/01/19 through 08/31/20 (12 Months)	3.00%	100.00%		$96,241	$96,241	
49							
50	Rate Year 8/31/2020 O&M Wages			$22,014,442	$3,304,290	$25,318,731	$25,318,731
51							
52	**Narragansett Electric Company Wage Adjustment 8/31/2020**						**$914,307**
53							
54	Incremental Full Time Equivalents 09/01/2020 through 8/31/2021			$34,937	$0	$34,937	
55	Incremental Full Time Equivalents, O&M portion			$16,476	$0	$16,476	
56							
57	Weighted Union Wage Increases Effective 09/01/2020 through 08/31/2021	2.72%	100.00%	$599,241		$599,241	
58	Non-Union Wage Increase Effective 09/01/20 through 08/31/21 (12 Months)	3.00%	100.00%		$99,129	$99,129	
59							
60	Rate Year 8/31/2021 O&M Wages			$22,630,159	$3,403,418	$26,033,577	$26,033,577
61							
62	**Narragansett Electric Company Wage Adjustment 8/31/2021**						**$714,846**

Line Notes

1-8	Workpaper 4, Page 1
10	Annualized wages based on June 30, 2017 employee complement and annual salaries
11	Workpaper 4, Page 9
12	Per Company books
13	Workpaper 4, Page 10
14	Per Human Resources
15	Sum of Lines 10 through 14
17-18	Line 15 x Column (a) x Column (b) Line 17 or Line 18, respectively
20	Sum of Lines 15 through 18
22-23	Line 20 x Column (a) x Column (b) Line 22 or Line 23, respectively
25	Sum of Lines 20 through 23
27-28	Line 25 x Column (a) x Column (b) Line 27 or Line 28, respectively
30	Sum of Lines 25 through 28
32	Line 4 x Line 30
34	Line 6 - Band A & B Financial Variable Pay, Workpaper 4, Page 4
35	Line 7
36	(1 + Column (a) x Column (b), Line 17 or Line 18, respectively) x (1 + Column (a) x Column (b), Line 22 or Line 23, respectively) x (1 + Column (a) x Column (b), Line 27 or Line 28, respectively) - 1
37	Line 34 x Line 36
38	Line 35 x Line 36
40	Sum of Lines 32 through 35 + Line 37 + Line 38
42	Line 40(f) - Line 8(f)
44	Workpaper 4, Page 10
45	Line 4 x Line 44
47-48	(Line 40 + Line 45) x Column (a) x Column (b) Line 47 or Line 48, respectively
50	Line 40 + Sum of Lines 45 through 48
52	Line 50(f) - Line 40(f)
54	Workpaper 4, Page 10
55	Line 4 x Line 54
57-58	(Line 50 + Line 55) x Column (a) x Column (b) Line 57 or Line 58, respectively
60	Line 50 + Sum of Lines 55 through 58
62	Line 60(f) - Line 50(f)

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 12
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The Narragansett Electric Company d/b/a National Grid
The Narragansett Electric Company Employees Salary and Wages
Rate Year Ending August 31, 2019, August 31, 2020 and August 31, 2021

Line	Description	Rate	Portion of Year	Union	Non-Union	Rate Year Amount	Test Year Amount
		Gas	Gas	Gas	Gas	Gas	Gas
		(a)	(b)	(c)	(d)	(e)	(f)
1	Test Year Total Base Wages			$25,827,239	$1,293,669		$27,120,908
2	Less Test Year Capitalized Wages			$14,138,118	$826,373		$14,964,491
3	Test Year O&M Wages			$11,689,121	$467,297		$12,156,417
4	O&M Portion			45.26%	36.12%		44.82%
5							
6	Test Year O&M Variable Pay			$136,250	$337,168		$473,418
7	Test Year O&M Overtime Wages			$3,310,002	$1,751		$3,311,754
8	Total Test Year Narragansett Electric Company O&M Wages			$15,135,373	$806,216		$15,941,589
9							
10	Steady State Wages at 6/30/17 (excluding Temporary Employees)			$31,505,956	$1,780,089	$33,286,045	
11	Normalize employees serving the electric business from the gas segment			($5,895,635)	($609,838)	($6,505,473)	
12	Test Year Temporary and Seasonal Employees			$94,585	$0	$94,585	
13	Incremental Full Time Equivalents			$1,234,192	$373,803	$1,607,995	
14	Vacancies			$532,980	$122,164	$655,144	
15	Total Steady State Wages at 6/30/17			$27,472,077	$1,666,218	$29,138,295	
16							
17	Weighted Union Wage Increases Effective 07/01/2017 through 06/30/2018	0.51%	100.00%	$140,108		$140,108	
18	Non-Union Wage Increase Effective 07/01/17 through 06/30/18 (12 Months)	3.64%	100.00%		$60,650	$60,650	
19							
20	Subtotal			$27,612,185	$1,726,868	$29,339,053	
21							
22	Weighted Union Wage Increases Effective 07/01/2018 through 06/31/2019	2.38%	100.00%	$657,170		$657,170	
23	Non-Union Wage Increase Effective 07/01/18 through 06/30/19 (12 Months)	3.25%	100.00%		$56,123	$56,123	
24							
25	Subtotal			$28,269,355	$1,782,991	$30,052,346	
26							
27	Weighted Union Wage Increases Effective 07/01/2019 through 08/31/2019	2.58%	16.99%	$123,916		$123,916	
28	Non-Union Wage Increase Effective 07/01/19 through 08/31/19 (2 Months)	3.00%	16.99%		$9,088	$9,088	
29							
30	Rate Year 8/31/2019 Total Base Wages			$28,393,271	$1,792,079	$30,185,351	
31							
32	Rate Year 8/31/2019 O&M Base Wages			$12,850,795	$647,299	$13,498,094	
33							
34	Test Year O&M Non-Financial Variable Pay			$136,250	$337,167.89	$473,418	
35	Test Year O&M Overtime Wages			$3,310,002	$1,751	$3,311,754	
36	Increase Through Rate Year			3.35%	7.55%		
37	Impact of O&M Non-Financial Variable Pay Increase Through Rate Year			$4,564	$25,456	$30,021	
38	Impact of O&M Overtime Wages Increase Through Rate Year			$110,885	$132	$111,017	
39							
40	Rate Year 8/31/2019 O&M Wages			$16,412,496	$1,011,807	$17,424,303	$17,424,303
41							
42	**Narragansett Electric Company Wage Adjustment 8/31/2019**						**$1,482,714**
43							
44	Incremental Full Time Equivalents 09/01/2019 through 8/31/2020			$660,207	$170,482	$830,689	
45	Incremental Full Time Equivalents, O&M portion			$298,810	$61,578	$360,388	
46							
47	Weighted Union Wage Increases Effective 09/01/2019 through 08/31/2020	2.90%	100.00%	$484,628		$484,628	
48	Non-Union Wage Increase Effective 09/01/19 through 08/31/20 (12 Months)	3.00%	100.00%		$32,202	$32,202	
49							
50	Rate Year 8/31/2020 O&M Wages			$17,195,934	$1,105,586	$18,301,520	$18,301,520
51							
52	**Narragansett Electric Company Wage Adjustment 8/31/2020**						**$877,217**
53							
54	Incremental Full Time Equivalents 09/01/2020 through 8/31/2021			$288,978	$0	$288,978	
55	Incremental Full Time Equivalents, O&M portion			$130,792	$0	$130,792	
56							
57	Weighted Union Wage Increases Effective 09/01/2020 through 08/31/2021	2.40%	100.00%	$415,841		$415,841	
58	Non-Union Wage Increase Effective 09/01/20 through 08/31/21 (12 Months)	3.00%	100.00%		$33,168	$33,168	
59							
60	Rate Year 8/31/2021 O&M Wages			$17,742,567	$1,138,754	$18,881,321	$18,881,321
61							
62	**Narragansett Electric Company Wage Adjustment 8/31/2021**						**$579,801**

Line Notes

1-8	Workpaper 4, Page 1
10	Annualized wages based on June 30, 2017 employee complement and annual salaries
11	Workpaper 4, Page 9
12	Per Company books
13	Workpaper 4, Page 11
14	Per Human Resources
15	Sum of Lines 10 through 14
17-18	Line 15 x Column (a) x Column (b) Line 17 or Line 18, respectively
20	Sum of Lines 15 through 18
22-23	Line 20 x Column (a) x Column (b) Line 22 or Line 23, respectively
25	Sum of Lines 20 through 23
27-28	Line 25 x Column (a) x Column (b) Line 27 or Line 28, respectively
30	Sum of Lines 25 through 28
32	Line 4 x Line 30
34	Line 6 - Band A & B Financial Variable Pay, Workpaper 4, Page 4
35	Line 7
36	(1 + Column (a) x Column (b), Line 17 or Line 18, respectively) x (1 + Column (a) x Column (b), Line 22 or Line 23, respectively) x (1 + Column (a) x Column (b), Line 27 or Line 28, respectively) - 1
37	Line 34 x Line 36
38	Line 35 x Line 36
40	Sum of Lines 32 through 35 + Line 37 + Line 38
42	Line 40(f) - Line 8(f)
44	Workpaper 4, Page 11
45	Line 4 x Line 44
47-48	(Line 40 + Line 45) x Column (a) x Column (b) Line 47 or Line 48, respectively
50	Line 40 + Sum of Lines 45 through 48
52	Line 50(f) - Line 40(f)
54	Workpaper 4, Page 11
55	Line 4 x Line 54
57-58	(Line 50 + Line 55) x Column (a) x Column (b) Line 57 or Line 58, respectively
60	Line 50 + Sum of Lines 55 through 58
62	Line 60(f) - Line 50(f)

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
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The Narragansett Electric Company d/b/a National Grid
Service Company Employees Salary and Wages
Rate Year Ending August 31, 2019, August 31, 2020 and August 31, 2021

Line	Description	Rate	Portion of Year	Union	Non-Union	Rate Year Amount	Test Year Amount
		Electric	Electric	Electric	Electric	Electric	Electric
		(a)	(b)	(c)	(d)	(e)	(f)
1	Service Company Test Year Total Base Wages			$88,805,821	$465,382,043		$554,187,863
2							
3	Narragansett Electric Company Share of Test Year Total Base Wages			$6,731,440	$28,316,200		$35,047,640
4	Less Test Year Capitalized Wages			$4,068,277	$11,025,070		$15,093,347
5	Test Year O&M Wages			$2,663,163	$17,291,130		$19,954,293
6	O&M Portion			39.56%	61.06%		56.93%
7							
8	Test Year O&M Variable Pay			$36,870	$2,197,822		$2,234,692
9	Test Year O&M Overtime Wages			$284,136	$95,132		$379,267
10	Total Test Year Service Company Wages to Narragansett Electric Company O&M			$2,984,169	$19,584,084		$22,568,253
11							
12	Total Service Company Steady State Wages at 6/30/17 (excluding Temporary Employees)			$94,499,627	$494,100,352	$588,599,980	
13	Narragansett Electric Company Share of Base Wages 6/30/17			7.58%	6.08%	6.32%	
14							
15	Steady State Wages at 6/30/17 Charged to Narragansett Company			$7,163,028	$30,063,567	$37,226,595	
16	Test Year Temporary and Seasonal Employees			$0	$53,564	$53,564	
17	Incremental Full Time Equivalents			$10,946	$405,835	$416,781	
18	Vacancies			$0	$0	$0	
19	Total Steady State Wages at 6/30/17			$7,173,974	$30,522,967	$37,696,941	
20							
21	Weighted Union Wage Increases Effective 07/01/2017 through 06/30/2018	0.32%	100.00%	$22,957		$22,957	
22	Non-Union Wage Increase Effective 07/01/17 through 06/30/18 (12 Months)	3.64%	100.00%		$1,111,036	$1,111,036	
23							
24	Subtotal			$7,196,931	$31,634,003	$38,830,934	
25							
26	Weighted Union Wage Increases Effective 07/01/2018 through 06/31/2019	2.51%	100.00%	$180,643		$180,643	
27	Non-Union Wage Increase Effective 07/01/18 through 06/30/19 (12 Months)	3.25%	100.00%		$1,028,105	$1,028,105	
28							
29	Subtotal			$7,377,574	$32,662,108	$40,039,682	
30							
31	Weighted Union Wage Increases Effective 07/01/2019 through 08/31/2019	2.72%	16.99%	$34,094		$34,094	
32	Non-Union Wage Increase Effective 07/01/19 through 08/31/19 (2 Months)	3.00%	16.99%		$166,479	$166,479	
33							
34	Rate Year 8/31/2019 Total Base Wages			$7,411,668	$32,828,586	$40,240,254	
35							
36	Rate Year 8/31/2019 O&M Base Wages			$2,932,056	$20,045,135	$22,977,191	
37							
38	Test Year O&M Non-Financial Variable Pay			$36,870	$1,677,551	$1,714,422	
39	Test Year O&M Overtime Wages			$284,136	$95,132	$379,267	
40	Increase Through Rate Year			3.31%	7.55%		
41	Impact of O&M Non-Financial Variable Pay Increase Through Rate Year			$1,220	$126,655	$127,876	
42	Impact of O&M Overtime Wages Increase Through Rate Year			$9,405	$7,182	$16,587	
43							
44	Rate Year O&M Wages			$3,263,687	$21,951,656	$25,215,342	$25,215,342
45							
46	**Narragansett Electric Company Wage Adjustment 8/31/2019**						**$2,647,090**
47							
48	Incremental Full Time Equivalents 09/01/2019 through 8/31/2020			$10,735	$180,305	$191,040	
49	Incremental Full Time Equivalents, O&M portion			$4,247	$110,094	$114,341	
50							
51	Weighted Union Wage Increases Effective 09/01/2019 through 08/31/2020	3.08%	100.00%	$100,652		$100,652	
52	Non-Union Wage Increase Effective 09/01/19 through 08/31/20 (12 Months)	3.00%	100.00%		$661,852	$661,852	
53							
54	Rate Year 8/31/2020 O&M Wages			$3,368,586	$22,723,602	$26,092,188	$26,092,188
55							
56	**Narragansett Electric Company Wage Adjustment 8/31/2020**						**$876,846**
57							
58	Incremental Full Time Equivalents 09/01/2020 through 8/31/2021			$5,262	$121,083	$126,345	
59	Incremental Full Time Equivalents, O&M portion			$2,082	$73,933	$76,015	
60							
61	Weighted Union Wage Increases Effective 09/01/2020 through 08/31/2021	2.68%	100.00%	$90,334		$90,334	
62	Non-Union Wage Increase Effective 09/01/20 through 08/31/21 (12 Months)	3.00%	100.00%		$683,926	$683,926	
63							
64	Rate Year 8/31/2021 O&M Wages			$3,461,001	$23,481,461	$26,942,463	$26,942,463
65							
66	**Narragansett Electric Company Wage Adjustment 8/31/2021**						**$850,275**

Line Notes

1	Per Company books
3-10	Workpaper 4, Page 2
12	Annualized wages based on June 30, 2017 employee complement and annual salaries
13	Line 3 / Line 1
15	Line 12 x Line 13
16	Per Company books
17	Workpaper 4, Pages 11-12
19	Sum of Lines 15 through 18
21-22	Line 19 x Column (a) x Column (b) Line 21 or Line 22, respectively
24	Sum of Lines 18 through 22
26-27	Line 24 x Column (a) x Column (b) Line 26 or Line 27, respectively
29	Sum of Lines 24 through 27
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34	Sum of Lines 29 through 32
36	Line 6 x Line 34
38	Line 8 - Band A & B Financial Variable Pay, Workpaper 4, Page 5
39	Line 9
40	(1 + Column (a) x Column (b), Line 21 or Line 22, respectively) x (1 + Column (a) x Column (b), Line 26 or Line 27, respectively) x (1 + Column (a) x Column (b), Line 31 or Line 32, respectively) - 1
41	Line 38 x Line 40
42	Line 39 x Line 40
44	Sum of Lines 36 through 39 + Line 41 + Line 42
46	Line 44(f) - Line 10(f)
48	Workpaper 4, Pages 11-12
49	Line 6 x Line 48
51-52	(Line 44 + Line 49) x Column (a) x Column (b) Line 51 or Line 52, respectively
54	Line 44 + Sum of Lines 49 through 52
56	Line 54(f) - Line 44(f)
58	Workpaper 4, Pages 11-12
59	Line 6 x Line 58
61-62	(Line 54 + Line 59) x Column (a) x Column (b) Line 61 or Line 62, respectively
64	Line 54 + Sum of Lines 59 through 62
66	Line 64(f) - Line 54(f)

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The Narragansett Electric Company d/b/a National Grid
Service Company Employees Salary and Wages
Rate Year Ending August 31, 2019, August 31, 2020 and August 31, 2021

Line	Description	Rate	Portion of Year	Union	Non-Union	Rate Year Amount	Test Year Amount
		Gas	Gas	Gas	Gas	Gas	Gas
		(a)	(b)	(c)	(d)	(e)	(f)
1	Service Company Test Year Total Base Wages			$88,805,821	$465,382,043		$554,187,863
2							
3	Narragansett Electric Company Share of Test Year Total Base Wages			$3,148,702	$17,338,207		$20,486,908
4	Less Test Year Capitalized Wages			$1,438,175	$6,939,697		$8,377,872
5	Test Year O&M Wages			$1,710,527	$10,398,510		$12,109,037
6	O&M Portion			54.32%	59.97%		59.11%
7							
8	Test Year O&M Variable Pay			$24,843	$1,265,599		$1,290,442
9	Test Year O&M Overtime Wages			$283,559	$56,019		$339,578
10	Total Test Year Service Company Wages to Narragansett Electric Company O&M			$2,018,928	$11,720,128		$13,739,056
11							
12	Total Service Company Steady State Wages at 6/30/17 (excluding Temporary Employees)			$94,499,627	$494,100,352	$588,599,980	
13	Narragansett Electric Company Share of Base Wages 6/30/17			3.55%	3.73%	3.70%	
14							
15	Steady State Wages at 6/30/17 Charged to Narragansett Electric Company			$3,350,582	$18,408,132	$21,758,713	
16	Test Year Temporary and Seasonal Employees			$0	$33,340	$33,340	
17	Incremental Full Time Equivalents			$5,120	$248,496	$253,616	
18	Vacancies			$0	$0	$0	
19	Total Steady State Wages at 6/30/17			$3,355,702	$18,689,967	$22,045,669	
20							
21	Weighted Union Wage Increases Effective 07/01/2017 through 06/30/2018	0.72%	100.00%	$24,161		$24,161	
22	Non-Union Wage Increase Effective 07/01/17 through 06/30/18 (12 Months)	3.64%	100.00%		$680,315	$680,315	
23							
24	Subtotal			$3,379,863	$19,370,282	$22,750,145	
25							
26	Weighted Union Wage Increases Effective 07/01/2018 through 06/31/2019	2.74%	100.00%	$92,608		$92,608	
27	Non-Union Wage Increase Effective 07/01/18 through 06/30/19 (12 Months)	3.25%	100.00%		$629,534	$629,534	
28							
29	Subtotal			$3,472,471	$19,999,816	$23,472,287	
30							
31	Weighted Union Wage Increases Effective 07/01/2019 through 08/31/2019	2.76%	16.99%	$16,283		$16,283	
32	Non-Union Wage Increase Effective 07/01/19 through 08/31/19 (2 Months)	3.00%	16.99%		$101,939	$101,939	
33							
34	Rate Year 8/31/2019 Total Base Wages			$3,488,754	$20,101,755	$23,590,509	
35							
36	Rate Year 8/31/2019 O&M Base Wages			$1,895,091	$12,055,023	$13,950,114	
37							
38	Test Year O&M Non-Financial Variable Pay			$24,843	$947,034	$971,877	
39	Test Year O&M Overtime Wages			$283,559	$56,019	$339,578	
40	Increase Through Rate Year			3.96%	7.55%		
41	Impact of O&M Non-Financial Variable Pay Increase Through Rate Year			$984	$71,501	$72,485	
42	Impact of O&M Overtime Wages Increase Through Rate Year			$11,229	$4,229	$15,458	
43							
44	Rate Year O&M Wages			$2,215,705	$13,133,806	$15,349,511	$15,349,511
45							
46	**Narragansett Electric Company Wage Adjustment 8/31/2019**						**$1,610,455**
47							
48	Incremental Full Time Equivalents 09/01/2019 through 8/31/2020			$5,021	$110,402	$115,423	
49	Incremental Full Time Equivalents, O&M portion			$2,728	$66,208	$68,936	
50							
51	Weighted Union Wage Increases Effective 09/01/2019 through 08/31/2020	2.44%	100.00%	$54,130		$54,130	
52	Non-Union Wage Increase Effective 09/01/19 through 08/31/20 (12 Months)	3.00%	100.00%		$396,000	$396,000	
53							
54	Rate Year 8/31/2020 O&M Base Wages			$2,272,563	$13,596,014	$15,868,577	$15,868,577
55							
56	**Narragansett Electric Company Wage Adjustment 8/31/2020**						**$519,066**
57							
58	Incremental Full Time Equivalents 09/01/2020 through 8/31/2021			$2,461	$74,140	$76,601	
59	Incremental Full Time Equivalents, O&M portion			$1,337	$44,462	$45,799	
60							
61	Weighted Union Wage Increases Effective 09/01/2020 through 08/31/2021	1.83%	100.00%	$41,612		$41,612	
62	Non-Union Wage Increase Effective 09/01/20 through 08/31/21 (12 Months)	3.00%	100.00%		$409,214	$409,214	
63							
64	Rate Year 8/31/2021 O&M Base Wages			$2,315,512	$14,049,690	$16,365,202	$16,365,202
65							
66	**Narragansett Electric Company Wage Adjustment 8/31/2021**						**$496,625**

