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

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PROFESSIONAL EXPERIENCE:

April 2019 – present **Michigan EIBC/IEI**, Lansing, MI **President**

- Organize and lead a staff of five employees, contractors, and student interns.
- Work with and inform each organization's Board of key decisions, upcoming events, long-term strategy, etc.
- Fundraise and coordinate both organization's annual budgets.
- Represent Michigan EIBC in the media, at the legislature, with regulators, and with the state administration in collaboration with a broad coalition.
- Conduct event planning including for annual conferences, networking events, tours, and legislative networking opportunities.
- Develop regulatory and legislative policy positions to support advanced energy businesses.
- Engage with the Michigan Public Service Commission and Michigan legislature on behalf of member companies.

Oct. 2017-March 2019 **Michigan EIBC/IEI**, Lansing, MI **VP for Policy Development**

- Develop regulatory and legislative policy positions to support advanced energy businesses.
- Coordinate regulatory interventions and engagement in regulatory stakeholder processes among member companies.
- Engage with the Michigan Public Service Commission and Michigan legislature on behalf of member companies.
- Support policy initiatives focused on wind energy, solar energy, electric vehicles, storage, taxation, and corporate purchasing of renewable energy.
- Represent Michigan EIBC in the media, at the legislature, with regulators, and with the state administration in collaboration with a broad coalition.
- Conduct event planning including for annual conferences, networking events, tours, and legislative networking opportunities.

Feb. 2017-March 2019 **5 Lakes Energy**, Lansing, MI **Senior Consultant**

- Research, analysis, communication, and advocacy surrounding complex energy issues.
- Lead wind and solar siting project to address opposition to deployment in coordination with philanthropy, industry, and stakeholders across nine Midwest states.
- Focus areas include renewable energy development, community engagement, stakeholder coordination, business sustainability, and electric vehicles.
- Support newsletter, website, and social media communications.

April 2015-Dec. 2016 **U.S. Senate**, Washington, DC **Legislative Assistant/Policy Advisor**

- Policy advisor to Senator Michael Bennet (D-CO) on agriculture, energy, environment, land, and natural resource issues.
- Legislative topics included: farming and ranching, public land conservation and management, water policy, energy development, renewable energy including energy tax incentives and transmission permitting, energy efficiency, endangered species, climate change, sportsmen's issues, environmental pollution and regulations, air quality, and biofuels.

- Drafting legislation; building coalitions; negotiating policy solutions; writing speeches; staffing the Senator at hearings of the Agriculture and Finance Committees.

2014-2015 **U.S. Senate**, Washington, DC **AAAS Congressional Science Fellow**

- Competitively selected AAAS Fellow sponsored by the American Geophysical Union. Served in the Office of Senator Michael Bennet (D-CO).
- Drafting legislation; helping to facilitate political coalitions; meeting with constituents; interacting with federal agencies; delivering policy briefings and recommendations.

2012-2014 **University of Michigan**, Ann Arbor, MI **Postdoctoral Research Fellow**

- Successfully obtained competitive grant funding for novel method to track air pollution from power plants and metal smelters into rainfall across the Great Lakes region.
- In collaboration with epidemiologists, developed and utilized new methods to assess the sources and pathways of human exposure to mercury pollution.
- Published five manuscripts; presented talks and organized scientific sessions at national and international conferences.

2007-2012 **University of Michigan**, Ann Arbor, MI **Graduate Researcher**

- Competed for and received National Defense Science and Engineering Graduate Fellowship and Graham Environmental Sustainability Institute Doctoral Fellowship.
- Developed groundbreaking methods to "fingerprint" mercury pollution from coal-fired power plants and trace it into rainfall, lake sediments, and fish.
- Published eight manuscripts, was interviewed for "The Environment Report" on NPR and general-circulation science magazines, presented research at national and international conferences.
- Ph.D. dissertation received university-wide ProQuest Distinguished Dissertation Award and departmental John Dorr Graduate Academic Achievement Award.

2005-2007 **Massachusetts Institute of Technology**, Boston, MA **Research Scientist**

- Found evidence for early life on Earth in ancient rocks. Published two manuscripts.

SERVICE & LEADERSHIP:

2021-present **Board Member** of Zero Emission Transportation Association Education Fund Board
2020-present **Board Member** of University of Michigan Earth and Environmental Sciences Alumni Board
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2017-2019 **Communications Chair** for Advancing Women in Energy
2013-2014 **Supported** the Ann Arbor Energy Commission on community solar projects
2009-2014 **Peer reviewer** of more than 20 scientific manuscripts
2009 **Initiator and organizer** of new departmental seminar series, University of Michigan
2008-2010 **President** of department student organization (GeoClub), University of Michigan
2008 **Lead organizer** of Michigan Geophysical Union Poster Conference
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ALJ/JSW/ar9/jt2 **Date of Issuance 2/4/2016**

Decision 16-01-045 January 28, 2016

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of SAN DIEGO GAS & ELECTRIC COMPANY (U902E) for Approval of its Electric Vehicle-Grid Integration Pilot Program.	Application 14-04-014 (Filed April 11, 2014)
And Related Matter.	Rulemaking 13-11-007

(See Attachment 3 for Service List)

DECISION REGARDING UNDERLYING VEHICLE GRID INTEGRATION APPLICATION AND MOTION TO ADOPT SETTLEMENT AGREEMENT

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DECISION REGARDING UNDERLYING VEHICLE GRID INTEGRATION APPLICATION AND MOTION TO ADOPT SETTLEMENT AGREEMENT

Summary

Today's decision addresses the vehicle-grid integration (VGI) proposal of San Diego Gas & Electric Company (SDG&E).[1] SDG&E's VGI proposal seeks authorization to establish and implement a pilot program to integrate the charging of plug-in electric vehicles (PEVs) with the electric grid through the use of an hourly time-variant rate. This rate would incentivize electric vehicle (EV) owners in SDG&E's service territory to use energy during non-peak periods to charge their EVs, and to maximize the use of the energy generated from renewable sources of energy during the time of day when these resources are at peak production, which are usually at non-peak periods of energy demand. Under the VGI proposal, SDG&E would deploy up to 550 EV site installations, and up to 5,500 EV charging stations, over a sign-up period of five years. These site installations and charging stations would be available for placement at site hosts, in return for an easement.

SDG&E originally sought authorization and approval of its VGI proposal in its application that it filed in April 2014. SDG&E filed its application in response to the goals and objectives set forth by Governor Brown and the California Legislature regarding the following: reduction of greenhouse gas emissions; increasing the amount of energy produced from renewable sources of energy; and increasing the amount of EV charging infrastructure to support one million PEVs by 2020.

[1] The abbreviations used in this decision are set forth in Attachment 1.

After the evidentiary hearings concluded, SDG&E and 16 other parties entered into a settlement (Proposed Settlement). The Proposed Settlement is based on SDG&E's VGI proposal, with a number of modifications agreed to by the settling parties. The cost of SDG&E's original VGI proposal, and the cost of the VGI proposal as modified by the Proposed Settlement are the same, about $103 million. Approximately $65 million of this cost is anticipated to be incurred during the sign-up and installation period and authorized up front. The remainder of the cost recovery, the long term operations and maintenance expenditures, would be sought by SDG&E in future general rate case proceedings.

In today's decision, we deny the motion of the settling parties to adopt the Proposed Settlement, and also reject SDG&E's original VGI proposal. One of the primary reasons for rejecting SDG&E's original VGI proposal and the Proposed Settlement is due to their cost and size.

As provided for in Rule 12.4(c) of the Commission's Rules of Practice and Procedure, we propose the alternative VGI program terms that are set forth in Attachment 2 of this decision and described in today's decision. These alternative terms, if accepted by SDG&E, would allow SDG&E to proceed with this alternative, which we refer to as the 2016 VGI Pilot Program. The 2016 VGI Pilot Program is essentially a scaled down version of SDG&E's VGI proposal, as modified by the Proposed Settlement, with the additional modifications made in today's decision. The 2016 VGI Pilot Program will have a budget of $45 million during the initial roll-out instead of $65 million, and will allow SDG&E to deploy and own approximately 350 EV site installations, corresponding to approximately 3,500 EV charging stations, during a sign-up period of approximately three years. Long term operations and maintenance costs shall be

tracked in a separate memorandum account, and offset by participation payments. SDG&E is authorized to seek cost recovery for its future operations and maintenance expenditures in its future general rate case proceedings. These alternative VGI program terms are based on our review of all of the evidence that was presented in the evidentiary hearings, the Proposed Settlement, the various pleadings of the parties, including the comments on the proposed decision, and a careful weighing and balancing of all the considerations set forth in the Governor's Executive Order and in various statutes.

If SDG&E accepts the alternative VGI program terms, we estimate that a typical residential ratepayer of SDG&E using 500 kilowatt hours per month in the inland and coastal zones would experience an increase of about 18 cents over the first year, or about a 0.02% increase. With the full rollout of 350 site installations and 3,500 charging stations at the end of the pilot period, the increase relative to current rates would be about $2.75 on an annual basis.

If SDG&E decides to accept the alternative VGI program terms and implements the 2016 VGI Pilot Program, all of the construction and installation of the EV charging infrastructure will be performed safely by licensed electrical contractors with EV infrastructure training certification, and will meet all applicable code requirements.

1. Procedural Background

San Diego Gas & Electric Company (SDG&E) filed Application (A.) 14-04-014 on April 11, 2014. SDG&E's application seeks authorization to establish and implement a pilot program to integrate the charging of plug-in electric vehicles (PEVs) with the electric grid through the use of an hourly

time-variant rate and a PEV charging infrastructure.[2] SDG&E refers to this as its vehicle-grid integration (VGI) pilot program.[3]

Prior to the filing of SDG&E's application, the Commission opened Order Instituting Rulemaking ("Rulemaking" or "R.") 13-11-007 in November 2013.[4] The Rulemaking was opened to address issues relating to expanding the use of alternative-fueled vehicles (AFV) in California. R.13-11-007 referenced that the Rulemaking would continue the work that was started in R.09-08-009 to support Governor Brown's Executive Order B-16-2012, which set a target of creating infrastructure to support up to one million zero-emission vehicles (ZEVs) by 2020, and to have 1.5 million ZEVs on California's roads by 2025. In addition, R.13-11-007 referenced the Governor's February 2013 "ZEV Action Plan," which describes how state agencies can support the ZEV target.

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[2] As used in this decision, a PEV refers to both a pure battery electric vehicle that plugs in to charge, and a plug-in hybrid electric vehicle that is powered by a combination of a gasoline engine and batteries.

[3] We refer to this as the "VGI pilot program" or the "VGI program." We also refer to the "VGI program" to mean SDG&E's VGI program concept as set forth in SDG&E's application and as modified in the settlement that the settling parties reached.

[4] An earlier Rulemaking was opened in R.09-08-009 to address the impacts that electric vehicles (EVs) may have on the electric infrastructure, and the actions the Commission should take. R.09-08-009 considered the tariffs, infrastructure, and policies needed to prepare for the deployment of electric vehicles, while recognizing the benefits that such vehicles could have in achieving California's climate change goals. Three decisions were issued in R.09-08-009. In Decision (D.) 10-07-044, the Commission considered the regulatory authority over entities that sell electric vehicle charging services to the public. In D.11-07-029, the Commission adopted steps to overcome the barriers to the deployment of electric vehicles. D.11-07-029 also adopted a prohibition on utility ownership of electric vehicle service equipment (EVSE) except for charging infrastructure for the utilities' own fleets or workplaces. This prohibition was subsequently overturned in D.14-12-079. Then in D.13-11-002, the Commission modified the requirements for the development of a PEV submetering protocol by adopting a roadmap for a two-phase pilot project.

The first prehearing conference (PHC) in A.14-04-014 was held on August 13, 2014. Due to common issues and related questions of fact, SDG&E's A.14-04-014 was consolidated with R.13-11-007 on September 29, 2014 in the scoping memo and consolidation ruling (scoping memo). The scoping memo recognized that a decision would soon be issued in R.13-11-007 concerning utility infrastructure ownership. That scoping memo adopted a procedural schedule that called for evidentiary hearings to begin during the week of April 6, 2015.

On December 18, 2014, the Commission adopted D.14-12-079 in these consolidated proceedings, which adopted rules to expand the utilities' role in the development and ownership of EV infrastructure by using a case-specific approach. D.14-12-079 also set aside the prohibition adopted in D.11-07-029 that electric utilities could not own EV charging infrastructure.

Following the issuance of D.14-12-079, a second PHC was noticed for, and held on January 21, 2015. The purpose of the second PHC was to discuss the effect of D.14-12-019 on the schedule adopted in the scoping memo, and SDG&E's intention to serve supplemental testimony.

On February 2, 2015, a ruling was issued that adopted a revised procedural schedule. In addition to revising the dates for service of the intervenor testimony, and the SDG&E rebuttal testimony, the evidentiary hearings were scheduled for the week of April 27, 2015.[5]

[5] A March 5, 2015 ruling allowed all of the parties to serve rebuttal testimony on April 13, 2015, and in an April 7. 2015 ruling an additional day of hearing was added.

Six days of evidentiary hearings were then held on April 27, 2015 through May 4, 2015. Over 70 exhibits were identified and admitted into the evidence.[6]

After the evidentiary hearings were concluded, and prior to the filing of opening and reply briefs, SDG&E notified the Administrative Law Judge (ALJ) and the parties on June 1, 2015 that SDG&E expected to file a motion to adopt a settlement agreement, and requested that the briefing schedule as established at the evidentiary hearings be delayed. Due to the upcoming filing date of the opening briefs, an e-mail ruling was issued on June 1, 2015 suspending the briefing schedule until further notice.

SDG&E and 16 other parties filed the "Joint Motion for Adoption of Settlement Agreement" (Settlement Motion) on June 3, 2015.[7] As described in more detail below, the Settlement Motion requests that the Commission approve the "Settlement Agreement Regarding San Diego Gas & Electric Company's Vehicle-Grid Integration Pilot Program Application, A.14-04-014" (Proposed Settlement), which was appended to the Settlement Motion as Attachment A. The Proposed Settlement is based on SDG&E's original VGI proposal as set forth in its application, but with modifications to address various parties' concerns

[6] Testimony and cross examination exhibits were sponsored by the following parties: SDG&E, California Energy Storage Alliance (CESA), ChargePoint, Inc. (ChargePoint), Environmental Defense Fund (EDF), Federal Executive Agencies (FEA), Green Power Institute (GPI), Joint Minority Parties (JMP), KnGrid, LLC (KnGrid), Natural Resources Defense Council (NRDC), Office of Ratepayer Advocates (ORA), Plug In America (PIA), The Utility Reform Network (TURN), and Utility Consumers' Action Network (UCAN).

[7] The parties who filed the Settlement Motion, and who are signatories to the proposed settlement are the following: SDG&E; Alliance of Automobile Manufacturers; American Honda Motor Company, Inc.; California Coalition of Utility Employees; CALSTART; Center for Sustainable Energy; ChargePoint; EDF; General Motors LLC; GPI; KnGrid; NRDC; NRG EV Services LLC; PIA; Sierra Club; Smart Grid Services, Siemens AG (Siemens); and The Greenlining Institute.

about customer choice, market innovation, inclusion of disadvantaged communities, and other issues.

As provided for in Article 12 of the Commission's Rules of Practice and Procedure, various parties filed opening and reply comments on the Settlement Motion.[8]

Following the filing of opening and reply comments on the Settlement Motion, a ruling was issued on August 5, 2015 by the assigned Commissioner and ALJ which, among other things, directed SDG&E to clarify portions of the Proposed Settlement. The clarification was sought so as to better understand how the Proposed Settlement would be implemented. SDG&E responded to those questions on August 21, 2015.

The August 5, 2015 ruling summarized the positions of the parties who filed responses and replies to the Settlement Motion. The ruling denied the request of some of the parties to hold additional evidentiary hearings on the Proposed Settlement. In denying that request, the ruling stated:

> After reviewing the proposed settlement, the responses and replies to the motion to adopt the proposed settlement, and reviewing the testimony and transcripts from the evidentiary hearing, we conclude that no additional hearings on the proposed settlement are needed. The testimony and the [evidentiary hearings] have already addressed many of the issues that the parties have raised about SDG&E's underlying VGI proposal, and about the proposed settlement. The proposed settlement also addresses many of the issues that ORA, TURN, and UCAN have raised about the settlement, although it may not contain the specificity or details that they desire. In addition, such hearings will require additional resources from both the parties and the Commission, which seem

[8] Those comments are summarized in the Position of the Parties section of this decision.

> unnecessary given the type of additional information that is being sought, and the information that is already in the record. (August 5, 2015 Ruling at 22-23.)

The August 5, 2015 ruling also directed the parties to file opening and reply briefs on whether the Proposed Settlement, SDG&E's original VGI proposal, or a variant of those proposals, should be adopted or not. The parties were also provided the opportunity to respond to SDG&E's August 21, 2015 responses in their opening and reply briefs.

Ten opening briefs were filed on September 4, 2015, and nine reply briefs were filed on September 18, 2015. This proceeding was submitted upon the filing of the reply briefs on September 18, 2015.

On October 7, 2015, Governor Brown signed Senate Bill (SB) 350 into law. (Statutes of 2015, Chapter 547, hereinafter Stats. 2015, Ch. 547.) The statutory provisions in SB 350 are effective January 1, 2016. SB 350 codified the Governor's call "for a new set of objectives in clean energy, clean air, and pollution reduction for 2030 and beyond." (Stats. 2015, Ch. 547, § 2(a).) SB 350 amended Public Utilities Code Section 399.11 to increase the amount of electricity generated and sold to retail customers from eligible renewable energy resources to 50% by December 31, 2030. SB 350 also added provisions to the Public Utilities Code to promote the widespread use of electricity as a transportation fuel in order to achieve the goals of the Charge Ahead California Initiative as set forth in Health and Safety Code (H&S) §§ 44258 and 44258.4.[9] (*See* Stats. 2015, Ch. 547, § 32.) As

[9] H&S § 44258.4(b) states in part: "The goals of this initiative are to place in service at least 1,000,000 zero-emission and near-zero-emission vehicles by January 1, 2023, to establish a self-sustaining California market for zero-emission and near-zero-emission vehicles in which zero-emission and near-zero-emission vehicles are a viable mainstream option for individual vehicle purchasers, businesses, and public fleets, to increase access for disadvantaged,

Footnote continued on next page

added by SB 350, the Legislature found and declared the following in Public Utilities Code Section 740.12(a)(1):

> (C) Widespread transportation electrification requires increased access for disadvantaged communities, low- and moderate-income communities, and other consumers of zero-emission and near-zero-emission vehicles, and increased use of those vehicles in those communities and by other consumers to enhance air quality, lower greenhouse gases emissions, and promote overall benefits to those communities and other consumers.
>
> (D) Reducing emissions of greenhouse gases to 40 percent below 1990 levels by 2030 and to 80 percent below 1990 levels by 2050 will require widespread transportation electrification.
>
> (E) Widespread transportation electrification requires electrical corporations to increase access to the use of electricity as a transportation fuel.
>
> (F) Widespread transportation electrification should stimulate innovation and competition, enable consumer options in charging equipment and services, attract private capital investments, and create high-quality jobs for Californians, where technologically feasible;
>
> (G) Deploying electric vehicles should assist in grid management, integrating generation from eligible renewable energy resources, and reducing fuel costs for vehicle drivers who charge in a manner consistent with electrical grid conditions.
>
> (H) Deploying electric vehicle charging infrastructure should facilitate increased sales of electric vehicles by making charging easily accessible and should provide the opportunity to access electricity as a fuel that is cleaner and less costly than gasoline or other fossil fuels in public and private locations.

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low-income, and moderate-income communities and consumers to zero-emission and near-zero-emission vehicles, and to increase the placement of those vehicles in those communities and with those consumers to enhance the air quality, lower greenhouse gases, and promote overall benefits for those communities and consumers."

Public Utilities Code Section 740.12 does not apply to this application because subdivision (d) of that code section provides:

> (d) This section applies to an application to the commission for transportation electrification programs and investments if one of the following conditions is met:
>
> (1) The application is filed on or after January 1, 2016.
>
> (2) The application is filed before January 1, 2016, but has an evidentiary hearing scheduled on or after July 1, 2016.

SDG&E's application was filed before January 1, 2016, and evidentiary hearings were held in 2015

2. Background of San Diego Gas & Electric Company VGI Pilot Program

This section summarizes SDG&E's VGI pilot program as described in SDG&E's application, its prepared testimony, and the testimony of the SDG&E witnesses at the evidentiary hearings.

SDG&E's application proposes the creation of a VGI pilot program to deploy EV charging infrastructure in its service territory, and to integrate that infrastructure into the electric grid through the use of an hourly time-varying rate. SDG&E's application proposes the widespread deployment of EV site installations, and charging stations, which would be integrated into the electric grid using a VGI rate.[10] SDG&E's application is the first of the applications from

[10] In this decision, we refer to a "site installation" as the site location for the placement of an EV charging site. Each site installation can have more than one "charging station," which is the term we use to refer to the electrical cable and plug adapter that connects to the EV and dispenses electricity. Our use of the term "charging station" is consistent with how that term is defined in Civil Code Section 1947.6(c), which refers to a "charging station" to mean "any level of electric vehicle supply equipment station that is designed and built in compliance with Article 625 of the California Electrical Code, as it reads on the effective date of this section, and delivers electricity from a source outside an electric vehicle into a plug-in electric vehicle." The

Footnote continued on next page

the three large electric utilities to request authority to establish and implement a pilot program to encourage PEV usage.[11]

SDG&E proposes in its application that it be authorized to own, install, and maintain EVSE and associated infrastructure at up to 550 sites to charge PEVs.[12] These sites are to be installed at multi-unit dwellings (MUDs) and at workplaces. According to SDG&E, these two locations are being targeted because they have a very low deployment of EV charging facilities, and cars are parked at these types of locations for long periods of time. Both of these location types provide the opportunity for grid-integrated charging during off-peak periods, and during the day when there is a high output of solar generation.

SDG&E contends that these two location types have the potential to increase EV ownership. MUDs comprise about 50% of the residential units in the greater San Diego region. SDG&E notes that of its employees who own or lease an EV, about 67% of those owners reported "that the presence of workplace charging influenced their EV buying or leasing decision and 79% said the presence of workplace charging will increase their EV miles driven per week."

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property owner or the lessor of the property, upon which the site installation is located is referred to as the "site host." The property upon which the site installation is located is sometimes referred to in this decision as the "VGI facility" or "facility site host." We note that the EV industry use of the term "charging station" differs from how we commonly refer to a single "gasoline station," and the "gasoline pumps" or "gasoline nozzles" that are situated at the gasoline station.

[11] Pacific Gas and Electric Company (PG&E) filed its EV application in A.15-02-009, and Southern California Edison Company (SCE) filed its EV application in A.14-10-014.

[12] In this decision, EVSE refers to "The conductors, including the ungrounded, grounded, and equipment grounding conductors, the electric vehicle connectors, attachment plugs, and all other fittings, devices, power outlets, or apparatuses installed specifically for the purpose of delivering energy from the premises wiring to the electric vehicle." (Exhibit SDG&E-8 at 4, footnote 6; See also, Proposed Settlement, § II. Definitions; H&S Code § 44268(d).)

(Exhibit SDG&E-2 at 6.) SDG&E also cites a February 2014 California PEV driver survey in support of the targeting of these two types of locations. The survey showed that of those who responded, 88% of PEV drivers live in a single-family detached home, 93% own their own homes, and 46% had access to workplace charging.

SDG&E's application proposes that these EV site installations offer a day-ahead time-variant hourly VGI rate. According to SDG&E, the VGI rate "will provide price signals that are intended to minimize [EV] charging impacts to SDG&E's system and local distribution capacity," and will "Encourage drivers to charge at times of grid surplus to efficiently integrate and manage charging loads with grid operation." (Exhibit SDG&E-3 at 1; Exhibit SDG&E-7 at 1.) SDG&E contends that the VGI rate is designed to alleviate the impact on the electricity grid by shifting usage to periods when there is a surplus of electricity such as excess solar generation in the afternoon, or during off-peak periods. In turn, this will reduce spending on the need for more infrastructure and power plants in order to meet the anticipated load growth from EV charging. The VGI pilot program is designed to "learn more about customers' EV charging behavior when exposed to hourly prices designed to encourage grid-integrated charging," and to explore whether "lower hourly prices encourage EV charging when available energy and capacity resources are more abundant," and whether "higher hourly prices discourage EV charging when these resources are scarcer." (Exhibit SDG&E-6 at 1.)

This VGI pilot program is based in part on SDG&E's experience with a VGI prototype site installation that was installed for the use of its employees in 2013. In 2014, the prototype site installation began using "an hourly VGI-like rate, with enabling charging technology and controls, to help to better

understand employee charging preferences." (Exhibit SDG&E-2 at 5.) SDG&E's VGI pilot program will use a VGI rate that will vary throughout the day to reflect the expected changes in energy prices and grid conditions. The PEV owners using these facilities will be sent day-ahead price signals to encourage PEV charging during off-peak periods. According to SDG&E, this "time-variant pricing is designed to encourage EV drivers to meet their charging needs while simultaneously enhancing grid efficiency by adding load at times of least cost." (Exhibit SDG&E-1 at 11.)

SDG&E proposes that the sign-ups and contracting for the VGI pilot program take place over four years, and that the installations take place over a period of four to five years. SDG&E's goal is to deploy at a blend of workplace and MUD sites a total of 550 site installations and 5,500 charging stations in accordance with the following schedule.[13]

- Year 1 (2015) – 50 site installations of 10 charging stations each.
- Year 2 (2016) – 100 site installations of 10 charging stations each.
- Year 3 (2017) – 200 site installations of 10 charging stations each.
- Year 4 (2018) – 200 site installations of 10 charging stations each.

According to SDG&E, this time schedule and number of installations is designed to encourage MUD and workplace site hosts to sign-up quickly, which it believes will encourage program success. The actual number of EV charging stations will vary from site to site. SDG&E notes that if more charging stations are installed at a site, that this will allow more EV drivers to charge instead of

[13] SDG&E does not expect that every charging station will request or justify the need for 10 charger units. Instead, the number of charger units at each charging station may differ depending on such things as space availability, and anticipated demand for EV charging.

having to wait for an EV charging station to become available. The deployment of the site installations and charging stations would be subject to the $103 million cap that SDG&E requests.

SDG&E requests that the costs of this program be capped at $103 ($102.753) million, and that SDG&E be allowed to recover these costs from its ratepayers through the establishment of a two-way interest-bearing VGI Balancing Account (VGIBA). SDG&E proposes that the VGIBA record the authorized revenue requirement and the actual operation and maintenance (O&M) and capital-related costs. During the five-year installation period, SDG&E proposes that any over/under collection be carried forward to the following year until the end of the installation period. Under SDG&E's VGI program, approximately $59.218 million in capital expenditures would be added to ratebase once the EV charging infrastructure becomes used and useful.

SDG&E contends that the size of the VGI pilot program is appropriate because it will support a robust study sample. Since the VGI rate is influenced by changes in the price of energy, and system and circuit conditions, the large number of EV site installations and charging stations are needed in order to obtain a reasonably strong statistical representation of the SDG&E circuits. The various circuits have different circuit characteristics including the following: the number of residential and commercial customers on each circuit; the amount of solar generation on each circuit; the load factor of the circuit; and the peak demand hours of the circuit. These circuit characteristics are expected to affect the calculation of the VGI rate's hourly prices across the more than 1,000 distribution circuits.

SDG&E proposes that to the greatest extent possible, it will contract with third parties to build, install, operate, and maintain the EV charging facilities

under a service level agreement. The charging facilities are to be built, installed and maintained in accordance with SDG&E's VGI specifications and supervision. SDG&E contends that the maintenance of the EV charging facilities will ensure that the EV charging stations remain in working order.

SDG&E proposes to use a two-step process to recruit qualified third parties to build, install, operate, and maintain the EV charging facilities. The first step will be a pass/fail round utilizing a Request for Information (RFI) process. Under the RFI process, a potential bidder will have to pass all of the criteria necessary to participate in the VGI pilot program. The second step is the Request for Proposal (RFP) process. Under the RFP process, a potential bidder will be scored based on criteria that focus on the VGI technical and operational specifications. Contracts will be awarded to multiple bidders who have met the criteria.

As for the site locations of these facilities, SDG&E plans to contract with those MUD and workplace site hosts who want to participate in SDG&E's VGI pilot program. Potential site hosts would be required to grant easements to SDG&E. SDG&E proposes under its pilot program to provide the site hosts with "no-cost charging equipment and installation, while the potential hosts provide a charging site location and appropriate parking for EV customers." (Exhibit SDG&E-2 at 2.) Under SDG&E's VGI pilot program, all of the EV charging infrastructure located at each site installation would be owned by SDG&E.

In selecting a site location for a site installation, SDG&E will solicit interest from potential MUD and workplace sites. SDG&E plans to evaluate and prioritize the site location using the following site selection criteria:

- Date of indicated interest (first-in-line priority);
- Current and expected volume of EV drivers;

- Number of VGI charging stations desired;
- Type of VGI installation (MUD, workplace);
- Nearby transformer available capacity;
- Distance between transformer and new service point;
- Site conditions related to construction feasibility (i.e., trenching surface, EVSE mounting surface, condition of facility);
- Land and property ownership;
- If leasing, term and conditions of lease; and
- Existing/available Americans with Disabilities Act (ADA) accessible parking.

After the VGI equipment is installed at a location, SDG&E will then offer charging services to the customers who use these facilities under SDG&E's VGI rate. SDG&E proposes to directly bill the customers who use the VGI site installations.

SDG&E considers its VGI program to be a pilot project because of the following: the unique VGI rate; the targeting of MUDs and workplaces only; and the four year enrollment period for the VGI program.

Under the VGI pilot program, the EV customers of SDG&E will have access to a technology platform that will allow an EV customer on the VGI rate to enter preferences for energy price and quantity (hours) into a mobile phone application or on a website. These preferences will then be used by SDG&E's VGI Service Pricing and Billing system to determine the parameters of the VGI rate, such as the maximum hourly price the EV customer is willing to pay, the duration of time the customer plans to be at the VGI charging facility, and how much energy the EV customer needs. SDG&E will then provide the EV customer with hourly pricing on a day-ahead basis. These day-ahead hourly VGI rates "will correspond with the expected changing hourly price of electricity and will

be designed to encourage EV charging to occur at times of the day that will minimize incremental peak loads on the electrical distribution system, integrate high levels of renewable energy use, and avoid charging on system peaks." (Exhibit SDG&E-2 at 3.) SDG&E's VGI customers will then be able to access their individual hourly and total charges after each charging session, as well as their historical usage.

Most of the costs of SDG&E's pilot program are attributable to the five main cost components of installing a VGI system. According to SDG&E, these following costs are likely to vary from site to site depending on the work needed and conditions at each site:[14]

- The first cost component is the engineering design and permitting of the selected site host.
- The second cost component is the new electric service that will be separately metered by SDG&E. As part of the new electric service, there "will be a pad-mounted meter pedestal and breaker panel with a new meter, all the necessary trenching, conduit, wire, and connectors from the transformer to the new meter pedestal, and a refill/repair of the trench." (Exhibit SDG&E-2 at 11.) SDG&E estimates that up to 25% of these new electric services will require a new transformer.
- The third cost component is the EVSE and installation costs. Under SDG&E's proposal, each site host is to consist of ten separate EV charging stations. Depending on the needs of the site host, EV charging load opportunities, and available electrical capacity, SDG&E plans to install a blend of Level 1 and Level 2 charging stations.

[14] The individual costs are described in Exhibit SDG&E-2, while Exhibit SDG&E-4 puts the costs into an annual revenue requirement. The $103 million mentioned earlier is the proposed revenue requirement over the life of the project

- The fourth cost component is the access control equipment and installation costs. The access control equipment will consist of a pad-mounted control kiosk which will contain the hardware necessary to activate a charging session for each charger port. The kiosk will have a meter to track individual customer usage for billing purposes, and this information will be sent daily to a data collection system for subsequent billing purposes.
- The fifth cost component is compliance with the ADA in terms of parking modifications and signage.

In addition to the site costs, SDG&E estimates that the one-time VGI information technology costs will run about $1.564 million. This cost is composed of software development and hardware costs, and phone and web applications.

SDG&E also points out that there will be O&M costs associated with the VGI pilot program. SDG&E estimates that these costs will consist of the following: replacement costs for charging equipment and cables; access control consisting of wireless service fees; customer engagement costs; support materials for customer engagement; billing system integration costs; customer support and billing integration services; the cost of a full-time employee to perform circuit level load modeling for the VGI rate calculations; and the cost of evaluating the deployment of the VGI pilot program and load impacts.

SDG&E estimates that under its VGI pilot program proposal, the first year bill impact would be approximately 18 cents for a typical residential customer using 500 kilowatt hours per month in both the Inland and Coastal climate zones, which is approximately a 0.02% increase for a typical Inland residential customer, and a 0.01% increase for a typical Coastal residential customer.

Regarding the management of the VGI pilot program, SDG&E will be responsible for the overall management of the program. The two key areas of

responsibility for SDG&E will be customer contact, and back-office support. The back-office support consists of the VGI pilot program billing function and support, which is responsible for making the EV customers aware of the VGI unit pricing, and the total cost of EV fueling as presented in the customer's bill. SDG&E plans to contract with third parties to build, install, operate, and maintain the EV charging facilities. The relationship with the third parties will be managed through a service level agreement between SDG&E and the third party.

To evaluate the cost effectiveness of the VGI pilot program, SDG&E proposes that a Research Plan be put into place to evaluate the pilot program. The pilot program is intended to result in increased electricity use and a decrease in fossil fuel use. According to SDG&E, the evaluation methodology will quantify the costs and benefits of those impacts. The evaluation methodology that SDG&E proposes to be used is based on an analytical model developed at SDG&E's request. SDG&E contends that the model uses cost effectiveness tests that are familiar to the Commission. SDG&E contends that the evaluation results "may provide policy makers with insights about various VGI solutions in the SDG&E EV charging market," and may also "provide policy makers with a method to evaluate the benefits of the VGI Pilot Program in general and the VGI Rate in particular." (Exhibit SDG&E-6 at 2.)

The Research Plan that SDG&E proposes consists of data collection and analysis. SDG&E proposes that the data collection begin the first year of the pilot, that load impact analysis and reporting begin after two years of

implementation, and that a cost effectiveness analysis be performed 18 months after the final VGI facility is installed.[15]

Under SDG&E's Research Plan, the following data collection and analysis is to take place: actual VGI installation costs; actual VGI operating costs; charging load profiles; estimated percentage of EV purchases related to the VGI pilot program; estimated VGI pilot program-related increases in ZEV miles traveled per EV; EV customer input on the VGI mobile and web applications, the VGI rate and overall convenience and ease of use of the VGI facility; VGI kilowatt hour (kWh) usage by price, over time; where available, EV related kWh usage at home will be reviewed with VGI kWh usage at workplace VGI facilities; and where possible, determine whether EV time of use (TOU) adoption has increased as a result of the VGI pilot.

SDG&E has already modeled EV charging in SDG&E's service territory under two sets of hypothesized scenarios. The first scenario includes an EV charger deployment with the pilot program using a VGI rate. According to SDG&E, the "VGI Rate encourages grid-integrated EV charging based on the dynamic hourly price that reflects grid supply and demand conditions." (Exhibit SDG&E-6 at 5.) The second scenario also includes EV charger deployment, but is deployed by a non-utility entity with EV charging priced as a flat fee. Although these two scenarios are illustrative only, SDG&E states that the results "show that the estimated Electric Supply costs for the SDG&E VGI Rate scenario are less than the Non-utility Flat Fee scenario by $7.5 to

[15] If after two years of implementation, the VGI pilot program produces load impacts, load impact studies will be conducted according to the load impact protocols adopted in D.08-04-051.

$20.2 million [Net Present Value] over the sensitivity ranges." (Exhibit SDG&E-6 at 35.) SDG&E further states that the illustrative results indicate that the VGI pilot program will provide net benefits, and "is beneficial to SDG&E ratepayers, EV customers, and the SDG&E service territory region in general." (Exhibit SDG&E-6 at 37.)

According to SDG&E, the data from SDG&E's pilot program and VGI rate will "help inform VGI policy development, create and expand EV charging solutions and benefit the EV charging market and SDG&E customers." (Exhibit SDG&E-1 at 2.) This data can help inform the Commission about the following: the relationship between pricing and charging behavior in the workplace and at home; whether EV charging customers can be encouraged through pricing to charge at a grid-friendly time of day while accommodating the needs of the EV charging customers; whether the pricing and availability of charging facilities will increase the miles driven per EV customer; and whether utility management of EV charging to non-peak periods can minimize or eliminate pressure on grid capacity, and take advantage of available energy supply.

In addition, SDG&E contends that the VGI pilot program will provide information on how effective PEV batteries and grid-integrated charging can provide energy storage support to the electric grid. According to SDG&E, the PEV battery storage can help reduce "system ramping needs by building loads during the lowest demand periods; providing load to absorb low cost energy supply; and avoiding local distribution impacts by minimizing load when local distribution system is near capacity." (Exhibit SDG&E-1 at 13.)

The VGI pilot program will also help position the market for future vehicle-to-grid (V2G) applications pursuant to the February 2014 California

Independent System Operator (CAISO) VGI roadmap, and the Energy Division's October 2013 VGI white paper.

SDG&E contends that its application is an innovative proposal that will allow the EV market to grow. This will take place through the offering of the hourly time-variant rate, and increased business opportunities and growth for businesses that provide support services to EV customers. According to SDG&E, it has "been a very committed supporter of Electric Vehicle Service Providers (EVSPs) that have installed residential, public and workplace charging facilities in the SDG&E service territory." (Exhibit SDG&E-2 at 6.)

SDG&E contends that its pilot program is supported by a number of different California policies which encourage the environmentally beneficial use of electricity as a transportation fuel. These policies include the following: Governor Brown's ZEV Action Plan; the opportunity to integrate renewable energy resources with EV charging; policies regarding energy storage, AFVs, and the Energy Division's VGI white paper; the Legislature's enactment of SB 17 (Stats. 2009, Ch. 327), which codifies state policy to encourage smart grid modernization and usage; and D.12-12-033, which adopted the Cap-and-Trade Greenhouse Gas (GHG) Allowance Revenue Allocation Methodology and the State Air Resources Board's (ARB) Cap-and-Trade Auction Proceeds Investment Plan. SDG&E also states that the VGI pilot program and the VGI rate are consistent with Public Utilities Code Section 8360(h) that customers should have timely information and control options, and that rates should be reasonable. In addition to testing the VGI rate at one of SDG&E's PEV site installations, SDG&E has been testing how driver decisions about EV charging time change in response to varying price ratios in different TOU periods.

As part of its application, SDG&E also requests that the Commission make a determination that SDG&E's pilot program be found eligible, pursuant to D.12-12-033, to receive funding from the revenues generated by the sale of the cap-and-trade allowances consistent with Public Utilities Code Section 748.5(c). In order to receive such a designation, SDG&E contends that D.12-12-033 requires the Commission to determine that the proposed project will have a goal of reducing GHGs, and that it be administered by the electrical corporation and is not otherwise funded by another funding source.

3. Background of Proposed Settlement

This section of the decision describes the Proposed Settlement. The Settlement Motion requests that the Proposed Settlement, which is appended to the Settlement Motion as Attachment A, be approved and adopted. The Proposed Settlement is based on, and would adopt with certain modifications, SDG&E's original VGI proposal as set forth in its application.

The Proposed Settlement consists of a preface, and the following sections: Introduction and Background; Definitions; Settlement Agreement Provisions; and Additional Terms and Conditions.

As described in the Settlement Motion and the text of the Proposed Settlement, the Proposed Settlement is based on 11 Guiding Principles that are to guide the VGI program implementation, and the 16 modifications made to SDG&E's original VGI proposal. These Guiding Principles and the modifications are described in the "Settlement Agreement Provisions" section of the Proposed Settlement. The Guiding Principles are as follows:

1. Must support the Governor's and California state goals to: achieve installation of grid-integrated infrastructure to support 1 million ZEVs by 2020; accelerate the adoption of 1.5 million

ZEVs by 2025, and support clean air and climate change objectives;

2. Must be structured to provide net benefits to all ratepayers;
3. Must protect ratepayers by ensuring that assets continue to be used and useful;
4. Must provide EV drivers the opportunity to maximize fuel cost savings relative to conventional transportation fuels;
5. Must provide equitable deployment of services to all ratepayers, including statutory requirements and directives to serve disadvantaged communities and increase access to clean transportation;
6. Must provide customer choice;
7. Must support broad-based investment in EV charging equipment and services by public, private and utility entities and avoid anticompetitive impacts on the markets for EV charging equipment and related services;
8. Must incorporate learning-by-doing and make adjustments to the VGI pilot program as needed;
9. Must provide data to help inform state policy;
10. Must utilize rate design and load management practices to facilitate the integration of renewable energy resources, as well as deliver other grid benefits; and
11. Must align with SDG&E's Diversified Business Enterprise (DBE) goal of 40% and request subcontractors to provide proposals in support of the 40% goal.

As part of the Proposed Settlement, the settling parties have agreed to 16 modifications to SDG&E's original VGI proposal. According to the Proposed Settlement, these "modifications to SDG&E's proposal are desirable to incorporate the views of stakeholders and to support the Governor's 2020 grid-integrated infrastructure and 2025 vehicle deployment goals, as well as

California's clean air and climate change objectives." (Proposed Settlement at 2.)

These 16 modifications are summarized as follows:

- The VGI facility site hosts will have the choice of two billing options: (1) the VGI rate offered directly to the PEV driver (VGI Rate-to-Driver); or (2) the VGI rate offered to the site host (VGI Rate-to-Host).
- If the VGI facility site host opts to receive the VGI Rate-to-Host pricing plan, the site host or its selected vendor, will be required to submit to SDG&E the load management tactics it will implement at its VGI facility, including the incremental costs and equipment required to implement the load management tactics, the prices or fees that it intends to levy on VGI facility users, and any vehicle or EVSE communication systems necessary to implement the load management tactics. SDG&E recognizes that the site hosts on the VGI Rate-to-Host pricing plan may want the flexibility to change prices or fees over time. If a site host does not submit a load management plan that is consistent with the Guiding Principles, the site host will be ineligible to participate until SDG&E determines that the site host's load management plan is consistent with the Guiding Principles. If a VGI facility site host opts for the VGI Rate-to-Host pricing plan, the site usage patterns will be monitored (just as they would for a site host that opts for the VGI Rate-to-Driver pricing plan), as well as tracking of the site host determined prices or fees.
- The VGI facility site hosts will choose EVSE and related services from a list of vendors prequalified by SDG&E to provide such services for the VGI program. SDG&E's VGI program does not include the installation of direct current (DC) fast charging equipment.
- SDG&E will assess a VGI program participation payment on VGI facility site hosts that elect to participate in the program. The participation payment is to be waived for VGI facilities located at sites in disadvantaged communities. SDG&E is to file for approval of the proposed participation payment with a Tier 2 advice letter, subject to protest by any party, after consulting with the VGI Program Advisory Council (PAC). In developing the

proposed participation payment, factors that will be considered include, but are not limited, to the following: customer commitment, avoiding adverse impacts to deployment, total VGI facility cost, and customer segment.

- After the first year of participation, the VGI facility site host shall have the annual option to switch VGI rate plans (i.e., the VGI Rate-to-Driver pricing plan or VGI Rate-to-Host pricing plan). In the event that the ownership of control of the VGI facility site changes, the new site host has the option to select a VGI rate plan, consistent with current utility tariff and billing practices.
- Third party vendors of EVSE and services pre-qualified by SDG&E for the VGI program may offer and contract with the VGI facility site host to provide any additional or complementary services, as long as these services do not interfere with the objectives of the VGI program. Specifically, such services may not include activities, agreements, arrangements, policies or procedures that inhibit the ability of the EV driver or VGI facility site host to respond to the pricing signal of the VGI rate. The costs of these additional services will not be borne by the VGI program, unless they are complementary services necessary to support the VGI program objectives. As such, SDG&E will encourage discussions during the RFI process that allow vendors to explore the funding of innovative opportunities that may exceed the minimum implementation requirements of the VGI program, and have the potential to enhance and improve the grid-integration outcomes of the VGI program overall.
- The third party vendors pre-qualified by SDG&E for the VGI program, in coordination with SDG&E customer contact personnel, will market and sign-up potential VGI facility site hosts to participate in the VGI program in the two targeted customer segments of MUDs and workplaces, and in any other customer sub-segments identified in the Proposed Settlement (e.g., disadvantaged communities, and housing or sites that support car-sharing entities). Responses to the RFP should reflect this requirement. Competitively neutral descriptions of the VGI rate plans will be prepared by SDG&E and shall be used by third parties. Third parties shall be permitted to develop and utilize

their own marketing materials at their own expense, consistent with and subject to SDG&E's co-branding policy and approval process. To create and maintain a positive customer experience with the VGI program, the third parties will be required to describe how they will share the initial and ongoing customer relationships with SDG&E and the VGI facility host and EV driver. Vendors will be permitted to contract directly with site hosts for services as long as these services do not interfere with the objectives of the VGI program.

  - SDG&E will solicit participation from multiple third parties to provide equipment, install, maintain and operate the VGI system in a manner consistent with SDG&E's supply management policy and procedures as outlined in Exhibit SDG&E-2 at 8. Construction, installation and maintenance contractors will have Electric Vehicle Infrastructure Training Program (EVITP) certification, and SDG&E will require that all construction, installation and maintenance of VGI facilities that is not performed by employees of SDG&E shall be performed by contractors signatory to the International Brotherhood of Electrical Workers (IBEW) who hold a valid C-10 contractor's licenses, as defined in the governing labor agreement between SDG&E and the IBEW.

- The VGI program will be included within SDG&E's companywide DBE goal of 40%. The RFP and contract will contain a DBE subcontracting plan, which requires the bidder/contractor to list its expected annual DBE spend and list any subcontractors it plans to use to achieve its DBE goal. Bidders will be requested to provide proposals in support of SDG&E's 40% goal.
- At least 10% of the VGI facilities will be installed in disadvantaged communities as identified by the California Environmental Protection Agency's CalEnviroScreen tool developed pursuant to SB 535 (Stats. 2012, Ch. 830.) SDG&E will work with community based organizations (CBOs) to assist with education and outreach, as well as pre-qualifying and signing-up hosts for participation in the VGI program. In addition, SDG&E

will: scale up deployment of VGI facilities at qualified locations above the 10% target (in line with the screening criteria identified in Exhibit SDG&E-2 at 7) to support accelerated EV adoption in disadvantaged communities; and complement and coordinate with federal, state, and locally funded programs, such as those being developed by the ARB pursuant to SB 1275 (Stats. 2014, Ch. 530), that are expected to grow the demand for EVs in disadvantaged communities, such as EV car-sharing services.

- All contractors shall have hiring goals to support opportunities to increase hiring from disadvantaged communities, including first-source hiring and targeted-hiring goals for projects in disadvantaged communities. The PAC will also monitor and provide recommendations, including specific numerical targets for meeting hiring targets, to contractors or subcontractors associated with the increase of hiring from disadvantaged communities, including best practices for hiring.
- SDG&E will solicit participation of a broad and diverse stakeholder advisory group known as the PAC in planning and implementing the VGI program following its approval by the Commission. The PAC will include representatives from local and state government (including representation from the Energy Division), industry, labor and other stakeholder participants, ratepayer and environmental advocates, and representatives of disadvantaged communities. The details regarding the roles, responsibilities and frequency of meetings are described in Appendix A of the Proposed Settlement.
- With guidance from the PAC, SDG&E will make program changes as needed during the course of the VGI program in line with the Guiding Principles. The settling parties recognize that certain changes may require filings that require Commission approval. Program changes will be made on an on-going basis, running concurrent with the VGI program, so as not to impact its overall progress. Data collection and program assessment criteria used to determine the need for any program change are identified in Exhibit SDG&E-6 at 35, and will be supplemented pursuant to the Proposed Settlement as described in Appendix B of the Proposed Settlement. Information will be provided to the

PAC in a manner similar to SDG&E's Procurement Review Group. Data will be provided to the PAC and Commission to assess the need for program changes.

- Metering at the EVSE level must be compatible with SDG&E billing and metering requirements (i.e., tolerances, accessibility, testability, and re-calibration, as needed), and/or submetering protocol if and as approved by the Energy Division. SDG&E reserves the right to make exceptions as conditions of the VGI program warrant. Minimum acceptable metering tolerance is anticipated to be 1% and if needed to meet meter testing and re-calibration requirements, removal (and replacement) of the entire EVSE will be acceptable.
    - The VGI bills will be sent directly to the SDG&E EV driver receiving the VGI rate, or to the VGI facility site host receiving the VGI rate under the VGI Rate-to-Host pricing plan. Data will be provided to SDG&E by the qualified third party to SDG&E's specifications in a manner acceptable to both parties to allow for this billing. Billing specifications are to send the VGI rate on a day-ahead basis, allow customer (site host or EV driver) to set charging needs, meet these charging needs, collect usage data and send data to SDG&E for billing processing. For exceptional instances when a non-SDG&E customer is allowed by the VGI facility site host at a site that is on the VGI Rate-to-Driver pricing plan to use the VGI facility for vehicle charging temporarily, the site host will have the option to be the VGI rate customer (i.e., enrolled in the VGI rate), and will be billed for this usage, similar to how the site host is billed under the VGI Rate-to-Host pricing plan.
- Unless directed otherwise by the Commission, as originally proposed SDG&E will cease marketing the VGI program and will not sign-up any additional sites as of the end of the fourth year of VGI program implementation, except for the following limited exception. The original proposal is modified for potential VGI facilities sites with documented plans for new construction or major tenant improvements. For such sites the VGI facility installation period may extend beyond the fifth year of the VGI program proposed installation period if the site host commitment is made by the end of the 4th year of VGI program

implementation. SDG&E will allow for flexibility in the design of the VGI facility configuration to meet the needs of a site host. The costs of any incremental configuration needs will not be funded within the VGI program. Implementation and site screening process will accommodate site host construction, tenant improvement timelines, and situational needs. The settling parties acknowledge that some sites may be rejected due to physical limitations, unusually large construction costs and/or level of difficulty.

- As stated throughout SDG&E's VGI program proposal, SDG&E will contract with one or more third parties to provide operating systems and related hardware to control EVSE networks to implement the VGI system. It is SDG&E's aim to specify "what" is required to be achieved per the objectives of the VGI Program, and not "how" these requirements are met. This is intended to foster innovation and enhancement to the customer's experience. Although described in Exhibit SDG&E-2 (Schimka), further clarification of the RFI and RFP processes are described in Appendix C to the Proposed Settlement.
- In order to provide an assessment of the VGI program consistent with the Guiding Principles, two years after the VGI program is launched SDG&E will provide an interim progress report to the Commission and serve it on all parties to A.14-04-014 and R.13-11-007. The interim progress report will include data as described in Appendix B of the Proposed Settlement, and a description of any program changes implemented by SDG&E prior to the date of the report. Parties will be permitted to file comments and reply comments on the report.

The Additional Terms and Conditions section of the Proposed Settlement cover three topics. The first topic addresses "Performance" of the settling parties with respect to the Proposed Settlement. The second topic provides that the Proposed Settlement is not intended to be precedent for any other proceeding, and that each settling party "expressly reserves its right to advocate, in other current and future proceedings, or in the event that the Settlement Agreement is

rejected by the Commission, positions, principles, assumptions, arguments and methodologies which may be different than those underlying this Settlement Agreement…." (Proposed Settlement at 9.) The third topic addresses the "Indivisibility" of the Proposed Settlement, and "General Provisions" of the Proposed Settlement.

4. Position of the Parties

This section describes the positions of the parties before the Proposed Settlement was entered into, and the positions that the various parties have taken after the Proposed Settlement was reached. The parties' positions are taken from their testimony, if they sponsored any, and from the various pleadings that were filed in connection with SDG&E's original proposal and the Proposed Settlement. In the sub-sections below, we first describe the positions taken by SDG&E and the settling parties, followed by the positions of the non-settling parties.

The various parties' positions are summarized below to provide the reader with some perspective and context in reading the discussion section of this decision.

4.1. Settling Parties

4.1.1. SDG&E

Prior to entering into the Proposed Settlement, SDG&E proposed that the Commission adopt its VGI pilot program as set forth in its application, and in the testimony of its various witnesses. The VGI pilot program, as proposed by SDG&E, calls for a pilot program, to be initiated over a four year period, for up to a total of 550 VGI site installations and 5,500 VGI charging stations. SDG&E plans to target workplaces and MUDs to locate the site installations. These two types of sites are being targeted by SDG&E because (1) they offer long term parking so that EV owners can charge their vehicles, and provide opportunities

for grid-integrated charging; and (2) these two types of locations are underserved by EV charging infrastructure. The total amount being requested by SDG&E is $103 million over a 22-year time horizon. Under SDG&E's original position, all of the site installations and EVSE equipment would be built and installed by SDG&E or its contractors, and all of the EVSE at all of the site installations would be owned by SDG&E. The only charging rate plan available to an EV driver using these site installations is a VGI rate that the EV driver is directly billed for by SDG&E.

SDG&E's present position advocates the adoption of the Proposed Settlement as reasonable and in the public interest. As part of the modifications agreed to by the settling parties in the Proposed Settlement, SDG&E has agreed to a more flexible approach as to what equipment can be installed, who can make use of the VGI rate, and the additional services a site host can use. As described in the summary of the Proposed Settlement, SDG&E now agrees to allow the MUD and workplace site hosts to have the choice of either the VGI Rate-to-Driver rate, or a VGI Rate-to-Host rate. Site hosts will be able to select the EVSE and the service they want from pre-qualified EVSE vendors. Since the Proposed Settlement is based on SDG&E's original VGI proposal, as modified by the Proposed Settlement, the amount being requested by SDG&E remains the same, as does the number of proposed EV site installations and EV charging stations. SDG&E contends that the modifications to SDG&E's original proposal, which resulted in the Proposed Settlement, address some of the settling parties' concerns about customer choice, market innovation, inclusion of disadvantaged communities, and other issues.