Line Notes

1	Per Company books
3-10	Workpaper 4, Page 2
12	Annualized wages based on June 30, 2017 employee complement and annual salaries
13	Line 3 / Line 1
15	Line 12 x Line 13
16	Per Company books
17	Workpaper 4, Pages 11-12
19	Sum of Lines 15 through 18
21-22	Line 19 x Column (a) x Column (b) Line 21 or Line 22, respectively
24	Sum of Lines 18 through 22
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29	Sum of Lines 24 through 27
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34	Sum of Lines 29 through 32
36	Line 6 x Line 34
38	Line 8 - Band A & B Financial Variable Pay, Workpaper 4, Page 5
39	Line 9
40	(1 + Column (a) x Column (b), Line 21 or Line 22, respectively) x (1 + Column (a) x Column (b), Line 26 or Line 27, respectively) x (1 + Column (a) x Column (b), Line 31 or Line 32, respectively) - 1
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44	Sum of Lines 36 through 39 + Line 41 + Line 42
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The Narragansett Electric Company d/b/a National Grid
Other Affiliates Employees Salary and Wages
Rate Year Ending August 31, 2019, August 31, 2020 and August 31, 2021

Line	Description	Rate	Portion of Year	Union	Non-Union	Rate Year Amount	Test Year Amount
		Electric	Electric	Electric	Electric	Electric	Electric
		(a)	(b)	(c)	(d)	(e)	(f)
1	Other Affiliates Test Year Total Base Wages			$627,727,377	$127,406,430		$755,133,806
2							
3	Narragansett Electric Company Share of Test Year Total Base Wages			$1,581,078	$386,682		$1,967,760
4	Less Test Year Capitalized Wages			$728,879	$223,147		$952,026
5	Test Year O&M Wages			$852,199	$163,535		$1,015,734
6	O&M Portion			53.90%	42.29%		51.62%
7							
8	Test Year O&M Variable Pay			$26,497	$6,789		$33,287
9	Test Year O&M Overtime Wages			$78,504	($3,440)		$75,064
10	Total Test Year Other Affiliates Wages to Narragansett Electric Company O&M			$957,200	$166,884		$1,124,084
11							
12	Total Affiliates Steady State Wages at 6/30/17 (excluding Temporary Employees)			$652,183,071	$123,158,619	$775,341,689	
13	Narragansett Electric Company Share of Base Wages 6/30/17			0.25%	0.30%	0.26%	
14							
15	Steady State Wages at 6/30/17 Charged to Narragansett Electric Company			$1,630,458	$369,476	$1,999,934	
16	Test Year Temporary and Seasonal Employees			$0	$448	$448	
17	Incremental Full Time Equivalents			$0	$0	$0	
18	Vacancies			$0	$0	$0	
19	Total Steady State Wages at 6/30/17			$1,630,458	$369,924	$2,000,382	
20							
21	Weighted Union Wage Increases Effective 07/01/2017 through 06/30/2018	0.58%	100.00%	$9,457		$9,457	
22	Non-Union Wage Increase Effective 07/01/17 through 06/30/18 (12 Months)	3.64%	100.00%		$13,465	$13,465	
23							
24	Subtotal			$1,639,914	$383,389	$2,023,304	
25							
26	Weighted Union Wage Increases Effective 07/01/2018 through 06/31/2019	2.47%	100.00%	$40,506		$40,506	
27	Non-Union Wage Increase Effective 07/01/18 through 06/30/19 (12 Months)	3.25%	100.00%		$12,460	$12,460	
28							
29	Subtotal			$1,680,420	$395,849	$2,076,270	
30							
31	Weighted Union Wage Increases Effective 07/01/2019 through 08/31/2019	2.46%	16.99%	$7,023		$7,023	
32	Non-Union Wage Increase Effective 07/01/19 through 08/31/19 (2 Months)	3.00%	16.99%		$2,018	$2,018	
33							
34	Rate Year 8/31/2019 Total Base Wages			$1,687,444	$397,867	$2,085,311	
35							
36	Rate Year 8/31/2019 O&M Base Wages			$909,532	$168,258	$1,077,790	
37							
38	Test Year O&M Non-Financial Variable Pay			$26,497	$6,280	$32,777	
39	Test Year O&M Overtime Wages			$78,504	($3,440)	$75,064	
40	Increase Through Rate Year			3.50%	7.55%		
41	Impact of O&M Non-Financial Variable Pay Increase Through Rate Year			$927	$474	$1,402	
42	Impact of O&M Overtime Wages Increase Through Rate Year			$2,748	($260)	$2,488	
43							
44	Rate Year O&M Wages			$1,018,208	$171,312	$1,189,520	$1,189,520
45							
46	**Narragansett Electric Company Wage Adjustment 8/31/2019**						**$65,436**
47							
48	Incremental Full Time Equivalents 09/01/2019 through 8/31/2020			$0	$0	$0	
49	Incremental Full Time Equivalents, O&M portion			$0	$0	$0	
50							
51	Weighted Union Wage Increases Effective 09/01/2019 through 08/31/2020	2.76%	100.00%	$28,103		$28,103	
52	Non-Union Wage Increase Effective 09/01/19 through 08/31/20 (12 Months)	3.00%	100.00%		$5,139	$5,139	
53							
54	Rate Year 8/31/2020 O&M Wages			$1,046,311	$176,452	$1,222,762	$1,222,762
55							
56	**Narragansett Electric Company Wage Adjustment 8/31/2020**						**$33,242**
57							
58	Incremental Full Time Equivalents 09/01/2020 through 8/31/2021			$0	$0	$0	
59	Incremental Full Time Equivalents, O&M portion			$0	$0	$0	
60							
61	Weighted Union Wage Increases Effective 09/01/2020 through 08/31/2021	2.20%	100.00%	$23,019		$23,019	
62	Non-Union Wage Increase Effective 09/01/20 through 08/31/21 (12 Months)	3.00%	100.00%		$5,294	$5,294	
63							
64	Rate Year 8/31/2021 O&M Wages			$1,069,330	$181,745	$1,251,075	$1,251,075
65							
66	**Narragansett Electric Company Wage Adjustment 8/31/2021**						**$28,312**

Line Notes

1	Per Company books
3-10	Workpaper 4, Page 2
12	Annualized wages based on June 30, 2017 employee complement and annual salaries
13	Line 3 / Line 1
15	Line 12 x Line 13
16	Per Company books
19	Sum of Lines 15 through 18
21-22	Line 19 x Column (a) x Column (b) Line 21 or Line 22, respectively
24	Sum of Lines 18 through 22
26-27	Line 24 x Column (a) x Column (b) Line 26 or Line 27, respectively
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36	Line 6 x Line 34
38	Line 8 - Band A & B Financial Variable Pay, Workpaper 4, Page 5
39	Line 9
40	(1 + Column (a) x Column (b), Line 21 or Line 22, respectively) x (1 + Column (a) x Column (b), Line 26 or Line 27, respectively) x (1 + Column (a) x Column (b), Line 31 or Line 32, respectively) - 1
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42	Line 39 x Line 40
44	Sum of Lines 36 through 39 + Line 41 + Line 42
46	Line 44(f) - Line 10(f)
49	Line 6 x Line 48
51-52	(Line 44 + Line 49) x Column (a) x Column (b) Line 51 or Line 52, respectively
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56	Line 54(f) - Line 44(f)
59	Line 6 x Line 58
61-62	(Line 54 + Line 59) x Column (a) x Column (b) Line 61 or Line 62, respectively
64	Line 54 + Sum of Lines 59 through 62
66	Line 64(f) - Line 54(f)

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Other Affiliates Employees Salary and Wages
Rate Year Ending August 31, 2019, August 31, 2020 and August 31, 2021

Line	Description	Rate	Portion of Year	Union	Non-Union	Rate Year Amount	Test Year Amount
		Gas	Gas	Gas	Gas	Gas	Gas
		(a)	(b)	(c)	(d)	(e)	(f)
1	Other Affiliates Test Year Total Base Wages			$627,727,377	$127,406,430		$755,133,806
2							
3	Narragansett Electric Company Share of Test Year Total Base Wages			$476,648	$81,071		$557,719
4	Less Test Year Capitalized Wages			$99,232	$10,036		$109,268
5	Test Year O&M Wages			$377,416	$71,035		$448,451
6	O&M Portion			79.18%	87.62%		80.41%
7							
8	Test Year O&M Variable Pay			$18,870	$9,935		$28,804
9	Test Year O&M Overtime Wages			$39,984	$338		$40,321
10	Total Test Year Other Affiliates Wages to Narragansett Electric Company O&M			$436,269	$81,307		$517,576
11							
12	Total Affiliates Steady State Wages at 6/30/17 (excluding Temporary Employees)			$656,313,717	$127,331,459	$783,645,176	
13	Narragansett Electric Company Share of Base Wages 6/30/17			0.08%	0.06%	0.07%	
14							
15	Steady State Wages at 6/30/17 Charged to Narragansett Electric Company			$498,354	$81,023	$579,378	
16	Test Year Temporary and Seasonal Employees			$159	$469	$628	
17	Incremental Full Time Equivalents			$0	$0	$0	
18	Vacancies			$0	$0	$0	
19	Total Steady State Wages at 6/30/17			$498,514	$81,492	$580,005	
20							
21	Weighted Union Wage Increases Effective 07/01/2017 through 06/30/2018	0.53%	100.00%	$2,642		$2,642	
22	Non-Union Wage Increase Effective 07/01/17 through 06/30/18 (12 Months)	3.64%	100.00%		$2,966	$2,966	
23							
24	Subtotal			$501,156	$84,458	$585,614	
25							
26	Weighted Union Wage Increases Effective 07/01/2018 through 06/31/2019	2.49%	100.00%	$12,479		$12,479	
27	Non-Union Wage Increase Effective 07/01/18 through 06/30/19 (12 Months)	3.25%	100.00%		$2,745	$2,745	
28							
29	Subtotal			$513,635	$87,203	$600,837	
30							
31	Weighted Union Wage Increases Effective 07/01/2019 through 08/31/2019	2.47%	16.99%	$2,155		$2,155	
32	Non-Union Wage Increase Effective 07/01/19 through 08/31/19 (2 Months)	3.00%	16.99%		$444	$444	
33							
34	Rate Year 8/31/2019 Total Base Wages			$515,790	$87,647	$603,437	
35							
36	Rate Year 8/31/2019 O&M Base Wages			$408,403	$76,796	$485,199	
37							
38	Test Year O&M Non-Financial Variable Pay			$18,870	$9,826	$28,696	
39	Test Year O&M Overtime Wages			$39,984	$338	$40,321	
40	Increase Through Rate Year			3.47%	7.55%		
41	Impact of O&M Non-Financial Variable Pay Increase Through Rate Year			$655	$742	$1,397	
42	Impact of O&M Overtime Wages Increase Through Rate Year			$1,387	$25	$1,413	
43							
44	Rate Year O&M Wages			$469,298	$87,728	$557,026	$557,026
45							
46	**Narragansett Electric Company Wage Adjustment 8/31/2019**						**$39,450**
47							
48	Incremental Full Time Equivalents 09/01/2019 through 8/31/2020			$0	$0	$0	
49	Incremental Full Time Equivalents, O&M portion			$0	$0	$0	
50							
51	Weighted Union Wage Increases Effective 09/01/2019 through 08/31/2020	2.76%	100.00%	$12,953		$12,953	
52	Non-Union Wage Increase Effective 09/01/19 through 08/31/20 (12 Months)	3.00%	100.00%		$2,632	$2,632	
53							
54	Rate Year 8/31/2020 O&M Wages			$482,251	$90,360	$572,610	$572,610
55							
56	**Narragansett Electric Company Wage Adjustment 8/31/2020**						**$15,584**
57							
58	Incremental Full Time Equivalents 09/01/2019 through 8/31/2020			$0	$0	$0	
59	Incremental Full Time Equivalents, O&M portion			$0	$0	$0	
60							
61	Weighted Union Wage Increases Effective 09/01/2020 through 08/31/2021	2.20%	100.00%	$10,610		$10,610	
62	Non-Union Wage Increase Effective 09/01/20 through 08/31/21 (12 Months)	3.00%	100.00%		$2,711	$2,711	
63							
64	Rate Year 8/31/2021 O&M Base Wages			$492,860	$93,070	$585,930	$585,930
65							
66	**Narragansett Electric Company Wage Adjustment 8/31/2021**						**$13,320**

Line Notes

1	Per Company books
3-10	Workpaper 4, Page 3
12	Annualized wages based on June 30, 2017 employee complement and annual salaries
13	Line 3 / Line 1
15	Line 12 x Line 13
16	Per Company books
19	Sum of Lines 15 through 18
21-22	Line 19 x Column (a) x Column (b) Line 21 or Line 22, respectively
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39	Line 9
40	(1 + Column (a) x Column (b), Line 21 or Line 22, respectively) x (1 + Column (a) x Column (b), Line 26 or Line 27, respectively) x (1 + Column (a) x Column (b), Line 31 or Line 32, respectively) - 1
41	Line 38 x Line 40
42	Line 39 x Line 40
44	Sum of Lines 36 through 39 + Line 41 + Line 42
46	Line 44(f) - Line 10(f)
49	Line 6 x Line 48
51-52	(Line 44 + Line 49) x Column (a) x Column (b) Line 51 or Line 52, respectively
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56	Line 54(f) - Line 44(f)
59	Line 6 x Line 58
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66	Line 64(f) - Line 54(f)

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/ 4780
Witness: Little

Compliance Attachment 2

Schedule 13

Health Care

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 13
Page 1 of 16

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Health Care

		Test Year Ended June 30, 2017 (Per Books)			Normalizing Adjustments			Test Year Ended June 30, 2017 (as Adjusted)		
		Total	Electric	Gas	Total	Electric	Gas	Total	Electric	Gas
		(a) = (b) + (c)	(b)	(c)	(d) = (e) + (f)	(e)	(f)	(g) = (h) + (i)	(h)	(i)
	Provider Company:									
1	Narragansett Electric Company	$5,255,398	$3,010,190	$2,245,208	($474,835)	($474,835)	$0	$4,780,562	$2,535,355	$2,245,208
2	National Grid USA Service Company	$6,887,847	$4,751,409	$2,136,438	($709,067)	($706,258)	($2,810)	$6,178,780	$4,045,151	$2,133,628
3	All Other Companies	$198,456	$140,104	$58,352	($33,410)	($33,410)	$0	$165,046	$106,694	$58,352
4	Total	$12,341,700	$7,901,703	$4,439,997	($1,217,312)	($1,214,503)	($2,810)	$11,124,388	$6,687,200	$4,437,188
5										
6										
7	Operation:									
8	Production Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	Power Production Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Natural Gas Storage, Terminaling	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	and Processing Exp.									
12	Transmission Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Regional Market Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Distribution Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Customer Service and	$0	$0	$0	$0	$0	$0	$0	$0	$0
17	Informational Expenses									
18	Sales Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	Administrative & General Expenses	$12,341,700	$7,901,703	$4,439,997	($1,217,312)	($1,214,503)	($2,810)	$11,124,388	$6,687,200	$4,437,188
20	Sub Total	$12,341,700	$7,901,703	$4,439,997	($1,217,312)	($1,214,503)	($2,810)	$11,124,388	$6,687,200	$4,437,188
21										
22	Maintenance:									
23	Transmission Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Distribution Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	Administrative & General Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Sub Total	$0	$0	$0	$0	$0	$0	$0	$0	$0
27										
28	TOTAL	$12,341,700	$7,901,703	$4,439,997	($1,217,312)	($1,214,503)	($2,810)	$11,124,388	$6,687,200	$4,437,188
		$0	$0	$0	$0	$0	$0	$0	$0	$0

Column Notes

(b) and (c)	Per Company Books
(h)	Column (b) + Column (e)
(i)	Column (c) + Column (f)

Line Notes

1(e)	Page 5, Line 2(b) + Line 6(b) +Line 10(b)
2(e)	Page 5, Line 3(b) + Line 7(b) + Line 11(b)
3(e)	Page 5, Line 4(b) + Line 8(b) + Line 12(b)
1(f)	Page 5, Line 2(c) + Line 6(c) + Line 10(c)
2(f)	Page 5, Line 3(c) + Line 7(c) + Line 11(c)
3(f)	Page 5, Line 4(c) + Line 8(c) + Line 12(c)
19	Equals Line 4

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Health Care

		Test Year Ended June 30, 2017 (as Adjusted)			Proforma Adjustments			Rate Year Ending August 31, 2019		
		Total	Electric	Gas	Total	Electric	Gas	Total	Electric	Gas
		(a) = (b) + (c)	(b)	(c)	(d) = (e) + (f)	(e)	(f)	(g) = (h) + (i)	(h)	(i)
	Provider Company:									
1	Narragansett Electric Company	$4,780,562	$2,535,355	$2,245,208	$1,245,104	$923,559	$321,545	$6,025,667	$3,458,914	$2,566,752
2	National Grid USA Service Company	$6,178,780	$4,045,151	$2,133,628	($1,637,896)	($1,219,336)	($418,561)	$4,540,884	$2,825,816	$1,715,068
3	All Other Companies	$165,046	$106,694	$58,352	$0	$0	$0	$165,046	$106,694	$58,352
4	Total	$11,124,388	$6,687,200	$4,437,188	($392,792)	($295,776)	($97,016)	$10,731,596	$6,391,424	$4,340,172
5										
6										
7	Operation:									
8	Production Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	Power Production Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Natural Gas Storage, Terminaling	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	and Processing Exp.									
12	Transmission Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Regional Market Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Distribution Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Customer Service and	$0	$0	$0	$0	$0	$0	$0	$0	$0
17	Informational Expenses									
18	Sales Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	Administrative & General Expenses	$11,124,388	$6,687,200	$4,437,188	($392,792)	($295,776)	($97,016)	$10,731,596	$6,391,424	$4,340,172
20	Sub Total	$11,124,388	$6,687,200	$4,437,188	($392,792)	($295,776)	($97,016)	$10,731,596	$6,391,424	$4,340,172
21										
22	Maintenance:									
23	Transmission Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Distribution Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	Administrative & General Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Sub Total	$0	$0	$0	$0	$0	$0	$0	$0	$0
27										
28	TOTAL	$11,124,388	$6,687,200	$4,437,188	($392,792)	($295,776)	($97,016)	$10,731,596	$6,391,424	$4,340,172
		$0	$0	$0	$0	$0	$0	$0	$0	$0

Column Notes
(b) Page 1, Column (h)
(c) Page 1, Column (i)
(h) Column (b) + Column (e)
(i) Column (c) + Column (f)

Line Notes
1(e) Page 5, Line 21(b)
2(e) Page 5, Line 22(b)
1(f) Page 5, Line 21(c)
2(f) Page 5, Line 22(c)
19 Equals Line 4

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Health Care

		Rate Year Ending August 31, 2019	Adjustments to Reflect Conditions in Rate Year Ending August 31, 2020	Rate Year Ending August 31, 2020	Adjustments to Reflect Conditions in Rate Year Ending August 31, 2021	Rate Year Ending August 31, 2021
		Electric	Electric	Electric	Electric	Electric
		(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) + (d)
	Provider Company:					
1	Narragansett Electric Company	$3,458,914	$124,175	$3,583,089	$108,568	$3,691,657
2	National Grid USA Service Company	$2,825,816	$101,447	$2,927,263	$88,696	$3,015,959
3	All Other Companies	$106,694	$3,830	$110,525	$3,349	$113,874
4	Total	$6,391,424	$229,452	$6,620,876	$200,613	$6,821,489
5						
6						
7	Operation:					
8	Production Expenses	$0	$0	$0	$0	$0
9	Power Production Expenses	$0	$0	$0	$0	$0
10	Natural Gas Storage, Terminaling	$0	$0	$0	$0	$0
11	and Processing Exp.					
12	Transmission Expenses	$0	$0	$0	$0	$0
13	Regional Market Expenses	$0	$0	$0	$0	$0
14	Distribution Expenses	$0	$0	$0	$0	$0
15	Customer Accounts Expenses	$0	$0	$0	$0	$0
16	Customer Service and	$0	$0	$0	$0	$0
17	Informational Expenses					
18	Sales Expenses	$0	$0	$0	$0	$0
19	Administrative & General Expenses	$6,391,424	$229,452	$6,620,876	$200,613	$6,821,489
20	Sub Total	$6,391,424	$229,452	$6,620,876	$200,613	$6,821,489
21						
22	Maintenance:					
23	Transmission Expenses	$0	$0	$0	$0	$0
24	Distribution Expenses	$0	$0	$0	$0	$0
25	Administrative & General Expenses	$0	$0	$0	$0	$0
26	Sub Total	$0	$0	$0	$0	$0
27						
28	TOTAL	$6,391,424	$229,452	$6,620,876	$200,613	$6,821,489
		$0	$0	$0	$0	$0

Column Notes
(a) Page 2, Column (h)

Line Notes
1(b) Page 5, Line 21(b)
2(b) Page 5, Line 22(b)
3(b) Page 5, Line 23(b)
1(d) Page 5, Line 30(b)
2(d) Page 5, Line 31(b)
3(d) Page 5, Line 32(b)
19 Equals Line 4