SDG&E contends that its original VGI proposal, and the Proposed Settlement (which is based on SDG&E's original VGI proposal), are unique

because it integrates and manages the charging of EVs with SDG&E's electric grid to reduce the impact on grid operation and infrastructure costs. SDG&E plans to offer the VGI rate at the site installations, which is a day-ahead dynamic hourly price for electricity to charge EVs.[16] That hourly price will reflect "changes in energy prices and grid conditions throughout the day, and accounts for loading on individual distribution circuits, as well as the loading on the overall system." (SDG&E, September 4, 2015 Opening Brief at 3.) According to SDG&E, the VGI rate is designed to encourage and integrate EV charging during off peak periods, and during times when the availability of renewable energy resources is plentiful. By charging at these times, SDG&E believes that this will reduce the need for costly system upgrades and new fossil generation. SDG&E contends that no other utility is proposing a rate to encourage the integration of an EV charging with the operation of the grid.

As noted in its testimony, SDG&E contends that the state's push toward more renewable energy will result in increased solar generation. This increase, due in part to solar generation, will produce more energy during the afternoon hours, when SDG&E expects marginal energy prices to be lower. Since solar generation is a renewable resource, this generation must be accepted into the grid regardless of price. SDG&E's VGI proposal "is designed to improve system efficiency by encouraging customers through price signals to charge vehicles when market prices are low, thereby avoiding charging during times of system demand peaks." (Exhibit SDG&E-1 at 6.)

[16] Under the Proposed Settlement, the site host has the option of selecting a VGI Rate-to-Driver, or a VGI Rate-to-Host. If a site host decides to receive the VGI Rate-to-Host, the site host or its selected vendor will be required to submit the load management tactics it plans to use, as well as the prices or fees it intends to levy on the EV drivers.

In order to support the goal of having more EVs on the road, SDG&E contends that much more EV charging infrastructure needs to be deployed at both public and private sites. Approval of the Proposed Settlement would support that goal through the targeting of MUDs and workplaces for the installation of EV charging infrastructure. Both of these kinds of site locations are currently underserved by the EV market. These two types of locations currently comprise 15% of the total non-residential EVSE units in SDG&E's service territory.

SDG&E maintains that the size of the Proposed Settlement, and its characterization that this is a pilot program, are appropriate in order to test the VGI rate, to support the state's goals, and to generate economies of scale.

With respect to testing the VGI rate, SDG&E contends that the number of site installations and charging stations is needed to support a robust study sample to ensure a strong statistical representation of SDG&E circuits, and to test SDG&E's cost effectiveness methodology. SDG&E contends that the larger program size will likely lead to lower prices for EVSE, and more innovation among the vendors. The size of the VGI program will also provide funds for ongoing maintenance for the EV charging stations, which will ensure that the EV charger ports are well maintained and in operational order. In addition, with the VGI Rate-to-Host option, SDG&E contends that the program size needs to remain as proposed in order to generate sufficient data on this rate option and the cost-effectiveness model.

SDG&E contends that if the Proposed Settlement is reduced or phased, as some opponents of the Proposed Settlement recommend, that this will nullify the value of the data collection and cost-effectiveness testing because the reduced duration and number of charging stations will not provide meaningful data

collection and analysis of the value of the VGI program, especially that of the VGI rate and the charging technologies. In addition, SDG&E contends that a "smaller program will attract less interest from those that could provide such innovative solutions, and those that do bid will have less scale over which to allocate development, manufacturing and support costs." (SDG&E, September 18, 2015 Reply Brief at 3.)

SDG&E also points out that the Proposed Settlement includes provisions that will benefit disadvantaged communities. As described earlier and in the Proposed Settlement, these include the following: (1) at least 10% of the VGI facilities will be installed in disadvantaged communities; (2) all contractors shall have hiring goals to support opportunities to increase hiring from disadvantaged communities; (3) the PAC will include representatives of disadvantaged communities; (4) the participation payment for site hosts will be waived for VGI facilities at sites located in disadvantaged communities; and (5) third party vendors pre-qualified by SDG&E for the VGI program will include disadvantaged communities in their efforts to market and sign-up potential facility site hosts.

SDG&E responded to some of the points raised by the other parties in its reply comments to the Settlement Motion, and in its reply brief.

SDG&E contends that the Proposed Settlement resolves concerns over competitive concerns. SDG&E points out that several entities who actively participate in the EV charging market support the Proposed Settlement. SDG&E further notes that the original concern over a site host not being able to select equipment and service options have been resolved in the Proposed Settlement through the competitive procurement provisions listed in Section III of the Proposed Settlement, and the VGI Rate-to-Host Option. SDG&E further

contends that as the demand for PEVs grows in SDG&E's service territory, that this will lead to an increase in demand for EV charging services at non-utility owned locations.

SDG&E also points out that substantial and urgent involvement by the utilities is necessary in order to reach the state's climate change objectives, and to reach the ZEV deployment goals. In order to meet these goals and objectives, SDG&E contends a lot more EVSE deployment is needed at public and private sites, and that the utilities need to be involved in these efforts.

SDG&E opposes the recommendations to reduce the size or to phase in SDG&E's VGI program. SDG&E contends that in order to measure the impact of the VGI rate, at least two years of data collection will be required. A reduced or phased-in program will not provide that opportunity because of the time it takes to implement all of the start-up steps and processes of the VGI program, for EV charging customers to use the VGI rate, and to measure whether the VGI pricing responses can be sustained over time. SDG&E contends that the VGI rate is designed to collect charges over a full year of service so that the EV charging customers are exposed to "high cost/low capacity hours, distribution circuit peak hours, and renewable oversupply hours." (SDG&E, September 18, 2015 Reply Brief at 5.) If the data is limited, it would not be suitable for a statistically valid representation of the VGI program performance. SDG&E contends that this data will allow the Commission and other state agencies to study EV market development, including the impact on non-VGI program EVSPs.

The amount of data and experience with the VGI rate also relates to when SDG&E should submit a report on the progress of the VGI pilot program. SDG&E opposes the shortened reporting timeframe that ORA and CESA recommend, and contends that neither ORA or CESA have specified why the

interim progress report and the comment process provided for the Proposed Settlement is insufficient. If the VGI pilot is reduced or phased, or if the report is to be issued sooner, SDG&E contends this will reduce the amount of data that can be analyzed, and may result in an inaccurate evaluation of the VGI pilot program.

In addition, SDG&E contends that if the recommendations to phase in the VGI program are adopted, this may discourage vendor participation in the program because potential vendors will need to decide whether it is worthwhile to participate, and will weigh their investment, development, and manufacturing costs over the reduced size of the VGI program. In addition, a reduced or phased VGI program will reduce the RFP process to a one-time event, instead of the open and ongoing RFP process contained in the Proposed Settlement. If the VGI program is reduced or phased, SDG&E contends that this may increase the unit cost, and reduce innovations regarding EV charging.

SDG&E contends that the concerns over the size of, and duration of, the VGI program, can be addressed through the Proposed Settlement's clauses regarding program changes that the PAC may recommend during the course of the VGI program, and the interim progress report that is to be provided two years after the launch of the program. (*See* Proposed Settlement, Section III, Paragraphs L and P.)

Some of the parties recommend that SDG&E should not be allowed to own both the site installations and charging stations, and that SDG&E should only install make ready stubs. SDG&E contends that the ownership of the EVSE facilities by the utility is critical. If the EVSE is owned by third parties, this could lead to a failure by the third party to maintain the EVSE, which could lead to stranded infrastructure. In addition, SDG&E contends that utility ownership is

needed because the VGI Rate-to-Driver option will require the use of a meter that will be used for billing purposes. In addition, utility ownership of the EVSE metering components is needed in order monitor the performance of the VGI facility, and to collect and send billing and performance data to SDG&E.

SDG&E contends that a common framework of make ready installations should not be uniformly applied to SDG&E, SCE, and PG&E. Instead, the use of different approaches by the three utilities, and the comparison of the results of the VGI program to the other utility approaches, will help guide future Commission actions.

With respect to the arguments of TURN and UCAN that the VGI pilot program is not cost effective, SDG&E contends that the illustrative cost-effectiveness modeling that it performed suggests that the VGI program can result in net benefits to both ratepayers and to society.

With respect to the Ratepayer Impact Measure (RIM) test, SDG&E notes that since the Commission has not required this test for energy efficiency, demand response, or distributed generation, it should not require this test for the VGI program. SDG&E also notes that at page 11 of the scoping memo and ruling in R.13-11-007, it stated that the pilot programs initiated as a result of the OIR would not be required to demonstrate positive cost-benefit ratios as a condition for approval.

JMP recommends that funding programs to subsidize EV purchases be established. SDG&E contends that it is in the business of selling electricity at retail, and that the Commission should ignore JMP's recommendation for SDG&E to become involved in the sale and financing of EVs, or to conduct research in that area.

In response to TURN's arguments concerning SDG&E's Electric Rules 15 and 16, and Public Utilities Code Section 783, SDG&E contends that those provisions do not apply. SDG&E contends that it is applying for a pilot program specific to grid-integrated EV charging facilities. SDG&E contends that those provisions cited by TURN are not applicable because the facility is to be owned end-to-end and operated by SDG&E as a separate service point, with an easement granted by the site host.

4.1.2. Other Settling Parties

In addition to SDG&E, the other settling parties to the Proposed Settlement are the following: Alliance of Automobile Manufacturers; American Honda Motor Company, Inc.; California Coalition of Utility Employees; CALSTART; Center for Sustainable Energy; ChargePoint; EDF; General Motors LLC; GPI; KnGrid; NRDC; NRG EV Services LLC; PIA; Sierra Club; Smart Grid Services, Siemens; and The Greenlining Institute. Some of these other settling parties sponsored testimony and/or filed pleadings. We summarize their positions in the paragraphs which follow.

4.1.2.1. Nine Settling Parties

Some of the settling parties filed opening and reply briefs recommending that the Proposed Settlement be adopted without any changes. They also filed a reply to the Settlement Motion.[17] These nine settling parties recommend that the Proposed Settlement be adopted without any additional changes. They point out

[17] These three pleadings were filed by the following nine settling parties: Alliance of Automobile Manufacturers, American Honda Motor Company, Inc., Coalition of California Utility Employees, EDF, General Motors LLC, NRDC, PIA, Sierra Club, and The Greenlining Institute.

that the Proposed Settlement was negotiated by a diverse set of organizations, and include significant modifications to SDG&E's original VGI proposal. Among the organizations that agreed to the Proposed Settlement are ChargePoint and NRG eVgo, which are the nation's two largest third party EV infrastructure companies. The nine settling parties contend that any additional changes would upset the balance that all of the settlement parties have negotiated.

These nine settling parties contend that the Proposed Settlement should be adopted for two principal reasons.

The first reason is that SDG&E's VGI proposal, as modified by the Proposed Settlement, will accelerate the PEV market to help meet federal air quality standards and California's GHG reduction targets. In turn, such a program will support the electric grid, and provide benefits to utility customers. These nine settling parties contend that there is no alternative but to use electricity as a transportation fuel if California is to comply with the 2023 and 2032 federal air quality standards. They contend this will require a significant expansion of charging infrastructure, as well as the widespread adoption of PEVs, in order to meet the air quality standards and California's policy goals.

The nine settling parties also contend that the Proposed Settlement properly targets MUDs and workplaces for the deployment of EV site installations. They contend that the research about the use and adoption of EVs support these two types of sites as a means to increase the adoption of EVs. In addition, the use of EV batteries to absorb peak solar generation can be used to displace gasoline, and encourage EV charging at off-peak periods to optimize the use of the existing electric grid.

The second reason that the nine settling parties mention as to why the Proposed Settlement should be adopted is that the modifications to SDG&E's

original application represent significant improvements over SDG&E's original proposal. These improvements, as described in their opening brief, include the following: the commitment to deploy at least 10% of the site installations in disadvantaged communities; coordinating the deployment of site installations in disadvantaged communities with programs to grow the demand for EVs in disadvantaged communities; increase hiring in disadvantaged communities; the ability for site hosts to select a VGI Rate-to-Host option; and including provisions to protect against the potential for anti-competitive effects on third-party charging providers.

In their response to the comments on the Settlement Motion, the nine settling parties point out that the membership-based organizations who signed the Proposed Settlement, also represent over 300,000 California utility customers. They contend it is inaccurate for the non-settling parties to state that they are the only entities representing the interests of ratepayers.

The nine settling parties contend that the recommendations of TURN and UCAN to transform SDG&E's VGI program into a full or partial make ready program should be rejected. The nine settling parties contend that the recommendations of TURN and UCAN essentially reiterates the request that ORA made in its April 13, 2015 motion that hearings be held on ORA's California Electric Vehicle Infrastructure Pilot (Cal EVIP) proposal, which was denied in the May 28, 2015 ruling. ORA's Cal EVIP proposal is similar to SCE's application that was filed in A.14-10-014, in which SCE proposes that make ready stubs be built. The nine settling parties contend that SDG&E's VGI program, as well as SCE's proposal, should be allowed to go forward as each proposal is different, and both programs can demonstrate the relative advantages of each program.

In JMP's comments on the Settlement Motion, JMP recommended that SDG&E's application fund the ARB's Enhanced Fleet Modernization Program and the Light-Duty Financing Assistance Program. The nine settling parties support these two programs, but believe that the funding for these programs should come from other sources such as the Greenhouse Gas Reduction Fund, and the Air Quality Improvement Program.

Regarding the Proposed Settlement's provision to allow the VGI Rate-to-Host option, the nine settling parties contend that this will allow the VGI price signals to be delivered to the site hosts if this option is chosen. The settling parties point out that under this option, the site hosts will be required to submit load management plans that are consistent with the Guiding Principles set forth in the Proposed Settlement. In addition, site hosts will be able to offer their own pricing or load management strategies.

CESA recommends in its comments on the Settlement Motion that certain protective measures be added to the Proposed Settlement to ensure that the VGI program meets the balancing test established in D.14-12-079. The nine settling parties in their reply to the Settlement Motion state that the Proposed Settlement already addresses these protective measures. These protective measures include: the collection of the data and metric described in Appendix B of the Proposed Settlement; the role and responsibilities of the PAC, which are addressed in Appendix A of the Proposed Settlement; the submission of the interim progress report; and that VGI program changes will be made as needed as described in the Guiding Principles of the Proposed Settlement.

Some of the parties in their comments on the Settlement Motion expressed concern about the size of the participation payment. The nine settling parties point out that the PAC can recommend the amount of such a payment. In

addition, the nine settling parties point out that the Proposed Settlement states that the following factors will be considered in developing the participation payment: customer commitment; avoiding adverse impacts to deployment; total VGI facility cost; and customer segment. In addition, under the Proposed Settlement, SDG&E will need to request approval of the proposed participation payment through a Tier 2 advice letter, which is subject to protest.

In response to TURN's contention that the Proposed Settlement does not comply with Public Utilities Code Section 740.8, the nine settling parties contend that TURN's interpretation of the statute focusing on direct benefits in the form of safer, more reliable, or less costly service, would render all of the environmental and public health benefits in that code section meaningless. The settling parties contend that the VGI program is designed to provide safer, more reliable, and less costly electric service. In addition, there are the environmental and public health benefits, such as: promoting energy efficiency by using an EV instead of gasoline; the reduction of air pollution and GHG emissions; and the increased use of electricity as a clean alternative transportation fuel. The settling parties contend that TURN has overlooked those benefits.

TURN argued that SDG&E's request to use the revenues from the sale of the cap-and-trade allowances should be denied because it violates the regulatory requirements. The nine settling parties contend that TURN's interpretation would lead to absurd results. Instead of addressing SDG&E's request to use the cap-and-trade revenues in a single coordinated proceeding, the nine settling parties contend that D.12-12-033 has already settled that issue, and that such a request can be raised in an appropriate proceeding.

Of the nine settling parties, three also sponsored testimony in this proceeding. The positions that these three parties took before the Proposed Settlement was entered into is summarized below.

4.1.2.1.1. Environmental Defense Fund (EDF)

EDF is a signatory to the Proposed Settlement, and also sponsored testimony in these proceedings. EDF recognizes that EVs possess the capability to provide grid benefits by charging at times when the benefit to the electric grid is the highest, such as utilizing renewable energy when it is abundant. EDF contends that the benefits of charging EVs in this manner will result in the following: (1) taking advantage of an abundance of solar and other zero-carbon energy on the grid; (2) enabling the smooth integration of increasing amounts of renewable energy while reducing reliance on GHG producing gas-fired resources to provide ramping services; and (3) enhancing value for EVs that will lead to increased market penetration. If the EVs are not charged in a "smart" manner, EDF contends that the EV load could then have a tremendous impact on grid resources if charged at peak times, and could lead to the building of additional infrastructure and power plants.

In order to meet the state's goals, EDF contends that intervention by the Commission is needed to help reach these goals. The current barriers to the low EV penetration in California include the following: lack of consumer awareness and information; higher upfront costs and range anxiety; and lack of access to public charging infrastructure away from home. In order to overcome these barriers and to meet the state's goals, the targeting of underserved markets such as MUDs and workplaces is needed. In addition, the EV charging must be done in a manner that benefits the grid and consumers by sending price signals to

charge when renewable resources are plentiful and inexpensive, and during off-peak hours.

EDF supports SDG&E's VGI program for the most part, but recommends: (1) that the Commission ensure that SDG&E's ownership of infrastructure does not undermine a competitive market for EV infrastructure and associated services; and (2) since SDG&E's VGI program is to be funded by ratepayers, the Commission should ensure that the utility be compensated on the basis of delivering the anticipated benefits of the pilot through a system of rewards tied to performance, including ensuring that disadvantaged communities are seeing benefits from the pilot.

EDF contends that SDG&E's ownership of the EV site installations and EV charging stations will help to expand the amount of EV charging infrastructure, and will accommodate the work schedules of EV drivers by charging at workplaces. EDF believes this will encourage competition in the EV market rather than discouraging it, and increase the demand for EVs. EDF also supports the recommendations of other parties for a robust education and outreach effort. However, EDF contends that the Commission should monitor market conditions, and ensure that competition and innovation is not compromised by allowing SDG&E to own the EV charging infrastructure.

In order to monitor the benefits of SDG&E's VGI program, EDF recommends that the Commission establish metrics to measure the extent to which these benefits have been realized. EDF suggests various environmental performance metrics and social justice performance metrics in Exhibit EDF-1. EDF contends that SDG&E's shareholders and ratepayers should both share the risk if the expected benefits do not materialize, and supports a performance

based ratemaking model that would reward shareholders based on agreed-upon and verified performance metrics

4.1.2.1.2. Natural Resources Defense Council (NRDC)

NRDC is a signatory to the Proposed Settlement and sponsored testimony. In its testimony, NRDC points out that the transportation sector is the single largest source of GHG emissions in California. In order to meet the federal Clean Air Act, and to achieve California's greenhouse gas emission reduction target, NRDC contends that the state's transportation sector will need to transition to ZEVs and near-ZEVs.

To meet these federal and state objectives, NRDC contends this will require significant adoption of PEVs by those who live in MUDs, and in disadvantaged communities. In response to some parties' arguments that EVs may not be the technology choice of the future and could lead to stranded investments, NRDC contends that numerous studies have concluded that in order to meet California's GHG emission reduction targets, that this will require the widespread use of ZEVs powered by low carbon electricity. NRDC contends that SDG&E's proposal for 5,500 charging stations will only result in a fraction of the EV charging stations that will be needed to recharge the number of PEVs that have been set as a goal for 2020 and 2025.

NRDC favors deploying EV site installations at both MUDs and workplaces. NRDC contends that potential EV owners are unlikely to purchase a PEV if they cannot recharge at one's residence. NRDC contends that targeting MUDs for the installation of EV site installations is necessary in order to scale up the adoption of PEVs. Through the targeting of workplaces for EV site installations, NRDC contends that this pilot can drive additional PEV sales,

increase the electric miles that are driven, helps to alleviate range anxiety, and ensure that PEVs are available in the afternoon to absorb and store the electricity produced during peak solar production.

With respect to the deployment of EV charging infrastructure in disadvantaged communities, NRDC supports requiring SDG&E to commit to deploying at least 10% of the site installations in disadvantaged communities. NRDC also points out that it advocated for the passage of the Charge Ahead California Initiative, and is advocating before the ARB for supplemental incentives to help low and moderate income households to purchase PEVs, and to increase access to ZEVs and near-ZEVs in disadvantaged communities. NRDC also supports JMP's recommendation for SDG&E to increase education and outreach efforts in underserved communities in partnership with CBOs.

NRDC favors electrifying the transportation sector because of the grid integration of tying EV charging to the availability of the existing spare generation capacity. If the EV charging load is integrated during off peak hours and at lower power levels that may reduce the need to construct new power plants.

In its rebuttal testimony, NRDC takes the position that each utility's proposal should be evaluated individually. Instead of requiring all three utilities to deploy a make ready approach, as some of the parties have advocated, NRDC contends that each utility proposal offers very different approaches toward meeting the state's goals. NRDC contends that SDG&E's VGI proposal has the potential of integrating EV charging load with the electricity generated from variable renewable resources such as solar. NRDC asserts that the "cost-effectiveness of a decision to buy a PEV with a higher incremental purchase

price hinges upon fuel savings, which can be maximized by charging during off-peak periods on time-variant rates." (Exhibit NRDC-2 at 3.)

Instead of adopting ORA's recommendation to form an "EVSE Pilot Working Group," NRDC recommends that SDG&E be directed to form an advisory group comprised of relevant stakeholders to help guide the implementation of the VGI program. NRDC opposes ORA's recommendation for a working group because of the lengthy delay that ORA's process would cause.

With respect to SDG&E's proposal to use competitive solicitations for independent contractors to furnish and install the site installations, NRDC recommends that SDG&E strengthen its commitments to supplier diversity and diversity contracting goals by: (1) improving minority contract spend; (2) improving outreach initiatives to increase and maintain diverse contractors; (3) consistent engagement with community groups to further strengthen supplier diversity efforts; (4) improving transparency and use of defined metrics to measure program progress and promote the improvement of industry standards; (5) investing in workforce training; and (6) early and consistent engagement with diverse businesses on upcoming contract needs.

4.1.2.1.3. Plug In America (PIA)

PIA sponsored rebuttal testimony. PIA's objective is "to accelerate the adoption of plug-in electric vehicles powered by clean, affordable, domestic electricity to reduce our nation's dependence on petroleum and improve the local and global environment." (Exhibit PIA-1 at 1.) PIA contends that the robust deployment of PEV infrastructure is critical for PEV market growth, and that the California utilities will play a major role in deploying infrastructure and encouraging the adoption of PEVs. PIA supports providing PEV drivers with

pricing signals so they can make intelligent choices about when they should charge their PEVs in order to maximize the use of renewables and off peak electricity.

However, PIA does not believe that SDG&E's VGI proposal maximizes EV drivers' usage of the charging stations because of SDG&E's limited deployment of Level 1 charging, and because SDG&E is not installing DC fast charging. PIA contends that PEV drivers and property owners of potential site installations need more flexibility in configuring the EV charging stations. PIA recommends that SDG&E implement additional or exclusive Level 1 charging for certain sites where it is appropriate. In addition, DC fast charging should be introduced as part of SDG&E's pilot program. PIA anticipates that Level 2 charging at the home will decrease as longer range PEVs are introduced into the market.

PIA contends that the offering of low cost or free low power charging at the workplace is one of the greatest incentives to PEV ownership. Level 1 or low power Level 2 charging at the workplace will enable most PEVs to recapture the energy used in the commute to work, while causing the least grid demand.

PIA contends that the EV infrastructure that is being built must be capable of evolving as the EV market develops. That is why PIA supports allowing EV drivers and property owners of the site installations "to choose their own EVSE or charging infrastructure from an approved list of vendors compatible with the goals and technology required by SDG&E's pilot program." (Exhibit PIA-1 at 6.)

Regarding the proposals to implement EV charging infrastructure using a make ready approach, PIA contends that the make ready strategy is unproven, and that such an approach has not resulted in significant deployments of make ready stubs as part of the Commission's settlement with NRG to deploy EV site installations.

4.1.2.2. Other Signatories Filing Separate Briefs and/or Sponsoring Testimony

Four of the other signatories to the Proposed Settlement filed separate briefs.[18] Those parties are ChargePoint, GPI, KnGrid, and Siemens. In the paragraphs below, we describe their positions.

4.1.2.2.1. ChargePoint, Inc. (ChargePoint)

ChargePoint filed its own opening and reply briefs in support of the Proposed Settlement, and a reply to the Settlement Motion. ChargePoint also sponsored testimony. ChargePoint recommends that the Proposed Settlement be adopted. ChargePoint does not support the adoption of SDG&E's VGI program as originally proposed. ChargePoint contends that the program modifications in the Proposed Settlement include provisions that address the "issues raised by various parties, including industry participants, environmental and clean energy advocacy organizations, and representatives of disadvantaged communities." (ChargePoint, September 4, 2015 Opening Brief at 3.)

ChargePoint mentions that among the program modifications in the Proposed Settlement are the following: the availability of the VGI Rate-to-Host option; allowing the site hosts to select the EVSE and services for their sites from a list of prequalified vendors; and the requirement that SDG&E assess a participation payment on site hosts, except at sites located in disadvantaged communities. According to Chargepoint, the modification to the VGI rate will result in more flexibility as to how the VGI rate can be offered, and encourage site hosts to participate in the VGI program. The modification allowing the site hosts to select the EVSE and services that they want will encourage innovation,

[18] Of these four, ChargePoint, GPI, and KnGrid also sponsored testimony.

and allow them to decide if services in addition to or complementary to the VGI program are appropriate. ChargePoint contends that the site host participation payment "will help ensure that EVSE will go where demand truly exists (which avoids stranded costs), and that requiring the site host to have 'skin in the game' will provide an incentive to 'right size' the installation and maintain it." (ChargePoint, September 4, 2015 Opening Brief at 6.)

Another modification that was made in the Proposed Settlement involves the addition of an interim progress report to the Commission, which is to include the data as described in Appendix B of the Proposed Settlement. ChargePoint contends that this will obligate SDG&E to begin collecting data on the first day of the program implementation, and allow the Commission and other parties to monitor, assess, and make improvements to the VGI program.

Prior to entering into the Proposed Settlement, ChargePoint filed a response to SDG&E's application indicating general support for a VGI rate, and raised issues about the structure of SDG&E's program. ChargePoint also sponsored testimony.

In general, ChargePoint's testimony addresses the scope and structure of SDG&E's VGI program, identifies potential impacts on competitive markets, and recommends ways in which to address such impacts and improve program design. ChargePoint recommends that the Commission order SDG&E to make certain modifications to its proposal to address the concerns that ChargePoint has raised. As described in its testimony, ChargePoint's concerns about SDG&E's original VGI program proposal center around three reasons.

The first reason for ChargePoint's concern is that it believes SDG&E's original proposal violates Public Utilities Code Section 740.3 because it allows SDG&E to unfairly compete with non-utility enterprises. In addition,

ChargePoint contends that SDG&E's original proposal fails the balancing test set forth in D.11-07-029, and reaffirmed in D.14-12-079, because SDG&E's proposal undermines competition and restricts customer choice. Prior to the Proposed Settlement, ChargePoint recommended that the Commission impose rules, conditions, and regulatory protections, as described in ChargePoint's testimony, to mitigate the anticompetitive impacts or unfair advantages caused by SDG&E's proposal.

The second reason why ChargePoint opposes SDG&E's original VGI proposal is because of several significant design flaws it sees in SDG&E's proposal. As described in ChargePoint's testimony, these flaws concern the following: the single specification EVSE process; the one-size-fits-all site specifications; the SDG&E customer requirement; the SDG&E VGI interface, and the mandated participation in the VGI rate; and providing free EVSE to the site hosts.

The third reason for ChargePoint's opposition to SDG&E's original VGI proposal is the size and phasing of the program. The size and phasing concerns are related to ChargePoint's concerns about program design and the anticompetitive impacts. ChargePoint is also concerned that the program would deploy 5,500 charging stations before any program review and adjustment takes place.

4.1.2.2.2. Green Power Institute (GPI)

GPI, a signatory to the Proposed Settlement, filed a reply brief in support of the Proposed Settlement. GPI also sponsored testimony.

GPI believes that on balance, the Proposed Settlement is "a step forward in promoting EV adoption, reducing GHG emissions, and protecting ratepayers

against undue costs." (GPI September 18, 2015 Reply Brief at 8.) GPI disagrees with those who advocate scaling back the size of the Proposed Settlement.

In its reply brief, GPI remains receptive to a number of modifications suggested by the other parties, especially those that would require SDG&E to only own the make ready stubs of the EV site installations. In its testimony, GPI took the position that SDG&E's program should only allow make ready ownership. GPI states in its reply brief that it would not be opposed to such a modification to the Proposed Settlement.

Although the Governor's Executive Order is not binding on the Commission, GPI contends that the Commission has been engaged in activities involving EVs that help fulfill the Governor's objectives, and that the statutory enactments require the Commission to meet a number of targets for EVs.

In its prepared testimony, GPI is supportive in general of SDG&E's application because of the concern that EV sales are falling behind the schedule that is required to meet Governor's goal of one million ZEVs by 2020, and 1.5 million ZEVs by 2025. GPI contends that at "the end of 2014 and beginning of 2015, sales of ZEVs in California were robust but declining, and sales are clearly below the levels of growth we need to see in order to reach the 2020 and 2025 goals." (Exhibit GPI-1 at 4.) In order to meet the 2020 goal, GPI contends that a 45% annual growth rate is needed. To meet the 2025 goal of 1.5 million ZEVs, a 26% annual growth rate is needed.

In order to meet those goals, GPI contends that the Commission and other entities will need to do much more than they are currently doing in order to promote the adoption of ZEVs. GPI believes that this can be accomplished by making the following changes to SDG&E's original VGI proposal.

First, GPI recommends that the four guiding principles set forth in the July 16, 2014 scoping memo and ruling in R.13-11-007, and which are described in Exhibit GPI-1, be used to evaluate SDG&E's application. In addition, GPI recommends that the following two additional principles be used as well:

- Promote utility-financed PEV infrastructure solutions that can be shown to be cost-effective, regardless of whether such facilities are owned by the utilities or third parties.
- Leverage utility resources and networks to maximize ratepayer education on PEVs, regardless of whether utilities or third parties manage such activities.

GPI's second recommendation is for the Commission to evaluate all three utility EVSE applications using a common evaluative framework. GPI contends that this framework should be based on the mandates set forth in the Governor's Executive Order concerning the goal for the deployment of ZEVs.

GPI's third recommendation is for the Commission to approve a make ready approach, as SCE proposes in its EV application, instead of SDG&E's proposal to own the EVSE infrastructure. Under GPI's recommendation, SDG&E would own and operate the infrastructure needed to accommodate the 5,500 charging stations, but would not own or operate the charging stations themselves. Alternatively, GPI recommends that the Commission allow SDG&E to own no more than 50% of the charging stations, and that third parties be allowed to bid on the ownership of the remaining 50% of the charging stations. GPI states that this third recommendation "is an appropriate balance between the policy concern of promoting EV ownership, and the EV market more generally, and anti-competitive impacts from allowing very large actors like SDG&E to be direct owners of chargers when there are viable third parties that can do so." (Exhibit GPI-1 at 10.)

The fourth recommendation of GPI is to reduce the timeframe of SDG&E's original VGI proposal. Instead of the five year rollout for SDG&E's VGI program, GPI recommends that the rollout be reduced to two years. In addition, GPI recommends that the additional data collection be reduced from five years to three years.

As described in Exhibit GPI-1, the fifth recommendation of GPI is for SDG&E to improve its cost-effectiveness analysis in several areas.

GPI's sixth recommendation is for SDG&E to clarify that one of the objectives of SDG&E's VGI rate is to absorb excess solar generation during times of peak production. GPI further recommends that SDG&E work with EVSE providers to incorporate the VGI rate into their software applications in order to make it as seamless as possible for EV drivers to take advantage of the VGI rate.

GPI's seventh recommendation is for the Commission and SDG&E to consider SDG&E's VGI proposal in the context of the Distribution Resource Plan (DRP). GPI contends that the goal of the DRP is to optimize the distribution grid for distributed energy resources, which includes EVs. As EV adoption grows, GPI contends it is likely the utilities will need to make significant upgrades to their distribution grids to accommodate the additional EV load, which needs to be considered in the DRP.

The eighth recommendation of GPI is for an independent evaluator to be appointed to oversee the expenditures associated with SDG&E's VGI program. GPI contends that the cost of an independent evaluator will be offset by the cost savings that will result from the evaluation of such costs.

In its rebuttal testimony, GPI supports the recommendations of other parties who favor a reduction in the size and scope of SDG&E's VGI proposal,

and the need for substantial third party education and outreach efforts. GPI recommends the following:

- GPI continues to support either the make ready approach, or that 50% of the EV site installations be owned by third parties.
- GPI agrees with the recommendations of ORA and TURN to scale back SDG&E's VGI proposal, and recommends that SDG&E be allowed to install make ready infrastructure for up to 200 MUD site installations and 100 workplace site installations, with up to 10 charging stations at each site installation.
- If a phased rollout is adopted, GPI recommends that the Commission preapprove phase 2 if the criteria described in GPI's rebuttal testimony is met by the phase 1 results.
- GPI recommends that some funds be set aside to help defray the costs of site installations for third party owners who can make a good case that they should receive at least a partial subsidy.
- GPI recommends that the Commission require a substantial increase in education and outreach funding (at least 25% of the budget for make ready infrastructure) for SDG&E's VGI program, with the majority of funding to go to third parties, such as Energy Upgrade California.
- GPI recommends that a workshop or additional steps be taken to focus on the education and outreach issues raised by SDG&E's application.

4.1.2.2.3. KnGrid, LLC (KnGrid)

KnGrid is a signatory to the Proposed Settlement, and also sponsored testimony.

In its testimony, KnGrid supports SDG&E's original VGI proposal because it believes the proposal is aligned with California's goal of fostering the development of a self-sustaining market for ZEVs. KnGrid contends that SDG&E's VGI proposal will address the cost barriers and consumer reluctance to EV adoption because SDG&E will be targeting the underserved MUD and

workplace market segments. During the five-year rollout and evaluation period, SDG&E will be able to experiment with different suppliers and technical approaches with respect to the offering of the VGI rate. KnGrid contends that the VGI rate will enable a PEV owner to use Level 2 charging in a manner "that helps electric system operators cost-effectively maintain system reliability as they increase the use of variable renewable sources of energy," and "enables lower total cost of ownership of PEVs through intelligent management of the vehicle's battery…." (Exhibit KnGrid-1 at 5.)

Before approving SDG&E's original VGI proposal, KnGrid recommends that the Commission first select a VGI interoperability standard in advance, and that the Commission require the EV charging infrastructure to adhere to this VGI interoperability standard. KnGrid contends that there are two available global VGI standards, ISO/IEC 15118 and SEP 2.0.[19] KnGrid contends that there is no value in developing a new VGI interoperability standard when these global standards are already available. KnGrid asserts that if the VGI interoperability standard is not established and codified at the outset, that this could result in additional risks in stranding ratepayer investments and costs because of the work and standards that have already been done.

4.1.2.2.4. Siemens

The other settling party who filed a separate opening brief, was Siemens, through its eMeter subsidiary. Siemens did not sponsor any testimony. Siemens is a supplier of EV charging hardware, software, and data management and control systems. Siemens supports the adoption of the Proposed Settlement.

[19] These abbreviations refer to the International Organization for Standardization (ISO), International Electrotechnical Commission (IEC), and Smart Energy Profile (SEP).

4.2. Non-Settling Parties

In the sections below, the positions of the non-settling parties are described. The summaries of their positions are taken from the pleadings that they filed, and from the testimony that they may have sponsored.

4.2.1. California Energy Storage Alliance (CESA)

CESA sponsored testimony in this proceeding, and filed comments on the Settlement Motion. CESA is a coalition made up of about "90 member companies that is committed to advancing the role of energy storage to promote the growth of renewable energy and a more efficient, affordable, clean, and reliable electric power system." (Exhibit CESA-1 at 1-2.) CESA's members include "energy storage technology manufacturers, renewable energy component manufacturers, renewable energy, fossil fuel and energy storage project developers, software developers, electrical contractors and systems integrators." (*Id.* at 2.)

In its testimony, CESA took the position that SDG&E's VGI proposal is "fundamentally flawed," and that the proposal would provide SDG&E with "an insurmountably unfair utility advantage if it were to proceed in its current form." (Exhibit CESA-1 at 2-3.) CESA claims that the critical flaw with SDG&E's proposal is that the playing field will be uneven because ratepayer funds will be used to install the SDG&E-owned EV site installations, which essentially provides site hosts with free EV charging infrastructure.

CESA contends that these EV charging infrastructure costs make up a substantial portion of the costs that third-party EV developers would have to incur. CESA's testimony estimates that the average per site EV service connection and EV charging infrastructure cost is about $60,000 including the total cost of ownership. CESA contends that SDG&E should not be allowed to

earn a rate of return on the EVSE that is rate based. Due to the uneven playing field, CESA contends this is likely to deter private investment, reduce customer choice, and slow innovation.

CESA also points out that SDG&E's vertically integrated ownership model will limit "customer choice of equipment and service pairings, and it proposes rigid network standards and payment mechanisms that could result in a balkanized statewide market for EV charging services." (Exhibit CESA-1 at 6.) Instead, the Commission should adopt a policy whereby EVSE and services can be "selected, purchased, and owned by customers to promote customer freedom of choice." (*Id*. at 7.) CESA also recommends that SDG&E's VGI rate structure be made available to third party developers of EV site installations. CESA contends that the benefit of opening up the ownership of the EVSE and the offering of other services will lead to innovative pricing, servicing, and technology solutions.

CESA contends that SDG&E's proposal to deploy 5,500 EV charging stations, with a target of a 20% market share, far exceeds a pilot program. CESA further contends that SDG&E's cost effectiveness arguments will ring hollow because third party investment in the EV charging market will falter, and there will be no other competitors to compare and test SDG&E's cost effectiveness results.

If the Commission agrees with SDG&E's 20% market share goal, CESA recommends that a competitive marketplace be preserved. This can be accomplished by allocating 20% of the authorized funding for SDG&E owned and operated EV site installations, and allocating 80% to make ready infrastructure and EVSE rebates to third parties. SDG&E should also be required to annually report on the deployment of SDG&E owned and third party owned

site installations, and to demonstrate that it is facilitating the growth of third party owned site installations. If ratepayer funds are sought to support additional utility investments, those costs would need to be justified, and stakeholders should be provided the opportunity to review the request for additional costs. To remove any incentive to unfairly impede competition, CESA recommends that the Commission restrict rate recovery of SDG&E owned site installations to actual pass-through costs. CESA further recommends that the EV charging tariff also be made available to third party owned site installations.

In its comments on the Settlement Motion, CESA takes the position that the Proposed Settlement still poses a significant risk to the provisioning of EV infrastructure and services by competing third parties. CESA recommends that the following protective measures be added to the Proposed Settlement to ensure that SDG&E's VGI program meets the balancing test adopted in D.14-12-079.

First, CESA recommends that an independent and diverse PAC be established, with the authority to report on key issues directly to the Commission. CESA recommends that the PAC include, but not be limited to, industry stakeholders that have no business engagements or obligation to SDG&E. These industry stakeholders, such as CESA, could provide independent and technically knowledgeable oversight. CESA also recommends that the PAC be permitted to provide regular periodic reports to the assigned Commissioner in R.13-11-007, and to Commission staff overseeing SDG&E's VGI program. CESA proposes that the reports address whether the VGI program is meeting the key points of the balancing test, and program modification recommendations.

CESA's second recommendation is that the data collection effort for the VGI program should include current and forward looking projections to

document the development of third-party and SDG&E-owned site installations. CESA recommends that this data be updated quarterly and provided to the PAC.

CESA's third recommendation is that 18 months after the Commission approves SDG&E's VGI program, SDG&E be required to file an interim progress report in R.13-11-007 containing the data in Appendix B of the Proposed Settlement, and which describes SDG&E's activities to date in implementing the VGI program, its impacts on deployment, and its market share in the market segments that SDG&E is targeting. CESA recommends that parties then be allowed to file comments on the interim progress report, including recommendations to change the VGI program. Workshops could then be ordered, or other appropriate action could be taken.

In order to encourage program participants to be actively involved and invested in the VGI program, CESA's fourth recommendation is to require a cost contribution from all participating VGI site hosts, except for those at sites located in disadvantaged communities. CESA recommends that this payment be in the amount of $1,000 per charging station. If SDG&E wants more than $1,000, SDG&E would have to consult with the PAC, and then file a Tier 2 advice letter to request approval.

The fifth recommendation of CESA is for the Commission to require SDG&E to implement the following procedures to ensure that third party site installations are not hampered, delayed, or overcharged.

(1) Data should be collected independently to assure accuracy of labor and costs, and that this data be subject to review and possible program adjustments.

(2) SDG&E should create appropriate firewalls to ensure that any non-utility EV site installations performed by SDG&E that use third-party charging platforms and applications are not shared with, or disclosed to, SDG&E's EV ownership personnel.

(3) Transparent policies and procedures should be created to ensure that third party site installations are queued fairly for the interconnection process, and that SDG&E site installations are not given priority or any preference.

(4) SDG&E should provide at least the same information and transparency to third party developers about EV charging sites or potential EV charging sites as SDG&E has.

(5) SDG&E should establish procedures to ensure unbiased pre-approval of design configurations that can be referenced by third parties, and not require extensive or repeated configuration studies of third party owned EV site installations.

4.2.2. Consumer Federation of California (CFC)

CFC filed a response to the Settlement Motion, and a reply brief. CFC recommends that the Commission reject the Proposed Settlement, and instead adopt the program recommended by TURN.

CFC contends that under the Proposed Settlement, all of SDG&E's ratepayers would be responsible for funding the development and construction of the 550 EV site installations across SDG&E's service territory. CFC takes the position that ratepayers should not be financially responsible for a program that in its view provides no tangible and definitive benefits to ratepayers. Although there may be environmental benefits, such as a reduction in GHG emissions and an increase in EV adoption, CFC contends such a program is outside the scope of utility service. CFC contends that shareholder monies should be used instead to support such a program.

In the event the Commission adopts an EV infrastructure program, CFC recommends that TURN's proposal for make ready stubs at 275 MUDs at a cost of $15 million should be adopted. This should then be followed by an evaluation afterwards of the cost allocation between ratepayers, site hosts, EV drivers, and SDG&E shareholders.

4.2.3. Federal Executive Agencies (FEA)

FEA represents the United States Department of the Navy, and other federal agencies. These agencies have many different locations in SDG&E's service territory, and a large number of the employees of these agencies are customers of SDG&E.

FEA sponsored testimony and filed various pleadings. The FEA is supportive in general of SDG&E's efforts to implement a VGI pilot program. However, FEA is concerned that none of the parties representing consumers support the Proposed Settlement, and recommends that the Proposed Settlement be rejected. FEA is also concerned with two rate design issues that have not been resolved by the Proposed Settlement. FEA contends that SDG&E's original VGI proposal, and the Proposed Settlement, fail to meet the requirement set forth in Public Utilities Code Section 740.3(c) which provides in part that the Commission "shall ensure that the costs and expenses of those programs are not passed through to electric or gas ratepayers unless the commission finds and determines that those programs are in the ratepayers' interest."

The first rate design issue that FEA is concerned about pertains to the volumetric rate design of the VGI rate. FEA acknowledges that the VGI rate is essentially a volumetric rate because the VGI rate will be charged to customers who use the service, when they use the service. As such, there is no practical way to separately levy demand charges and customer charges on this usage. FEA recommends that SDG&E monitor and track the revenue received from actual usage and compare that with SDG&E's projected usage. FEA also recommends that SDG&E file monitoring reports with the Commission about the usage. Such reports will provide all the parties with information as to whether

the volumetric rate should be redesigned and rates adjusted to recover a reasonable amount of revenues from the users of the EV site installations.

The second rate design concern of FEA is that the EV charging infrastructure costs will be spread across all of SDG&E's customers, instead of being confined to the users of the EV site installations. FEA contends that the EV drivers using the site installations should eventually pay for the full cost of the EV infrastructure. FEA recommends that as an initial step, the 2016 revenue requirement request of $3.8 million be included in the VGI base rates. FEA proposes that this amount be adjusted over time with the goal that the EV users of the site installations pay for the infrastructure costs, along with their EV charging usage. FEA acknowledges that requiring full cost recovery from EV drivers at the outset may increase the charging rate too much, which may deter potential EV drivers from utilizing these site installations.

4.2.4. Joint Minority Parties (JMP)

JMP refers to the following groups who have joined together and participated in this proceeding: National Asian American Coalition, Ecumenical Center for Black Church Studies, Jesse Miranda Center for Hispanic Leadership, Christ Our Redeemer AME Church, National Hispanic Christian Leadership Conference, Orange County Interdenominational Alliance, and the Los Angeles Latino Chamber of Commerce. JMP states that it is the "only direct-services oriented party representing minority groups in this proceeding," and represents ratepayers who will not utilize the VGI program infrastructure, but will be responsible for paying for the program. (JMP, July 3, 2015 Comments on Settlement Motion at 2.)

JMP sponsored testimony and filed pleadings in this proceeding. Although the JMP favors greater usage of EVs and the Governor's renewable

energy goals, JMP take issue with the excessive cost (over $100 million) and size (550 site installations with 5,500 charging stations) of both SDG&E's original VGI proposal and the Proposed Settlement. JMP contends that SDG&E has not provided sufficient evidence that the increased availability of EVSE will result in a substantial increase in EV adoption.

With a proposed budget of more than $100 million, JMP cautions that if the assumptions and projections of SDG&E are flawed, that considerable resources will be wasted. JMP recommends that SDG&E's original VGI program, and the Proposed Settlement, be rejected as not being in the interest of ratepayers, and unreasonable in light of the record. If the program is approved in some form, JMP recommends that the scope of the program be significantly reduced in size, cost, and cost recovery.

The JMP contend that since the VGI rate program is a new concept with significant unknown risk and uncertain benefits, SDG&E's VGI proposal and Proposed Settlement should be restricted to "a focused and narrowly sized test pilot program." (JMP, September 4, 2015 Opening Brief at 4.) They point out that an additional 5,500 charging stations would flood the existing 730 EV charging stations that exist already. In addition, the duration of this program includes installations over a five year period, and 20 years of cost recovery and O&M costs associated with the EVSE over their useful lives.

The JMP also question the assumptions about the benefits of SDG&E's VGI program. JMP points out that the anticipated benefits are based on the assumption that as more EV site installations are installed, that this will lead to the increased adoption of PEVs. However, the testimony of JMP and others point out that the high cost of a PEV will act as a barrier to increased PEV adoption. JMP also questions whether PEVs will be selected by consumers as the

preferred AFV in the coming years. JMP notes that hydrogen powered vehicles will soon be introduced in California, and that such vehicles can be fueled much quicker, and have a greater range than PEVs. JMP is also concerned about continuing low prices for oil, which may deter consumers from purchasing EVs even if there are rebates. Another reason as to why SDG&E's program should be scaled back is because of the changing technology involving PEVs and the alternative charging technologies that exist today.

The Proposed Settlement includes a provision that 10% of the site installations will be located in disadvantaged communities as identified by the CalEnviroScreen tool. The JMP is concerned with the lack of specificity regarding site selection in disadvantaged communities. JMP points out that the CalEnviroScreen tool provides data on a numerous indicators, and lacks the specificity needed to select site hosts in disadvantaged communities that can best utilize the EV site installations and to stimulate more EV adoption. The JMP also contend that SDG&E's responses to the August 5, 2015 ruling to clarify how potential site hosts in disadvantaged communities will be identified were vague.

JMP recommends that the site selection for EV site installations in disadvantaged communities should give priority to those communities with the greatest economic hardship factors. These factors could include such things as income, environmental pollution, and ethnic composition of neighborhoods. In addition, the site selection should be coordinated with the SB 1275 EV car sharing program, and in communities where there is a high level of participation in PEV subsidy programs.

JMP also contends that the Proposed Settlement lacks sufficient provisions to ensure that those living in disadvantaged communities will adopt EVs. Although the Proposed Settlement states that SDG&E will complement and

coordinate with government programs, such as SB 1275, there are insufficient details in the Proposed Settlement as to how this will be accomplished. JMP recommends that provisions be included in the VGI program which commits a specific amount of funding to subsidize the purchase of EVs in the form of rebates. JMP also recommends that the size of the rebate be higher for those with lesser incomes. Without subsidies and incentives to assist low income consumers in purchasing EVs, JMP contends that the EV charging facilities in disadvantaged communities will go underutilized, and result in unnecessary costs. JMP states that "Providing funds to reduce the high initial price of EVs is a far more tried and true and reasonable method of encouraging EV adoption than building EVSE where demand does not yet exist." (JMP, July 20, 2015 Reply Comments on Settlement Motion at 4.) JMP also believes that there will be a need for a massive educational, marketing, and outreach effort if rebates to purchase EVs are offered to those living in disadvantaged communities.

As for the role of the PAC, JMP contends that the PAC may be ineffective, and that its input will not be taken seriously. JMP points out that the Proposed Settlement lacks details on how the PAC members will be chosen, and states that there is nothing to prevent the PAC from being stacked with a majority of representatives from only a few organizations.

JMP favors the adoption of a pilot program that will mitigate the risk of stranded assets and reduce excessive costs. JMP supports TURN's proposal to reduce the scope of SDG&E's program, and to focus site selection at MUDs rather than at workplaces. JMP agrees with TURN's position that potential EV owners view the need for home charging as a significant factor, and that the MUD locations are currently underserved by the EVSE market.

JMP also recommends that SDG&E only provide the infrastructure up to the make ready stub. This will reduce the costs to ratepayers, while also reducing the cost barriers to third party EVSE suppliers, which is likely to lead to more third party EV site installations.

JMP opposes SDG&E's ownership of EVSE because of the anti-competitive impact on third parties, and the ongoing maintenance costs that would be required if the EV site installations are owned by SDG&E. JMP is open to limiting SDG&E's ownership of EV site installations to locations where third party EVSE providers are not interested in participating.

The JMP contends that the group of ratepayers who will benefit the least from the VGI program are low income ratepayers who will be required to pay a proportionate share of the VGI program costs. These same low income ratepayers are also the least likely to be able to afford PEVs. If the VGI program is successful, SDG&E's shareholders will benefit from the increased sales of electricity and distributed load. Instead of having ratepayers bear all of the risks of funding this program, the JMP favors shifting part of these costs onto shareholders, and the EV owners who will be using the site installations. JMP recommends that SDG&E's shareholders fund at least 50% of the program costs. JMP contends that this will help shift the burden away from all ratepayers, most of whom will not be utilizing the EV site installations.

The JMP recommends that ratepayers living in disadvantaged communities should only pay 10% of the program costs. JMP contends that this is equitable because only 10% of the EV site installations will be located in disadvantaged communities, and because low income ratepayers will be least able to afford an EV and are unlikely to use the EV site installations. Alternatively, JMP recommends that all low income ratepayers be responsible for

only 10% of the costs, and those enrolled in the California Alternate Rates for Energy (CARE) be completely exempt.

4.2.5. Marin Clean Energy

In its comments on the Settlement Motion, Marin Clean Energy supports the steps taken in the Proposed Settlement to expand the flexibility and the opportunity for customer choice in the deployment of EVSE. However, Marin Clean Energy cautions the Commission to be aware of possible anti-competitive impacts on non-utility load serving entities when it comes to site selection and electricity supply.

4.2.6. Office of Ratepayer Advocates (ORA)

ORA sponsored testimony, and filed a number of different pleadings in this proceeding. ORA recommends that a much smaller VGI program be adopted instead of the Proposed Settlement. Prior to the Proposed Settlement, ORA had recommended in its testimony that the Commission deny SDG&E's VGI proposal, and adopt ORA's Cal EVIP as the framework to design, approve, and implement the utilities' EV pilot programs.

With respect to the size of SDG&E's proposal, ORA contends there is no significant evidence that increasing the number of site installations at MUDs and workplaces will increase PEV adoption. ORA also contends SDG&E's proposal may create stranded assets if PEV technology develops to the point where large scale charging infrastructure is not needed. ORA further contends that SDG&E's VGI proposal is much larger than the size of other PEV charging infrastructure pilots in the United States, and larger than other pilot programs the Commission has authorized. Due to the number of charging stations in SDG&E's proposal, and its proposal to own all of the site installations and charging stations, ORA contends that SDG&E will likely have an unfair market advantage over third

party EVSPs. ORA contends that SDG&E's market advantage will be further reinforced by the ratepayer funding of SDG&E's VGI proposal.

With respect to the cost of SDG&E's proposal, ORA contends that the Commission should not approve a pilot program costing $103 million to test the unproven assumption that the siting of EV site installations at MUDs and workplaces will increase PEV adoption. ORA contends that ratepayers will end up paying for this EV infrastructure until around 2037 because $55 million of the $103 million represents capital costs for the EV infrastructure, which would be placed into ratebase under SDG&E's VGI proposal. ORA contends that SDG&E's proposal to install 5,500 charging stations exceeds the definition of a pilot project, and "more clearly resembles a full scale business model which is inappropriate when risking ratepayer money." (Exhibit ORA-1 at 2-15.)

In the event the Commission decides to adopt a VGI program similar to what SDG&E proposes, ORA recommends in its testimony that: (1) SDG&E's pilot program be reduced to 500 charging stations at a cost of $7.7 million, instead of the 5,500 charging stations that SDG&E requests; and (2) SDG&E's ownership of the site installations be restricted to 20% of the market (250 site installations), and that the remainder be open to third party participation. If the Commission only wants to adopt an SDG&E-owned pilot program, ORA recommends that SDG&E be authorized to install and own 200 charging stations. ORA further recommends that SDG&E submit a report approximately one year after the VGI program is implemented, in addition to the interim progress report that would be due under the Proposed Settlement.