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Health Care

		Rate Year Ending August 31, 2019	Adjustments to Reflect Conditions in Rate Year Ending August 31, 2020	Rate Year Ending August 31, 2020	Adjustments to Reflect Conditions in Rate Year Ending August 31, 2021	Rate Year Ending August 31, 2021
		Gas	Gas	Gas	Gas	Gas
		(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) + (d)
	Provider Company:					
1	Narragansett Electric Company	$2,566,752	$108,830	$2,675,583	$84,013	$2,759,596
2	National Grid USA Service Company	$1,715,068	$72,719	$1,787,787	$56,136	$1,843,923
3	All Other Companies	$58,352	$2,474	$60,826	$1,910	$62,736
4	Total	$4,340,172	$184,023	$4,524,195	$142,060	$4,666,255
5						
6						
7	Operation:					
8	Production Expenses	$0	$0	$0	$0	$0
9	Power Production Expenses	$0	$0	$0	$0	$0
10	Natural Gas Storage, Terminaling	$0	$0	$0	$0	$0
11	and Processing Exp.					
12	Transmission Expenses	$0	$0	$0	$0	$0
13	Regional Market Expenses	$0	$0	$0	$0	$0
14	Distribution Expenses	$0	$0	$0	$0	$0
15	Customer Accounts Expenses	$0	$0	$0	$0	$0
16	Customer Service and	$0	$0	$0	$0	$0
17	Informational Expenses					
18	Sales Expenses	$0	$0	$0	$0	$0
19	Administrative & General Expenses	$4,340,172	$184,023	$4,524,195	$142,060	$4,666,255
20	Sub Total	$4,340,172	$184,023	$4,524,195	$142,060	$4,666,255
21						
22	Maintenance:					
23	Transmission Expenses	$0	$0	$0	$0	$0
24	Distribution Expenses	$0	$0	$0	$0	$0
25	Administrative & General Expenses	$0	$0	$0	$0	$0
26	Sub Total	$0	$0	$0	$0	$0
27						
28	TOTAL	$4,340,172	$184,023	$4,524,195	$142,060	$4,666,255
		$0	$0	$0	$0	$0

Line Notes
1(b) Page 5, Line 30(c)
2(b) Page 5, Line 31(c)
3(b) Page 5, Line 32(c)
1(d) Page 5, Line 39(c)
2(d) Page 5, Line 40(c)
3(d) Page 5, Line 41(c)
19 Equals Line 4

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Health Care

		Explanation of Adjustments:	Provider Company	Total (a) = (b) + (c)	Electric (b)	Gas (c)
1	Page 1	Adjustments: (to normalize Historic Year)				
2		(IFA) Integrated Facilities Agreement	Narragansett Electric Company	($411,192)	($411,192)	$0
3		(IFA) Integrated Facilities Agreement	National Grid USA Service Company	($649,042)	($649,042)	$0
4		(IFA) Integrated Facilities Agreement	All Other Companies	($19,138)	($19,138)	$0
5						
6		Inspection & Maintenance	Narragansett Electric Company	($44,179)	($44,179)	$0
7		Inspection & Maintenance	National Grid USA Service Company	($389)	($389)	$0
8		Inspection & Maintenance	All Other Companies	($8,620)	($8,620)	$0
9						
10		Major Storm Activity	Narragansett Electric Company	$0	$0	$0
11		Major Storm Activity	National Grid USA Service Company	($48,053)	($48,053)	$0
12		Major Storm Activity	All Other Companies	($5,651)	($5,651)	$0
13						
14		RI Government Relations and Federal Affairs	Narragansett Electric Company	($19,464)	($19,464)	$0
15		RI Government Relations and Federal Affairs	National Grid USA Service Company	($11,582)	($8,773)	($2,810)
16						
17			TOTAL	($1,217,312)	($1,214,503)	($2,810)
18						
19						
20						
21	Page 2	Adjustments: (to reflect conditions in the Rate Year 8/31/19)				
22						
23		To increase costs for:				
24			Narragansett Electric	$1,245,104	$923,559	$321,545
25			National Grid USA Service Co.	($1,637,896)	($1,219,336)	($418,561)
26			All Other Companies	$0	$0	$0
27						
28			TOTAL	($392,792)	($295,776)	($97,016)
29						
30	Page 3 and Page 4	Adjustments: (to reflect conditions in the Rate Year 8/31/20)				
31						
32		Payroll Inflator				
33		3.59% Electric	Narragansett Electric	$233,005	$124,175	$108,830
34		4.24% Gas	National Grid USA Service Co.	$174,166	$101,447	$72,719
35			All Other Companies	$6,304	$3,830	$2,474
36						
37			TOTAL	$413,475	$229,452	$184,023
38						
39	Page 3 and Page 4	Adjustments: (to reflect conditions in the Rate Year 8/31/21)				
40						
41		Payroll Inflator				
42		3.03% Electric	Narragansett Electric	$192,581	$108,568	$84,013
43		3.14% Gas	National Grid USA Service Co.	$144,833	$88,696	$56,136
44			All Other Companies	$5,259	$3,349	$1,910
45						
46			TOTAL	$342,672	$200,613	$142,060

Line Notes

2(b)-4(b)	Workpaper 1, Line 9
6(b) - 8(b)	Schedule 3, Page 6, Line 7(d)
10(b) - 12(b)	Schedule 3, Page 6, Line 7(f)
21(b)	Page 6, Line 35(a) - Page 1, Line 1(h)
22(b)	Page 6, Line 35(b) - Page 1, Line 2(h)
21(c)	Page 7, Line 35(a) - Page 1, Line 1(i)
22(c)	Page 7, Line 35(b) - Page 1, Line 2(i)
30(b)	Page 3, Line 1(a) * Payroll Inflator Rate from Schedule 8, Page 6, Line 47(i)
31(b)	Page 3, Line 2(a) * Payroll Inflator Rate from Schedule 8, Page 6, Line 47(i)
32(b)	Page 3, Line 3(a) * Payroll Inflator Rate from Schedule 8, Page 6, Line 47(i)
30(c)	Page 4, Line 1(a) * Payroll Inflator Rate from Schedule 8, Page 6, Line 47(j)
31(c)	Page 4, Line 2(a) * Payroll Inflator Rate from Schedule 8, Page 6, Line 47(j)
32(c)	Page 4, Line 3(a) * Payroll Inflator Rate from Schedule 8, Page 6, Line 47(j)
39(b)	Page 3, Line 1(c) * Payroll Inflator Rate from Schedule 8, Page 6, Line 74(i)
40(b)	Page 3, Line 2(c) * Payroll Inflator Rate from Schedule 8, Page 6, Line 74(i)
41(b)	Page 3, Line 3(c) * Payroll Inflator Rate from Schedule 8, Page 6, Line 74(i)
39(c)	Page 4, Line 1(c) * Payroll Inflator Rate from Schedule 8, Page 6, Line 74(j)
40(c)	Page 4, Line 2(c) * Payroll Inflator Rate from Schedule 8, Page 6, Line 74(j)
41(c)	Page 4, Line 3(c) * Payroll Inflator Rate from Schedule 8, Page 6, Line 74(j)

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Health Care

	Description	Narragansett Electric Company Electric	National Grid Service Company Electric	Other Affiliates Electric	Total Electric
		(a)	(b)	(c)	(d)
1	Total Normalized Test Year Medical and Dental Costs to Narragansett Electric O&M				$6,687,200
2					
3	Medical and Dental Costs using 6/30/17 enrollment				
4	Medical	$6,246,260	$73,893,894	$0	
5	Dental	$321,787	$3,772,222	$0	
6	Sub-Total Medical and Dental Costs	$6,568,046	$77,666,116	$0	
7					
8					
9	Number of Steady State Rate Year Employees	392	6,051		
10					
11	Healthcare and Dental Costs Per Employee 2018 Rates				
12	Medical	$15,934	$12,212		
13	Dental	$821	$623		
14	Total Medical and Dental Costs Per Employee 2018 Rates	$16,755	$12,835		
15					
16	Incremental Full-Time Equivalents	25	64		
17	Vacancies	26	0		
18	Approved Incremental Full-Time Equivalents and Vacancies	51	64		
19					
20	Sub-Total Medical and Dental Costs for Approved Incremental Full-Time Equivalents and Vacancies				
21	Medical	$812,651	$781,558		
22	Dental	$41,865	$39,898		
23	Sub-Total Medical and Dental Costs	$854,516	$821,456		
24					
25	Total Medical and Dental Costs				
26	Medical	$7,058,911	$74,675,453		
27	Dental	$363,652	$3,812,120		
28	Total Medical and Dental Costs	$7,422,563	$78,487,572		
29					
30					
31	Share of Medical and Dental Costs for Rate Year Ended August 30, 2019				
32	Percentage Charged to Narragansett Electric - Total	100.00%	6.32%		
33	Percentage Charged to Narragansett Electric - O&M Labor	46.60%	56.93%		
34					
35	Allocation of Rate Year Medical and Dental Costs to O&M	$3,458,914	$2,825,816	$106,694	$6,391,424
36					
37	Proforma Healthcare Adjustment				($295,776)

Line Notes
1 Page 1, Line 28(h)
4(a) Page 8, Line 1(c)
4(b) Page 10, Line 1(c)
5(a) Page 8, Line 2(c)
5(b) Page 10, Line 2(c)
6 Line 4 + Line 5
9(a) Workpaper 4, Page 9, Line 2(f) + Line 4(f)
9(b) Workpaper 4, Page 9, Line 11(f)
12 Line 4/Line 9
13 Line 5/Line 9
14 Line 12 + Line 13
16 Workpaper 4, Pages 10-12
17 Workpaper 4, Page 13
21 Line 12 x Line 18
22 Line 13 x Line 18
23 Line 21 + Line 22
26 Line 4 + Line 21
27 Line 5 + Line 22
28 Line 26 + Line 27
32(b) Schedule 12, Page 8, Line 13(e)
33(a) Schedule 12, Page 6, Line 4(f)
33(b) Schedule 12, Page 8, Line 6(f)
35 Line 28 x Line 32 x Line 33
37 Line 35 - Line 1

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Health Care

	Description	Narragansett Gas Gas (a)	National Grid Service Company Gas (b)	Other Affiliates Gas (c)	Total Gas (d)
1	Total Normalized Test Year Medical and Dental Costs to Narragansett Electric O&M				$4,437,188
2					
3	Medical and Dental Costs using 6/30/17 enrollment				
4	Medical	$4,969,152	$73,893,894	$0	
5	Dental	$324,270	$3,772,222	$0	
6	Sub-Total Medical and Dental Costs	$5,293,422	$77,666,116	$0	
7					
8					
9	Number of Steady State Rate Year Employees	342	6,051		
10					
11	Healthcare and Dental Costs Per Employee 2018 Rates				
12	Medical	$14,530	$12,212		
13	Dental	$948	$623		
14	Total Medical and Dental Costs Per Employee 2018 Rates	$15,478	$12,835		
15					
16	Incremental Full Time Equivalents	19	64		
17	Vacancies	9	0		
18	Approved Incremental Full-Time Equivalents and Vacancies	28	64		
19					
20	Sub-Total Medical and Dental Costs for Approved Incremental Full-Time Equivalents and Vacancies				
21	Medical	$406,831	$781,558		
22	Dental	$26,548	$39,898		
23	Sub-Total Medical and Dental Costs	$433,380	$821,456		
24					
25	Total Medical and Dental Costs				
26	Medical	$5,375,983	$74,675,453		
27	Dental	$350,818	$3,812,120		
28	Total Medical and Dental Costs	$5,726,802	$78,487,572		
29					
30					
31	Share of Medical and Dental Costs for Rate Year Ended August 30, 2019				
32	Percentage Charged to Narragansett Electric - Total	100.00%	3.70%		
33	Percentage Charged to Narragansett Electric - O&M Labor	44.82%	59.11%		
34					
35	Allocation of Rate Year Medical and Dental Costs to O&M	$2,566,752	$1,715,068	$58,352	$4,340,172
36					
37	Proforma Healthcare Adjustment				($97,016)

Line Notes
1 Page 1, Line 28(c)
4(a) Page 5, Line 1(c)
4(b) Page 6, Line 1(c)
5(a) Page 5, Line 2(c)
5(b) Page 6, Line 2(c)
6 Line 4 + Line 5
9(a) Workpaper 4, Page 9, Line 3(f) + Line 5(f)
9(b) Workpaper 4, Page 9, Line 11(f)
12 Line 4/Line 9
13 Line 5/Line 9
14 Line 12 + Line 13
16 Workpaper 4, Pages 10-12
17 Workpaper 4, Page 13
21 Line 12 x Line 18
22 Line 13 x Line 18
23 Line 21 + Line 22
26 Line 4 + Line 21
27 Line 5 + Line 22
28 Line 26 + Line 27
32(b) Schedule 12, Page 9, Line 13(e)
33(a) Schedule 12, Page 7, Line 4(f)
33(b) Schedule 12, Page 9, Line 6(f)
35 Line 28 x Line 32 x Line 33
37 Line 35 - Line 1

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 13

The Narragansett Electric Company d/b/a National Grid
Summary of Healthcare Costs - 2018 Plans
Based on Open Enrollment Data as of June 2017

National Grid - Narragansett Electric
Employer (ER) Contribution

		Non Union	Union	Total		
		Total ER Costs (a)	Total ER Costs (b)	Total ER Costs (c) = (a) + (b)	Steady State Employees (d)	Per Emp Cost (e) = (c) * (d)
1	Medical	$603,340	$5,642,920	$6,246,260	392	$15,934
2	Dental	$30,407	$291,380	$321,787	392	$821
3						
4	**Total**	**$633,746**	**$5,934,300**	$6,568,046		$16,755

Column Notes
(c) Column (a) + Column (b)
(d) Workpaper 4, Page 9, Line 2(f) + Line 4(f)
(e) Column (c) * Column (d)

Line Notes
1(a) Page 11, Line 88
1(b) Page 11, Line 88
2(a) Page 11, Line 108
2(b) Page 11, Line 108

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The Narragansett Electric Company d/b/a National Grid
Summary of Healthcare Costs - 2018 Plans
Based on Open Enrollment Data as of June 2017

National Grid - Narragansett Gas
Employer (ER) Contribution

		Non Union	Union	Total		
		Total ER Costs	Total ER Costs	Total ER Costs	Steady State Employees	Per Emp Cost
		(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) * (d)
1	Medical	$254,866	$4,714,286	$4,969,152	342	$14,530
2	Dental	$12,010	$312,260	$324,270	342	$948
3						
4	**Total**	**$266,875**	**$5,026,547**	$5,293,422		$15,478

Column Notes
(c) Column (a) + Column (b)
(d) Workpaper 4, Page 9, Line 3(f) + Line 5(f)
(e) Column (c) * Column (d)

Line Notes
1(a) Page 12, Line 88
1(b) Page 12, Line 88
2(a) Page 12, Line 108
2(b) Page 12, Line 108

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The Narragansett Electric Company d/b/a National Grid
Summary of Healthcare Costs - 2018 Plans
Based on Open Enrollment Data as of June 2017

National Grid - Service Company
Employer Contribution

		Non Union	Union	Total		
		Total ER Cost	Total ER Cost	Total ER Cost	Steady State Employees	Per Emp Cost
		(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) * (d)
1	Medical	$54,802,931	$19,090,964	$73,893,894	6,051	$12,212
2	Dental	$2,850,220	$922,002	$3,772,222	6,051	$623
3						
4	Total	$57,653,151	$20,012,965	$77,666,116		$12,835

Column Notes
(c) Column (a) + Column (b)
(d) Workpaper 4, Page 9, Line 11(f)
(e) Column (c) * Column (d)

Line Notes
1(a) Page 13, Line 88
1(b) Page 13, Line 88
2(a) Page 13, Line 108
2(b) Page 13, Line 108

The Narragansett Electric Company d/b/a National Grid
Summary of Healthcare Costs - 2018 Plans
Based on Open Enrollment Data for June 2017 and Rates for 2018

National Grid - Narragansett Electric
Non Union
Medical - Composite Average

			Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
1	**EPO with Wellness & Spousal Surcharge**						
2		EE	$551	$150	4	$26,440	$7,200
3		EE+Spouse	$952	$450	1	$11,420	$5,400
4		EE+Child(ren)	$962	$300	2	$23,076	$7,200
5		Family	$1,553	$550	2	$37,261	$13,200
6			$4,017	$1,450	9	**$98,198**	$33,000
7							
8	**EPO with Wellness but without Spousal Surcharge**						
9		EE	$551	$150	0	$0	$0
10		EE+Spouse	$1,052	$350	5	$63,101	$21,000
11		EE+Child(ren)	$962	$300	0	$0	$0
12		Family	$1,653	$450	11	$218,134	$59,400
13			$4,217	$1,250	16	**$281,235**	$80,400
14							
15	**EPO without Wellness but with Spousal Surcharge**						
16		EE	$501	$200	1	$6,010	$2,400
17		EE+Spouse	$902	$500	1	$10,820	$6,000
18		EE+Child(ren)	$912	$350	0	$0	$0
19		Family	$1,503	$600	2	$36,061	$14,400
20			$3,817	$1,650	4	**$52,891**	$22,800
21							
22	**EPO without Wellness and without Spousal Surcharge**						
23		EE	$501	$200	0	$0	$0
24		EE+Spouse	$1,002	$400	1	$12,020	$4,800
25		EE+Child(ren)	$912	$350	0	$0	$0
26		Family	$1,603	$500	5	$96,152	$30,000
27			$4,017	$1,450	6	**$108,172**	$34,800
28							
29	**CDHP1 - Health Savings Plan with Wellness & Spousal Surcharge**						
30		EE	$607	$60	2	$14,579	$1,440
31		EE+Spouse	$1,085	$250	0	$0	$0
32		EE+Child(ren)	$1,071	$130	0	$0	$0
33		Family	$1,682	$320	1	$20,188	$3,840
34			$4,446	$760	3	**$34,767**	$5,280
35							
36	**CDHP1 - Health Savings Plan with Wellness but without Spousal Surcharge**						
37		EE	$607	$60	0	$0	$0
38		EE+Spouse	$1,185	$150	0	$0	$0
39		EE+Child(ren)	$1,071	$130	0	$0	$0
40		Family	$1,782	$220	1	$21,388	$2,640
41			$4,646	$560	1	**$21,388**	$2,640
42							
43	**CDHP1 - Health Savings Plan without Wellness but with Spousal Surcharge**						
44		EE	$557	$110	1	$6,689	$1,320
45		EE+Spouse	$1,035	$300	0	$0	$0
46		EE+Child(ren)	$1,021	$180	0	$0	$0
47		Family	$1,632	$370	0	$0	$0
48			$4,246	$960	1	$6,689	$1,320
49							
50	**CDHP1 - Health Savings Plan without Wellness and without Spousal Surcharge**						
51		EE	$557	$110	0	$0	$0
52		EE+Spouse	$1,135	$200	0	$0	$0
53		EE+Child(ren)	$1,021	$180	0	$0	$0
54		Family	$1,732	$270	0	$0	$0
55			$4,446	$760	0	$0	$0

Union
Medical - Composite Average

		Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
PPO						
	EE	$663	$152	40	$318,024	$73,123
	EE+1	$1,325	$305	23	$365,730	$84,092
	EE+Child(ren)			0		
	Family	$1,890	$435	36	$816,570	$187,755
		$3,878	$892	99	$1,500,324	$344,971
POS						
	EE	$663	$173	66	$524,873	$137,069
	EE+1	$1,325	$346	52	$827,077	$215,989
				0		
	Family	$1,891	$494	123	$2,790,645	$728,786
		$3,879	$1,013	241	$4,142,595	$1,081,845
CDHP						
	EE	$686	$79	0	$0	$0
	EE+1	$1,372	$158	0	$0	$0
				0	$0	$0
	Family	$1,957	$226	0	$0	$0
		$4,016	$463	0	$0	$0

The Narragansett Electric Company d/b/a National Grid
Summary of Healthcare Costs - 2018 Plans
Based on Open Enrollment Data for June 2017 and Rates for 2018

National Group - Narragansett Electric
Non Union
Medical - Composite Average

		Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
1	**CDHP2 - Health Investment Plan with Wellness & Spousal Surcharge**					
2	EE	$582	$10	0	$0	$0
3	EE+Spouse	$1,043	$140	0	$0	$0
4	EE+Child(ren)	$1,035	$30	0	$0	$0
5	Family	$1,615	$160	0	$0	$0
6		$4,276	$340	0	$0	$0
7						
8	**CDHP2 - Health Investment Plan with Wellness but without Spousal Surcharge**					
9	EE	$582	$10	0	$0	$0
10	EE+Spouse	$1,143	$40	0	$0	$0
11	EE+Child(ren)	$1,035	$30	0	$0	$0
12	Family	$1,715	$60	0	$0	$0
13		$4,476	$140	0	$0	$0
14						
15	**CDHP2 - Health Investment Plan without Wellness but with Spousal Surcharge**					
16	EE	$532	$60	0	$0	$0
17	EE+Spouse	$993	$190	0	$0	$0
18	EE+Child(ren)	$985	$80	0	$0	$0
19	Family	$1,565	$210	0	$0	$0
20		$4,076	$540	0	$0	$0
21						
22	**CDHP2 - Health Investment Plan without Wellness and without Spousal Surcharge**					
23	EE	$532	$60	0	$0	$0
24	EE+Spouse	$1,093	$90	0	$0	$0
25	EE+Child(ren)	$985	$80	0	$0	$0
26	Family	$1,665	$110	0	$0	$0
27		$4,276	$340	0	$0	$0
28						
29	**Opt Out**	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
30	EE			5	0	$0
31						
32				**Total Non-union Medical Costs**	**$603,340**	**$180,240**
33						
34						

Union
Medical - Composite Average

	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
Opt Out					
EE	0	0	44	0	0
			Total Union Medical Costs	**$5,642,920**	**$1,426,816**