ORA's primary recommendation, however, is for the Commission to deny SDG&E's application, and establish a pilot plan framework to design, approve, and implement the EV charging applications of SDG&E, PG&E, and SCE, and to

use that framework to guide the development of successive pilots or full-scale programs. ORA refers to its framework as Cal EVIP.[20]

As described in ORA's testimony, the Cal EVIP is based on four guiding principles, several design principles, and an implementation process. As part of the Cal EVIP process, an EVSE Pilot Working Group (Working Group) would be formed. The objective of the Working Group is to develop an EVSE Pilot Plan that can be deployed in each utility's service territory. As described at page 4-1 of Exhibit ORA-1, an EVSE Pilot Plan Study would be developed first to "examine the ability of different EVSE ownership models to address EVSE cost and access barriers." After this study is completed, EV pilots could then be authorized in each utility's territory. ORA's testimony recommends that hearings be held on ORA's Cal EVIP framework, and that the Commission approve such a framework.

Around the time ORA submitted its prepared testimony, ORA filed a motion on April 13, 2015 requesting that the three utility EV applications be consolidated, and that hearings be held on ORA's Cal EVIP proposal. A ruling denying ORA's motion was issued on May 28, 2015. The ruling denied ORA's motion because of D.14-12-079, which decided that each utility request should be examined on a case-specific basis.

In its September 4, 2015 opening brief, ORA recommends that a smaller program be authorized based on SDG&E's VGI proposal. ORA recommends that the program be divided into two phases.

[20] Exhibit ORA-2 specifically refers to ORA's Cal EVIP proposal. Although the Cal EVIP proposal is not specifically referenced in Exhibit ORA-1, ORA's proposal appears to be based on the principles and design guidelines referenced in Chapters 4 and 6 of Exhibit ORA-1.

In Phase One, ORA recommends that SDG&E be allowed to deploy make ready infrastructure[21] to support 750 charging stations, 10% of which would be in disadvantaged communities. ORA recommends that in Phase One, 75% of the charging stations be deployed in MUDs, and that 25% be deployed at workplaces.[22] Phase One should be at least 12 months long, and should continue until the 750 charging stations have been deployed.

Under ORA's proposal, the costs of Phase One would be funded by ratepayers for the EV service connection and the EV supply infrastructure. ORA recommends a 100% rebate for the costs of EV charger equipment that is deployed on a site host's property located in a disadvantaged community. Under ORA's proposal, the cost of the EV charger equipment would be the responsibility of the site hosts, third party EVSPs, or SDG&E's shareholders should SDG&E be allowed to own the charging stations.

If a program participation payment is assessed, ORA contends that the amount should be sufficient to defray more than a nominal portion of the customer site program costs.

ORA supports allowing the site hosts to choose from the VGI Rate-to-Host or VGI Rate-to-Driver options. ORA recommends that steps be taken in Phase One to develop performance requirements that the VGI Rate-to-Host participants

[21] ORA does not support utility ownership of charging stations, but recognizes that in Phase One, areas may be identified where utility ownership may be needed to increase EV adoption.

[22] ORA suggests that if there is insufficient interest to site the charging stations at MUDs, SDG&E could file an advice letter to modify the scope of the program. In addition, SDG&E should submit a report on why potential MUD host sites did not decide to participate, and to identify other barriers to overcome the lack of participation.

must satisfy, and to develop performance measures to assess the effectiveness of the site host's load management plan.

Due to the variables in the selection of site hosts, ORA recommends that the Commission be more involved, and provide oversight and direction during Phase One. At the outset of this program, the challenge of selecting the site hosts should be a priority. These challenges include such variables as: EV demand; site related characteristics; site owner willingness to sign easements; and VGI program requirements such as locating the site installations in a variety of distribution circuits, and siting them in disadvantaged communities.

ORA recommends that SDG&E submit quarterly progress reports during Phase One, and after 600 charging stations have been installed, that SDG&E issue an interim report on Phase One. Once 750 charging stations have been installed, a final report would be submitted. ORA recommends that hearings be scheduled on the Interim Report so that stakeholders can identify elements of the program that should be modified for Phase Two.

Based on the data and information gathered in Phase One, Phase Two implementation could then begin. ORA suggests that this phase could cover the remaining 4,750 charging stations, for a total of 5,500 charging stations.

ORA recommends that the Commission specify the format of the progress reports, which should describe at a minimum the following: how specific VGI program issues were identified; the processes for prioritizing issues; and the methods and timelines to resolve these issues. With respect to the Interim Report, ORA recommends that it "reflect information, data trends, and findings related to a list of performance metrics including, but not limited to, VGI marketing, education, and outreach…, site acquisition and installation efforts, EVSE deployment per market segment, EV charger utilization at the site level,

load impacts, fuel savings, and GHG reductions." (ORA September 4, 2015 Opening Brief at 16.)

4.2.7. Shell Energy North America (US), L.P. (Shell Energy)

Shell Energy raises two issues with respect to SDG&E's original VGI proposal, and the Proposed Settlement.

The first issue that Shell Energy is concerned about is that SDG&E would be the exclusive owner of the EV site installations and the EVSE under SDG&E's VGI proposal and the Proposed Settlement. In SDG&E's response to the August 5, 2015 ruling to clarify the Proposed Settlement, SDG&E responded that "utility ownership is necessary to ensure that all ratepayers, who are funding the VGI Program, are protected…." (August 21, 2015 SDG&E Response at 18; *See* Exhibit SDG&E-8 at 4-5.)

Shell Energy opposes SDG&E's position regarding the ownership of the EV site installations and the EVSE, and contends the Commission must allow for third party ownership of the EV site installations. Although one of the Guiding Principles of the Proposed Settlement is that the SDG&E program "must provide customer choice," Shell Energy contends there is no opportunity under either SDG&E's proposal or the Proposed Settlement for a third party to own and operate the EV site installation. Shell Energy contends that third party ownership of these facilities will do the following: reduce the utility costs borne by ratepayers; promote a competitive market for EV charging; increase the number of market participants; provide EV charging customers with a real service alternative; and prevent mischief if SDG&E owns both the upstream infrastructure and the EV site installation, and is also the electricity supplier. Shell Energy also points out that under the Proposed Settlement, SDG&E will be reviewing the site hosts' load management tactics for consistency with the

Guiding Principles, which could lead to SDG&E's regulation of the fees charged at the EV stations. In its comments on the Settlement Motion, Shell Energy also raised concern about the amount of the participation payment that site hosts would be responsible for, and to ensure that such a payment does not result in a competitive disadvantage for some market participants.

The second issue that Shell Energy raises is that the EV station owner or operator should be given the option of selecting its own electricity provider under direct access, or SDG&E, as its electricity provider. If the Commission allows SDG&E to own the EV site installations, Shell Energy contends that SDG&E should be required to purchase electricity from an electric service provider (ESP). Shell Energy contends that this new ESP load should not be subject to the cap on direct access under Public Utilities Code Section 365.1(b) and D.10-03-022, and that any new load should be exempt from the Power Charge Indifference Adjustment and any other departing load charges because this is unanticipated incremental load.

4.2.8. The Utility Reform Network (TURN)

TURN sponsored testimony in this proceeding and filed various pleadings. TURN supports the goal of promoting the adoption of PEVs in California. However, TURN does not believe that SDG&E's original VGI proposal and the Proposed Settlement are the best ways to achieve that goal, and that ratepayers should not have to bear all of these costs.

TURN recommends that SDG&E's original VGI proposal and the Proposed Settlement be rejected. TURN points out that under both of these proposals, the size of the program, and the ownership of the EV charging infrastructure, remain unchanged. TURN further contends that SDG&E's proposal and the Proposed Settlement are not reasonable or in the public interest because SDG&E's

ratepayers bear all of the risk, while SDG&E is providing ratepayer subsidized site installations and EVSE to site hosts for free or at a minimal cost. Although the Proposed Settlement is signed by 17 parties, TURN contends that virtually all of these parties supported SDG&E's application and did not raise major concerns.

TURN contends that the ratepayer funding and size of the VGI program raise competitive concerns. This may discourage third parties from investing in site installations in the future because of the 100% ratepayer funding of SDG&E's site installations.

TURN also contends that SDG&E's VGI program poses a significant risk of stranded costs to ratepayers because this is a new and developing market in which there is no guarantee that the EV site installations will be utilized, or that the additional EV site installations will result in the widespread adoption of EVs. In addition, future changes in EV charging technology and battery life could affect the utilization of the site installations. TURN further asserts that "the majority of the benefits go to the electric vehicle drivers, the owners of the properties that get free EV charging equipment, and utility shareholders." (TURN September 4, 2015 Opening Brief at 2.)

Although a participation fee was agreed to in the Proposed Settlement, TURN contends it is likely that such a fee will be nominal, and will not cover a substantial portion of the EV charging infrastructure costs. TURN also contends that SDG&E's cost effectiveness analyses, as described in TURN's testimony, demonstrates that the ratepayer benefits of the proposals are less than one-fifth of the costs of the program, and that non-participating ratepayers may not see any benefits. TURN further contends that SDG&E has failed to justify the need for 5,500 charging stations, and that SDG&E's ownership of the site installations

and charging stations is not required in order to test the potential benefits of the VGI rate. TURN also asserts that given the other market barriers to EV adoption (e.g., cost of EVs, range anxiety, charging time, battery replacement costs, and low cost of gasoline), there is no certainty that transportation electrification will be the most effective solution to reducing transportation emissions.

Regarding the Proposed Settlement's provision for SDG&E to submit an interim progress report two years after the VGI program is launched, TURN agrees with UCAN's comment on the Settlement Motion that "the interim progress report is not a sufficient check on the VGI Program because there is no requirement that SDG&E pause or suspend the program if the findings show it is unsuccessful." (TURN, July 2015 Reply Comments on Settlement Motion at 3.)

If the Commission decides to allow SDG&E to proceed with the original proposal or the Proposed Settlement, TURN recommends at a minimum that the program be phased in two parts, and with sufficient off-ramps to ensure that the program can be paused or terminated early if the program is not successful in promoting the adoption of EVs in SDG&E's service territory. The first phase should be a limited scale pilot to test the assumptions that form the basis of the program. Data collection and a report should occur, which would then trigger the start of the regulatory process for a second phase through the filing of a new application. TURN also recommends that the Commission require some sharing of costs and risks through a shareholder performance mechanism that places 10% of the capital costs at risk based on performance, as described in its opening brief and testimony. In addition, TURN recommends some contribution from site owners, that some of the fixed costs be included in the EV charging rate, and that site hosts be charged for special facilities pursuant to SDG&E's electric Rules 15 and 16. TURN also recommends that SDG&E be required to remove the EV site

installations from ratebase if the site installations are not regularly used for one year.

Instead of authorizing SDG&E to proceed with its original VGI proposal or the Proposed Settlement, TURN recommends that TURN's proposal be adopted instead. As described in its opening brief and testimony, TURN's proposal recommends that SDG&E be allowed to install and maintain make ready stubs at 275 MUDs to support 2,750 charging stations.

TURN contends that locating the site installations at MUDs is more likely to result in the adoption of EVs because all relevant studies emphasize the need for home charging, and MUDs are currently underserved by EV charging. The make-ready stubs would be composed of the supporting infrastructure for the charging equipment. The make ready stubs would allow the site host to retain ownership of the charging stations, instead of the charging stations being owned by SDG&E as provided for in SDG&E's original proposal and the Proposed Settlement. The Proposed Settlement's VGI Rate-to-Host option supports TURN's recommendation for SDG&E to build make ready stubs because under the Proposed Settlement, site hosts have the option of choosing the VGI Rate-to-Host option. Under TURN's proposal, this would allow the Commission to test whether the deployment of the make ready stubs will encourage EV market growth in a newly developing market.

TURN also contends that SDG&E should choose circuits with representative load shapes, instead of testing the majority of circuits in SDG&E's service territory. In addition, under TURN's proposal, the site host would select and pay for its own EVSE. TURN contends this shifts the technology risks to site hosts rather than on ratepayers, and allows the site hosts to select the EVSE and services that best meets their needs. Requiring the site host to purchase its EVSE

will also result in the site host having a financial interest in the installation of EV charging infrastructure at its site.

TURN's proposal would be subject to a cost cap of $15 million, which would be composed of $10.809 million for capital, $2.611 million for O&M expenses, and an allowance for unforeseen expenditures. TURN contends that its proposal would achieve "most of the EV adoption benefits and data collection benefits at a significantly lower cost." (TURN, September 18, 2015 Reply Brief at 9.)

TURN contends that SDG&E's VGI program fails to comply with Public Utilities Code Sections 453 and 783. TURN points out that pursuant to SDG&E's electric Rules 15 and 16, the installation of a second service line extension requires the customer to pay for any special or added facilities beyond the service line extension. TURN contends that under the VGI program, the trenching and conduits associated with the EVSE would have to be paid for by the ratepayers. TURN contends that SDG&E would waive Rules 15 and 16, which would violate the provisions of Public Utilities Code Sections 453 and 783.

TURN also contends that pursuant to Public Utilities Code Sections 740.3 and 740.8, the Commission must ensure that any ratepayer funded costs must provide direct benefits to ratepayers. These direct benefits must be in the form of safer, more reliable, or less costly service. TURN contends that the cost effectiveness test that SDG&E used demonstrates that the program is not cost effective, and SDG&E has not demonstrated that the VGI program will result in direct benefits to ratepayers.

SDG&E attempts to justify the funding of the VGI program by ratepayers as similar to taxpayer funding. TURN contends that SDG&E's argument ignores the fact that taxpayer funding comes from all taxpayers, whereas funding of the

VGI program would only be by ratepayers. TURN reminds the Commission to keep this in mind before using ratepayer funds for the VGI program that in its view primarily benefits SDG&E, site hosts, and EV drivers.

SDG&E requests that the Commission determine that SDG&E's VGI program is eligible to receive funding from the revenues generated through the sale of cap-and-trade allowances. TURN opposes SDG&E's request. TURN contends that SDG&E has not demonstrated that the VGI program meets the regulatory requirement that governs the use of cap-and-trade allowances because under the Proposed Settlement non-ratepayers can use the EV charging. TURN further contends that that in order to qualify for this funding, SDG&E must demonstrate that the installation of the EV charging stations is the cause of the expanded EV adoption which results in the GHG reductions. TURN also contends that before the Commission authorizes the use of the cap-and-trade allowances, that the Commission carefully consider SDG&E's request along with other alternative projects.

4.2.9. Utility Consumers' Action Network (UCAN)

UCAN sponsored testimony in this proceeding and filed various pleadings. In general, UCAN "supports the goals of EV grid integration that encourages EV ownership while avoiding the contribution of EV demand to the coincident system peak and the individual customer non-coincident peaks thus avoiding the need to add new generation and [transmission and distribution] capacity as the EV market grows." (Exhibit UCAN-1 at 6.) However, UCAN disagrees with the approach taken in SDG&E's original VGI proposal, and in the Proposed Settlement, and recommends that both approaches be rejected. UCAN contends that the Proposed Settlement fails to address concerns about the size, length, cost, and utility ownership of the VGI program.

As more fully described in its testimony, comments on the Settlement Motion, and its opening brief, UCAN remains concerned about the following in the Proposed Settlement:

- The VGI pilot sample size of 5,500 charging stations is too large, especially in light of the existing 240 non-single family residential locations with about 730 EV charging stations;
- SDG&E's cost effectiveness analysis is flawed, and it is uncertain whether ratepayers will benefit;
- The cost of the VGI proposal is too high, with $59 million in rate base and almost $103 million in total costs, yet SDG&E refers to this program as a pilot when the VGI program is much larger than a traditional pilot;
- The recovery of the capital cost of the charger equipment and other program and administrative expenses takes too long and will not be recovered until 2037;
- SDG&E favors utility-owned EVSE which increases ratebase, while others favor leaving EVSE investment to non-utility third party investors, and installation of make ready stubs only;
- The VGI program has many goals other than cost effectiveness, but the protocol and data requirements to assess these issues are not well defined;
- The decision to install 5,500 charging stations seems to focus on contributing to the Governor's EV goals of one million EVs in California by 2020, rather than to test the cost effectiveness of the program or to test grid integration using the VGI rate;
- There are no off ramps or exit strategies to terminate or redesign the program in the event the preliminary results of the pilot prove to be unsuccessful, and the Proposed Settlement's interim progress report is not designed to lead to any changes to the VGI program. UCAN agrees with TURN's suggestion that the VGI program be divided into two phases.

- Utility ownership of EVSE may be a less successful strategy than utility facilitation and stimulation of direct private and public sector investment in EVSE and operations.
- The amount of the program participation payment in the Proposed Settlement has not been defined, and is not the equivalent of having "skin in the game."
- Under the Proposed Settlement, the PAC's authority is advisory only, and SDG&E would be free to disregard any advice that is offered.
- The third party vendors of EVSE are permitted under the Proposed Settlement to offer site hosts additional services.
- Under the Proposed Settlement, the site host is permitted to add additional charges for the EV drivers who use the charging stations so long as the site host provides a plan which explains its load management tactics.

UCAN recommends that a smaller and less expensive pilot program be adopted. As set forth in UCAN's briefs and its testimony, UCAN's recommended approach is to make changes to SDG&E's original VGI proposal as described below. UCAN contends that its recommendation will allow for more third party involvement, and provide the Commission and SDG&E with valuable information regarding the pilot at a much lower and reasonable cost to ratepayers. UCAN recommends the following:

1. Reduce the size of the VGI pilot to the first 150 site installations installed over two years. A second phase after the first 150 may be acceptable if the initial cost effectiveness tests are positive.
2. Limit 50 to 75 of the 150 site installations to utility owned. The remaining 75 to 100 should be designed to provide infrastructure only (i.e., make ready stubs) with non-utility parties owning the actual site installations.
3. Test the dynamic VGI rate against other fixed period EV TOU rates to assess potential free ridership, incremental EV purchases, and incremental charger use by all owners,

comparing the VGI rate test group relative to the EV TOU control group.

4. Establish quantifiable site selection criteria to ensure sufficient capacity utilization of the EVSE to ensure positive cost effectiveness results, e.g., number of vehicles expected at each location, minimum standards for site installation capacity utilization.

5. SDG&E should focus initially on workplace site locations. The workplace installations draw on the entire population of EV drivers residing at both single-family residences and MUDs. Focusing on MUDs would only attract the incremental EV charging usage from the MUDs. Workplaces also offer the best sites for the testing of grid management during the day.

6. Tailor the charging stations per site to the size of the workplace or MUD site location instead of 10 charging stations at each site. The size of the potential workplace or MUD sites should determine the optimal number of charging stations per station. Site installations should be modular if possible, so as to permit expansion or to reduce investment, and thus avoiding the risk that the expected charger use may not materialize.

7. Prior to any further installations, the initial cost effectiveness results should be reviewed to determine whether the pilot should be terminated, expanded or redesigned. The cost effectiveness results should also determine whether utility-owned or infrastructure only installations have been more successful in terms of ratepayer cost responsibility, grid integration, incremental EV purchases, EV charger use and EV miles driven.

8. Refocus the program on leveraging non-utility investors in EVSE by acting more as a facilitator following the initial pilot phase of the program.

UCAN also provides other reasons as to why the size and length of SDG&E's VGI program should be reduced:

First, the size of SDG&E's proposal, as well as the Proposed Settlement, is too large and will make it difficult for third parties to compete because of the utility ownership, the number of site installations and charging stations to be deployed, and ratepayer funding of this infrastructure. UCAN contends this will provide SDG&E with an unfair market advantage. The VGI Rate-to-Host may not be a desirable option because the site host will need to prepare a load management plan, and a communications system to implement the load management plan.

Second, under the Proposed Settlement, SDG&E would own the site installations and the charging stations. However, this type of ownership will not test how the electric grid can be successfully managed in the future by the utility in the likely scenario where most of the EV site installations and charging stations are owned by third parties. UCAN contends that the VGI program should be designed to address third party ownership, such as requiring SDG&E to provide make ready infrastructure.

Third, under a make ready approach, SDG&E and its ratepayers would be indifferent as to the type of metering and billing services, and the technology to provide these services, which site hosts may want to offer.

Fourth, UCAN agrees with TURN that SDG&E's ratepayers should not be viewed as a source of taxpayer funding in order to implement the VGI program. Usually, a grant or subsidy program is paid for by taxpayers, but in this instance SDG&E's ratepayers are paying for the site installations and charging stations.

Fifth, for the reasons set forth in its testimony, UCAN contends that SDG&E's cost effectiveness analysis is flawed. UCAN contends that when the proper RIM test is used, the test demonstrates that SDG&E's VGI program is not cost effective.

4.2.10. Vote Solar Initiative (Vote Solar)

Vote Solar filed comments on the Settlement Motion, and an opening brief. Vote Solar supports efforts to promote the wider adoption of EVs and their integration into the electric grid. However, Vote Solar contends that the Proposed Settlement will allow SDG&E to select the most profitable charging opportunities in its service territory with ratepayer funding. Vote Solar also contends that the Proposed Settlement does not account for how EV batteries will be used to balance the grid instead of adding additional fossil fuel generation to meet the EV load.

Vote Solar recommends that the Proposed Settlement, as drafted, be rejected. Vote Solar recommends that the Proposed Settlement be approved if the following four additional modifications are incorporated into the Proposed Settlement.

The first modification that Vote Solar recommends is to require SDG&E, as part of the siting evaluation criteria, to include a site host's impact on alleviating grid constraints as identified in SDG&E's DRP. In addition, Vote Solar recommends that SDG&E be required to solicit applications in areas where grid constraints exist. Vote Solar contends these changes will allow SDG&E to evaluate the potential of using the VGI program to alleviate such constraints.

The second modification is to require SDG&E to establish clear criteria to demonstrate accountability, and to measure the effectiveness of the VGI goals. Vote Solar recommends that a plan be established for the measurement, evaluation, and verification of the VGI results at all of the EV site installations. Such a plan will provide the Commission with clear guidance on how to evaluate services in a uniform manner, and will ensure that site hosts know what is expected of them.

Vote Solar's third modification is that SDG&E should specify whether its EV charging equipment will have the capability for bidirectional power flow, from the grid into the EV battery, and from the EV battery into the grid. Vote Solar contends that this capability should be considered due to the size of SDG&E's proposal. If this capability is not considered, Vote Solar contends that this will fail to maximize the potential benefit of EV batteries providing grid services.

Vote Solar's fourth recommendation is to require SDG&E "to set aside $2 for every $1 spent on infrastructure upgrades for its VGI program to support interconnection of third party-owned systems outside the Applicant's program." (Vote Solar, September 4, 2015 Opening Brief at 5.) Vote Solar contends that such an "approach would preserve competition, encourage sustainable growth of the market, and create a level playing field for non-utility installations." (*Ibid.*)

5. Discussion of the Application and Proposed Settlement

5.1. Introduction to Analysis

SDG&E and the other settling parties filed their Settlement Motion requesting that the Commission approve and adopt the Proposed Settlement. The Proposed Settlement is based on SDG&E's original VGI proposal. As stated in the "Settlement Agreement Provisions" of the Proposed Settlement, "The settling parties find reasonable, as modified, SDG&E's proposal for the implementation of its VGI Program and cost recovery as described in SDG&E's Application and supporting testimony."

As summarized earlier in this decision, some of the parties presented testimony at the evidentiary hearings as to why SDG&E's VGI proposal should be adopted, while other parties proposed a variety of changes to SDG&E's

original VGI proposal. Thus, SDG&E's original VGI proposal was fully litigated in evidentiary hearings.

A review of the Proposed Settlement reveals that many of the modifications to SDG&E's VGI proposal incorporate certain positions taken by some of the parties before the Proposed Settlement was agreed upon. Due to a full vetting of SDG&E's original VGI proposal, and the positions taken by the other parties, a ruling was issued on August 5, 2015 which directed the parties to file opening and reply briefs on whether or not the Proposed Settlement, SDG&E's original proposal, or a variant of those proposals, should be adopted.

In deciding whether or not the Proposed Settlement regarding SDG&E's VGI proposal should be approved, and in deciding whether SDG&E's original VGI proposal or a scaled down version of the proposal should be adopted, there are four principal considerations that we must adhere to as we go through our analysis. We describe those considerations below, and then discuss them in more detail as we analyze SDG&E's original VGI proposal and the Proposed Settlement.

The first consideration is Public Utilities Code Section 451, which provides that the charge to ratepayers must be just and reasonable. Some of the parties contend that the cost, size, and scope of SDG&E's original VGI proposal, and the Proposed Settlement, would result in costs to ratepayers that would be unjust and unreasonable.

Since the Proposed Settlement, and SDG&E's underlying application, involves SDG&E ownership of EV charging infrastructure, the second consideration is the directive set forth in D.14-12-079. In D.14-12-079, the Commission endorsed an expanded role for the electric utilities to develop and support PEV charging infrastructure, and eliminated the blanket prohibition in

D.11-07-029 against electric utility ownership of PEV charging infrastructure. To evaluate whether a utility should be permitted to own PEV charging infrastructure, the Commission in D.14-12-079 determined that this should be decided on a case-specific approach, and that the balancing test in D.11-07-029 of weighing the benefits of electric utility ownership of PEV charging infrastructure against the potential competitive limitation that may result from that ownership, should be used.

The third consideration is the various code sections in the Public Utilities Code, the H&S Code, and the Public Resources Code, that address the deployment of EVs, EV charging infrastructure, GHG reductions, and the amount of energy that is to come from renewable sources of energy. In addition, the Governor's Executive Order and ZEV Action Plan provide further guidance concerning these various code sections, and what action needs to be taken.

The fourth consideration is that before a settlement can be approved and adopted, the Commission, pursuant to Rule 12.1(c), must evaluate whether the settlement is reasonable in light of the whole record, consistent with the law, and in the public interest.

Since the Proposed Settlement is based on SDG&E's original VGI proposal, as modified by the Proposed Settlement, we need to analyze the elements of SDG&E's underlying VGI proposal, together with the modifications that the Proposed Settlement would make, applying these four considerations

5.2. Rationale for EV Charging and SDG&E' VGI Concept

We first discuss the objectives behind SDG&E's VGI proposal and the Proposed Settlement, and our reasons for actively encouraging the deployment of EV charging infrastructure.

At the current time, there are approximately 15,000 EVs and 750 non-residential EV charging stations in the San Diego region.

The overarching objective of the VGI program, as set forth in SDG&E's original VGI proposal, and in the Proposed Settlement, is to help implement the goals set by Governor Brown and the State of California to deploy EV charging infrastructure to support one million ZEVs by 2020, and to have 1.5 million ZEVs on California's roads by 2025. Through the deployment of EV charging infrastructure, and promoting the adoption of EVs in California, SDG&E believes this will help to achieve the goal of reducing GHGs by reducing the number of vehicles that use fossil fuels, and increasing the use of renewable sources of energy by using the grid integrated VGI rate.

These goals are set forth in the Governor's Executive Order, and in various California statutes.[23] In Governor Brown's Executive Order B-16-2012, signed on March 23, 2012, the Commission and other state agencies were directed to establish benchmarks to help achieve the build-out of ZEV infrastructure able to support up to one million vehicles, and to integrate EV charging into the electricity grid by 2020. That Executive Order further directs the state agencies to establish benchmarks to help achieve the goal of having over 1.5 million ZEVs on California's roads by 2025.[24]

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[23] For example, see: Public Utilities Code Sections 399.11, 740.2, 740.3, and 740.8; H&S Code §§ 38501, 38550, 38551; Public Resources Code Section 25740; and Stats. of 2013, Ch. 418, § 1.