Dental - Composite Average

	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
35 **With Ortho**					
36 EE	$24	$20	9	$2,546	$2,160
37 EE+Spouse	$47	$40	11	$6,222	$5,280
38 EE+Child(ren)	$52	$45	1	$629	$540
39 Family	$94	$60	18	$20,400	$12,960
40	$218	$165	39	$29,797	$20,940
41			**Total Non-union Dental Costs**	**$29,797**	**$20,940**
42					
43 **Without Ortho**	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
44 EE	$23	$15	0	$0	$0
45 EE+Spouse	$51	$25	1	$610	$300
46 EE+Child(ren)	$55	$30	0	$0	$0
47 Family	$94	$40	0	$0	$0
48	$223	$110	1	$610	$300
49			**Total Non-union Dental Costs**	**$610**	**$300**
50					
51			**Total Non-union Dental Costs**	**$30,407**	**$21,240**
52					
53			**NG USA Service Co.**		
54			**Total Medical and Dental Costs - Non-union**	**$633,746**	**$201,480**

Dental - Composite Average

	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
With Ortho					
EE	$36	$9	98	$41,823	$10,456
EE+1	$71	$18	98	$83,646	$20,912
Family	$101	$25	115	$139,881	$34,970
	$208	$52	311	$265,351	$66,338
			Total Union Dental Costs	**$265,351**	**$66,338**
Without Ortho	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
EE	$34	$8	10	$4,054	$1,014
EE+1	$68	$17	10	$8,109	$2,027
				$0	$0
Family	$96	$24	12	$13,866	$3,467
	$198	$49	32	$26,029	$6,507
			Total Non-union Dental Costs	**$26,029**	**$6,507**
			Total Union Dental Costs	**$291,380**	**$72,845**
			NG USA Service Co.		
			Total Union Medical and Dental Costs	**$5,934,300**	**$1,499,661**

The Narragansett Electric Company d/b/a National Grid
Summary of Healthcare Costs - 2017 Plans
Based on Open Enrollment Data for Calendar Year 2017 and Rates for 2018

National Grid - Narragansett Gas
Non Union
Medical - Composite Average

		Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
1	**EPO with Wellness & Spousal Surcharge**					
2	EE	$551	$150	1	$6,610	$1,800
3	EE+Spouse	$952	$450	1	$11,420	$5,400
4	EE+Child(ren)	$962	$300	0	$0	$0
5	Family	$1,553	$550	1	$18,630	$6,600
6		$4,017	$1,450	3	$36,661	$13,800
7						
8	**EPO with Wellness but without Spousal Surcharge**					
9	EE	$551	$150	0	$0	$0
10	EE+Spouse	$1,052	$350	1	$12,620	$4,200
11	EE+Child(ren)	$962	$300	0	$0	$0
12	Family	$1,653	$450	3	$59,491	$16,200
13		$4,217	$1,250	4	$72,111	$20,400
14						
15	**EPO without Wellness but with Spousal Surcharge**					
16	EE	$501	$200	1	$6,010	$2,400
17	EE+Spouse	$902	$500	0	$0	$0
18	EE+Child(ren)	$912	$350	0	$0	$0
19	Family	$1,503	$600	0	$0	$0
20		$3,817	$1,650	1	$6,010	$2,400
21						
22	**EPO without Wellness and without Spousal Surcharge**					
23	EE	$501	$200	0	$0	$0
24	EE+Spouse	$1,002	$400	1	$12,020	$4,800
25	EE+Child(ren)	$912	$350	0	$0	$0
26	Family	$1,603	$500	2	$38,461	$12,000
27		$4,017	$1,450	3	$50,481	$16,800
28						
29	**CDHP1 - Health Savings Plan with Wellness & Spousal Surcharge**					
30	EE	$607	$60	0	$0	$0
31	EE+Spouse	$1,085	$250	1	$13,019	$3,000
32	EE+Child(ren)	$1,071	$130	0	$0	$0
33	Family	$1,682	$320	0	$0	$0
34		$4,446	$760	1	$13,019	$3,000
35						
36	**CDHP1 - Health Savings Plan with Wellness but without Spousal Surcharge**					
37	EE	$607	$60	0	$0	$0
38	EE+Spouse	$1,185	$150	1	$14,219	$1,800
39	EE+Child(ren)	$1,071	$130	0	$0	$0
40	Family	$1,782	$220	2	$42,777	$5,280
41		$4,646	$560	3	$56,996	$7,080
42						
43	**CDHP1 - Health Savings Plan without Wellness but with Spousal Surcharge**					
44	EE	$557	$110	0	$0	$0
45	EE+Spouse	$1,035	$300	0	$0	$0
46	EE+Child(ren)	$1,021	$180	0	$0	$0
47	Family	$1,632	$370	1	$19,588	$4,440
48		$4,246	$960	1	$19,588	$4,440
49						
50	**CDHP1 - Health Savings Plan without Wellness and without Spousal Surcharge**					
51	EE	$557	$110	0	$0	$0
52	EE+Spouse	$1,135	$200	0	$0	$0
53	EE+Child(ren)	$1,021	$180	0	$0	$0
54	Family	$1,732	$270	0	$0	$0
55		$4,446	$760	0	$0	$0

Union
Medical - Composite Average

	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
PPO					
EE	$624	$166	71	$531,646	$141,135
EE+1	$1,325	$305	9	$143,112	$32,906
			0	$0	$0
Family	$1,508	$420	198	$3,583,408	$998,181
	$3,457	$890	278	$4,258,166	$1,172,221
POS					
EE	$663	$173	5	$39,763	$10,384
EE+1	$1,325	$346	5	$79,526	$20,768
			0	$0	$0
Family	$1,891	$494	13	$294,946	$77,027
	$3,879	$1,013	23	$414,236	$108,179
CDHP					
EE	$654	$74	3	$23,529	$2,648
EE+1			0	$0	$0
			0	$0	$0
Family	$1,530	$170	1	$18,355	$2,040
	$2,183	$244	4	$41,884	$4,688

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The Narragansett Electric Company d/b/a National Grid
Summary of Healthcare Costs - 2017 Plans
Based on Open Enrollment Data for Calendar Year 2017 and Rates for 2018

National Grid - Narragansett Gas
Non Union
Medical - Composite Average

	CDHP2 - Health Investment Plan with Wellness & Spousal Surcharge	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
1						
2	EE	$582	$10	0	$0	$0
3	EE+Spouse	$1,043	$140	0	$0	$0
4	EE+Child(ren)	$1,035	$30	0	$0	$0
5	Family	$1,615	$160	0	$0	$0
6		$4,276	$340	0	$0	$0
7						

	CDHP2 - Health Investment Plan with Wellness but without Spousal Surcharge	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
8						
9	EE	$582	$10	0	$0	$0
10	EE+Spouse	$1,143	$40	0	$0	$0
11	EE+Child(ren)	$1,035	$30	0	$0	$0
12	Family	$1,715	$60	0	$0	$0
13		$4,476	$140	0	$0	$0
14						

	CDHP2 - Health Investment Plan without Wellness but with Spousal Surcharge	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
15						
16	EE	$532	$60	0	$0	$0
17	EE+Spouse	$993	$190	0	$0	$0
18	EE+Child(ren)	$985	$80	0	$0	$0
19	Family	$1,565	$210	0	$0	$0
20		$4,076	$540	0	$0	$0
21						

	CDHP2 - Health Investment Plan without Wellness and without Spousal Surcharge	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
22						
23	EE	$532	$60	0	$0	$0
24	EE+Spouse	$1,093	$90	0	$0	$0
25	EE+Child(ren)	$985	$80	0	$0	$0
26	Family	$1,665	$110	0	$0	$0
27		$4,276	$340	0	$0	$0
28						

	Opt Out	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
29						
30	EE			1	0	$0
31						
32			Total Non-union Medical Costs		$254,866	$67,920
33						
34						

Dental - Composite Average

	With Ortho	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
35						
36						
37	EE	$24	$20	1	$283	$240
38	EE+Spouse	$47	$40	6	$3,394	$2,880
39	EE+Child(ren)	$52	$45	2	$1,258	$1,080
40	Family	$94	$60	6	$6,800	$4,320
41		$218	$165	15	$11,735	$8,520
42				**Total Non-union Dental Costs**	**$11,735**	**$8,520**
43						

	Without Ortho	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
44						
45	EE	$23	$15	1	$275	$180
46	EE+Spouse	$51	$25	0	$0	$0
47	EE+Child(ren)	$55	$30	0	$0	$0
48	Family	$94	$40	0	$0	$0
49		$223	$110	1	$275	$180
50				**Total Non-union Dental Costs**	**$275**	**$180**
51						
52				**Total Non-union Dental Costs**	**$12,010**	**$8,700**
53						
54				**NG USA Service Co.**		
55				**Total Medical and Dental Costs - Non-union**	**$266,875**	**$76,620**

Union
Medical - Composite Average

	Opt Out	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
	EE	0	0	24	0	0
				Total Union Medical Costs	$4,714,286	$1,285,088

Dental - Composite Average

	With Ortho	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
	EE	$41	$10	82	$40,614	$10,153
	EE+1	$71	$18	18	$15,364	$3,841
					$0	$0
	Family	$103	$26	204	$251,539	$62,885
		$215	$54	304	$307,516	$76,879
				Total Union D	**$307,516**	**$76,879**

	Without Ortho	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
	EE	$34	$8	2	$811	$203
	EE+1	$68	$17	2	$1,622	$405
					$0	$0
	Family	$96	$24	2	$2,311	$578
		$198	$49	6	$4,744	$1,186
				Total Non-union Dental Costs	**$4,744**	**$1,186**
				Total Union Dental Costs	**$312,260**	**$78,065**
				NG USA Service Co.		
				Total Union Medical and Dental Costs	**$5,026,547**	**$1,363,153**

The Narragansett Electric Company d/b/a National Grid
Summary of Healthcare Costs - 2018 Plans
Based on Open Enrollment Data for June 2017 and Rates for 2018

National Grid - Service Company
Non Union
Medical - Composite Average

		Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
1	**EPO with Wellness & Spousal Surcharge**					
2	EE	$551	$150	483	$3,192,683	$869,400
3	EE+Spouse	$952	$450	44	$502,490	$237,600
4	EE+Child(ren)	$962	$300	104	$1,199,972	$374,400
5	Family	$1,553	$550	109	$2,030,706	$719,400
6		$4,017	$1,450	740	$6,925,851	$2,200,800
7						
8	**EPO with Wellness but without Spousal Surcharge**	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
9	EE	$551	$150	0	$0	$0
10	EE+Spouse	$1,052	$350	248	$3,129,814	$1,041,600
11	EE+Child(ren)	$962	$300	0	$0	$0
12	Family	$1,653	$450	612	$12,136,161	$3,304,800
13		$4,217	$1,250	860	$15,265,975	$4,346,400
14						
15	**EPO without Wellness but with Spousal Surcharge**	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
16	EE	$501	$200	260	$1,562,628	$624,000
17	EE+Spouse	$902	$500	24	$259,685	$144,000
18	EE+Child(ren)	$912	$350	55	$601,601	$231,000
19	Family	$1,503	$600	59	$1,063,789	$424,800
20		$3,817	$1,650	398	$3,487,704	$1,423,800
21						
22	**EPO without Wellness and without Spousal Surcharge**	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
23	EE	$501	$200	0	$0	$0
24	EE+Spouse	$1,002	$400	133	$1,598,689	$638,400
25	EE+Child(ren)	$912	$350	0	$0	$0
26	Family	$1,603	$500	329	$6,326,778	$1,974,000
27		$4,017	$1,450	462	$7,925,467	$2,612,400
28						
29	**CDHP1 - Health Savings Plan with Wellness & Spousal Surcharge**	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
30	EE	$607	$60	370	$2,697,098	$266,400
31	EE+Spouse	$1,085	$250	22	$286,416	$66,000
32	EE+Child(ren)	$1,071	$130	48	$617,137	$74,880
33	Family	$1,682	$320	59	$1,191,113	$226,560
34		$4,446	$760	499	$4,791,765	$633,840
35						
36	**CDHP1 - Health Savings Plan with Wellness but without Spousal Surcharge**	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
37	EE	$607	$60	0	$0	$0
38	EE+Spouse	$1,185	$150	120	$1,706,269	$216,000
39	EE+Child(ren)	$1,071	$130	0	$0	$0
40	Family	$1,782	$220	331	$7,079,548	$873,840
41		$4,646	$560	451	$8,785,817	$1,089,840
42						
43	**CDHP1 - Health Savings Plan without Wellness but with Spousal Surcharge**	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
44	EE	$557	$110	199	$1,331,201	$262,680
45	EE+Spouse	$1,035	$300	12	$149,027	$43,200
46	EE+Child(ren)	$1,021	$180	25	$306,425	$54,000
47	Family	$1,632	$370	32	$626,828	$142,080
48		$4,246	$960	268	$2,413,481	$501,960
49						
50	**CDHP1 - Health Savings Plan without Wellness and without Spousal Surcharge**	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
51	EE	$557	$110	0	$0	$0
52	EE+Spouse	$1,135	$200	63	$857,991	$151,200
53	EE+Child(ren)	$1,021	$180	0	$0	$0
54	Family	$1,732	$270	177	$3,679,540	$573,480
55		$4,446	$760	240	$4,537,532	$724,680

Union
Medical - Composite Average

	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
All Union Plans					
EE	$691	$156	495	$4,104,293	$925,652
EE+1	$1,326	$332	139	$2,211,803	$552,945
				$0	$0
Family	$1,858	$409	573	$12,774,868	$2,811,753
	$3,875	$896	1,207	$19,090,964	$4,290,349

The Narragansett Electric Company d/b/a National Grid
Summary of Healthcare Costs - 2018 Plans
Based on Open Enrollment Data for June 2017 and Rates for 2018

National Grid - Service Company
Non Union
Medical - Composite Average

		Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
1	**CDHP2 - Health Investment Plan with Wellness & Spousal Surcharge**					
2	EE	$582	$10	15	$104,715	$1,800
3	EE+Spouse	$1,043	$140	1	$12,522	$1,680
4	EE+Child(ren)	$1,035	$30	2	$24,844	$720
5	Family	$1,615	$160	2	$38,766	$3,840
6		$4,276	$340	20	$180,847	$8,040
7						
8	**CDHP2 - Health Investment Plan with Wellness but without Spousal Surcharge**					
9	EE	$582	$10	0	$0	$0
10	EE+Spouse	$1,143	$40	4	$54,888	$1,920
11	EE+Child(ren)	$1,035	$30	0	$0	$0
12	Family	$1,715	$60	11	$226,413	$7,920
13		$4,476	$140	15	$281,301	$9,840
14						
15	**CDHP2 - Health Investment Plan without Wellness but with Spousal Surcharge**					
16	EE	$532	$60	7	$44,667	$5,040
17	EE+Spouse	$993	$190	1	$11,922	$2,280
18	EE+Child(ren)	$985	$80	0	$0	$0
19	Family	$1,565	$210	2	$37,566	$5,040
20		$4,076	$540	10	$94,155	$12,360
21						
22	**CDHP2 - Health Investment Plan without Wellness and without Spousal Surcharge**					
23	EE	$532	$60	0	$0	$0
24	EE+Spouse	$1,093	$90	1	$13,122	$1,080
25	EE+Child(ren)	$985	$80	0	$0	$0
26	Family	$1,665	$110	5	$99,915	$6,600
27		$4,276	$340	6	$113,037	$7,680
28						
29	**Opt Out**	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
30	EE			748	0	$0
31						
32				**Total Non-union Medical Costs**	**$54,802,931**	**$13,571,640**
33						
34						
35	**Dental - Composite Average**					
36	**With Ortho**	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
37	EE	$24	$20	1,295	$366,278	$310,800
38	EE+Spouse	$47	$40	856	$484,222	$410,880
39	EE+Child(ren)	$52	$45	203	$127,680	$109,620
40	Family	$94	$60	1,566	$1,774,803	$1,127,520
41		$218	$165	3,920	$2,752,983	$1,958,820
42				**Total Non-union Dental Costs**	**$2,752,983**	**$1,958,820**
43						
44	**Without Ortho**	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
45	EE	$23	$15	143	$39,314	$25,740
46	EE+Spouse	$51	$25	95	$57,923	$28,500
47	EE+Child(ren)	$55	$30	0	$0	$0
48	Family	$94	$40	0	$0	$0
49		$223	$110	238	$97,237	$54,240
50				**Total Non-union Dental Costs**	**$97,237**	**$54,240**
51						
52				**Total Non-union Dental Costs**	**$2,850,220**	**$2,013,060**
53						
54				**NG USA Service Co.**		
55				**Total Medical and Dental Costs - Non-union**	**$57,653,151**	**$15,584,700**

Union
Medical - Composite Average

	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
Opt Out					
EE	0	0	202	0	0
			Total Union Medical Costs	**$19,090,964**	**$4,290,349**

Dental - Composite Average

	Monthly ER costs	Monthly EE Costs	Enrollment as of June 2017	2018 Projected ER Costs	2018 Projected EE Costs
With Ortho					
EE	$30	$5	530	$188,024	$34,521
EE+1	$71	$18	157	$134,005	$33,501
				$0	$0
Family	$92	$17	512	$566,240	$101,550
	$193	$40	1,199	$888,269	$169,572
			Total Union Dental Costs	**$888,269**	**$169,572**
Without Ortho					
EE	$34	$8	17	$6,892	$1,723
EE+1	$68	$17	16	$12,974	$3,243
				$0	$0
Family	$96	$24	12	$13,866	$3,467
	$198	$49	$45	$33,732	$8,433
			Total Union Dental Costs	**$33,732**	**$8,433**
			Total Union Dental Costs	**$922,002**	**$178,005**
			NG USA Service Co.		
			Total Union Medical and Dental Costs	**$20,012,965**	**$4,468,354**

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

AT RICHMOND, MARCH 26, 2020

CLERK'S OFFICE
COMMONWEALTH OF VIRGINIA
2020 MAR 26 A 10:14

PETITION OF

VIRGINIA ELECTRIC AND POWER COMPANY

CASE NO. PUR-2019-00154

For approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia, and for approval of an addition to the terms and conditions applicable to electric service

FINAL ORDER

On September 30, 2019, Virginia Electric and Power Company ("Dominion" or "Company") filed a petition with the State Corporation Commission ("Commission") for approval of a plan for electric distribution grid transformation projects ("Petition") pursuant to § 56-585.1 A 6 ("Section A 6") of the Code of Virginia ("Code"). Specifically, the Company is requesting approval of additional investments over the first three years of its ten-year grid transformation plan ("Plan"). The Company refers to these additional proposed investments as "Phase IB" of the Plan.[1] Pursuant to Section A 6, the Commission is required to issue its final order on the Petition within six months of the filing date.

On October 4, 2019, the Commission issued an Order for Notice and Hearing that, among other things: established a procedural schedule; set an evidentiary hearing date; directed Dominion to provide public notice of its Petition; and provided interested persons an opportunity to file comments on the Petition or to participate in the case as a respondent by filing a notice of

[1] Ex. 2 (Petition) at 5-6. The Company notes that the Commission previously approved certain proposed Phase I investments related to cyber and physical security, including supporting telecommunications infrastructure, which the Company refers to as "Phase IA" of the Plan. *See Petition of Virginia Electric and Power Company, For approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2018-00100, Doc. Con. Cen. No. 190130074, Final Order (Jan. 17, 2019) ("2018 Grid Mod Final Order").

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participation. Notices of participation were filed by: Appalachian Power Company; Appalachian Voices ("Environmental Respondents"); ChargePoint, Inc. ("ChargePoint"); Electrify America, LLC ("Electrify America"); the Sierra Club ("Sierra Club"); Walmart, Inc. ("Walmart"); and the Virginia Office of the Attorney General, Division of Consumer Counsel ("Consumer Counsel"). The Company, Environmental Respondents, ChargePoint, Electrify America, Sierra Club, Walmart, Consumer Counsel and Commission Staff ("Staff") pre-filed testimony in this matter.

Beginning January 27, 2020, the Commission convened a hearing on the Company's Petition.[2] During the hearing, the Commission received the testimony of public witnesses.[3] The Commission also received testimony and exhibits from Dominion, respondents, and Staff. The hearing concluded on January 30, 2020. Post-hearing briefs were subsequently filed by Dominion, Environmental Respondents, ChargePoint, Electrify America, Sierra Club, Consumer Counsel, and Staff on February 28, 2020.[4]

NOW THE COMMISSION, having considered the record, the pleadings, and the applicable law, is of the opinion and finds as follows.

Code of Virginia

As amended by the Grid Transformation and Security Act ("GTSA"),[5] Code § 56-576 defines an "electric distribution grid transformation project" ("GT Project") to mean:

> a project associated with electric distribution infrastructure, including related data analytics equipment, that is designed to accommodate or facilitate the integration of utility-owned or customer-owned renewable electric generation resources with the utility's electric distribution grid or to otherwise enhance electric

[2] Staff and all parties except Appalachian Power Company participated at the hearing.

[3] Tr. 8-65.

[4] Walmart filed a letter in lieu of a post-hearing brief ("Post-Hearing Letter").

[5] 2018 Va. Acts ch. 296.

distribution grid reliability, electric distribution grid security, customer service, or energy efficiency and conservation, including advanced metering infrastructure; intelligent grid devices for real time system and asset information; automated control systems for electric distribution circuits and substations; communications networks for service meters; intelligent grid devices and other distribution equipment; distribution system hardening projects for circuits, other than the conversion of overhead tap lines to underground service, and substations designed to reduce service outages or service restoration times; physical security measures at key distribution substations; cyber security measures; energy storage systems and microgrids that support circuit-level grid stability, power quality, reliability, or resiliency or provide temporary backup energy supply; electrical facilities and infrastructure necessary to support electric vehicle charging systems; LED street light conversions; and new customer information platforms designed to provide improved customer access, greater service options, and expanded access to energy usage information.

As amended by the GTSA, Section A 6 directs that:

A utility shall, without regard for whether it has petitioned for any rate adjustment clause pursuant to clause (vi), petition the Commission, not more than once annually, for approval of a plan for electric distribution grid transformation projects. Any plan for electric distribution grid transformation projects shall include both measures to facilitate integration of distributed energy resources and measures to enhance physical electric distribution grid reliability and security. In ruling upon such a petition, the Commission shall consider whether the utility's plan for such projects, and the projected costs associated therewith, are reasonable and prudent. Such petition shall be considered on a stand-alone basis without regard to the other costs, revenues, investments, or earnings of the utility; without regard to whether the costs associated with such projects will be recovered through a rate adjustment clause under this subdivision or through the utility's rates for generation and distribution services; and without regard to whether such costs will be the subject of a customer credit offset, as applicable, pursuant to subdivision 8 d. The Commission's final order regarding any such petition for approval of an electric distribution grid transformation plan shall be entered

> by the Commission not more than six months after the date of filing such petition.

Section A 6 further declares that: "[e]lectric distribution grid transformation projects are in the public interest."

Like its first grid transformation plan proposed in Case No. PUR-2018-00100, the Company's current Plan will be costly to customers. If the ten-year Plan were fully implemented, the lifetime revenue requirement – the cost to customers over the life of the investments – would be nearly $7 billion, including financing costs.[6] Phase IB alone would have a lifetime revenue requirement of $837.8 million, including financing costs.[7] These costs are significant and, if approved, would ultimately be borne by customers through their monthly electric bills.

For purposes of this Order, the Commission has grouped the Company's proposed investments into several categories of related elements. These categories and the costs of each are as follows: (i) advanced metering infrastructure ("AMI") (total cost: $752.5 million; Phase IB: $303.8 million); (ii) cyber security and stakeholder engagement and customer education (total cost: $197.7 million; Phase IB: $10.4 million); (iii) the customer information platform (total cost: $668.9 million; Phase IB: $36.5 million); (iv) pilot programs and hosting capacity analysis (total cost: $65.9 million; Phase IB: $34.8 million); (v) grid hardening (total cost: $2.9 billion; Phase IB: $210.8 million); and (vi) the self-healing grid and related investments (total cost: $2.1 billion; Phase IB: $241.5 million).[8]

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[6] Ex. 27 (Myers) at Table 3 (Revised).

[7] The Company also proposes to spend $83.7 million of capital costs associated with the customer information platform, which will not be in service until after Phase IB concludes and were not included in the Company's Phase IB lifetime revenue requirement calculation.

[8] Ex. 27 (Myers) at Tables 3-7 (Revised) (including financing costs).

After consideration of the entire record, we find that Dominion has proven that the Phase IB costs of cyber security, stakeholder engagement and customer education, the customer information platform, the pilot programs and hosting capacity analysis, and certain components of grid hardening are reasonable and prudent, subject to certain requirements as discussed further below. We find that the Company has not proven the reasonableness and prudence of the plan or the costs associated with AMI, the self-healing grid and related investments, and certain components of grid hardening. These parts of the Plan are not approved. This disapproval is without prejudice to re-file for similar components in future proceedings. In total, through this Final Order, we approve additional incremental grid transformation-related costs of approximately $212 million[9] and additional related costs involving cyber security, stakeholder engagement and customer education, and telecommunications.[10] The approved components include both measures to facilitate integration of distributed energy resources ("DER") and measures to enhance physical electric distribution grid reliability and security, consistent with the statutory purpose of the GTSA.

The Commission has followed all applicable statutory provisions. In considering the Company's cost-benefit analysis results, the Commission finds this evidence relevant and has weighed those results along with other relevant evidence in the record. Among other things, we recognize that the cost-benefit analysis is based on the full ten-year Plan and is not solely limited

[9] These amounts do not include an additional $83.7 million in capital costs we approve herein related to the customer information platform that the Company did not include in its calculation of the lifetime revenue requirement. *Id.* at Table 1 (Revised) and Appendix A at 8.

[10] Some, but not all, of the costs of cyber security, stakeholder engagement and customer education and telecommunications relate to approved components of the Plan. Based on the record, it is not possible to calculate an exact level of approved spending in these categories; however, we will direct the Company to make a compliance filing identifying those costs and to track incurred costs necessary to demonstrate that spending in these categories is only related to approved components of the Plan.

to Phase IB.[11] The Commission has also considered both the arguments supporting the cost-benefit analysis, as well as those criticizing or opposing the results.[12] We do not herein establish a specific cost-benefit test for approval of a proposed GT Project. We agree with the Company in this regard that "the results of the [cost-benefit analysis] do not end the analysis of whether the proposed investments are reasonable and prudent."[13] We have evaluated the proposed spending on a project-by-project basis in light of all the evidence in the record to determine whether the proposed Phase IB spending is reasonable and prudent, recognizing that the General Assembly has declared GT Projects to be in the public interest.[14]

Advanced Metering Infrastructure

As part of the Plan, the Company proposes to fully deploy AMI across its Virginia service territory. The proposed Phase IB spending associated with AMI is $303.8 million ($752.5 million over ten years).[15] The Company previously requested approval to fully deploy AMI as part of its first application for approval of a grid transformation plan, but this request was denied in the 2018 Grid Mod Final Order. In denying approval, we cited Environmental Respondents witness Golin, who testified that AMI and related technologies "are beneficial and cost-effective *only to the extent* the Company utilizes them *to maximize* the potential gains of

[11] *See, e.g.,* Staff's Post-Hearing Brief at 9.

[12] *See, e.g.,* Ex. 4 (Hulsebosch Direct) at 3-19; Ex. 16 (Norwood) at 8-12; Ex. 18 (O'Donnell) at 17-28; Ex. 23 (Volkmann) at 6-28; Ex. 29 (Hulsebosch Rebuttal) at 6-16.

[13] Dominion's Post-Hearing Brief at 50.

[14] No party suggested that any of the components of the proposed Plan did not meet the definition of an "electric grid transformation project." *See, e.g.,* Ex. 16 (Norwood) at 8; Ex. 25 (Essah) at 14. They are therefore deemed "in the public interest" pursuant to Section A 6.

[15] Ex. 27 (Myers) at Table 4 (Revised) (including financing costs).

rate optionality, energy efficiency, demand response, and DERs ..." and "[w]ithout a well-reasoned plan, this expensive equipment could be under-utilized and provide *little to no benefit to customers* and the utility."[16]

Environmental Respondents, Sierra Club and Consumer Counsel all urged rejection of Dominion's AMI proposal in that proceeding. We agreed for the reasons articulated by witness Golin and others. Our rejection was specifically without prejudice and invited Dominion to re-submit a proposal for deployment of AMI in a future proceeding subject to certain requirements set forth in the 2018 Grid Mod Final Order. Among other things, we stated that a future proposal must include any plan for time-varying rates.[17] We concluded the 2018 Grid Mod Final Order by stating that "spending billions of dollars of customers' money on full deployment is reasonable and prudent *only* if the expenditure is accompanied by a sound and well-crafted plan to *fulfill the promise that smart meter technology* and other grid enhancements offer."[18]

Rate design in the form of time-varying rates, sometimes called "time of use" or "TOU" rates, holds the promise of being an extremely effective – if not the most effective – mechanism for energy efficiency and demand response. Demand response, in the form of peak-shaving, reduces the need to call upon additional generation units at times of peak demand, which may also have the added benefit of reducing carbon emissions. It also has the benefit of reducing the need to build additional generation units, the costs of which would otherwise be borne by customers. TOU rate design can empower customers to respond to price signals to reduce or

[16] 2018 Grid Mod Final Order at 8 (emphasis added).

[17] *Id.* at 11.

[18] *Id.* at 15 (emphasis added).

shift consumption times and amounts. AMI is necessary to implement such rate design, and without TOU rates, one of the most significant benefits of AMI is lost to customers. So, it is reasonable and prudent in a grid transformation plan under Section A 6 that both be deployed together.[19]

In its current Petition, Dominion has not submitted a comprehensive plan to maximize the potential of AMI. In particular, while Dominion wants approval to collect from its customers the substantial costs of *full* deployment of AMI technology, it has failed to submit a comprehensive proposal to roll out TOU rate design across its entire territory and make such rates available to all its customers.[20] Rather, on December 12, 2019 and February 14, 2020, in a proceeding docketed as Case No. PUR-2019-00214, Dominion submitted and supplemented a separate, stand-alone proposal for approval of another TOU rate pilot,[21] limited to no more than 10,000 of

[19] The record in this proceeding also shows that the Company has installed approximately 485,000 AMI meters through the end of 2019 and continues to install additional AMI meters. Tr. 198-206. In this regard, the Commission notes that the instant case specifically involves the approval of a particular AMI project as part of a grid transformation plan under Section A 6 and, thus, the outcome herein is without prejudice for purposes of other proceedings.

[20] A comprehensive proposal to offer TOU and related rate designs to all of Dominion's customers – either as a voluntary (opt-in) or as the default (opt-out) tariff – could be accomplished in conjunction with a base rate case in which rate design issues can be comprehensively addressed. Under current statutes, however, it is unclear when Dominion would be required to submit to a full base rate case. An earnings review is scheduled for 2021; however, it is not known at this time whether that earnings review will require a full base rate case. There is also an opportunity during a Triennial Review for revenue neutral changes to rate design in the absence of a full base rate case, but such rate design would be limited to a revenue neutral TOU proposal. *See, e.g.*, Consumer Counsel's Post-Hearing Brief at 16; Staff's Post-Hearing Brief at 6-7.

[21] Nearly ten years ago, Dominion applied for – and this Commission approved – three dynamic pricing TOU pilot offerings. *Commonwealth of Virginia, ex rel. State Corporation Commission: In re: Virginia Electric and Power Company's Proposed Pilot Program on Dynamic Rates*, Case No. PUE-2010-00135, Order Establishing Pilot Program, 2011 S.C.C. Ann. Rept. 386 (Apr. 8, 2011). These TOU pilots were undertaken in conjunction with the Company's three AMI demonstration pilots conducted in Charlottesville, Midlothian and Northern Virginia, which were not themselves subject to prior Commission approval. *See Application of Virginia Electric and Power Company, For approval to implement new demand-side management programs and for approval of two rate adjustment clauses pursuant to § 56-585.1 A 5 of the Code of Virginia*, Case No. PUE-2009-00081, 2010 S.C.C. Ann. Rept. 362, 366, Order Approving Demand-Side Management Programs (Mar. 24, 2010) ("The Company also

Dominion's 2.5 million Virginia customers, apparently in response to the 2018 Grid Mod Final Order and subsequent legislation.[22] The Company asserts that the proposed pilot – which will take several years to complete – is a prerequisite to system-wide TOU rates.[23] In this regard, the Commission concludes that the Company has simply not provided a concrete, definitive plan to implement TOU rates on a system-wide basis and bring the benefits of full AMI deployment to customers in a timely manner.[24] Accordingly, we once again find the Petition contains an insufficient plan to maximize the potential of AMI, and that the substantial cost to customers of AMI is not reasonable and prudent based on the record established herein. Once again, this rejection is without prejudice.

Cyber Security and Stakeholder and Customer Education

Cyber Security

The Company proposes cyber security spending of $7.2 million ($186.6 million over ten years).[25] As part of Phase IB, the Company proposes to deploy cyber security protections necessary to protect the other Phase IB projects.[26] No party specifically took issue with the

states that the three AMI-enabled demonstration projects do not require Commission approval prior to implementation - only that approval is needed for cost recovery thereof.").

[22] *See, e.g.*, Ex. 45 (Morgan Rebuttal) at 8-9; Dominion's Post-Hearing Brief at 17; Ex. 7 (Frost Direct) at 7; Tr. 263, 267-68; 278. *See also* 2019 Va. Acts ch. 763, Enactment Clauses 3 and 4. Among other things, these enactment clauses direct Dominion to "develop and submit to the ... Commission for approval retail rate schedules designed to offer time-varying pricing, include at least one non-demand rate schedule."

[23] Tr. 267-70.

[24] *See, e.g.*, Tr. 268, 281.

[25] Ex. 27 (Myers) at Table 5 (Revised) (including financing costs).

[26] *See, e.g.*, Dominion's Post-Hearing Brief at 37.

Company's proposed Phase IB cyber security component,[27] and the Commission generally supports reasonable utility spending to support enhanced utility security.[28] Consistent with our determination in the 2018 Grid Mod Final Order, the Commission finds reasonable and prudent the costs of the Company's proposed Phase IB cyber security program, with the exception of the proposed spending that is related exclusively to components of the Plan that are not approved herein.[29]

Stakeholder Engagement and Customer Education

The Company proposes to spend $3.2 million ($11.1 million over ten years) on stakeholder engagement and customer education.[30] To facilitate stakeholder engagement, the Company will continue to convene grid modernization workshops involving varying interests, including environmental advocates, municipal representatives and low income advocates.[31] The Commission approves stakeholder engagement costs, as well as the customer education costs, to the extent they are necessary to support the approved components herein, such as the Smart

[27] The Environmental Respondents opposed all of Phase IB, or alternatively, request the Commission condition future cost recovery on meeting or exceeding appropriate performance benchmarks. Environmental Respondents Post-Hearing Brief at 2, 14.

[28] 2018 Grid Mod Final Order at 7.

[29] Thus, the Commission finds that such spending related exclusively to components of the Plan that are not approved herein is not reasonable and prudent and is not approved, In addition, as we did in the 2018 Grid Mod Final Order, the Commission directs the Company to separately track approved spending and to maintain documentation to facilitate Staff audit to ensure such spending is not related to unapproved components of the Plan. 2018 Grid Mod Final Order at 7 n.14.

[30] Ex. 27 (Myers) at Table 3 (Revised) (including financing costs).

[31] Ex. 2 (Plan) at 18-19.

Charging Infrastructure Pilot Program ("Smart Charging Pilot") and to prepare for future grid modernization filings.[32] The Commission finds such costs are reasonable and prudent.

Customer Information Platform

The Company proposes to deploy a customer information platform, including a meter data management system, at a cost of $36.5 million for Phase IB ($668.9 million over ten years).[33] The customer information platform, among other things, replaces the Company's legacy customer information system, the primary system supporting processes such as metering, billing, credit, services orders and revenue reporting.[34] Staff and Walmart support approval and Consumer Counsel does not oppose approval of the customer information platform.[35] The Commission finds that the costs of the new customer information platform are reasonable and prudent and should be approved. For example, the evidence in this matter showed that:

- "the Phase 1B investment in the [customer information platform] . . . is well supported by detailed cost estimates and a competitive [request for proposal] process;"[36]

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[32] Proposed educational spending is not approved to the extent that it is related exclusively to components of the Plan that are not approved herein. The Commission directs the Company to separately track approved spending and to maintain documentation to facilitate Staff audit to ensure such spending is not related to unapproved components of the Plan.

[33] Ex. 27 (Myers) at Table 3 (Revised) (including financing costs). The Phase IB customer information platform lifetime revenue requirement of $36.5 million includes only O&M expenses and financing costs. The Company also proposes to spend $83.7 million of capital costs associated with the customer information platform, which will not be in service until after Phase IB concludes and were not included in the Company's Phase IB lifetime revenue requirement calculation, but are nevertheless approved by this Final Order. *Id.* at Table 1 (Revised) and Appendix A at 8. The Commission has found such costs reasonable and prudent.

[34] *See, e.g.*, Dominion's Post-Hearing Brief at 20.

[35] *See, e.g.*, Consumer Counsel's Post-Hearing Brief at 4; Walmart's Post-Hearing Letter at 2; Staff's Post-Hearing Brief at 19. The remaining parties took no position with the exception of Environmental Respondents which opposed all components of Phase IB or alternatively, recommended the Commission condition future cost recovery on meeting or exceeding appropriate performance benchmarks.

[36] Ex. 27 (Myers) at 17.

- "[t]he existing [system] is no longer vendor supported, [and] is quickly approaching the end of its useful life;"[37]
- "the existing system is an outdated technology that is getting very close to . . . not functioning anymore;"[38]
- "the existing [system] is unable to effectively and efficiently offer an expanded set of rate structures and customer-centric programs . . . .;"[39] and
- The new customer information platform "will provide customers the option to compare available rates and make assumptions on changing usage."[40]

Pilot Programs and Hosting Capacity Analysis

The Commission includes the following Plan elements in this category: Locks Campus Microgrid (total cost: $13.6 million; Phase IB: $12.3 million), the Smart Charging Pilot (total cost: $51.1 million; Phase IB: $22.2 million), and the hosting capacity analysis (total cost: $1.2 million; Phase IB: $0.3 million).[41]

Locks Campus Microgrid

With the Locks Campus Microgrid project, the Company seeks to install a microgrid at its Locks Campus in Petersburg, Virginia. The microgrid will consist of a group of interconnected loads and DER that act as a small power grid, able to operate when connected to the larger electric grid and also able to continue to operate as an "island" when normal power is interrupted.[42] Through this project, the Company states it "will obtain real-world data, better

[37] Dominion's Post-Hearing Brief at 20.

[38] *Id.* at 21 (internal quotation marks omitted).

[39] Ex. 8 (Arruda Direct) at 9.

[40] *Id.* at 11.

[41] Ex. 27 (Myers) at Tables 3 and 6 (Revised) (including financing costs).

[42] Ex. 9 (Wright Direct) at 17.

understand DER performance characteristics, perform testing of DER grid support and islanding capabilities, vet new technology integration into the distribution grid, and evaluate microgrid operations architecture for potential future applications."[43] Staff, Walmart, Sierra Club, ChargePoint, and Electrify America took no position on this component and Consumer Counsel and Environmental Respondents opposed it generally.[44] Based on the limited scope and experimental nature of this pilot-type program related to the integration of DER on the Company's system, the Commission finds the Locks Campus Microgrid is reasonable and prudent.

Smart Charging Pilot

With the Smart Charging Pilot, the Company seeks to obtain "data and tools necessary to understand and manage future [electric vehicle ("EV")] charging load in furtherance of additional investments, pilots, programs, or rate designs that will support EV adoption while minimizing the impact of EV charging on the distribution grid."[45] The pilot will consist of: (i) rebates for the infrastructure and upgrades, if necessary, at EV charging sites; and (ii) rebates for the smart charging equipment that enables managed charging.[46] The Company also proposes to own up to four charging stations as part of Phase IB to support electrification in the rideshare market.[47] The data collected as part of the pilot will enable the Company "to design customer

[43] Ex. 2 (Plan) at 25; *see also* Ex. 38 (Wright Rebuttal) at 18.

[44] *See, e.g.,* Staff's Post-Hearing Brief at 26; Consumer Counsel's Post-Hearing Brief at 17; Environmental Respondents' Brief at 2.

[45] Ex. 7 (Frost Direct) at 35.

[46] *Id.* Dominion states that managed charging allows a utility or third-party to remotely control vehicle charging by turning it up, down, or off to better correspond to the needs of the grid. *Id.* at 39

[47] *Id.* at 41.

offerings specific to the charging behavior of its customers."[48] The pilot will also inform "future options for alternative rates and programs for electric transportation."[49]

Several respondents sponsored testimony that was largely focused on the Smart Charging Pilot, including Sierra Club, Electrify America, and ChargePoint. Each of these parties was generally supportive of the pilot;[50] however, ChargePoint recommended that the Company's proposed ownership of four charging stations be rejected and the spending be converted to additional rebates.[51] ChargePoint, among other things, objected to "inject[ing] the utility into the competitive EV space."[52] Dominion, however, maintains that "it is important to consider various utility investment models as part of the Pilot Program with the understanding that one model . . . may be better suited for some segments and geographic areas . . ." and that "many rideshare rides start or end in low income areas, which are often less likely to have [fast charging] located nearby."[53]

The Commission approves the proposed Smart Charging Pilot Program, including the Company's proposed limited ownership of four charging stations for purposes of collecting relevant data during the term of the Pilot. The Commission finds that collecting relevant data to

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[48] *Id.* at 47.

[49] Ex. 34 (Frost Rebuttal) at 25-26.

[50] In addition, Walmart supported the proposed Pilot; Consumer Counsel did not oppose it; and Staff took no position. *See, e.g.,* Walmart's Post-Hearing Letter at 2; Consumer Counsel's Post-Hearing Brief at 17; Staff's Post-Hearing Brief at 26-27. As noted earlier, Environmental Respondents' generally opposed all aspects of the Plan based on concerns with the Company's cost/benefit analysis.

[51] *See, e.g.,* ChargePoint's Post-Hearing Brief at 12.

[52] *See, e.g., id.*

[53] Ex. 34 (Frost Rebuttal) at 24.

facilitate the increased deployment of EVs on the Company's electric grid through the proposed Pilot is reasonable and prudent. Such approval does not, however, represent any guarantee that additional utility ownership of charging stations will be approved by the Commission.

The integration of EV charging into the Company's electric system raises important issues, many of which were not able to be fully explored in this proceeding. For example, Electrify America requests the Commission direct Dominion "to work with EV charging companies to eliminate minimum charges and to develop and propose new rate designs that will support the growing private market for fast charging services."[54] Sierra Club witness Camp also recommends the Commission implement an energy-only time-of-use rate for EV customers.[55] Consumer Counsel witness Norwood recommends, among other things, that the Company study "cost allocation methods that fairly recognize the direct benefits of such [infrastructure] investment."[56] While we decline to adopt these specific recommendations in this case based on the record established herein, the Commission recognizes that the continued deployment of charging stations in the Commonwealth represents a significant, ongoing issue that impacts the public interest. In this regard, the Commission has recently issued an order establishing a separate proceeding for the investigation and consideration of electric vehicle-related issues, which has been docketed as Case No. PUR-2020-00051.

[54] *See, e.g.*, Electrify America's Post-Hearing Brief at 8.

[55] Ex. 22 (Camp) at 19-24.

[56] Ex. 16 (Norwood) at 22. The Company opposed this recommendation because it has not requested cost recovery in this proceeding. Ex. 34 (Frost Rebuttal) at 26.