[24] The Governor's Executive Order subsequently became the focus of the Governor's Interagency Working Group on Zero-emission Vehicles, which issued a report entitled the "2013 ZEV Action Plan" in February 2013. The 2013 ZEV Action Plan identified specific strategies and actions that various state agencies would take to meet the milestones set forth in the Executive Order

In Section 1 of Chapter 418 of the Statutes of 2013, which enacted H&S Code § 44268, the Legislature found and declared, in part, the following:

(a) California is the nation's largest market for cars and light-duty trucks.

(b) The transportation sector is the biggest contributor to California's greenhouse gas emissions and accounts for approximately 40 percent of these emissions.

(c) California should encourage the development and success of zero-emission vehicles to protect the environment, stimulate economic growth, and improve the quality of life in the state.

(d) California should encourage and support the development of infrastructure for open and accessible public site installations.

(e) In order to reach the goal of 1.5 million electric drive vehicles in California by 2025, electric vehicle (EV) consumers need confidence that they can access a robust network of publicly available EV site installations. Any EV driver should be able to access any publicly available EV site installation, regardless of the system provider.

In H&S Code § 44258.4(b), the Charge Ahead California Initiative was established. (Stats. 2014, Ch. 530.) That subdivision states in part that two of the goals of this initiative are, (1) to place in service at least 1,000,000 zero-emission and near-zero-emission vehicles by January 1, 2023; and (2) to establish a self-sustaining California market for zero-emission and near-zero-emission vehicles in which zero-emission and near-zero emission vehicles are a viable mainstream option for individual vehicle purchasers, businesses, and public fleets. In Section 1 of Chapter 530 of the legislative enactment of the Charge Ahead California Initiative, the Legislature, in part, found and declared the following:

(e) Zero-emission and near-zero-emission vehicles, including light-, medium-, and heavy-duty vehicles and buses, can improve the

health and welfare of all residents, especially those in lower income households and disadvantaged communities, by reducing air pollution and greenhouse gas emissions.

…

(h) Automakers and truck manufacturers are in early commercialization of zero-emission and near-zero-emission vehicles, which can dramatically lower smog and greenhouse gas emissions even when emissions from the production, distribution, and refining of fuels and the generation of electricity are considered.

(i) Electric utilities are providing clean renewable electricity in increasing amounts to transportation customers throughout the state. Charging-service providers are beginning to deploy electric vehicle charging infrastructure throughout the state. Expanding the market for zero-emission and near-zero emission vehicles to underserved markets in California is a priority.

SB 350 (Stats. 2015, Ch. 547) was signed after the evidentiary hearings and briefing period had concluded, and is effective on January 1, 2016. Although SB 350 specifically exempts SDG&E's VGI application from the transportation electrification provisions of newly added Public Utilities Code Section 740.12 (Stats. 2015, Ch. 547, § 32) because the application was filed before the applicable date for SB 350, many of the provisions of that code section are instructive as to why the Commission should forge ahead with projects such as a VGI pilot program. Subdivision (a)(1) of Public Utilities Code Section 740.12 finds and declares, in part, the following:

(A) Advanced clean vehicles and fuels are needed to reduce petroleum use, to meet air quality standards, to improve public health, and to achieve greenhouse gas emissions reduction goals.

(B) Widespread transportation electrification is needed to achieve the goals of the Charge Ahead California Initiative….

(C) Widespread transportation electrification requires increased access for disadvantaged communities, low- and moderate-income communities, and other consumers of zero-emission and near-zero-emission vehicles, and increased use of those vehicles in those communities and by other consumers to enhance air quality, lower greenhouse gases emissions, and promote overall benefits to those communities and other consumers.

(D) Reducing emissions of greenhouse gases to 40 percent below 1990 levels by 2030 and to 80 percent below 1990 levels by 2050 will require widespread transportation electrification.

(E) Widespread transportation electrification requires electrical corporations to increase access to the use of electricity as a transportation fuel.

…

(G) Deploying electric vehicles should assist in grid management, integrating generation from eligible renewable energy resources, and reducing fuel costs for vehicle drivers who charge in a manner consistent with electrical grid conditions.

(H) Deploying electric vehicle charging infrastructure should facilitate increased sales of electric vehicles by making charging easily accessible and should provide the opportunity to access electricity as a fuel that is cleaner and less costly than gasoline or other fossil fuels in public and private locations.

All of the above references to the Executive Order and the various statutes provide the impetus and the legal grounds for the Commission to take action to approve and authorize the deployment of EV charging infrastructure by SDG&E, although, as discussed later, not on the size and scale that the settling parties agreed to in the Proposed Settlement.

Some of the parties contend that since the Commission is not an executive agency of the state, but rather a constitutional agency, the Commission should not be obligated to follow the Governor's Executive Order to deploy sufficient

EV charging infrastructure to support one million ZEVs by 2020. However, as noted in the footnote above, there are numerous statutes which direct the Commission and other state agencies "to evaluate and implement policies to promote the development of equipment and infrastructure needed to facilitate the use of electric power … to fuel low-emission vehicles," and "to overcome any barriers to the widespread deployment and use of plug-in hybrid and electric vehicles." (Pub. Util. Code §§ 740.3(a), 740.2.) This legislative direction to encourage the development of EV charging infrastructure, to promote the widespread adoption of EVs so as to reduce GHG emissions, and to promote the use of renewable energy resources, must not be ignored. The deployment of EV charging infrastructure will help assure potential purchasers of EVs that EV charging will be available. Thus, we conclude there is sufficient legal authority for the Commission to approve and authorize some form of a VGI program to be implemented by SDG&E.

The other goal of the VGI proposal is to test the offering of a VGI rate to EV drivers, and the deployment of EV site installations and the associated EV charging stations to site hosts. The VGI rate is designed to foster prudent use of the energy on the electric grid by offering lower electricity rates to EV drivers and site hosts of the EV site installations to encourage EV charging during off-peak electricity periods, and to maximize the use of energy generated from renewable resources during off-peak periods. The VGI rate will be made available on a day-ahead basis so that the EV drivers and site hosts are aware of the price of electricity on an hourly basis for their EV charging needs. The VGI rate for different hours of the day will be calculated by SDG&E, taking into account the amount of electricity that will be generated during the various hours of the day, the price of the electricity, and anticipated congestion conditions on

the CAISO transmission grid and SDG&E's local distribution circuits, and the effect of forecast error from the supply of variable renewable energy resources. Shortly before or after the day-ahead VGI rate is established, the EV driver can then use a software application to input how much the driver is willing to pay to charge the EV, and the amount of electricity or time it will take to charge the EV. Under the Proposed Settlement, if the VGI Rate-to-Host option is selected, the site host or its selected vendor will be required to supply SDG&E with a plan for managing the EV charging load.

Although some of the parties to this proceeding may disagree with the cost, size, or scope of SDG&E's VGI pilot program, none of the parties disagree with the goal of the VGI program to optimize efficient use of available electricity. SDG&E's VGI proposal is also consistent with R.13-11-007. When R.13-11-007 was initiated, the Commission stated that the first track of the OIR would "evaluate the potential and value of vehicle-grid integration, including the use of vehicle batteries for demand response or energy storage." (R.13-11-007 at 2.) The Commission stated that this first track "will evaluate utility activities that can support VGI initiatives and seek to establish rules that allow utilities, PEV drivers, and the grid to capture safely and reliably the benefits of PEV battery storage for the managed charging, and for providing demand response ancillary services to the grid and power markets." (*Id.* at 15.)

SDG&E's VGI proposal responds to R.13-11-007 in that SDG&E is proposing a pilot program to test the potential and value of a VGI program in SDG&E's service territory. As proposed, the design of SDG&E's VGI proposal would fulfill the ZEV Action Plan's goal of reducing the negative impacts of peak-time charging and integrating renewable energy resources into the grid. (*See* R.13-11-017 at 15.) As described by several witnesses, the electrification of

vehicles used for transportation offers opportunities to reduce air pollution and GHGs. Under SDG&E's VGI proposal, EV charging customers will be offered varying prices at different times of each day in order to incentivize them to charge their EVs during off-peak periods, and to maximize the use of the renewable energy that is available. Thus, the EV charging load will be integrated into the available electrical capacity on the grid. This type of VGI program should, in theory, reduce the amount of new generation assets that may need to be built in the future to meet growing EV charging load and over-generation conditions. Accordingly, we find that the goal of SDG&E's original VGI proposal, and as modified in the Proposed Settlement, is a reasonable concept to pursue because it responds to the call in R.13-11-017 for utility activities that support VGI initiatives.

In addition, the VGI proposal addresses the concerns in Public Utilities Code Section 740.2 about: (1) the widespread use of PEVs and EVs and the role and development of public charging infrastructure; (2) the impact of EVs and PEVs on grid stability and the integration of renewable energy resources; and (3) the widespread use of PEVs and EVs to achieve the state's goals regarding the reduction of GHGs, obtaining more electric generation from renewable sources of energy, and the shifting of emissions reductions responsibilities from the transportation sector to the electric industry.

5.3. Cost and Size of SDG&E's VGI Proposal and the Proposed Settlement

Although the Governor's Executive Order and the applicable statutes suggest or require the Commission to take action, the actions we take must still be compatible with other applicable Public Utilities Code sections. Among these code sections is Public Utilities Code Section 451, which requires that the charges

that ratepayers pay are just and reasonable. In considering what action we need to take in terms of promoting EVs and EV charging infrastructure, that needs to be balanced with the statutory requirement of having just and reasonable rates.

Thus, the next part of our analysis is to examine the cost and size of SDG&E's original VGI proposal, and the Proposed Settlement, and whether the cost of such a program results in just and reasonable rates. We address the cost and size of SDG&E's VGI proposal first because those are the two largest disagreements that the non-settling parties have with SDG&E's original VGI proposal, and with the Proposed Settlement.

Our analysis of the cost of the program refers to the amount that SDG&E and the settling parties are requesting for the VGI program. The size of the VGI program refers to the number of EV site installations and EV charging stations that SDG&E and the settling parties request be deployed, and the duration of the VGI program. We refer to the scope of the VGI program to mean the various program elements of how the program will be implemented and managed on a daily basis, and the disagreements that some parties may have with particular program elements. We discuss the concerns with the scope of the program elements towards the end of this discussion.

The cost of both SDG&E's original VGI proposal and the Proposed Settlement are the same. SDG&E and the settling parties are requesting almost $103 million for the duration of the VGI program. $55 million of the $103 million represents the capital costs of the EV infrastructure, and $39.4 million represents O&M costs. Recovery of these costs would take place over a span of about 22 years.

The size of SDG&E's VGI proposal, and that of the Proposed Settlement, are the same. Under both VGI programs, up to 550 EV site installations would be

deployed over a four- to five-year period, and up to 5,500 EV charging stations would be deployed throughout SDG&E's service territory. SDG&E would be the owner of both the EV site installations and the EV charging stations under both VGI proposals. However, under the Proposed Settlement, the site host would be allowed to choose the EVSE and related services from a list of vendors pre-qualified by SDG&E.

The parties whose primary interest is representing ratepayers who will be financially impacted by the utility's programs oppose both the cost and size of the VGI programs. As summarized earlier in the positions of the parties, these parties contend that SDG&E's VGI program is much larger in cost and size than any pilot programs that have been authorized by the Commission in the past. These parties, as well as others, contend that the request to install 550 site installations and to deploy 5,500 charging stations, would provide SDG&E with a competitive advantage because SDG&E will dominate the EV charging market in a few years in the San Diego region if the VGI program, as proposed, is approved. Some of the parties contend that most of SDG&E's ratepayers, who will end up paying for the program, will never use the EV charging infrastructure.

SDG&E and the other settling parties, including some groups whose primary interests are environmental in nature but whose members are also ratepayers of SDG&E,[25] recommend that the cost and size of the VGI program be approved as requested. SDG&E contends that the cost and size of the VGI program is appropriate and reasonable because it will provide sufficient

[25] These environmental concerns and interests are reflected in Public Utilities Code Sections 740.2, 740.3, and 740.8.

information and data to test the VGI rate and program. Deployment of the 550 site installations and the 5,500 charging stations over the four year sign-up period will allow for testing of the VGI program under a variety of circuit conditions. In addition, the locations being targeted by the VGI program are MUDs and workplaces, which are currently underserved by today's EV charging marketplace. SDG&E further contends that if the cost and size of the program is reduced, the sample size for testing the VGI rate will be reduced. SDG&E further contends that the rate impact on its ratepayers will be minimal, as shown in Exhibit SDG&E-3.

We are concerned with the cost of the VGI program as requested in SDG&E's application, and in the Proposed Settlement. Pursuant to Public Utilities Code Section 451, the charges to the utility's customers must be just and reasonable. In addition, before EV program costs can be passed on to SDG&E's ratepayers, the requirements in Public Utilities Code Sections 740.3(c) and 740.8 must be met.[26]

We first discuss whether the cost of SDG&E's original VGI proposal, and the VGI program in the Proposed Settlement, is just and reasonable.

Under SDG&E's original proposal, as well as the Proposed Settlement, the VGI program is intended and designed to be a pilot program. Potential site hosts will be recruited over a four year period to site an EV site installation on the site host's real property. A maximum of 550 site installations will be installed, with

[26] We are not persuaded by UCAN's comments to the proposed decision that before deciding whether the costs of the VGI program are just and reasonable under Public Utilities Code Section 451 that the Commission must first consider the cost effectiveness of the pilot project, and reject the pilot program if it is not cost effective. Instead, our analysis follows the four principal considerations that are described in section 5.1 of this decision.

approximately 5,500 charging stations. Data from the pilot will then be reported to the Commission in order to determine whether the VGI program should be expanded at a future date.

The cost of the VGI program will be nearly $103 million over the 22-year recovery period. Some parties assert that this exceeds the cost of any pilot program, or research, development, and demonstration project, that the Commission has authorized in the past. However, SDG&E and other proponents of the Proposed Settlement contend that the cost of the VGI program is appropriate and necessary in order to achieve the state's objectives of deploying EV charging infrastructure to support one million ZEVs by 2020, and to have 1.5 million ZEVs on California roads by 2025.

Although the rate impact on SDG&E's ratepayers would be less than half of one percent in the first year, we are concerned that the proposed deployment schedule may not result in an immediate growth of the EV market. In addition, the primary beneficiaries of SDG&E's VGI program in the near term will be the EV owners who end up using the EV charging infrastructure, and the site hosts who will receive the EVSE infrastructure in return for a grant of an easement and a participation payment. We acknowledge that over the long term there will be the societal benefits of less GHGs, and the increased use of renewable energy and avoided new power plants if EV owners take advantage of the VGI pricing structure. However, these societal benefits must be weighed with who will receive the direct benefits of the VGI program, who will end up paying for the program, and whether potential site hosts and potential EV owners will respond

as SDG&E and others predict.[27] Also, since the VGI proposal is supposed to be a pilot program, a more frequent review of the pilot program's progress is warranted as suggested by some of the parties.

SDG&E's analysis of the benefits anticipates that as a result of the deployment of the EV charging infrastructure as proposed in SDG&E's original proposal and in the Proposed Settlement, that there will be a growth in the number of EVs on California's roads. However, we are not as certain that the EV adoption rate will be as SDG&E expects. SDG&E's witness acknowledges that its analysis is "illustrative" only, and is not intended to be predictive of what will occur in the future. Also, some of the parties opposed to SDG&E's original VGI proposal and the Proposed Settlement cast doubt on how the projected EV adoption rate was derived, and whether SDG&E's projections will actually materialize given the challenges of convincing consumers to switch from gasoline fueled vehicles to EVs. As testified to by various parties, these challenges include: the price of EVs; educating consumers about the price of EVs with rebates or grants; range anxiety; sufficient EV charging infrastructure at residences and other locations; the trend toward longer EV mileage ranges; and the cost of operating an EV versus a gasoline vehicle.

With regard to the size of the project as proposed in SDG&E's original VGI proposal and in the Proposed Settlement, we are persuaded that a scaled down project is a more appropriate project, rather than spending $103 million to deploy 550 site installations, and 5,500 charging stations over a four to five year time

[27] Some of these concerns are also considerations that the Commission is to take into account under Public Utilities Code Section 740.1 when evaluating a utility's research, development and demonstration project.

period. In order to secure the sites needed to locate the EV charging site installations, the property owners of prospective MUD and workplace sites will need to consent, provide an easement to SDG&E, and to pay a participation fee under the Proposed Settlement. Although the theory of implementing and securing such sites makes sense on paper, getting sufficient property owners to agree to these preconditions may prove to be more difficult. In addition, since the EV charging market is still developing and battery technology is changing, there are still many unknowns regarding the EV market, and how potential site hosts and EV owners will respond. For all of the above reasons, we are not convinced that it would be a wise use of ratepayer monies to authorize a pilot project of the cost and size contemplated in SDG&E's original VGI proposal and in the Proposed Settlement. Instead, the cost and size of the VGI pilot project should be reduced to test how EV owners will respond, and how property owners will respond to receiving a free EV site installation and EV charging stations in return for an easement allowing such use, and paying a participation fee to participate in the VGI program. A scaled-down pilot size will also avoid deploying infrastructure on a huge scale while battery technology is still evolving.

Related to the cost and size of SDG&E's original VGI proposal, and the Proposed Settlement, is the duration of the program. The sign-up period to become a site host would last for four years. An interim report regarding the progress of the VGI program would not be submitted until two years after the VGI program is launched, at which time parties could comment on the report.

We are not comfortable with having a pilot program that stretches into five years, and for which ratepayers will be paying over a period of 22 years. In addition, we are concerned with the schedule in SDG&E's original VGI proposal,

and in the Proposed Settlement, that a progress report about the VGI program will not be submitted until two years into the program. Neither of those two time periods suggests that the duration of this program is a pilot program. We do not want to approve and authorize a pilot project that will cost $103 million without being able to timely review and evaluate the progress of the VGI program. Also, it would be foolhardy to authorize a pilot project of this amount, using ratepayer money, without some assurance that EV drivers will be using these site installations and charging stations on a frequent basis, and that such a deployment will contribute materially to the widespread adoption of EVs for everyday transportation.

For the reasons stated above, we conclude, pursuant to Public Utilities Code Section 451, that the charges SDG&E's ratepayers would have to pay for SDG&E's original VGI proposal, or the VGI program in the Proposed Settlement, would be unjust and unreasonable.

5.4. Applying the EVSE Ownership Balancing Test

The cost and size of SDG&E's original VGI proposal, and the Proposed Settlement, also raise cost-related issues about whether SDG&E should be entitled to own the EVSE. Under SDG&E's VGI proposal, and the Proposed Settlement, SDG&E would own the EV site installation and the associated EV charging stations. If we adopt a scaled down version of the Proposed Settlement, the issue of utility ownership of EVSE still remains. In this section of the decision, we address the EVSE ownership issue that was addressed in D.14-12-079.

In D.14-12-079, the Commission set aside the prohibition adopted in D.11-07-029 that electric utilities could not own EV charging infrastructure. The Commission adopted rules in D.14-12-079 to expand the utilities' role in the

development and ownership of electric vehicle infrastructure. These rules consist of using a case-specific approach to assess "any proposed utility program based upon the facts of specific requests," and a balancing test. (D.14-12-079 at 8.) The balancing test is based on the test that was adopted in D.11-07-079, which weighs the benefits of utility ownership of the EV charging infrastructure against the competitive limitation that may result from that ownership.

In applying the balancing test, the Commission stated in D.14-12-079 at 8, that the Commission will assess "the likely competitive impact on the market segment targeted, and whether any anticompetitive impacts can be prevented or adequately mitigated through the exercise of existing rules or conditions." In conducting such an approach, the Commission will examine, at a minimum, the following:

1) The nature of the proposed utility program and its elements; for example, whether the utility proposes to own or provide charging infrastructure, billing services, metering, or customer information and education.
2) Examination of the degree to which the market into which the utility program would enter is competitive, and in what level of concentration.
3) Identification of potential unfair utility advantages, if any.
4) If the potential for the utility to unfairly compete is identified, the commission will determine if rules, conditions or regulatory protections are needed to effectively mitigate the anticompetitive impacts or unfair advantages held by the utility. (D.14-12-079 at 8-9.)

The Commission also stated that "the benefits analysis applied in the balancing test will rely heavily on the guidance from Pub. Util. Code § 740.8." (D.14-12-079 at 9.)

Under both the original VGI proposal, and the Proposed Settlement, SDG&E would own the EV site installations and the EV charging stations. Under the Proposed Settlement, site hosts or their designees would have two additional options. The first is that the site host or designee can choose to take service under the VGI Rate-to-Host billing option. The second option is that the site host or designee will be allowed under either the VGI Rate-to-Driver or the VGI Rate-to-Host billing options to choose the EVSE and related services that they want, so long as the vendor has been preapproved by SDG&E. These two options appear to mitigate potential anticompetitive impacts by allowing the site host to offer VGI or other forms of pricing to site users, and by allowing preapproved third party providers to offer EVSE and related services to the site hosts. This allows site hosts to offer similar or enhanced EV charging services to EV owners. Having a choice of EVSE providers and other services promotes competition and innovation among the various providers of the EVSE and related services. We also note that the addition of these two options in the Proposed Settlement helps to resolve the unfair competition concerns that were raised originally by potential competitors.

As part of the balancing test adopted in D.14-12-079, the weighing of the benefits of utility ownership is to rely heavily on the guidance set forth in Public Utilities Code Section 740.8. Before its amendment in 2015 by SB 350, the ratepayer "interests" in Public Utilities Code Section 740.8 means direct benefits that includes activities that "promote energy efficiency, reduction of health and environmental impacts from air pollution, and greenhouse gas emissions related to electricity and natural gas production and use, and increased use of alternative fuels."

SDG&E points out that one of the benefits of SDG&E owning the EV charging infrastructure is that this will ensure that the EVSE remains in working order. The other benefits are that it will allow SDG&E to test the VGI rate, and the deployment of the EV site installations and charging stations will help spur the growth of EV charging infrastructure and the adoption of EVs.

In addition, applying the "interests" of ratepayers, as described in Public Utilities Code Sections 740.3 and 740.8, another benefit is that the VGI rate could result in lower electricity rates for EV charging, if EV owners respond to the VGI rate and charge at certain times of the day. Also, the EV charging under the VGI rate could absorb and maximize the electricity output from the use of renewable energy resources, reduce the use of fossil fuels in automobiles and for generating electricity, and promote the use of EV charging at the underserved MUDs and workplaces.

As testified to by several parties, there are three primary competitors in the San Diego area that are offering EV charging site installations or charging stations. If SDG&E's original proposal, or the Proposed Settlement, is approved, SDG&E would be the largest provider of EV charging site installations and EV charging stations once the VGI program is fully built out. SDG&E contends, however, that according to some projections, if SDG&E is allowed to deploy 5,500 charging stations, SDG&E will control less than 20% of non-residential EVSE in 2020, and only about 9% of EVSE in 2023. SDG&E's market share of the EV charging stations is expected to drop if the EV market develops as projected, which should allow other participants to enter the EV charging market.

ChargePoint and CESA noted in their testimony that SDG&E's original VGI proposal amounts to a vertically integrated ownership model. Several parties expressed concern that this vertical concentrated ownership by SDG&E of

the site installations and charging stations, and the offering of this infrastructure to site hosts for free or for a participation payment, could undercut the ability of third party providers of EVSE and EV charging services to compete in the EV charging marketplace. This could also lead to third party providers leaving the market. However, at least two potential competitors of SDG&E have agreed to the Proposed Settlement, which suggests that their competitive concerns have been addressed or resolved by the Proposed Settlement.

Other parties oppose SDG&E's ownership of the EV site installations and charging stations because SDG&E plans to include this infrastructure in ratebase, which would earn a return over 22 years.

Based on the testimony presented, if SDG&E's original VGI proposal or the Proposed Settlement is authorized by the Commission, SDG&E's ownership of the EVSE could pose competitive problems for nonutility vendors of EVSE and related EV charging services during the initial deployment by SDG&E of the EV charging site installations and charging stations. The competitive problems that would arise spring from the number of site installations and charging stations that SDG&E would own and control after four or five years of the VGI program. We recognize the need for utility involvement in spurring the development of an EV charging infrastructure, but at the same time we must be cognizant of the competitive impacts that SDG&E's concentrated ownership could have on third parties, especially during the early years of deploying EV charging infrastructure. If the EV market does not develop as projected after four to five years, SDG&E will be one of the leading providers of EV charging in the San Diego region at the end of that period.

As part of the balancing test adopted in D.14-12-079, we must also consider whether these potential anticompetitive impacts can be mitigated through rules,

conditions, or regulatory protections. SDG&E points out that any anticompetitive impacts that could arise as a result of SDG&E's ownership are offset by the Commission's regulatory authority over SDG&E, and over the VGI rate that can be charged. Another mitigation measure that could be taken, as some of the non-settling parties have suggested, is to reduce the cost and size of the VGI program, which would reduce the number of EV site installations and charging stations that SDG&E would own.

Applying the balancing test in D.14-12-079 and D.11-07-029, the ratepayers' interests and benefits as described in Public Utilities Code Sections 740.3 and 740.8, and the concern of unfair competition in Public Utilities Code Section 740.3(c), we conclude that EVSE ownership by SDG&E should be permitted in a scenario as proposed by SDG&E in the Proposed Settlement, or in a scaled down VGI pilot program patterned after the Proposed Settlement.

In applying the balancing test and the ratepayers' interest test to SDG&E's original VGI proposal, we reach the opposite result. We conclude that the balancing test for utility ownership of EVSE would not be met, as applied to SDG&E's original VGI proposal, because third party suppliers and operators would be prevented from offering EVSE and related services to the site hosts that SDG&E would be targeting. In addition, SDG&E would be able to offer the site installations and the EV charging stations at no cost to potential site hosts. This amounts to a ratepayer funded subsidy of the costs of deploying EV charging infrastructure, which would undercut the ability of third party providers to enter the marketplace. Thus, applying the EVSE ownership balancing test to SDG&E's original VGI proposal, we conclude that under the facts of that proposal, SDG&E should not be allowed to own the EVSE infrastructure.

Applying the balancing test to SDG&E's ownership of the EV charging infrastructure in the Proposed Settlement, or to a scaled down version of the Proposed Settlement, we conclude that the advantages of allowing SDG&E to own the EV site installations and the EV charging stations would be in the ratepayers' interests and outweigh the disadvantages that could result from a lack of competition. That is because under the Proposed Settlement, site hosts or their designees, can choose the VGI Rate-to-Host option, which allows site hosts to offer a similar VGI rate or other pricing option to EV charging customers. In addition, the Proposed Settlement allows the site host or its designee to select the EVSE and related EV charging services from preapproved vendors, which allows third party providers to offer competing EVSE and EV charging services. In addition, under the Proposed Settlement, the site host would have to pay a participation fee which will help offset a portion of EV charging infrastructure costs. Under a scaled down version of the Proposed Settlement, SDG&E ownership of EV charging infrastructure would be acceptable because there would be fewer EV site installations and charging stations owned by SDG&E.