Hosting Capacity Analysis

A hosting capacity analysis defines the amount of DER that can be connected to each segment of the distribution grid without causing voltage or loading issues and indicates to customers whether distribution grid investments may be necessary to integrate their DER.[57] In Phase IB, the Company proposes to perform a hosting capacity analysis for both utility scale and net metering DER and publish the results using online interactive maps.[58]

The Company asserts that the intelligent grid devices that are proposed to be installed as part of AMI and the self-healing grid will enable more advanced and dynamic hosting capacity analysis in the future.[59] Staff witness Volkmann explained, however, that the Company currently has the capability to successfully engage in a "round one" hosting capacity analysis with the information currently available to the Company.[60] We do not approve the Company's AMI or self-healing grid proposals as discussed herein; however, we do find the proposed hosting capacity analysis, using information currently available to the Company, is reasonable and prudent.

Grid Hardening

The Company's grid hardening proposal is one of the most expensive components of the Plan. Over ten years, it makes up the single largest category of proposed spending, with a lifetime revenue requirement of approximately $3 billion ($210.8 million over Phase IB). The

[57] Ex. 9 (Wright Direct) at 9.

[58] *Id.* at 10.

[59] Ex. 2 (Plan) at 24. Staff supported this component of the Plan; Consumer Counsel and Environmental Respondents opposed it; and the remaining parties took no position.

[60] Tr. 446.

four sub-components of Grid Hardening are: (i) mainfeeder hardening (total cost: $1.6 billion; Phase IB: $112.4 million); (ii) targeted corridor improvement (total cost: $37.4; Phase IB: $12.5 million); (iii) proactive component upgrade (total cost: $1.2 billion; Phase IB: $70.1 million); and (iv) voltage island mitigation (total cost: $143.6 million; Phase IB: $15.7 million).[61] Consumer Counsel, Environmental Respondents and Staff opposed the grid hardening proposals, in large part based on concerns with the Company's cost-benefit analysis.[62]

Mainfeeder Hardening

During Phase IB, the Company proposes to harden 11 mainfeeders serving approximately 24,000 customers.[63] These mainfeeders were selected based on outage history and "essentially represent the 'worst of the worst' performing feeders in terms of customers experiencing poor reliability."[64] While the average Dominion customer experienced 127 outage minutes annually between 2014 and 2018, the customers served by the targeted 11 mainfeeders experienced 348 outage minutes on average annually, which is significantly worse than the system average.[65] The Company anticipates that Phase IB mainfeeder hardening will, on average, reduce outage time annually by 94 minutes for each customer served by the selected mainfeeders, a 27% improvement.[66]

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[61] Ex. 27 (Myers) at Table 7 (Revised) (including financing costs).

[62] *See, e.g.,* Consumer Counsel's Post-Hearing Brief at 17; Environmental Respondents' Post-Hearing Brief at 2; Staff's Post-Hearing Brief at 29-33. The remaining parties took no position.

[63] *See, e.g.,* Dominion's Post-Hearing Brief at 32.

[64] *Id.*

[65] Ex. 9 (Wright Direct) at 23-26. Figures are excluding major events.

[66] *Id.* at 26.

The Commission finds that Phase IB mainfeeder hardening is reasonable and prudent and should be approved as a pilot-type program as proposed by the Company,[67] targeting customers with the worst reliability records, to validate the projected reliability improvements resulting from this type of program. Such a pilot-type program would provide credible measurement and evaluation to determine whether there are demonstrative improvements in reliability that result from hardening these mainfeeders. Commission approval herein does not guarantee any additional future approvals associated with the Company's full ten-year mainfeeder hardening program, which, if fully implemented over ten years, would cost approximately $1.6 billion.[68] The Commission expects to see actual data collected to analyze the specific impacts of mainfeeder hardening before it will approve any additional spending on future phases related to mainfeeder hardening.[69] The Company shall also report annually on mainfeeder hardening, as detailed further below.

Targeted Corridor Improvements

The Company proposes to spend $12.5 million during Phase IB ($37.4 million over ten years) on targeted corridor improvements.[70] The targeted corridor improvements would consist of (i) a remediation of ash tree mortality program and (ii) an herbicide program for ground floor

[67] *See, e.g.,* Dominion's Post-Hearing Brief at 7.

[68] Ex. 27 (Myers) at Table 7 (Revised) (including financing costs).

[69] Further, any additional spending would depend upon the Company demonstrating that the reliability improvements are reasonable and prudent based on the record in that case.

[70] Ex. 27 (Myers) at Table 7 (Revised) (including financing costs).

maintenance.[71] We find the targeted corridor improvements are reasonable and prudent based on the record in this proceeding. The evidence showed, for example, that:

- Identifying and proactively removing ash trees impacted by emerald ash borer infestation before they become too brittle will reduce safety risk, reduce the cost of removal, and eliminate dead hazard trees that could cause outages;[72]

- While the Company has been removing affected ash trees for several years, the pace of the impact to the system is growing, with approximately 75% of the ash trees already dead or in declining health;[73]

- The Company has completed several pilot projects to determine the most effective approach to an herbicide program;[74] and

- The Company's proposed herbicide program is designed to reduce the amount of incompatible growth on the Company's distribution corridors and reduce outages and improve accessibility to Company facilities for routine inspections or unplanned restoration work.[75]

Proactive Component Upgrades

The Company proposes to spend $70.1 million during Phase IB ($1.2 billion over ten years) on proactive component upgrades.[76] In Phase IB, the Company is proposing to proactively upgrade (i) substation transformers deemed to be at a high risk of failure, and (ii) service transformers identified by smart meters as either being overloaded or not providing appropriate voltage levels.[77]

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[71] Ex. 9 (Wright Direct) at 27-28.

[72] *Id.* at 27.

[73] *Id.* at 27-28.

[74] *Id.* at 28.

[75] *Id.*

[76] Ex. 27 (Myers) at Table 7 (Revised) (including financing costs).

[77] Ex. 9 (Wright Direct) at 29.

The Commission does not find that the proposed proactive component upgrade program is reasonable and prudent based on the record in this case. First, the service transformer-related component is dependent on AMI meters, which the Commission does not approve herein. In addition, the evidence showed that:

- The ten-year cost of the proactive component upgrade program exceeds $1 billion, making it one of the larger components of the overall Plan;
- The Company acknowledges that the program "is not cost-effective under a traditional cost-benefit analysis;"[78]
- Although the primary-asserted benefit of this component is reliability improvements, the Company did not present specific reliability improvement metrics (reduced minutes of interruption before and after, reduced customer interruptions, etc.) that could be measured and verified after-the-fact for the program;[79] and
- Unlike mainfeeder hardening, the proactive component upgrade program does not target customers with below average reliability.

Voltage Island Mitigation

The Company proposes to spend $15.7 million during Phase IB ($143.6 million over ten years) on voltage island mitigation to address portions of the distribution grid without any available system redundancy.[80] For Phase IB, the Company proposes to mitigate two voltage islands which serve 2,600 customers.[81] The Commission finds that Phase IB Voltage Island Mitigation is reasonable and prudent at the level proposed for Phase IB. The evidence showed, for example:

[78] Ex. 28 (Baine Rebuttal) at 6. Staff witness Volkmann also testified that, based on the Company's own analysis, the Poor Health [Substation] Transformer component of the proactive component upgrade program was not cost-effective on a stand-alone basis, even considering reliability benefits. Tr. 408.

[79] *See, e.g.,* Ex. 9 (Wright Direct) at 29-32; Ex. 29 (Hulsebosch Rebuttal) at 29.

[80] Ex. 27 (Myers) at Table 7 (Revised) (including financing costs).

[81] Ex. 9 (Wright Direct) at 34.

- The communities served by voltage islands are exposed to the risk of an extended outage, in the range of 24 hours, if the single substation transformer fails;[82] and

- The Company's proposal would apply various solutions that would eliminate the risk of extended outages and would include installing a second transformer at each location and reconfigure feeders to provide both capacity to restore all customers in the event of a failure of the existing transformer, but also to improve the day-to-day service reliability.[83]

Self-Healing Grid and Related Elements

The Company proposes to spend $54 million during Phase IB ($873 million over ten years)[84] to deploy certain technology referred to as fault location, isolation, and service restorage, or FLISR. This technology is also referred to as the self-healing grid. This investment is closely related to, and dependent on, the Company's proposed Phase IB telecommunications investment, which would cost an additional $152.7 million in Phase IB ($1.1 billion over ten years).[85] Also connected to the self-healing grid investment are the Company's proposed investments in advanced analytics (total cost: $67.1 million; Phase IB: $12.8 million) and the enterprise asset management system ("EAMS") (total cost: $41.4 million; Phase IB: $22 million).[86] In total, these related investments would have a Phase IB lifetime revenue requirement of approximately $241.5 million and represent the largest component (almost 30 percent) of the Company's

[82] *Id.* at 33.

[83] *Id.* at 33-34.

[84] Ex. 27 (Myers) at Table 6 (Revised) (including financing costs).

[85] *Id.* at Table 5 (Revised) (including financing costs). At the hearing, Company witness Wright indicated that a small portion of the telecommunications component is related to the Locks Campus Microgrid and grid hardening. Tr. 258. The Commission approves necessary telecommunications spending related to the Locks Campus Microgrid and grid hardening, but only to the extent those components are approved herein. The Company is directed to track approved spending and to maintain documentation to facilitate Staff audit to ensure such spending is not related to unapproved components of the Plan.

[86] Ex. 40.

proposed Phase IB spending. During Phase IB, the Company would install the self-healing grid on mainfeeders serving 88,000, or just 3.5%, of the Company's 2.5 million Virginia customers.[87] Over ten years, this group of investments would ramp up significantly and result in the installation of the self-healing grid on mainfeeders serving over 2 million of the Company's customers.[88] Over ten years, the lifetime revenue requirement would top $2.1 billion, representing approximately 30 percent of the costs of the ten-year Plan.[89]

The Company's self-healing grid proposal is expensive and sweeping. No respondent or Staff supported it.[90] The Company's justification for this proposed investment is to improve customer reliability.[91] Similarly, the Company's cost-benefit analysis shows that the primary benefit of this proposal is improved reliability.[92] Unlike the Company's mainfeeder hardening proposal, however, the self-healing component is not targeted at customers with below average reliability.[93] Rather, the Company states it is targeting mainfeeders with the largest number of customers.[94] The Commission finds that the Company has not sufficiently established the need for this level of investment to improve overall system reliability, and we will not commit customers to pay for such an expensive investment based on this record. In sum, the

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[87] Ex. 7 (Frost Direct) at 7; Ex. 9 (Wright Direct) at 8.

[88] Ex. 9 (Wright Direct) at 7-8.

[89] Ex. 27 (Myers) at Tables 5-6 (Revised) (including financing costs).

[90] *See, e.g.,* Consumer Counsel's Post-Hearing Brief at 17; Staff's Post-Hearing Brief at 27-29; Environmental Respondents' Brief at 2.

[91] *See e.g.,* Ex. 9 (Wright Direct) at 6.

[92] *See, e.g.,* Ex. 29 (Hulsebosch Rebuttal) at 27.

[93] *See, e.g.,* Tr. 159, 250.

[94] See, e.g., Ex. 9 (Wright Direct) at 7-8.

Commission finds that the proposed self-healing grid and related investments are not reasonable and prudent.

Further in this regard, we note that Dominion correctly points out that the GTSA requires the Company to propose GT Projects aimed at improved reliability.[95] The GTSA, however, does not require the Commission to approve *any* reliability-related GT Project at *any* cost. Instead, the GTSA directs the Commission to consider the reasonableness and prudence of the Company's proposal. The Commission finds that the record simply does not support the need for this level of costs to customers when the purported gains in reliability are speculative and not targeted to the worst-performing locations.

Finally, Dominion requests the opportunity to demonstrate the reliability and resiliency improvements of the self-healing grid through a pilot-type program.[96] While we find a limited pilot-type program is reasonable for Phase IB mainfeeder hardening, we do not find it reasonable and prudent for the self-healing grid. If effective, mainfeeder hardening has the potential to improve service for customers with reliability significantly below system average. That is not the case for the self-healing grid, which is not targeted at customers with below average reliability. In addition, we find that the Company has not sufficiently established the specific parameters of a pilot that would support a research and development ("R&D") project for cost-benefit review; and while the Commission has not applied a strict cost-benefit analysis herein, we consider the reasonableness and prudence of using customers to fund specific pilot-type R&D projects, as we have done herein with mainfeeder hardening.

[95] *See, e.g.,* Dominion's Post-Hearing Brief at 52-54.

[96] *See, e.g., id.* at 7.

Cost Caps

The Commission further finds that the Phase IB components approved herein are reasonable and prudent only if they are limited to the amount of capital and operations and maintenance ("O&M") costs proposed for each approved component by the Company on rebuttal for the following: the customer information platform; the pilot programs and hosting capacity analysis; and mainfeeder hardening. We do not find it reasonable and prudent for the Company to incur any amount of costs above those proposed costs. Any costs that exceed the cost estimates for approved components on rebuttal must be proven by Dominion in a future proceeding to be reasonable and prudent before recovery thereof from ratepayers shall be permitted. The cost caps established herein shall be by individual program (*i.e.*, customer information platform, Locks Campus Microgrid, Smart Charging Pilot, hosting capacity analysis, and mainfeeder hardening), and shall be separate for capital and O&M costs.[97] Dominion did not oppose the imposition of cost caps on approved spending.[98]

Some, but not all, of the costs of certain components relate to other approved components of the Plan. For example, an unspecified amount of the cyber security component is necessary to provide security for the other approved Phase IB components. Based on the record, it is not possible to calculate an exact level of approved spending in these categories – cyber security, stakeholder engagement and customer education, and telecommunications. We only approve the requested investment in these components to the extent the costs are related to approved investments. We direct the Company to track that information as previously discussed. With respect to these investments, we also direct the Company to make a compliance filing within

[97] *See, e.g.*, Staff's Post-Hearing Brief at 10.

[98] Ex. 28 (Baine Rebuttal) at 18.

45 days hereof that identifies, separately for each of the foregoing components of spending (cyber security, stakeholder engagement and customer education, and telecommunications), the amount of (i) capital and (ii) O&M costs approved herein. Such amounts shall also be costs caps with respect to these components.

Reporting Requirements

On or before March 31, 2021, and each year thereafter until further order of the Commission, the Company shall file an annual report on the approved elements of the Plan, both Phase IA and IB, consistent with the Company's proposed reporting metrics.[99]

In addition, with respect to approved Phase IB mainfeeder hardening, the report shall include mainfeeders and miles hardened, costs per mile, performance improvements measured by event count, duration, restoration and System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) impacts, and any other information mutually determined by Dominion and Staff to be useful in evaluating mainfeeder hardening. The Company shall also provide a comparison of the realized benefits of mainfeeder hardening compared to the projected benefits presented in Schedule 7 of Company witness Wright's direct testimony.[100]

Conclusion

Through this Final Order we address the Company's request for approval of additional investments over the first three years of its ten-year Plan, referred to as Phase IB. Today we approve costs of approximately $212 million and additional related costs involving cyber

[99] *Id.* at Rebuttal Schedule 4.

[100] Ex. 9 (Wright Direct).

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security, stakeholder engagement and customer education, and telecommunications, but deny approval of the remaining elements contained in Dominion's Petition and Plan.[101] This results in the denial of approximately $626 million in proposed costs that would be borne by customers in their monthly bills. We recognize the importance of the Plan's overall objectives. We have approved those elements in which the heavy costs to customers have been adequately justified by the overall benefits to customers, and we have denied approval to those elements whose heavy costs were not justified by the overall benefits to customers. As required by the statute, we have considered whether Dominion's "plan for such projects, and the projected costs associated therewith, are reasonable and prudent."[102] Accordingly, in exercising the Commission's discretion thereunder, we have denied those projects for which we have found that the plan, or the projected costs, are not reasonable and prudent.

Accordingly, IT IS SO ORDERED, and this matter IS DISMISSED.

Commissioner Patricia L. West participated in this matter.

AN ATTESTED COPY hereof shall be sent electronically by the Clerk of the Commission to all persons on the official Service List in this matter. The Service List is available from the Clerk of the Commission.

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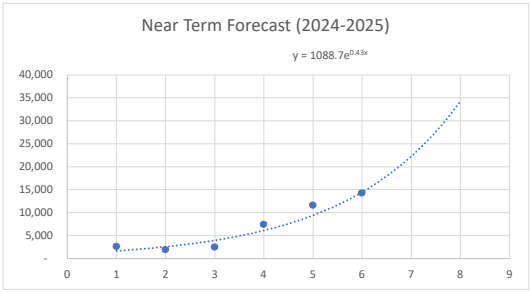
[101] Includes financing costs.

[102] Section A 6.

DTE Energy Company
DTE LDV EV Sales Forecast

Case No. :U-21534
Attachment: U-21534 MEIUDE-1.4 EV Sales Forecast
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Michigan Sales Data	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Total Light-Duty Sales			502,308	557,692	573,571	605,366	609,333	649,273	606,500	530,000	542,254	456,504	506,503	556,501	606,500	626,780	634,658	639,172
% of New Vehicle Sales National																		
External Forecast 1														13.0%	16.4%	21.6%	27.0%	32.6%
External Forecast 2														13.0%	20.0%	25.0%	30.0%	35.0%
External Forecast 3														7.1%	7.7%	10.7%	11.8%	12.8%
External Forecast 4														21.9%	26.5%	31.2%	37.1%	42.6%
External Forecast 5														16.0%	23.0%	28.0%	34.0%	40.0%
External Forecast 6														4.9%	5.6%	6.4%	7.2%	8.1%
Michigan % Discount vs National														52.5%	55.0%	57.5%	60.0%	62.5%
Portion of MI EVs in DTEE														73.2%	72.8%	72.4%	72.0%	71.6%
Michigan Sales Forecast																		
External Forecast 1														37,871	54,819	77,817	102,956	130,307
External Forecast 2														37,981	66,715	90,100	114,238	139,819
External Forecast 3														21,415	24,819	36,169	41,640	46,633
External Forecast 4														121,874	160,723	195,555	235,458	272,287
External Forecast 5														46,746	76,722	100,912	129,470	159,793
External Forecast 6														27,397	33,832	40,020	45,579	51,472
Average														48,881	69,605	90,095	111,557	133,385
DTE Annual EV Sales Forecast	375	1,390	1,828	2,030	1,124	1,737	1,974	2,571	1,878	2,448	7,359	11,535	14,200	22,273	34,281	57,301	80,321	95,504
% Sales in DTEE	#DIV/0!	#DIV/0!	0.5%	0.5%	0.3%	0.4%	0.5%	0.6%	0.5%	0.7%	2.0%	3.7%	4.1%	5.9%	8.3%	13.4%	18.6%	22.0%
DTEE Cumulative Volume	375	1,765	3,593	5,623	6,747	8,485	10,404	12,307	13,443	15,000	21,862	32,007	44,378	64,622	97,778	153,342	231,689	324,621
% of Total DTEE Vehicles	0.0%	0.0%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%	0.3%	0.3%	0.4%	0.6%	0.8%	1.2%	1.8%	2.9%	4.4%	6.1%



DTE Energy Company **Case No. :U-21534**
DTE Fleet EV Sales Forecast **Attachment: U-21534 MEIUDE-1.4 EV Sales Forecast**
Page: 2 of 2

Michigan Discount	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Total Light-Duty Sales			48%	50%	53%	55%	58%	60%	63%
New Vehicle Sales									
External Forecast A									
Medium-Duty			13	20	31	47	73	103	132
Heavy-Duty			3	8	18	35	58	80	106
School Buses			3	5	5	7	7	9	12
Transit Buses			1	2	3	4	9	12	16
External Forecast B									
Medium-Duty			10	25	44	76	113	161	216
Heavy-Duty			5	10	22	41	62	91	128
School Buses			5	7	11	15	22	30	40
Transit Buses			1	1	2	3	4	5	7
TEP Additions to Forecast									
Medium-Duty									
Heavy-Duty									
School Buses						66	66	66	66
Transit Buses				4	6	10	7	7	7
Average of Forecasts (Unit Sales)									
Medium-Duty			11	22	37	62	93	132	174
Heavy-Duty			4	9	20	38	60	85	117
School Buses			4	6	8	11	14	19	26
Transit Buses			1	1	2	3	6	9	11
DTEE Fleet Forecast (Annual Sales)									
Medium-Duty	-	-	-	-	**37**	**62**	**93**	**132**	**174**
Heavy-Duty	-	-	**1**	-	-	-	-	**4**	**9**
School Buses	**6**	-	-	-	**8**	**77**	**80**	**85**	**92**
Transit Buses	-	-	**12**	-	**8**	**13**	**13**	**16**	**18**
Cumulative DTEE Fcst									
Medium-Duty	**0**	-	-	-	**37**	**99**	**192**	**324**	**498**
Heavy-Duty	**0**	-	**1**	**1**	**1**	**1**	**1**	**5**	**14**
School Buses	**6**	**6**	**6**	**6**	**14**	**91**	**172**	**257**	**349**
Transit Buses	**0**	-	**12**	**12**	**20**	**34**	**47**	**63**	**81**

Exhibit MEIU-19 (LSS-19) is *Confidential* and Filed Under Seal

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-2.1a

Respondent: P. Bennett

Page: 1 of 1

Question: Electric Vehicle Issues

1. Company witness Bennett describes several instances where the Company proposes to provide rebates in disadvantaged communities ("DAC") as identified by the Michigan State Plan for EV Infrastructure Deployment.

a. Figure 17 in the Michigan State Plan for EV Infrastructure Deployment shows three (3) different types of DAC communities: MDOT EJ Priority, CEJST DAC, and MDOT EJ Priority and CEJST DAC. Which of these types of communities does the Company propose to use to determine rebate eligibility?