To help mitigate possible anticompetitive impacts, and to encourage and promote the growth of private investment in EV infrastructure, particularly in the market segments that do not receive utility ratepayer funding through the VGI pilot program, additional regulatory protection and guidance is needed. In order to achieve the goal of deploying sufficient EV charging infrastructure to support the needs of one million ZEVs by 2020, and to have 1.5 million ZEVs on California's roads by 2025, we recognize that additional investments are needed beyond the VGI pilot program at MUDs and workplaces. In addition to the targeting of MUDs and workplaces, additional efforts at encouraging participation at single family residences and public charging venues is needed.

In order to prevent and mitigate potential anticompetitive activities, we agree with some of CESA's recommendations that certain procedures be implemented to ensure that third party EV site installations are not hampered or delayed. As pointed out in its comments on the proposed decision, we also recognize that SDG&E has certain protective mechanisms in place. We adopt the recommendation of CESA that SDG&E create appropriate firewalls to ensure that any non-utility EV site installations performed by SDG&E, or its contractors, that use third party charging platforms and applications, are not shared with or disclosed to personnel at SDG&E engaged in EV-related activities. We also adopt CESA's recommendation that SDG&E adopt policies and procedures to ensure that third party EV site installations are queued fairly for the interconnection process, and that the SDG&E site installations are not given priority or any preference. In addition, we adopt CESA's recommendation that SDG&E provide third party EV charging developers with information about the distribution system upgrade costs and load data for potential EV site installations. These adopted recommendations, along with the additional language recommended by SDG&E in its comments, have been incorporated into the alternative VGI program terms set forth in Attachment 2 of this decision.

We do not adopt CESA's recommendation that the data regarding the VGI pilot program costs be collected independently because the Commission and its staff have the authority to inspect the books, accounts, papers, or records of the public utility. (Public Utilities Code Sections 313, 314.) Also, we do not adopt CESA's recommendation that procedures be established to preapprove or shorten the time to review design configurations because each EV site installation is site-specific. However, we encourage SDG&E to work with the

PAC if such standardization is needed to achieve the EV infrastructure deployment goal.

5.5. Public Utilities Code Sections 740.3 and 740.8

Next, we discuss the cost-related issue of what needs to occur before the costs associated with the development of equipment or infrastructure for EVs can be passed on to electric ratepayers. Public Utilities Code Section 740.3(c) provides in pertinent part:

> The commission's policies authorizing utilities to develop equipment or infrastructure needed for electric-powered … low-emission vehicles shall ensure that the costs and expenses of those programs are not passed through to electric … ratepayers unless the commission finds and determines that those programs are in the ratepayers' interest. The commission's policies shall also ensure that utilities do not unfairly compete with nonutility enterprises.

Thus, before the costs of the VGI program can be passed on to SDG&E's ratepayers, the Commission must find and determine: (1) that the program is in the ratepayers' interests; and (2) that the utility does not unfairly compete with nonutility enterprises. This unfair competition provision is similar to the balancing test that is to be applied to utility ownership of EVSE, as discussed in the previous section of this decision.

Public Utilities Code Section 740.8 is instructive because it defines the "interests" of ratepayers as it is used in Public Utilities Code Section 740.3(c).

Prior to January 1, 2016, Public Utilities Code Section 740.8 defined the "interests" of ratepayers as follows:[28]

[28] In the pleadings of the parties filed in these proceedings, the parties referred to the pre-January 1, 2016 version of Public Utilities Code Section 740.8 as the basis for their arguments regarding how Public Utilities Code Section 740.3(c) should be interpreted.

> As used in Section 740.3, 'interests' of ratepayers, short- or long-term, mean direct benefits that are specific to ratepayers in the form of safer, more reliable, or less costly gas or electrical service, consistent with Section 451, and activities that benefit ratepayers and that promote energy efficiency, reduction of health and environmental impacts from air pollution, and greenhouse gas emissions related to electricity and natural gas production and use, and increased use of alternative fuels.

Then, as a result of SB 350, which became effective on January 1, 2016, Public Utilities Code Section 740.8 was amended to now read:

> As used in Section 740.3 or 740.12, 'interests' of ratepayers, short- or long-term, mean direct benefits that are specific to ratepayers, consistent with both of the following:
>
> (a) Safer, more reliable, or less costly gas or electrical service, consistent with Section 451, including electrical service that is safer, more reliable, or less costly due to either improved use of the electric system or improved integration of renewable energy generation.
>
> (b) Any one of the following:
>
> (1) Improvement in energy efficiency of travel.
>
> (2) Reduction of health and environmental impacts from air pollution.
>
> (3) Reduction of greenhouse gas emissions related to electricity and natural gas production and use.
>
> (4) Increased use of alternative fuels.
>
> (5) Creating high-quality jobs or other economic benefits, including in disadvantaged communities identified pursuant to Section 39711 of the H&S Code.[29]

[29] Both versions of Public Utilities Code Section 740.8, as well as Public Utilities Code Sections 701.1, 740.2, and 740.3, rebut CFC's contention that the VGI pilot program is outside the scope of SDG&E's provisioning of utility service. For example, Public Utilities Code

Footnote continued on next page

TURN originally argued that the reference to "direct benefits" in the pre-January 1, 2016 version of Public Utilities Code Section 740.8 should be interpreted to only refer to "safer, more reliable, or less costly gas or electrical service." In addition, since the "direct benefits that are specific to ratepayers" phrase precedes the phrase pertaining to "activities that benefit ratepayers" of that code section, TURN contends that the Legislature intended that these "direct benefits" should be preferred over the benefits to ratepayers that promote energy efficiency, reduce health and environmental impacts from air pollution, and GHG emissions related to electricity and natural gas production and use, and increase the use of alternative fuels. We do not agree with TURN's interpretation of the intent of Public Utilities Code Section 740.8 as it existed prior to the amendment by SB 350. The first use of the conjunction "and" in Section 740.8, as it existed before January 1, 2016, clearly suggests that both "benefits that are specific to ratepayers" and "activities that benefit ratepayers" are to be considered. Also, the reference to "direct benefits" refers to both "benefits that are specific to ratepayers" and to "activities that benefit ratepayers," and therefore that code section does not prefer "direct benefits that are specific to ratepayers" over "activities that benefit ratepayers."

Section 701.1(a) states in part that "in addition to other ratepayer protection objectives, a principal goal of electric and natural gas utilities' resource planning and investment shall be to minimize the cost to society of the reliable energy services that are provided by natural gas and electricity, and to improve the environment…." In addition, Public Utilities Code Section 740.2(f) provides that the Commission is to adopt rules to address among other things: "The impact of widespread use of plug-in hybrid and electric vehicles on achieving the state's goals pursuant to the California Global Warming Solutions Act of 2006 and renewables portfolio standard program and what steps should be taken to address possibly shifting emissions reductions responsibilities from the transportation sector to the electrical industry."

TURN's original argument is now moot in light of the amendment to Public Utilities Code Section 740.8 as made by SB 350, as quoted earlier. As amended, Public Utilities Code Section 740.8 no longer describes "direct benefits" as referring to "benefits that are specific to ratepayers in the form of safer, more reliable, or less costly gas or electrical service." Instead, "direct benefits" refers to the benefits listed in subdivision (a), and any one of the benefits listed in subdivision (b) of Public Utilities Code Section 740.8.Thus, in deciding whether the costs of the VGI pilot program can be passed on to SDG&E's ratepayers, the benefits resulting from such costs must be consistent with the benefits described in § 740.8. As a result of the VGI program, all customers, including the EV charging customer or the site host, are likely to receive "less costly" electrical service if the EV owner charges during the off-peak periods as determined by SDG&E's VGI rate, and the VGI rate is integrated into the grid which takes into account the conditions on the grid and the availability of renewable sources of energy during off-peak periods. As some of the witnesses testified, the VGI program can reduce costs by eliminating or reducing the need for additional generating capacity to meet the growth in EV charging demand.[30] Consistent with Public Utilities Code Section 740.8(b), the other direct benefits of the VGI program that accrue to all ratepayers are the following: (1) it could promote accelerated adoption of EVs which will promote the efficiency of travel; (2) it could reduce the health and environmental impacts

[30] In addition, the VGI service meets the "safer," "more reliable," and "less costly" interests of ratepayers in Public Utilities Code Section 740.8(a) because: (1) all of the construction and installation of the EV charging infrastructure will be performed safely, and to code, by licensed electrical contractors with EV infrastructure training certification; and (2) the VGI service will be a "more reliable" and "less costly" service because it will match EV charging demand to electricity supply, including integrating variable renewable sources of energy.

from air pollution because less fossil-based transportation fuels will be utilized; (3) the deployment of more EVs could reduce the amount of GHG emissions; (4) integrating the charging of EVs with the VGI rate would incentivize consumption during peak periods of renewable energy generation, which could maximize the use of renewable and alternative fuels to power vehicles; and (5) an integrated VGI program could eliminate or lessen the need to build more electric generation assets to meet growing EV charging load.

Therefore, under the ratepayers' interests test, as set forth in Public Utilities Code Sections 740.3(c) and 740.8, the VGI program would be in the ratepayers' interest.

However, the other factor that we must consider before the EV program costs can be passed on to SDG&E's ratepayers, is that the EV program does not unfairly compete against nonutility enterprises. (Public Utilities Code Section 740.3(c).) This factor is related to the cost and size of the VGI program, as well as the balancing test, all of which we discussed earlier. If SDG&E's original VGI proposal or the Proposed Settlement is approved, some of the parties are concerned that this will lead to too much EV charging infrastructure being concentrated in the hands of SDG&E, and that SDG&E will be able to select the most profitable sites ahead of the third party competitors. They point to the number of existing EV charging stations in SDG&E's service area, and what will occur if SDG&E is allowed to own the EV site installations and charging stations as requested in the original VGI proposal and Proposed Settlement. Instead of allowing SDG&E to own the EV charging infrastructure, some of the parties favor partial or entire ownership of these assets by the site hosts or their designees. Prior to entering into the Proposed Settlement, ChargePoint asserted that since ratepayers would be fully funding the costs of the EV charging

infrastructure, that this was analogous to predatory pricing because SDG&E would be giving away the EV site installation and EV charging stations to site hosts for free. ChargePoint argued that this would make it difficult for competitive suppliers to expand their business in SDG&E's service territory.

Other parties, including SDG&E and some of those who agreed to the Proposed Settlement, point out that some of the leading EVSE manufacturers and operators have agreed to the Proposed Settlement, which is an indication that these potential competitors of SDG&E are no longer concerned that the Proposed Settlement will result in anticompetitive impacts. SDG&E also contends that since its VGI pilot is subject to the Commission's regulation and oversight, that it would be impossible for SDG&E to enjoy or exercise market power. SDG&E also notes that it would be purchasing the EVSE from other vendors, and therefore is not competing with EVSE manufacturers. SDG&E also notes that it is targeting MUDs and workplaces, which are currently underserved by the EV charging market.

In applying the unfair competition factor in Public Utilities Code Section 740.3(c) to SDG&E's original VGI proposal, we recognize that the 100% SDG&E ownership of the EV site installations SDG&E proposes to deploy, combined with the SDG&E prescribed specifications for the EVSE, may result in anticompetitive impacts on EV charging operators and EVSE manufacturers. These impacts could occur because SDG&E would be the largest EV charging operator in the San Diego region if SDG&E's original VGI proposal is approved without any changes, and the EV market does not develop as projected. Also, SDG&E would have an advantage over nonutility EVSE manufacturers and EV charging operators because SDG&E would be providing this infrastructure at no cost to the site host. As a result, nonutility competitors would be placed at a

competitive disadvantage because they would have to pay for these costs or secure grants to offset these costs. Thus, if SDG&E's original VGI proposal were to be adopted by the Commission, which we do not, it is questionable whether the costs of such a program could be passed on to ratepayers because of these anticompetitive impacts.

We note that consistent with Public Utilities Code Section 740.3(c), the Commission, in authorizing the deployment of EV infrastructure, has been directed to "ensure that utilities do not unfairly compete with nonutility enterprises." In order to encourage nonutility EV charging providers to remain in, and to enter, the EV charging market, the Commission needs to be aware of activities that could be construed as being anticompetitive.

Under the Proposed Settlement, the anticompetitive impacts would be reduced somewhat because the site hosts or their designees would be allowed to choose the EVSE and related services that they want, so long as the equipment and services are on SDG&E's preapproved list. This is likely to lead to more competitive offerings of EVSE and other kinds of related services by potential competitors of SDG&E, as well as to innovations in providing this kind of equipment and services. In addition, under the Proposed Settlement, the site hosts would be obligated to pay a participation fee, which will help offset the ratepayer funding of the VGI program to some degree. Also, under the Proposed Settlement, site hosts can choose to receive the VGI Rate-to-Host option, which provides the site host or its designee with some flexibility on how the VGI rate is offered to EV owners. One additional consideration is that under the Proposed Settlement, SDG&E would target the underserved markets of MUDs and workplaces to locate EV site installations. Since these segments are currently underserved, it is difficult to accept the argument that targeting of

these segments is anticompetitive. Thus, if the Proposed Settlement is to be adopted by the Commission, the anticompetitive impacts would be less of a concern for passing on the costs of the Proposed Settlement to SDG&E's ratepayers.

If the cost and the size of the VGI program is reduced from what is being offered in the Proposed Settlement, that would strengthen the reasoning for finding that a scaled down VGI program will not result in SDG&E unfairly competing with non-utility enterprises. That is because the number of EV site installations and charging stations owned by SDG&E would be reduced, which would result in fewer EV site installations being owned by a single EV charging operator. As a result of this reduced ownership by SDG&E, other EVSE manufacturers and operators would have an opportunity to compete and expand their presence in the EV charging market. Thus, the costs of a scaled down version of the Proposed Settlement would meet the criteria for passing those costs on to SDG&E's ratepayers.

5.6. Decisional Crossroad

Having concluded that the charges to SDG&E's ratepayers associated with the cost and size of SDG&E's original VGI proposal, and the Proposed Settlement, would be unjust and unreasonable, we arrive at a decisional crossroad. That crossroad is whether we should reject both SDG&E's original VGI proposal and the Proposed Settlement without approving any alternative program. Or should we adopt a scaled down VGI program similar to what some of the other parties have recommended in their testimony and briefs.

As discussed earlier in this decision, the legislative enactments clearly direct that action be taken to deploy EV charging infrastructure and to promote the use of EVs, to encourage the use of renewables, and to reduce GHG

emissions. If we reject SDG&E's VGI program and the Proposed Settlement without approval of some alternative program, we essentially would have to start all over again at the beginning. That is, SDG&E would have to file a new application, and we would be in the position of applying the same review and decision-making processes again. This would further delay SDG&E's efforts at developing an EV charging infrastructure.

In order to achieve the goals and targets set forth in Public Utilities Code Sections 740.2 and 740.3, the Governor's Executive Order, and H&S Code § 44258.4, the Commission and the regulated electric utilities of this state need to be proactive. Rejecting SDG&E's original VGI proposal and the Proposed Settlement outright without the adoption of an alternative program will delay efforts to reach the state's goals and targets.

However, in authorizing and approving an alternative program, the Commission needs to be cognizant of the existing code sections, including Public Utilities Code Section 451, which requires just and reasonable rates, and to weigh and balance the state's policy objectives, such as environmental concerns, with the cost and benefits of such an alternative.[31]

In order to achieve the goals and targets set forth in the Governor's Executive Order and the various statutes, there needs to be proactive involvement by the public and private sectors. Utility ratepayers will not be able to, and should not, bear all of the costs of encouraging EV infrastructure development and promoting the use of EVs. This highlights the need to balance

[31] TURN notes that although SB 350's enactment of Public Utilities Code Section 740.12 does not apply to SDG&E's application, subdivision (b) of that code section states that "Programs proposed by electrical corporations shall seek to minimize overall costs and maximize overall benefits."

all of the competing priorities, policies, and programs, with just and reasonable rates, and in a manner that does not negatively impact the private EVSE market.

Earlier, we discussed SDG&E's original VGI proposal, and the Proposed Settlement. We discussed the cost and size of the two programs, the EVSE ownership issue, and whether the costs of those two programs could be passed on to SDG&E's ratepayers. We concluded that the cost and size of SDG&E's original VGI proposal and the Proposed Settlement would lead to unjust and unreasonable charges to SDG&E's ratepayers. In addition, we concluded that the EVSE ownership balancing test could not be met if SDG&E's original VGI proposal were to be adopted. With respect to utility ownership of EVSE in the Proposed Settlement, we concluded that EVSE ownership by SDG&E should be permitted in a scenario as set forth in the Proposed Settlement, or in a scaled down VGI pilot program patterned after the Proposed Settlement. As to whether the costs of SDG&E's original VGI proposal could be passed on to ratepayers, we concluded that it is questionable whether the costs associated with SDG&E's original VGI proposal could be passed on to SDG&E's ratepayers because of the anticompetitive impacts. For the Proposed Settlement, we concluded that the anticompetitive impacts would be less of a concern. For a scaled down version of the Proposed Settlement, we concluded that the costs could be passed on to SDG&E's ratepayers because of the reduced number of EV site installations and charging stations owned by SDG&E.

Based on our earlier discussion, as summarized in the paragraph above, we conclude that SDG&E's original VGI proposal as set forth in A.14-04-014 would result in charges to SDG&E's ratepayers that would be unjust and unreasonable under the circumstances. Accordingly, SDG&E's request in A.14-04-014 to adopt its original VGI proposal is denied.

In deciding whether the Settlement Motion's request to adopt the Proposed Settlement should be granted or not, we are guided by Rule 12.1(d) of the Commission's Rules of Practice and Procedure. Rule 12.1(d) states as follows: "The Commission will not approve settlements, whether contested or uncontested, unless the settlement is reasonable in light of the whole record, consistent with law, and in the public interest."

As discussed earlier, we have concluded that the cost and size of the Proposed Settlement would result in charges to SDG&E's ratepayers that would be unjust and unreasonable under the circumstances. Put simply, the cost and the size of the Proposed Settlement is too large for a pilot program that is designed to test the VGI rate in an environment where all of the EV charging infrastructure will be installed at MUDs and workplaces at a moderate cost or no cost to the site hosts. Since SDG&E's ratepayers would pay for all of the costs associated with the Proposed Settlement, we believe that the $103 million cost to ratepayers would be too burdensome in light of the Proposed Settlement's projected benefits. Applying Rule 12.1(d) to these concerns, we conclude that the Proposed Settlement is unreasonable in light of the whole record, and is inconsistent with the law because the charges to SDG&E's ratepayers for the Proposed Settlement would be unjust and unreasonable under Public Utilities Code Section 451. Accordingly, the Settlement Motion's request to adopt the Proposed Settlement is denied.

5.7. Alternative VGI Program Terms

5.7.1. Background

Rule 12.4 provides that when the Commission rejects a settlement, "the Commission may take various steps," including those set forth in subdivisions (a), (b), and (c) of Rule 12.4. Those subdivisions state as follows:

(a) Hold hearings on the underlying issues, in which case the parties to the settlement may either withdraw it or offer it as joint testimony,

(b) Allow the parties time to renegotiate the settlement,

(c) Propose alternative terms to the parties to the settlement which are acceptable to the Commission and allow the parties reasonable time within which to elect to accept such terms or to request other relief.

At this point in time, proposing alternative terms that are acceptable to the Commission for a VGI pilot program is a much quicker process to authorizing and adopting a pilot program. It is preferable to: having SDG&E start the clock over again by filing a new application; holding hearings on the underlying issues since most of those issues have been litigated already; or allowing the parties to renegotiate the settlement, and then submitting it to the Commission for approval.

Notwithstanding our rejection of SDG&E's original VGI proposal, and the denial of the Settlement Motion's request to adopt the Proposed Settlement, we do find merit in authorizing and adopting an alternative VGI program similar to the Proposed Settlement, but on a reduced scale and with increased oversight. As discussed earlier, none of the parties to these proceedings object to the concept of a VGI rate. The parties, however, disagree on the cost and size of the program, and with some of the elements or details of how the program should be structured.

In the discussion which follows, we use the Proposed Settlement to serve as the template for what we propose as the alternative VGI program terms that are acceptable to the Commission, and discuss the various parties' concerns with the elements and details of the VGI program. As discussed below, we have revised the Proposed Settlement to reflect the alternative VGI program terms.

The alternative VGI program terms are attached to this decision as Attachment 2. These alternative VGI program terms include: a reduction in the cost, size, and duration of the VGI pilot program; ensuring that a sufficient number of MUDs are represented in the site locations; more frequent reporting; and excluding certain customers from the costs of the pilot program. If SDG&E decides to accept the alternative VGI program terms, SDG&E is authorized by today's decision to implement what we refer to as the 2016 VGI Pilot Program.

Setting aside the cost and size of the Proposed Settlement for a moment, the Proposed Settlement offers a viable framework to deploy the VGI rate at EV charging infrastructure located at MUDs and workplaces, while allowing site hosts to choose the VGI Rate-to-Host option, and to choose the EVSE and EV charging related services from preapproved vendors (whose eligibility is determined on a rolling basis). As discussed earlier, this will help promote competition in the EV charging market. The Proposed Settlement also has procedures in place to encourage involvement by the PAC and CBOs in the siting of EV charging locations, and to suggest program changes to the VGI program. All of the above are attributes that should be retained in the terms of the alternative VGI program that we approve of today.

5.7.2. Proposals Regarding the Cost, Size, Structure, and Duration

ORA, TURN, and UCAN are the principal parties who have recommended reductions to the cost, size, structure, and duration of a VGI program for SDG&E.

As noted in the positions of the parties, ORA has made several different recommendations about what SDG&E's VGI pilot program should consist of. ORA's original recommendation was to adopt its Cal EVIP proposal as the framework to evaluate the EV applications of each of the three electric utilities.

ORA then recommended that if SDG&E's application was not denied, that the Commission should allow SDG&E to install 500 charging stations at a cost of $7.7 million, and that SDG&E's ownership of the EVSE be limited, and that the remainder be open to third party participation. In the event the Commission wants an SDG&E-owned pilot program, ORA recommended that SDG&E be allowed to install and own 200 EV charging stations. Then in its September 4, 2015 opening brief, ORA recommends that SDG&E be allowed to deploy make ready infrastructure to support 750 charging stations in Phase 1, 10% of which would be located in disadvantaged communities. Of the 750 charging stations, ORA recommends that 75% of the charging stations be deployed in MUDs, and 25% be deployed at workplaces. Phase 2 would then follow after quarterly progress reports, an interim report (after 600 charging stations have been installed), and a final report, are issued.

TURN recommends that SDG&E be allowed to install and maintain make ready stubs at 275 MUDs to support 2,750 charging stations. TURN's proposal would have a cost cap of $15 million ($10.809 million for capital; $2.611 million for O&M expense, and the remainder for unforeseen expenses).

UCAN recommends that a smaller and less expensive pilot program patterned after SDG&E's original proposal be adopted. UCAN recommends that SDG&E be allowed to install 150 EV site installations over two years, and that SDG&E be allowed to own 50 to 75 of these site installations. The remaining EV site installations would be composed of make ready stubs that third parties would own. UCAN recommends that deployment of these EV site installations focus initially on workplaces. A second phase could then take place if the initial cost effectiveness tests for the 150 site installations are positive.

5.7.2.1. Make Ready Stubs

Several of the parties recommend that SDG&E prepare make ready stubs only, or that a large percentage of the EV site installations be make ready stubs. Some of these parties contend that a make ready approach will allow for more ownership of EVSE infrastructure by non-utility third parties, which will promote competition in the EV charging market.

SDG&E and some of the other parties contend that each of the utilities are proposing their own individual EV charging programs, and that each utility should be allowed to build the EV charging infrastructure in the manner that each utility requested. SDG&E contends that allowing each utility to do so will provide the Commission with data about various program approaches, and will help guide the Commission in deciding how EV charging infrastructure should be deployed in the future.

We are not persuaded by the arguments that we should require SDG&E to use a make ready approach for some or all of its EV site installations. We see value in having SDG&E retain 100% ownership of the EV charging stations to ensure that all of these ratepayer-funded charging stations are working and remain available for EV charging. Along with other EV pilot program results and available market data, the ownership of the EV charging stations by SDG&E may also inform future Commission action on EV charging infrastructure ownership, and related transportation electrification issues. For those same reasons, we do not adopt the proposals of ORA, TURN, and UCAN for a VGI program that would require SDG&E to build all, or a certain percentage of, make ready stubs. Thus, our alternative VGI program terms do not require SDG&E to install stand-alone make ready stubs.

Some of the parties suggest that a portion of the VGI program monies be set aside to help fund the deployment of EV charging infrastructure by third parties. This recommendation to set aside funds for the benefit of third parties is based in part on anticompetitive concerns. We decline to set aside part of the VGI program funds approved in today's decision to help fund the deployment of EV charging infrastructure by third parties. As discussed, the Proposed Settlement, and the alternative VGI program terms, contains provisions that will encourage third party participation and competition. In addition, this decision is addressing a pilot program for SDG&E to deploy EV charging infrastructure, and SDG&E's application is not requesting that the Commission approve funds to help subsidize deployment of EV charging infrastructure by third parties.

5.7.2.2. Cost, Size, and Duration

Next, we address the cost, size, and duration of the alternative VGI program terms.

Although the proposals of ORA, TURN, and UCAN all propose that SDG&E construct some percentage of make ready stubs, these proposals also recognize that the cost and size of an alternative program should be reduced. As described earlier in this decision, some of the other parties also recommend that the cost, size, or duration of the pilot program be reduced.

ORA proposed in its testimony that its Cal EVIP proposal be adopted. ORA's Cal EVIP proposal was the subject of the May 28, 2015 ruling in which ORA requested that the EV applications of the three electric utilities be consolidated, and that hearings be held on ORA's Cal EVIP proposal. The May 28, 2015 ruling denied ORA's motion because D.14-12-079 had already decided that each utility request should be examined on a case-specific basis. This effectively stopped ORA's Cal EVIP proposal from going forward. We

affirm the May 28, 2015 ruling. In addition, for the reasons we discussed earlier about the actions that need to be taken to fulfill the Governor's Executive Order and related legislative enactments, we do not adopt ORA's Cal EVIP proposal in this decision as it would require the Commission, the three large electric utilities, and the parties, to start at square one to develop a new framework using ORA's Cal EVIP proposal, and to have the utilities file new applications consistent with the Cal EVIP framework.

As discussed earlier, we see merit in adopting a scaled down version of the Proposed Settlement. Due in part to the uncertainty of how site hosts and potential EV purchasers will respond to the large scale deployment of 550 EV site installations, and 5,500 EV charging stations, a scaled down version of the Proposed Settlement is warranted.