Answer: The Company is committed to supporting all the types of disadvantaged communities identified by the Michigan State Plan for EV Infrastructure Deployment. This includes MDOT EJ Priority, CEJST DAC, and MDOT EJ Priority and CEJST DAC communities. Our rebate program is designed to be inclusive and broad in its impact. Therefore, eligibility for rebates will not be limited to a single type of DAC community. Instead, we propose to determine rebate eligibility based on all three types of DAC communities identified in Figure 17 of the Michigan State Plan for EV Infrastructure Deployment.

Attachment: *None*

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-2.4a

Respondent: P. Bennett

Page: 1 of 1

Question: 4. According to Company witness Bennett, to qualify for a Business Charger Rebate, an MUD would have to demonstrate "tenant interest in installing EV chargers." (p. 45)

a. What does the Company expect to require for this demonstration?

Answer: To demonstrate tenant interest in installing EV chargers, an MUD could use one or more of the following:

- tenant surveys,
- signed letters of interest from tenants,
- pre-commitments from tenants,
- documents from past requests for EV charging, or
- data on the number of tenants with EVs.

Attachment: *None*

JUSTIN R. BARNES

(919) 825-3342, jbarnes@eq-research.com

EDUCATION

Michigan Technological University Houghton, Michigan
Master of Science, Environmental Policy, August 2006
Graduate-level work in Energy Policy.

University of Oklahoma Norman, Oklahoma
Bachelor of Science, Geography, December 2003
Area of concentration in Physical Geography.

RELEVANT EXPERIENCE

President, May 2023 – present
Director of Research, July 2015 – April 2023
Senior Analyst & Research Manager, March 2013 – July 2015
EQ Research, LLC Cary, North Carolina

- Oversee state legislative, regulatory policy, utility IRP and general rate case tracking services that covers policies such as net metering, interconnection standards, rate design, renewables portfolio standards, state energy planning, state and utility incentives, tax incentives, and permitting. Responsible for service design, formulating improvements based on client needs, and ultimate delivery of reports to clients. Expanded service to cover energy storage.
- Oversee and perform policy research and analysis to fulfill client requests, and for internal and published reports, focused primarily on drivers of distributed energy resource (DER) markets and policies.
- Provide expert witness testimony on topics including cost of service, rate design, distributed energy resource (DER) value, and DER policy including incentive program design, rate design issues, and competitive impacts of utility ownership of DERs.
- Managed the development of a solar power purchase agreement (PPA) toolkit for local governments, a comprehensive legal and policy resource for local governments interested in purchasing solar energy, and the planning and delivery of associated outreach efforts.

Senior Policy Analyst, January 2012 – May 2013;
Policy Analyst, September 2007 – December 2011
North Carolina Solar Center, N.C. State University Raleigh, North Carolina

- Responsible for researching and maintaining information for the Database of State Incentives for Renewables and Efficiency (DSIRE), the most comprehensive public source of renewables and energy efficiency incentives and policy data in the United States.
- Managed state-level regulatory tracking for private wind and solar companies.
- Coordinated the organization's participation in the SunShot Solar Outreach Partnership, a U.S. Department of Energy project to provide outreach and technical assistance for local governments to develop and transform local solar markets.
- Developed and presented educational workshops, reports, administered grant contracts and associated deliverables, provided support for the SunShot Initiative, and worked with diverse group of project partners on this effort.
- Responsible for maintaining the renewable portfolio standard dataset for the National Renewable Energy Laboratory for use in its electricity modeling and forecasting analysis.
- Authored the *DSIRE RPS Data Updates*, a monthly newsletter providing up-to-date data and historic compliance information on state RPS policies.

- Responded to information requests and provided technical assistance to the general public, government officials, media, and the energy industry on a wide range of subjects, including federal tax incentives, state property taxes, net metering, state renewable portfolios standard policies, and renewable energy credits.
- Extensive experience researching, understanding, and disseminating information on complex issues associated with utility regulation, policy best practices, and emerging issues.

SELECTED ARTICLES and PUBLICATIONS

- EQ Research and Synapse Energy Economics for Delaware Riverkeeper Network. *Envisioning Pennsylvania's Energy Future*. 2016.
- Barnes, J., R. Haynes. *The Great Guessing Game: How Much Net Metering Capacity is Left?*. September 2015. Published by EQ Research, LLC.
- Barnes, J., Kapla, K. *Solar Power Purchase Agreements (PPAs): A Toolkit for Local Governments*. July 2015. For the Interstate Renewable Energy Council, Inc. under the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *2013 RPS Legislation: Gauging the Impacts*. December 2013. Article in Solar Today.
- Barnes, J., C. Laurent, J. Uppal, C. Barnes, A. Heinemann. *Property Taxes and Solar PV: Policy, Practices, and Issues*. July 2013. For the U.S. DOE SunShot Solar Outreach Partnership.
- Kooles, K, J. Barnes. *Austin, Texas: What is the Value of Solar; Solar in Small Communities: Gaston County, North Carolina*; and *Solar in Small Communities: Columbia, Missouri*. 2013. Case Studies for the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *The Report of My Death Was An Exaggeration: Renewables Portfolio Standards Live On*. 2013. For Keyes, Fox & Wiedman.
- Barnes, J. *Why Tradable SRECs are Ruining Distributed Solar*. 2012. Guest Post in Greentech Media Solar.
- Barnes, J., multiple co-authors. *State Solar Incentives and Policy Trends*. Annually for five years, 2008-2012. For the Interstate Renewable Energy Council, Inc.
- Barnes, J. *Solar for Everyone?* 2012. Article in Solar Power World On-line.
- Barnes, J., L. Varnado. *Why Bother? Capturing the Value of Net Metering in Competitive Choice Markets*. 2011. American Solar Energy Society Conference Proceedings.
- Barnes, J. *SREC Markets: The Murky Side of Solar*. 2011. Article in State and Local Energy Report.
- Barnes, J., L. Varnado. *The Intersection of Net Metering and Retail Choice: an overview of policy, practice, and issues*. 2010. For the Interstate Renewable Energy Council, Inc.

TESTIMONY & OTHER REGULATORY ASSISTANCE

Indiana Utility Regulatory Commission. Cause No. 45990. March 2024. On behalf of the Citizen's Action Coalition of Indiana. Centerpoint Indiana South generation rate case application. Addressed: (a) numerous cost of service and cost allocation issues associated with production plant, transmission plant, coal ash disposal, MISO expenses, and service advertisement expenses; (b) cost-shifting caused by special contract customers and customers served under an industrial back-up service rate; and (c) the proper calculation of a residential customer charge based on customer-related costs.

West Virginia Public Service Commission. Case No. 23-0460-E-42T. November 2023. On behalf of the West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia. Monongahela Power and Potomac Edison general rate case application. Addressed issues that included the utilities' proposed elimination of net metering and related issues of subsidization, the methodology for setting monthly customer charges, demand limits within the small commercial rate schedules, piloting non-residential TOU rates, distribution cost allocation, the utilities' proposed distribution infrastructure investment program and long-term distribution planning, and support mechanisms for reducing energy burdens on low-income customers.

New Mexico Public Regulation Commission. Case No. 23-00071-UT. November 2023. On behalf of the Coalition for Community Solar Access. New Mexico community solar tariffs implementation proceeding. Addressed the methodology for quantifying any subsidy provided to community solar participants, the calculation of the community solar subsidy cap associated with the New Mexico's community solar law, the utilities' proposed administrative cost riders, and the utilities' proposed community solar eligibility restrictions.

Michigan Public Service Commission. Case No. U-21297. June 2023. On behalf of the Michigan Energy Innovation Business Council and The Institute for Energy Innovation. DTE Electric Company general rate case application. Sponsored a proposal for the establishment of time-varying rate options for non-residential customers.

North Carolina Utilities Commission. Docket Nos. E-34 Sub 54 and Sub 55. June 2023. On behalf of Appalachian Voices. New River Light and Power general rate case application. Analyzed the utility's proposal to establish NEM with a supplemental standby charge based on an evaluation of customer-sited solar costs and benefits and the utility's proposal for an increase in the residential fixed charge. Recommended the elimination of the DG standby charge based on corrections to NRLP's solar value analysis and a decrease in the residential fixed charge based on revised calculations of customer-related costs.

Georgia Public Service Commission. Docket No. 44280. Direct Testimony in October 2022 and Supplemental Testimony in November 2022. On behalf of Georgia Interfaith Power and Light. Georgia Power Company general rate case application. In Direct Testimony, provided a review and analysis of the cost allocation regime for coal combustion residual costs and provided recommended changes thereto; and evaluated the Company's proposals designed to shift residential customers to service under demand rate designs, including general analysis of the cost causation basis for demand rates and specific attributes and Company experience with its residential demand rate. In Supplemental Testimony, evaluated the Company's proposal to end its monthly netting DG tariff (i.e., NEM) and require mandatory demand rate service for future DG customers and recommended that NEM be retained without a mandatory demand rate requirement based on analysis demonstrating that doing so would not adversely affect non-DG customers.

Wisconsin Public Service Commission. Docket No. 5-UR-110. September 2022. On behalf of RENEW Wisconsin. Wisconsin Electric Power Company general rate case application. Provided an exhibit showing residential fixed charges among all major IOUs in the nation and testimony explaining the methodology used to develop the exhibit.

Wisconsin Public Service Commission. Docket No. 6690-UR-127. September 2022. On behalf of RENEW Wisconsin. Wisconsin Public Service Corporation general rate case application. Provided an exhibit showing residential fixed charges among all major IOUs in the nation and testimony explaining the methodology used to develop the exhibit.

Wisconsin Public Service Commission. 3270-UR-124. September 2022. On behalf of RENEW Wisconsin. Madison Gas and Electric general rate case application. Provided an exhibit showing residential fixed charges among all major IOUs in the nation and testimony explaining the methodology used to develop the exhibit. (*Note: Exhibit was introduced at the hearing and testimony on the methodology provided orally at the hearing; written testimony was not filed).*

Michigan Public Service Commission. Case No. U-20836. May 2022. On behalf of the Michigan Energy Innovation Business Council and The Institute for Energy Innovation. DTE Electric Company general rate case application. Addressed the utility's proposal for changes to its DG Tariff, including

excluding generation capacity value from the export rate and requiring DG customers to take service under a newly proposed residential demand rate. Also evaluated the cost causation and other rate attributes of the proposed residential demand rate.

Virginia State Corporation Commission. Docket No. PUR-2021-00171. January 2022. On behalf of Appalachian Voices. Old Dominion Power Company general rate case application. Evaluation of the cost basis for the residential customer charge, AMI deployment and the timeline for deployment of TOU rates, class allocation of distribution and production demand costs, and the Company's proposal for a DSM/EE pilot program and cost recovery rider.

Michigan Public Service Commission. Case No. U-20963. June 2021. On behalf of the Michigan Energy Innovation Business Council and the Institute for Energy Innovation. Consumers Energy Company general rate case. Provided an evaluation of the utility's proposed home battery program and offered recommendations for modifications to the program to improve its cost-effectiveness and delivery of benefits to participants and non-participants through changes to battery operational plans, elimination of restrictions on consumer use of the batteries, battery sizing modifications to fit actual customer needs, and use of solar-paired storage to provide greater resiliency.

Colorado Public Utilities Commission. Proceeding No. 20AL-0432E. March 2021. On behalf of the Colorado Solar and Storage Association and the Solar Energy Industries Association. Public Service Company of Colorado (Xcel Energy Colorado) general rate case. Provided analysis and recommendations on several non-residential rate design issues, including the utility's practice of switching small commercial customers to demand rates, relaxing the demand threshold at which commercial customers are subject to demand rates, the utility's proposal for modifying time-varying pricing windows, and the establishment of a pilot time-of-use rate for Secondary General (SG) commercial customers intended to remedy the misalignment between the SG non-coincident demand rate design and cost causation and set a foundation for a default time-varying rate option for SG class customers.

Kentucky Public Service Commission. Docket Nos. 2020-00349 and 2020-00350. March 2021 (Phase 1) and July/August 2021 (Phase 2). On behalf of the Kentucky Solar Energy Industries Association. Kentucky Utilities and Louisville Gas and Electric general rate case applications. Provided an analysis of the utilities' current tariffs governing purchases from qualifying facilities and recommended changes to align them with state regulations, recent precedent, and accepted methodologies of energy and capacity pricing.

South Carolina Public Service Commission. Docket Nos. 2020-264-E and 2020-265-E. February 2021. On behalf of the Solar Energy Industries Association and the North Carolina Sustainable Energy Association. Docket for establishing a Solar Choice tariff for customers of Duke Energy Carolinas and Duke Energy Progress. Provided testimony in support of a stipulated settlement discussing the critical role that a proposed smart thermostat rebate and enabling technologies more generally play in the successfully meeting the legislative objectives for Solar Choice tariffs.

South Carolina Public Service Commission. Docket No. 2020-229-E. January 2021. On behalf of the Solar Energy Industries Association and the North Carolina Sustainable Energy Association. Docket for establishing a Solar Choice tariff for customers of Dominion Energy South Carolina. Provided an analysis of the proposed Solar Choice tariff from the standpoint of NEM successor best practices, alignment with the enabling statute, and cost of service basis. Offered an alternative Solar Choice tariff proposal based on this analysis. Surrebuttal testimony provided an evaluation of solar customer cost of service correcting erroneous assumptions used by the Office of Regulatory Staff in its direct testimony.

Virginia State Corporation Commission. Docket No. PUR-2020-00134. January 2021. On behalf of the Behind the Meter Solar Alliance. Docket for Dominion Virginia's 2020 RPS Plan. Offered testimony

supporting the designation of small-scale resource carve-out eligibility being limited to behind the meter resources, based on the underlying Virginia statute and other public policy reasons.

South Carolina Public Service Commission. Docket No. 2019-182-E. October 2020. On behalf of the Solar Energy Industries Association and the North Carolina Sustainable Energy Association. Docket for establishing a cost-benefit analysis methodology and protocols for net metering and DERs. Provided discussion of historic regulatory use of DG cost-benefit and cost of service studies, how results should be viewed, and a discussion of the role of economic benefits and resiliency in DER cost-benefit analyses.

Kentucky Public Service Commission. Docket No. 2020-00174. October 2020. On behalf of the Kentucky Solar Industries Association. Kentucky Power general rate case. Provided an evaluation and critique of the cost of service support for, and design of, Kentucky Power's proposed net metering successor tariff and offered recommendations for developing cost-based DER rate designs. Also recommended changes to the utility's QF tariff and calculation of capacity costs.

New Jersey Board of Public Utilities. Docket No. EO18101111. September 2020. On behalf of Sunrun, Inc. Public Service Gas and Electric energy storage deployment plan proposal. Offered alternative proposal for a program utilizing non-utility owned energy storage assets under an aggregator model with elements for benefits sharing and ratepayer risk reduction.

Virginia State Corporation Commission. Docket No. PUR-2020-00015. July 2020. On behalf of Appalachian Voices. Appalachian Power Company general rate case. Analysis of the cost basis for the residential customer charge, the Company's winter declining block rate proposal, and a proposed Coal Asset Retirement Rider (Rider CAR) providing for advance collection of anticipated accelerated depreciation of coal generation assets. Provided an alternative residential customer charge recommendation and an alternative rates proposal for addressing winter bill volatility for electric heating customers.

North Carolina Utilities Commission. Docket No. E-2 Sub 1219. April 2020. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Progress general rate case. Provided analysis of available rate options for electric vehicle charging and recommended the adoption of residential and non-residential EV-specific rate options and appropriate design characteristics for those rate options.

North Carolina Utilities Commission. Docket No. E-7 Sub 1214. January 2020. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case. Provided analysis of available rate options for electric vehicle charging and recommended the adoption of residential and non-residential EV-specific rate options and appropriate design characteristics for those rate options.

Virginia State Corporation Commission. Docket No. PUR-2019-00060. November 2019. On behalf of Appalachian Voices. Old Dominion Power Company general rate case application. Analysis of the cost basis for the residential customer charge, proposal to change the residential customer charge from a monthly charge to a daily charge, and design of proposed customer green power program and utility owned commercial behind the meter solar proposal. Proposed modified optional rate structure for mid- to large-size non-residential customers with on-site solar and/or low load factors.

Georgia Public Service Commission. Docket No. 42516. October 2019. On behalf of Georgia Interfaith Power and Light, Southface Energy Institute, and Vote Solar. Georgia Power Company general rate case application. Analysis of the cost basis for the residential customer charge, the validity of the utility's minimum-intercept study, and a proposal to change the residential customer charge from a monthly charge to a daily charge.

Hawaii Public Utilities Commission. Docket No. 2018-0368. July 2019. On behalf of the Hawaii PV Coalition. Hawaii Electric Light Company (HELCO) general rate case application. Provided analysis of HELCO's proposed changes to its decoupling rider to make the decoupling charge non-bypassable and the alignment of the proposed modifications with state policy goals and the policy rationale for decoupling.

Virginia State Corporation Commission. Docket No. PUR-2019-00067. July 2019.* On behalf of the Southern Environmental Law Center. Appalachian Power Company residential electric vehicle (EV) rate proposal. Provided review and analysis of the proposal and developed comments discussing principles of time-of-use (TOU) rate design and proposing modifications to the Company's proposal to support greater equity among rural ratepayers and greater rate enrollment. ***This work involved comment preparation rather than testimony.**

New York Public Service Commission. Case No. 19-E-0065. May 2019. On behalf of The Alliance for Solar Choice. Consolidated Edison (ConEd) general rate case application. Provided review and analysis of the competitive impacts and alignment with state policy of ConEd's energy storage, distributed energy resource management system, and earnings adjustment mechanism (EAM) proposals. Proposed model for improving the utilization of customer-sited storage in existing demand response programs and an alternative EAM supportive of utilization of third party-owned battery storage.

South Carolina Public Service Commission. Docket No. 2018-318-E. March 2019. On behalf of Vote Solar. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

South Carolina Public Service Commission. Docket No. 2018-319-E. February 2019. On behalf of Vote Solar. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

New Orleans City Council. Docket No. UD-18-07. February 2019. On behalf of the Alliance for Affordable Energy. Entergy New Orleans general rate case application. Analysis of the cost basis for the residential customer charge, rate design for AMI, DSM and Grid Modernization Riders, and DSM program performance incentive proposal. Developed recommendations for the residential customer charge, rider rate design, and a revised DSM performance incentive mechanism.

New Hampshire Public Utilities Commission. Docket No. DE 17-189. May 2018. On behalf of Sunrun Inc. Review of Liberty Utilities application for approval of customer-sited battery storage program, analysis of time-of-use rate design, program cost-benefit analysis, cost-effectiveness of utility-owned vs. non-utility owned storage assets. Developed a proposal for an alternative program utilizing non-utility owned assets under an aggregator model with elements for benefits sharing and ratepayer risk reduction.

North Carolina Utilities Commission. Docket No. E-7 Sub 1146. January 2018. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

Ohio Public Utilities Commission. Docket No. 17-1263-EL-SSO. November 2017*. On behalf of the Ohio Environmental Council. ***Testimony prepared but not filed due to settlement in related case.**

Duke Energy Ohio proposal to reduce compensation to net metering customers. Provided analysis of capacity value of solar net metering resources in the PJM market and distribution of that value to customers. Also analyzed the cost basis of the utility proposal for recovery of net metering credit costs, focused on PJM settlement protocols and how the value of DG customer exports is distributed among ratepayers, load-serving entities, and distribution utilities based on load settlement practices.

North Carolina Utilities Commission, Docket No. E-2 Sub 1142. October 2017. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and advanced metering infrastructure deployment plans and cost-benefit analysis.

Public Utility Commission of Texas, Control No. 46831. June 2017. On behalf of the Energy Freedom Coalition of America. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate DG rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits, and alignment of demand ratchets with cost causation principles and state policy goals, focused on impacts on customer-sited storage.

Utah Public Service Commission, Docket No. 14-035-114. June 2017. On behalf of Utah Clean Energy. Rocky Mountain Power application for separate distributed generation (DG) rate class. Provided analysis of grandfathering of existing DG customers and best practices for review of DG customer rates and DG value. Developed proposal for addressing revisions to DG customer rates in the future.

Colorado Public Utilities Commission, Proceeding No. 16A-0055E. May 2016. On behalf of the Energy Freedom Coalition of America. Public Service Company of Colorado application for solar energy purchase program. Analysis of program design from the perspective of customer demand and needs, and potential competitive impacts. Proposed alternative program design.

Public Utility Commission of Texas, Control No. 44941. December 2015. On behalf of Sunrun, Inc. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits.

Oklahoma Corporation Commission, Cause No. PUD 201500274. November 2015. On behalf of the Alliance for Solar Choice. Analysis of Oklahoma Gas & Electric proposal to place distributed generation customers on separate rates, rate impacts, cost basis of proposal, and alignment with rate design principles.

South Carolina Public Service Commission, Docket No. 2015-54-E. May 2015. On behalf of The Alliance for Solar Choice. South Carolina Electric & Gas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-53-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Carolinas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-55-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Progress application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2014-246-E. December 2014. On behalf of The Alliance for Solar Choice. Generic investigation of distributed energy policy. Distributed energy best practices, including net metering and rate design for distributed energy customers.

AWARDS, HONORS & AFFILIATIONS

- Solar Power World Magazine, Editorial Advisory Board Member (October 2011 – March 2013)
- Michigan Tech Finalist for the Midwest Association of Graduate Schools Distinguished Masters Thesis Awards (2007)
- Sustainable Futures Institute Graduate Scholar Michigan Tech University (2005-2006)

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-1.20a

Respondent: A. Willis

Page: 1 of 1

Question: 20. Please refer to Willis Direct at pp. 31-32 proposing a participation cap of 1,000 customers for proposed rate D3.11.

a. Is the stated cap intended to be permanent? Please explain in detail.

Answer: Please refer to the testimony of Company Willis Witness at pp 31-32, which characterizes the 1,000-customer limit as a starting point. In full, “In addition, the proposed tariff caps enrollment on the rate at 1,000 customers to account for potential unanticipated usage patterns on the rate – this is consistent with the Commission approval of Rate Schedule D1.13, a residential, voluntary time of use rate, in Case No. U-21297. The Commission approved a cap of 10,000 customers, or ~0.5% of the Company’s approximately 2 million residential customers in that case. Considering the same 0.5% percentage and the ~200k commercial secondary customers forecasted in this case suggests 1,000 customers as an appropriate starting point.”

Attachment: *None*

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-1.19a

Respondent: A. Willis

Page: 1 of 1

Question: 19. Please refer to Willis Direct at p. 43, proposing a participation cap of 50 MW of contract capacity for proposed rate D14.

a. Is the stated cap intended to be permanent? Please explain in detail.

Answer: It is intended to remain in place “until such time that D14 is supported by its own cost of service class” (Willis p. 43), at which point the Company would reevaluate the cap.

Attachment: *None.*

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-1.18a

Respondent: P. Sharma

Page: 1 of 1

Question: 18. Please refer to the Direct Testimony of Aaron Willis ("Willis Direct") at p. 34 and p. 44 stating that the proposed D3.11 and D14 rate schedules will be made available no later than December 31, 2025.

a. What is the earliest date that the Company believes it could make these new rates available?

Answer: The Company objects for the reasons that the request calls for speculation and is incapable of answering in its present form. Subject to and without waiving its objection, the Company would respond as follows: The Company can't project the date when the new rates will be available. Scope for this work must be processed through the IT organizations Annual Planning Cycle (APC). Once this is completed through the APC project approval process, the requirements will be gathered, and a project implementation schedule can be provided.

Please refer to Sharma's testimony Page 6 -9 for details on the IT APC process.

Attachment: None

Co-respondent: A. Willis, Legal

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-1.18e

Respondent: P. Sharma

Page: 1 of 1

Question: 18. Please refer to the Direct Testimony of Aaron Willis ("Willis Direct") at p. 34 and p. 44 stating that the proposed D3.11 and D14 rate schedules will be made available no later than December 31, 2025.

e. Please explain with specificity what remains to be "developed" with regard to the D3.11 and D14 rate schedules.

Answer: The Company objects for the reasons that the request calls for speculation and is incapable of answering in its present form. Subject to and without waiving its objection, the Company would respond as follows: Scope for this work must be processed through the IT organizations Annual Planning Cycle (APC). Once this is completed through the APC project approval process, the requirements will be gathered and the requested information can be provided.

Please refer to Sharma's testimony Page 6 -9 for details on the IT APC process.

Attachment: None.

Co-respondent: A. Willis, Legal

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-1.18f

Respondent: P. Sharma

Page: 1 of 1

Question: 18. Please refer to the Direct Testimony of Aaron Willis ("Willis Direct") at p. 34 and p. 44 stating that the proposed D3.11 and D14 rate schedules will be made available no later than December 31, 2025.

f. Please identify and explain all of the individual steps involved with testing the proposed D3.11 and D14 rates in the Company's billing system.

Answer: The Company objects for the reasons that the request calls for speculation and is incapable of answering in its present form. Subject to and without waiving its objection, the Company would respond as follows: Scope for this work must be processed through the IT organizations Annual Planning Cycle (APC), Once this is completed through the APC project approval process, the requirements will be gathered and the requested information can be provided.

Please refer to Sharma's testimony Page 6 -9 for details on the IT APC process.

Attachment: None.

Co-respondent: A. Willis, Legal

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-1.18b

Respondent: A. Willis

Page: 1 of 1

Question: 18. Please refer to the Direct Testimony of Aaron Willis ("Willis Direct") at p. 34 and p. 44 stating that the proposed D3.11 and D14 rate schedules will be made available no later than December 31, 2025.

b. Please explain with specificity why it would take the Company approximately 1 year from the date of a Commission decision to implement the proposed new rates.

Answer: The referenced testimony says the "Company intends to have the rate available for customers no later than the end of the projected test year in the instant case". This is the same language proposed and approved for Rate Schedule D1.13 in Case No. U-21297. Further refer to MEIUDE-1.18a.

Attachment: None

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-1.18d

Respondent: P. Sharma

Page: 1 of 1

Question: 18. Please refer to the Direct Testimony of Aaron Willis ("Willis Direct") at p. 34 and p. 44 stating that the proposed D3.11 and D14 rate schedules will be made available no later than December 31, 2025.

d. Please identify and explain any aspects of the implementation of the proposed D3.11 and D14 rate schedules that are more complex and would take longer to accomplish than the implementation of the ACPP rates.

Answer: The Company objects for the reasons that the request calls for speculation and is incapable of answering in its present form. Subject to and without waiving its objection, the Company would respond as follows: The Company can't compare this project implementation with the implementation of ACPP rates. Scope for this work must be processed through the IT organizations Annual Planning Cycle (APC). Once this is completed through the APC project approval process, the requirements will be gathered, and a project implementation schedule can be provided.

Please refer to Sharma's testimony Page 6 -9 for details on the IT APC process.

Attachment: None.

Co-respondent: A. Willis, Legal

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-1.27a

Respondent: M. Hatsios

Page: 1 of 1

Question: 27. Please see the Company's electric tariff at Section C4.4 - Choice of Rates, which states in relevant part "If requested, the Company will advise the customer in the selection of the rate which will give him the lowest cost of service, based on the information at hand, but the responsibility for the selection of the rate lies with the customer."

a. Please describe in general a typical interaction between the customer and a Company representative when a customer requests such service.

Answer: Customer Representatives (CRs) are trained to walk customers through an analysis of their account, including month-over-month and year-over-year comparisons, and communicate the rate the customer is currently enrolled in. The CR will then utilize the Bill Analyzer and Bill Simulator tools to provide insight into factors that affect a customer's bill and to simulate the impact of a new rate.

The CR will also encourage customers to use the DTE Insight App, to monitor their monthly use in greater detail, set budgets, and get personalized tips for lowering energy usage and ultimately their bill, access their energy usage online, and to take the "New to Energy Savings' quiz where they will get personalized tips to save money & energy.

Attachment: *none*

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-3.3b

Respondent: M. Hatsios

Page: 1 of 1

Question: Please refer to the Company's response to MEIUDE-1.27a describing the interaction between a customer and a customer service representative when they seek DTE's advisement on selecting a rate, which states in part "The CR will then utilize the Bill Analyzer and Bill Simulator tools to provide insight into factors that affect a customer's bill and to simulate the impact of a new rate." Please also refer to the Company's response to MEIUDE-1.27c stating "The Company does not provide customers a rate comparison report. CRs are trained to inform customers that they can complete this comparison on their own at dteenergy.com."

b. Is the Bill Simulator tool capable of modeling non-residential rate schedules? Please identify the rate schedules, if any, that cannot be modeled in the Bill Simulator tool.

Answer: No, the Bill Simulator Tool cannot model non-residential rates at this time. The rates that are not modeled in the Tool are all the non-residential rates.

Attachment: None.

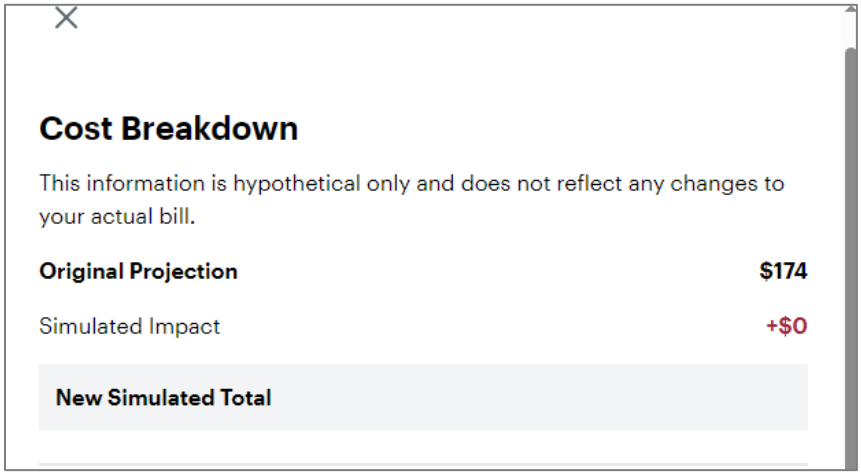
MPSC Case No: U-21534
Requester: MEIU
Question No.: MEIUDE-3.3a
Respondent: M. Hatsios
Page: 1 of 2

Question: Please refer to the Company's response to MEIUDE-1.27a describing the interaction between a customer and a customer service representative when they seek DTE's advisement on selecting a rate, which states in part "The CR will then utilize the Bill Analyzer and Bill Simulator tools to provide insight into factors that affect a customer's bill and to simulate the impact of a new rate." Please also refer to the Company's response to MEIUDE-1.27c stating "The Company does not provide customers a rate comparison report. CRs are trained to inform customers that they can complete this comparison on their own at dteenergy.com."

a. Please provide a visual representation of the output produced by the Bill Simulator tool when conducting an annual forecast calculation, such as a screenshot of how the results are portrayed.

Answer: Below are the results (in screen prints) that the customer service representatives (CRs) and customers would see when using the Bill Simulator Tool to model a one-month and 12-month view.

Artifact to see the results for one month:



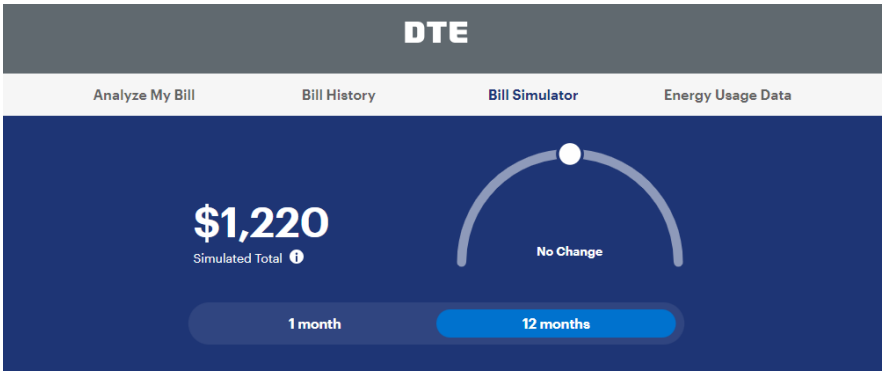
Requester: MEIU

Question No.: MEIUDE-3.3a

Respondent: M. Hatsios

Page: 2 of 2

Artifact to see the results for 12 months:



Attachment: None.

BILLING DETERMINANTS						
Rate Schedule	TOU (D3.11 and D4.1)		D3 General Service	D4 Large General Service		
Billing Month	On-Peak Energy (kWh)	Off-Peak Energy (kWh)	Total Energy (kWh)	Billed Demand (kW)	1st 200 kWh/ kW Billed Demand (kWh)	Excess Energy (kWh)
January						
February						
March						
April						
May						
June						
July						
August						
September						
October						
November						
December						
ANNUAL						

BILLING RATES ($/kW or $/kWh as applicable)						
Power Supply						
Distribution						
PSCR						
Surcharges						
TOTAL ENERGY						
TOTAL DEMAND						

MONTHLY AND ANNUAL BILL RESULTS								
Rate Schedule	D3		D3.11		D4.1		D4	
Billing Month	Power Supply ($)	Distribution ($)	Power Supply ($)	Distribution ($)	Power Supply ($)	Distribution ($)	Power Supply ($)	Distribution ($)
January								
February								
March								
April								
May								
June								
July								
August								
September								
October								
November								
December								
ANNUAL								
TOTAL BASE								
PSCR (Annual)								
Surchages (Annual								
GRAND TOTAL								
Average Rate ($/kWh)								

MPSC Case No.	**U-21534**
Responding Party:	Attorney General
Respondent:	Sebastian Coppola
Requestor:	EVgo
Question No.:	**EVgo-AG-1**

EVgo-AG 1.01.

Refer to footnote 16 in Mr. Coppola's testimony, which refers to "recent articles in the Wall Street Journal, the Detroit News, and other publications." Please provide copies of each of the articles referenced in footnote 16, and/or provide accessible links to each of those articles.

Response:
Below are links to a set of articles and attached are copies of those articles.

https://www.wsj.com/business/earnings/general-motors-gm-q2-earnings-report-2024-f8dcdd49?mod=Searchresults_pos3&page=1

https://www.wsj.com/business/earnings/tesla-tsla-q2-earnings-report-2024-3e849b36?mod=Searchresults_pos6&page=1

https://www.wsj.com/business/autos/ev-electric-vehicle-slowdown-ford-gm-tesla-b20a748e?mod=article_inline

https://www.detroitnews.com/story/business/autos/2024/04/23/teslas-first-quarter-net-income-tumbles-on-lower-sales-price-cuts/73430223007/

https://www.detroitnews.com/story/business/autos/2024/04/18/europe-car-sales-drop-in-march-as-ev-weakness-persists/73371516007/

https://www.detroitnews.com/story/business/autos/2024/04/19/the-ev-bust-in-europe-is-a-red-flag-for-regions-climate-goals/73384477007/

https://www.npr.org/2024/02/07/1227707306/ev-electric-vehicles-sales-2024

Date: 8/12/24

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-4.1a

Respondent: A. Willis

Page: 1 of 1

Question: Please refer to the Rebuttal Testimony of Aaron Willis ("Willis Rebuttal") at p. 19 lines 11-13 stating, "An on-peak window beginning at 1:00 pm certainly presents the possibility of customer's shifting load to before the period and in doing so inadvertently create a new system peak hour in the noon – 1:00 pm hour."

a. Please admit that Witness Willis did not conduct any quantitative analysis of the actual potential for load shifting by Schedule D14 customers under a 1-5 PM on- peak window. If your response is anything other than an unqualified admission that Witness Willis did not conduct such an analysis, please provide that analysis and all associated workpapers in executable spreadsheet format with all formulas and file linkages intact.

Answer: I did not conduct such a quantitative analysis.

Attachment: *None*

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-4.1b

Respondent: A. Willis

Page: 1 of 1

Question: Please refer to the Rebuttal Testimony of Aaron Willis ("Willis Rebuttal") at p. 19 lines 11-13 stating, "An on-peak window beginning at 1:00 pm certainly presents the possibility of customer's shifting load to before the period and in doing so inadvertently create a new system peak hour in the noon – 1:00 pm hour."

b. Please explain in detail why a shift in DTE's system peak during one or more months to the hour from noon – 1 PM would have detrimental impacts on DTE's system and customers.

Answer: A mistimed TOU on-peak window which reset the system peak to something higher than what it would otherwise be, regardless of the hour of the new system peak, runs counter to the concept of managing peak loads. All else equal, it would require the Company to support incremental demand, which, all else equal, has an incremental cost.

Attachment: *None*

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-4.2a

Respondent: A. Willis

Page: 1 of 1

Question: Please refer to Willis Rebuttal at pp. 21-22 discussing the deployment of a primary voltage time-of-use ("TOU") rate by Consumers Energy ("CE") and the enrollment caps that were formerly in place for CE's Schedule GPTU.

a. Does Witness Willis dispute Mr. Barnes' assertion that the enrollment limitations on CE's Schedule GPTU were eliminated in their entirety prior to CE being able to conduct a cost of service evaluation of Schedule GPTU customers as a separate class? If your response is that Witness Willis does dispute Mr. Barnes' assertion, please provide specific evidence that his assertion is incorrect.

Answer: No.

Attachment: *None*

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-4.3a

Respondent: A. Willis

Page: 1 of 1

Question: Please refer to Willis Rebuttal at p. 18 lines 7-12 stating, "To the extent an existing D4 customer could benefit by switching to the Company's proposed D3.11, they would be able to do so. Moreover, if the customer exceeds 50 kW of demand, they may also be able to leverage the Company's proposed primary TOU rate D14, which has an even lower average power supply rate (by 13% compared to D4 and based on the better D11 load factor) and a lower distribution demand charge."

a. Please admit that a Schedule D4 customer with a demand of greater than 50 kW would be eligible to switch to Schedule D14 only if they also modified their delivery voltage to take service at primary voltage. If your response is anything other than an unqualified admission, please explain in detail why this is not the case.

Answer: Deny. While some customers may require a change to their delivery voltage, the Company currently serves approximately 250 customers at a primary voltage but who have elected to be billed on D4.

Attachment: *None*

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-4.3b

Respondent: S. Deol

Page: 1 of 1

Question: Please refer to Willis Rebuttal at p. 18 lines 7-12 stating, "To the extent an existing D4 customer could benefit by switching to the Company's proposed D3.11, they would be able to do so. Moreover, if the customer exceeds 50 kW of demand, they may also be able to leverage the Company's proposed primary TOU rate D14, which has an even lower average power supply rate (by 13% compared to D4 and based on the better D11 load factor) and a lower distribution demand charge."

b. Please provide an estimate of the costs that a customer desiring to upgrade their service from secondary voltage to primary voltage would need to incur.

Answer: The cost of upgrading from a secondary to primary service will depend on a variety of factors specific to the customer, including, for example, whether the service is OH or UG and distance to the primary.

Attachment: *None*

Co-respondent: A. Willis

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-4.4a

Respondent: A. Willis

Page: 1 of 1

Question: Please refer to Willis Rebuttal at p. 21 lines 9-11 stating, "Given the seven years it apparently took for 0.84% of CE's commercial secondary customers to enroll on their TOU rate, it does not seem likely that there will be any near-term concerns related to enrollment limitations on D3.11.

a. Please provide Witness Willis's analysis of enrollment on CE's commercial secondary TOU rate by year demonstrating when enrollment reached the threshold of 0.50% of total secondary commercial customers. If Witness Willis did not conduct such a review and analysis, please so state.

Answer: The Company objects to the question as written as the Company did not offer any claim with respect to an "analysis of enrollment on CE's commercial secondary TOU rate by year demonstrating when enrollment reached the threshold of 0.50% of total secondary commercial customers". Subect to and without waiving its objection, the Company would respond as follows:

The Company did not conduct any such analysis.

Attachment: *None*

Co-respondent: Legal

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-4.5a

Respondent: P. Bennett

Page: 1 of 1

Question: Responding to a proposal to increase the income-threshold to 300% or 400% of the federal poverty level for residential customer rebates, according to witness Bennett (p. 18), “During the stakeholder engagement phase of the TEP development, the Company received feedback from some stakeholders that this was too high.”

a. How many stakeholders gave this feedback?

Answer: The feedback was received orally during stakeholder discussions. At least one stakeholder gave this feedback, with not much apparent opposition from the rest of the participants.

Attachment: *None*

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-4.5b

Respondent: P. Bennett

Page: 1 of 1

Question: Responding to a proposal to increase the income-threshold to 300% or 400% of the federal poverty level for residential customer rebates, according to witness Bennett (p. 18), “During the stakeholder engagement phase of the TEP development, the Company received feedback from some stakeholders that this was too high.”

b. Was this feedback captured in a survey question or in discussion at a stakeholder meeting?

Answer: Feedback was captured in discussions at the stakeholder meetings. While the Company proposes to ensure uniformity in how income thresholds are treated across DTE programs, it is open to revisiting this decision with the next stakeholder meeting discussion, using the latest data from the current EV Income Rebates pilot.

Attachment: None

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-4.5ci

Respondent: P. Bennett

Page: 1 of 1

Question: Responding to a proposal to increase the income-threshold to 300% or 400% of the federal poverty level for residential customer rebates, according to witness Bennett (p. 18), “During the stakeholder engagement phase of the TEP development, the Company received feedback from some stakeholders that this was too high.”

c. Did the Company survey all stakeholders to determine the appropriate income- threshold?

i. If so, what income threshold options were presented to stakeholders?

Answer: No, the Company did not survey all stakeholders regarding income-threshold levels.

Attachment: *None*

MPSC Case No: U-21534

Requester: MEIUA

Question No.: MEIUDE-4.6a

Respondent: P. Bennett

Page: 1 of 1

Question: According to witness Bennett (p. 19), self-attestation of income could lead to fraud.

a. Please provide all evidence (including reports, data from other programs, etc.) to support this statement.

Answer: Without attributing a specific motive, the Company's experience is that forty-two percent (42%) of the people who have previously applied for the EV Rebate, which is income-qualified, were determined not to be eligible for the rebate, which indicates a need for proper program administration.

Attachment: None

MPSC Case No: U-21534

Requester: MEIU

Question No.: MEIUDE-4.6b

Respondent: P. Bennett

Page: 1 of 1

Question: According to witness Bennett (p. 19), self-attestation of income could lead to fraud.

b. Has the Company observed any such fraud in already existing programs?

Answer: Please see response to MEIUDE-4.6a.

Attachment: *None*

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the Application of **DTE ELECTRIC COMPANY** authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	))))))	**Case No. U-21534**

PROOF OF SERVICE

STATE OF SOUTH CAROLINA)
) ss.
COUNTY OF BERKELEY)

Summer R. Dukes, the undersigned, being first duly sworn, deposes and says that she is a Paralegal at Potomac Law Group PLLC and that on the 20th day of September, 2024 she served the Official Exhibit List and Exhibits 9-33 of the Michigan Energy Innovation Business Council, the Institute for Energy Innovation and Advanced Energy United, via email, upon those individuals listed on the attached Service List.

Summer Dukes

Digitally signed by Summer Dukes
Date: 2024.09.20 12:49:34 -04'00'

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