In order to adequately design and test the VGI rate under a variety of circuit conditions, while deploying EV charging infrastructure in sufficient quantities and minimizing the impact on SDG&E's ratepayers, a pilot program larger than the programs suggested by ORA, TURN, UCAN, and others, should be adopted. The pilot program should be reduced in duration, and the cost and size of the VGI program should also be reduced. The alternative VGI program terms that are agreeable to the Commission are to allow SDG&E to install approximately 350 EV site installations, with approximately 3,500 charging stations, over an approximately three year sign-up period. SDG&E shall complete all of the site installations and charging stations within one-year of the close of the sign-up period. SDG&E will be allowed to rate base the costs of the site installations and charging stations over their useful lives. This alternative VGI program shall be subject to a maximum budget of $45 million for the sign-up and installation period. This $45 million limit is approximately 69% of what

is being requested in SDG&E's original VGI proposal and in the Proposed Settlement, and is based on the estimated cost of 350 EV site installations and 3,500 EV charging stations over the first three years of the VGI program, before requirement of a participation fee, as originally proposed in Exhibit SDG&E-4, Table JBA-5. As shown in that table, the three-year capital and O&M costs total to $41.449 million.

With this startup budget, we expect SDG&E to deploy a minimum of 300 EV site installations, with a minimum of 3,000 charging stations. This is the minimum amount of site installations and charging stations we believe are needed to have a robust sample size to test the VGI rate. According to SDG&E's testimony, this startup budget should be sufficient to cover about 350 EV site installations, and 3,500 charging stations during the three year sign-up period. Budget permitting, SDG&E shall endeavor to reach or exceed the goal of 350 site installations and 3,500 charging stations during the sign-up period.[32] If sufficient funds remain at the end of the three year sign-up period, SDG&E is authorized to extend the sign-up period to increase the number of site installations and charging stations with the remaining budget.

As discussed in section 5.7.11, SDG&E shall establish a memorandum account to track its O&M costs, and apply the participation payments it receives from the site host, as an offset to the O&M costs.

SDG&E is authorized to seek cost recovery of its future capital and O&M costs in its general rate case proceedings after the $45 million is expended.

[32] We recognize, however, that these goals may be affected by costs and conditions over which SDG&E has limited control.

SDG&E will need to justify in those proceedings the continuing viability of the 2016 VGI Pilot Program and those proposed expenditures.

With a budget of $45 million, the first year impact on a typical residential customer using 500 kWh per month in the inland and coastal zones would be about an 18 cents increase for the year, or a 0.02% increase. With the full rollout of 350 site installations and 3,500 charging stations at the end of three years, the impact in the third year would amount to about a $2.75 increase over current rates on an annual basis.

We find that the cost, size, and duration, of this alternative VGI program terms is more reflective of a pilot program because the sign-up period for potential site hosts is shorter, the overall budget has reduced the cost and size of how much EVSE infrastructure will be deployed, and the Commission will be able to evaluate the results of the pilot in a shorter period of time. The smaller pilot size is also appropriate given the uncertainties of the developing EV market, and how potential site hosts and EV drivers will respond.

5.7.3. Site Selection Criteria

Today's approval for an alternative VGI program of approximately 350 EV site installations is large enough to test the VGI rate in a variety of different circuits and under different conditions. In order to obtain a representative mix of different circuits in the 350 site installations that would be deployed under the approved alternative VGI program, we will require as part of the alternative VGI program terms in Attachment 2 of this decision, that SDG&E select site host locations that represent a diversity of electric circuits.[33]

[33] We also note that the site selection criteria includes SDG&E's site selection criteria that is summarized in the "Background of SDG&E's VGI Pilot Program" in section 2 of this decision.

Vote Solar recommends that the site selection criteria consider how a potential site host could alleviate grid constraints as identified in SDG&E's DRP. In its testimony, GPI pointed out that possible conflicts could arise between SDG&E's DRP and its VGI proposal.

By way of background, Public Utilities Code Section 769 requires electrical corporations, such as SDG&E, to submit their DRP to the Commission by July 1, 2015. The Commission opened R.14-08-013 to guide the utilities in the development of their DRPs, and to review, approve, or modify the DRPs. The goal of the DRPs is to move the utilities toward a full integration of distributed energy resources (DER) into the utilities distribution system, planning, operations, and investment. The term "distributed resources," as used in Public Utilities Code Section 769 includes EVs.[34]

SDG&E filed its DRP in A.15-07-003, which was subsequently consolidated with R.14-08-013. SDG&E's DRP addresses how DER can be incorporated into the utility's existing and future electric distribution infrastructure and planning procedures.

We agree with Vote Solar that the site selection criteria should also be informed by the activities required of the utilities in R.14-08-013. We agree with Vote Solar's recommendation because, as noted above, the definition of "distributed resources" includes EVs. Also, the second Guiding Principle of the alternative VGI program terms in Attachment 2 of this decision provides that the implementation of the 2016 VGI Pilot Program is to be guided by the principle that it "Must be structured to provide net benefits to all ratepayers." The concept

[34] The term "distributed resources" also refers to "distributed energy resources" (DER). Both of these terms are used interchangeably in R.14-08-013 and A.15-07-003.

of net benefits is also included in Public Utilities Code Section 769(b)(3) and (b)(4). Pursuant to those two subdivisions, SDG&E's DRP proposal shall: "(3) propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources;" and "(4) Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers."

The effective integration of EVs as distributed resources in SDG&E's system is important to the design of the VGI rate because that rate incorporates location-based capacity constraints into pricing to benefit customers by avoiding upgrades and new generation capacity. Also, SDG&E's DRP proposal points out that the VGI rate can be used to send price signals to modify EV charging behavior in a way that is responsive to the needs of the local distribution system. As part of the DRP, SDG&E plans to expand its distribution planning process to include analysis to "help better identify where DER can interconnect with minimal impact and where interconnecting a DER can add value to the grid." (SDG&E A.14-07-003, DRP at 20.)

Accordingly, we agree that SDG&E's site selection in the 2016 VGI Pilot Program should coordinate and leverage the work being performed in R.14-08-013, such as the integration capacity analysis, to help identify potential locations for the EV site installations. The integration capacity analysis examines "the amount of DER capacity that can be installed on a distribution circuit without requiring significant distribution upgrades." (SDG&E A.14-07-003, DRP at 22.) We have added this coordination and leveraging of the work being performed in R.14-08-013 as one of the "Modifications To SDG&E's VGI

Framework" in Attachment 2. Similarly, the future results from the 2016 VGI Pilot Program may help inform the work that is being performed in connection with R.14-08-013. Coordinating the activities in the 2016 VGI Pilot Program with the work being done in connection with SDG&E's DRP in R.14-08-013 will result in a cost effective method of coordination that is consistent with Public Utilities Code Section 769(b)(3).

In the comments on the proposed decision, SDG&E and other parties expressed concern that the Commission should not overly rely on the DRP proceeding since it is still ongoing. We do not intend to prejudge the outcome of R.14-08-013 through this decision or in these proceedings. However, it is prudent to ensure that the developments in the methodologies and decisions in the DRP proceeding are leveraged in the 2016 VGI Pilot Program, and that such developments be considered in the site selection criteria and prioritization process.

5.7.4. Guiding Principles

The purpose of the 11 Guiding Principles that are set forth in the Proposed Settlement, is to help inform the modifications that were made to SDG&E's original VGI application, and to guide the implementation of the VGI program. Since this VGI program is to be a pilot program, we want to ensure that the budget approved for such a program is spent wisely. For that reason, we include two additional Guiding Principles as part of the alternative VGI program terms, in Attachment 2 to this decision, that are acceptable to the Commission. The first Guiding Principle that we add is: "Must manage program costs." The second Guiding Principle is to leverage the program funds to minimize overlap with similar activities that SDG&E and state agencies are pursuing. Thus, the second Guiding Principle that we add is: "Must complement other utility clean energy

programs and other non-utility programs, such as those being implemented pursuant to the Charge Ahead California Initiative (Stats. 2014, Ch. 530) which will build consumer demand for clean energy and zero emission vehicles."

With respect to allowing site hosts to choose between the VGI Rate-to-Driver, and the VGI Rate-to-Host option, we encourage SDG&E to enroll a significant number of the EV site installations under both of the VGI billing options. This will allow the Commission, SDG&E, and other parties, to compare these two options, how site hosts implement the VGI Rate-to-Host option, and whether these rate options affect the time of day of the EV charging.

5.7.5. Targeting of MUDs and Workplaces

The next item to discuss in the alternative VGI program terms is the targeting of MUDs and workplaces. SDG&E's original VGI proposal, and the Proposed Settlement, does not address the specific number of EV site installations and EV charging stations that will be deployed at MUDs and at workplaces. Some of the parties recommend that the VGI program focus exclusively on MUDs, while others favor a focus on workplaces.

The testimony demonstrates that both MUDs and workplaces are currently underserved by the EV charging market, and that potential and current EV owners value the convenience of being able to charge their EVs at their place of residence. There is also evidence to suggest that some workplaces may wish to provide free or reduced fees to charge their employees' EVs. In addition, some workplaces may want an EV site installation as a symbol of their environmental consciousness. Since property owners at both MUDs and workplaces will need to grant easements to SDG&E in order to site EV charging infrastructure at these locations, owners of MUDs may be more reluctant than owners of workplaces to grant easements due to tenant turnover and the uncertainty of attracting a tenant

who may need EV charging. In addition, due to property size constraints of a MUD, there may be insufficient parking spaces to accommodate EV charging. As a result, the siting of EV charging infrastructure at workplaces may be easier than trying to site this infrastructure at MUDs. If this occurs, SDG&E and third party providers of EV charging services may be reluctant to site such services at MUDs. For all of those reasons, we should ensure that the targeting of MUDs remains a priority. Accordingly, an alternative VGI program term will be added to the 2016 VGI Pilot Program that requires that between 40% and 60% of all site installations and charging stations are to be deployed at MUDs, with a target of approximately 50%.

5.7.5.1. Civil Code Section 1947.6

An issue related to the deployment of EV charging infrastructure at MUDs is the enactment of Civil Code Section 1947.6 (Stats. 2014, Ch. 529). Subdivision (a) of that code section provides in part that if certain conditions are met, a lessor of a dwelling "shall approve a written request of a lessee to install an electric vehicle site installation at a parking space allotted for the lessee that meets the requirements of this section and complies with the lessor's procedural approval process for modification to the property." Civil Code Section 1947.6(b)(1) specifically excludes Civil Code Section 1947.6(a) from applying to a residential rental property where EV "site installations already exist for lessees in a ratio that is equal to or greater than 10 percent of the designated parking spaces."

Pursuant to Civil Code Section 1947.6, a tenant of a residential rental property can make a request of the landlord to install EV charging infrastructure. This code section contemplates that the landlord will pay for all the costs associated with the installation of the EV charging infrastructure, and that the tenant will reimburse the landlord for those costs. (*See* Civil Code

Section 1947.6(g). With the alternative VGI program that we approve in this decision, SDG&E is to provide the EV charging infrastructure at no cost to the site host except for a participation payment. A situation could arise where the VGI program may conflict with Civil Code Section 1947.6, such as where the owner of the MUD may look to SDG&E to provide the EV charging infrastructure, instead of paying out-of-pocket to install this infrastructure.[35] This is an issue that we will direct the Energy Division to monitor and to determine if it affects MUD siting decisions. The Energy Division should also bring this issue to the attention of the California Energy Commission and the ARB, and to cooperate with those agencies regarding this issue.

5.7.6. Charging Technology

There are currently three primary EV charging methods that can be used with most EVs, and the charging method that Tesla uses to charge its vehicles. The three primary charging methods are Level 1 charging, Level 2 charging, and DC fast charging. As part of the modifications made in the Proposed Settlement, it specifically excludes DC fast charging as part of SDG&E's VGI program.

Prior to agreeing to the Proposed Settlement, PIA recommended that SDG&E's VGI program include DC fast chargers as part of SDG&E's deployment of EV charging stations. Other parties also suggest that new charging technologies may replace Level 1 and Level 2 charging in the future.

[35] This potential conflict is another reason why the funding of the alternative VGI program has been reduced. If more monies are available for siting EV charging infrastructure, potential sites host may come to expect subsidized funding of the EV charging infrastructure in the future. Such an expectation by potential site hosts could reduce third party involvement in the EV charging market.

As part of the alternative VGI program terms, we will not delete the statement that "SDG&E's VGI program does not include the installation of DC Fast Charging equipment." DC fast charging is capable of supplying electricity into an EV in a much shorter amount of time than Level 1 or Level 2 charging. Since the VGI rate is based on time-differentiated hourly rate, it may be more advantageous to use a slower charging method such as Level 1 and Level 2 charging. For that reason, SDG&E's VGI program shall not include DC fast charging.

5.7.7. Disadvantaged Communities

The Proposed Settlement targets disadvantaged communities for the placement of 10% of the EV site installations and EV charging stations. The targeting of disadvantaged communities for the siting of EV site installations raises an issue about whether the CalEnviroScreen tool will be able to identify locations that could benefit the most from the placement of such stations. Possible locations, for example, could include communities with higher pollution levels, or communities that could provide the highest benefit for a given deployment.

In the Proposed Settlement, SDG&E committed to work with CBOs to help with education and outreach, and to prequalify and sign-up site hosts for participation in the VGI program. As part of the alternative VGI program terms, we will also require SDG&E to work with the CBOs to identify disadvantaged communities that could benefit the most from the deployment of EV site installations.

The Proposed Settlement also contains other methods for how disadvantaged communities can be targeted. One method is for preapproved third party vendors to market and sign-up potential VGI facility site hosts,

including those located in disadvantaged communities. The Proposed Settlement also provides that SDG&E will solicit the participation of the PAC in planning and implementing the VGI program. As part of the PAC responsibilities, the PAC can recommend program changes to prioritize potential VGI host sites for the equitable deployment of EV charging infrastructure. In addition, the identification of disadvantaged communities can also be coordinated with the work that ARB is doing in disadvantaged communities to increase EV adoption as part of the Charge Ahead California Initiative, including the programs set forth in H&S Code § 44258.4(c)(4) such as EV car sharing, and leveraging lessons learned from similar CARB-funded programs. All of the above methods have been retained in the alternative VGI program terms that appear in Attachment 2 of this decision.

In addition, SDG&E is to coordinate the deployment of site installations in disadvantaged communities with other Commission authorized programs that target low income customers and limited English proficiency customers. Such coordination could occur by working with the CBOs involved in the Community Help and Awareness of Natural Gas and Electricity Services program, which was originally authorized in Commission Resolution CSID-004 in November 2010, and most recently in D.15-12-047.

We note that in SB 535 (Stats. 2012, Ch. 830), the California Environmental Protection Agency was directed in H&S Code § 39711 to identify disadvantaged communities to carry out the intent of the California Global Warming Solutions Act of 2006 (Stats. 2006, Ch. 488) to direct resources to disadvantaged communities to mitigate adverse impacts from climate change. As noted earlier, the CalEnviroScreen tool was developed in accordance with SB 535 to identify disadvantaged communities. However, the use of a state-wide scope for

determining which disadvantaged communities would be eligible for site installations poses a challenge to the extent that certain utility territories – as a result of their relative geographic size, local industrial composition, and residents – have relatively few census tracts that are scored within the top quartile by the CalEnviroScreen tool on a state-wide basis. The inclusion of census tracts located within other utility service territories in the definition of disadvantaged communities would have the consequence of excluding from eligibility the census tracts in such utility territories that are disadvantaged when compared to the rest of the service territory, but relatively less disadvantaged when compared to communities elsewhere in California. For the purposes of this initial pilot program, we find it reasonable to be more inclusive, and select the definition that will enable greater access to charging infrastructure, including those in rural areas. For those reasons, it is reasonable to define eligible disadvantaged communities as the top quartile of census tracts as identified by CalEnviroScreen on either a state-wide or a utility-wide basis, whichever is broader. To determine which basis is appropriate in the case of SDG&E's service territory, SDG&E is directed to calculate the number of census tracts qualifying under each option, and to submit this information, along with a request to use the broader of the two options, as part of a Tier 1 advice letter.

5.7.8. Monitoring, Reporting, and Data Collection

Another issue that parties have raised is the frequency of the monitoring and reporting of the pilot program, and the type of data that should be reported.

Under the Proposed Settlement, an interim report providing an assessment of the VGI program would not be due until two years after the VGI program is launched. As discussed earlier, several parties recommend that the reports be issued much earlier and more frequently so that the Commission can evaluate

how the program is doing, and to make any needed changes or adjustments. We agree that more frequent monitoring and reporting is needed. As part of the alternative VGI program terms, we will require SDG&E to have a check-in meeting with the Commission's Energy Division staff every three months to provide the staff with updates regarding the following: (1) the amount of interest in siting EV site installations at MUDs and workplaces; (2) the number of EV site installations that were approved, or that are in the pipeline, for deployment; (3) the site selection criteria used in selecting the sites that will host the EV site installations; (4) the number of EV site installations and EV charging stations that SDG&E has deployed under the approved alternate VGI program terms; (5) the rate option that the site hosts have chosen; (6) how the VGI-Rate-to-Host option is being implemented by the site hosts; (7) the usage rates at these EV site installations and charging stations; (8) the timing patterns of EV charging and the degree to which these times correlate to times of low VGI rates; (9) the amount of program funds spent during the quarter, and the cumulative amount spent; and (10) observable trends or correlations between the number of EV site installations deployed compared to EV charging use and growth in the number of EVs.

We will also require SDG&E to file in R.13-11-007, or in a successor proceeding, semi-annual reports containing the information reported in the quarterly check-in meetings, the data described in Appendix B to Attachment 2 of this decision, and a description of any program changes implemented by SDG&E prior to the date of the report. This reporting requirement will terminate on February 1, 2021. The report shall be posted on SDG&E's website, and a notice of the availability of that report shall be served on the R.13-11-007 and A.14-01-014 service lists. Parties may then file and serve opening comments on each semi-annual report within 30 days of the service of the report in

R.13-11-007, and parties may file and serve reply comments within 50 days of the service of the report.

Several of the parties recommend that improvements should be made to the type of data that is to be collected about the VGI program. CESA recommends that the data collection effort for the VGI program should include current and forward looking projections to document and compare the development of third-party and SDG&E-owned site installations. CESA also recommends that the cost data for the VGI program be collected independently to ensure the accuracy of those costs. ORA recommends that the data collected include information and data trends, relating to a list of performance metrics including, but not limited to, VGI marketing, education, and outreach, site acquisition and installation efforts, EVSE deployment per market segment, EV charger utilization at the site level, load impacts, fuel savings, and GHG reductions. UCAN contends that the data requirements need to be better defined in order to assess whether the goals and objectives of the VGI program have been met. In its comments on the proposed decision, TURN requests that the proposed decision be more specific about the data SDG&E is required to collect and report regarding EV adoption and potential anti-competitive effects.

Regarding the type of data that is to be reported, Appendix B to the Proposed Settlement addresses the supplemental data collection. This supplemental data collection is in addition to the data collection and analysis referenced in Exhibit SDG&E-6 at 35-37. Attachment 2 of this decision, and Appendix B of Attachment 2 replicate the type of data to be reported. As discussed above, we have modified the Proposed Settlement by the alternative VGI program terms. The alternative terms add quarterly updates for SDG&E to

provide information on 10 issues, and accelerate the time in which the reports are to be filed.

With the exception of TURN's recommendations, we are not persuaded by the various parties' arguments that data in excess of what we have already described is needed, and therefore do not adopt their recommendations regarding data collection. TURN's recommendation has been incorporated into Appendix B of Attachment 2 of this decision.

We believe that all of this data that is being required through the alternative VGI program terms will be useful in evaluating SDG&E's VGI program, to decide if any changes need to be made, and to help decide whether the VGI pilot program should be expanded or if other EV programs should be launched. This data may also aid in comparative evaluations of the SDG&E 2016 VGI Pilot Program relative to other utilities' EV infrastructure and rate programs. In addition, the data and reports will provide the necessary information about how the 2016 VGI Pilot Program is performing, and if it is on track to achieve the goals set forth in today's decision.

We recognize, however, that the format of the monitoring, data reporting, and collection is crucial. There is a need to report data in a manner that ensures that the Commission can conduct an analysis of EV charging technologies that will work in a harmonious manner across the utilities' service territories. (*See* Public Utilities Code Section 740.2(e)). Due to the common geospatial nature of the proposed pilot programs of SDG&E, SCE, and PG&E, SDG&E shall work with the PAC to select a geographic information system (GIS) based tool and interface that the public and other utilities can use to track the progress and

attributes of the deployment.[36] The task of selecting a GIS tool has been included as part of the modifications to the alternative VGI program terms in Attachment 2 of this decision. As discussed earlier, the Commission also encourages SDG&E to use this data to help inform SDG&E's DRP efforts pursuant to Public Utilities Code Section 769 in which SDG&E identifies the VGI rate design as a means of optimizing the use of grid assets on the local distribution system.

5.7.9. Metering and Billing

One of the Proposed Settlement's modifications addresses how the metering will be done for the EV charging stations. The metering at the EVSE level must be compatible with SDG&E's billing and metering requirements (such as, tolerances, accessibility, testability, and re-calibration), and/or the approved submetering protocol. For those sites that have chosen the VGI Rate-to-Driver, SDG&E will send the bill directly to the EV driver (who is an SDG&E customer). For those sites on the VGI Rate-to-Host option, SDG&E will send the bill to the site host. Since site hosts can choose the EVSE from preapproved vendors, the data from the EV charging stations is to be provided to SDG&E in a manner acceptable to the vendor and SDG&E, and that meets SDG&E's specifications.

The metering procedure of SDG&E raises the issue of the submetering protocol as set forth in section III. M of the Proposed Settlement. SDG&E will be the owner of both the EV site installation and the charging stations. Under most situations, the site installation will have its own electric service drop. This

[36] H&S Code § 44268.2(b) requires that an EV charging provider disclose to the National Renewable Energy Laboratory the geographic location of the charging station and other information.

service drop at the site installation can then feed more than one EV charging station. Under this system design, SDG&E will be engaged in multiple customers of record submetering, as defined in D.13-11-002, when it provides billing to each individual EV charging customer using an EV charging station that is serving the VGI Rate-to-Driver option. Under the VGI program, each EV charging station will be capable of identifying the specific EV driver who is using the charging station at a particular time. This will occur through the inputting of a customer-specific identifier prior to the EV charging station dispensing electricity. This identifying information should, in theory, minimize submetering billing disputes.

In carrying out these submetering billing activities, SDG&E shall ensure that its submetering and billing activities are consistent with the PEV submetering protocols for multiple customers of record that are pending adoption contingent upon the pilots pursued in compliance with D.13-11-002, and that the data it receives from the EVSE vendors, pending the capabilities determined in the RFI and RFP processes, is compliant with these submetering protocols that are in development for the second pilot phase testing multiple customer of record submetering. We recognize that the submetering protocols proposed for adoption in D.13-11-002 apply to a customer of the utility who owns the metering equipment, and is performing the submetering and billing activities. However, the basis for these same protocols should apply to the utility-owned submetering and billing activity that SDG&E will be performing. As a result, we have added as part of the alternative VGI program terms, that the D.13-11-002 concept for multiple customer of record submetering is an example of the approved protocol that will be used in the 2016 VGI Pilot Program to serve the VGI Rate-To-Driver option.

There is the potential to learn from SDG&E's submetering activities, and to apply and extend those lessons learned toward offering a VGI rate to other electricity customers. If vendors supply EVSE that can receive, record and securely transmit accurate data to SDG&E consistent with the protocols for communicating data proposed by SDG&E and pursuant to the pending submetering protocol, this may allow SDG&E to broadly offer the VGI rate in the future to PEV customers, or to EV charging station providers, who use compliant EVSE. In its analysis and reporting of the progress and results of its 2016 VGI Pilot Program, SDG&E shall also include an evaluation of the effectiveness of the VGI rate, and provide recommendations on the potential impact of making the VGI rate available to non-utility owned EV charging stations, including those at places other than MUDs and workplaces.

We also note that consistent with the Guiding Principle to "Support clean air and climate change objectives," the use of EV submeters can help meet the State's Low Carbon Fuel Standard (LCFS) Program administered by the ARB. As part of the ARB's LCFS regulations, the reporting of electricity used as a transportation fuel can be accomplished by "the use of metering to measure the electricity directly dispensed to all vehicles at each residence…." (California Code of Regulations, Title 17, § 95491(a)(3)(D).)

An issue related to metering and billing, and the type of EVSE to be installed, concerns the issue of interoperability standards that KnGrid originally raised. SDG&E's testimony states it has no intention to develop new interoperability standards, and will evaluate the proposals of the various EVSE vendors during the RFP process. We decline to adopt specific interoperability standards for the VGI pilot program. There is insufficient testimony before us in this proceeding to choose what specific standards should be adopted. Instead, as

provided for in modification number 21 and Appendix C of the alternative VGI program terms, the process for how SDG&E will evaluate competing EVSE products is set forth in Attachment 2.

5.7.10. Program Advisory Council

Some of the parties have questioned the composition of the PAC, and whether the activities of the PAC will have any effect on the VGI program.

Regarding the composition of the PAC, Appendix A of the Proposed Settlement already addresses that, which we have retained as part of the alternative VGI program terms. Appendix A to the Proposed Settlement and Appendix A to Attachment 2 of today's decision, provides that SDG&E will seek participation in the PAC from a broad and diverse stakeholder group, including representatives from local and state government (including representation from the Energy Division), industry, labor and other stakeholders, ratepayer and environmental advocates, and representation from Disadvantaged Communities. That provision will ensure that the PAC will be composed of a variety of participants interested in the development of the EV charging infrastructure in SDG&E's service territory. To ensure that there is participation from the local and regional planning organization for transportation in the San Diego area, we require as part of the alternative VGI program terms that SDG&E seek the participation of the San Diego Association of Governments on the PAC.

As for concerns that the PAC will not be able to affect the VGI program, we disagree. Although the PAC will not have formal decision-making authority, it will make recommendations and/or provide key information and materials to SDG&E's VGI program managers about possible program changes to the VGI program. In accordance with Appendix A of the Proposed Settlement, which has been retained in Appendix A of Attachment 2 of this decision, "SDG&E will give

careful consideration to all programmatic modifications recommended by the PAC at their meetings and implement such changes deemed feasible and necessary."

In addition, we delegate to the Energy Division of the Commission the authorization to resolve disputes, and to modify and approve modifications to the 2016 VGI Pilot Program that are minor in nature and which are not specified in this decision to be submitted by an Advice Letter. The Energy Division may informally communicate such modification or approval through its participation in the PAC.

We also note that under the alternative VGI program terms, we have accelerated the time for SDG&E to provide reports about the VGI program. Since parties will have the opportunity to comment on these semi-annual reports, if members of the PAC do not think SDG&E is considering their VGI program input, such concerns can be brought up in the parties' comments on the semi-annual reports, or in protests to advice letters that may propose specific program modifications.

The Proposed Settlement also has procedures in place to encourage involvement by the PAC and CBOs in the siting of EV charging locations, and to suggest program changes to the VGI program.

For all of the above reasons, no additional changes need to be made to the composition of the PAC, or to the role of the PAC.

5.7.11. Participation Payment

Several parties have raised questions about the participation payment that site hosts would be required to pay under the terms of the Proposed Settlement. They question how the size of the participation payment will be determined, and whether the participation payment will be sufficient for site hosts to have a

vested interest in having an EV site installation located on the premises. Some of the parties also raised these concerns in their comments on the proposed decision.

The Proposed Settlement, and the alternative VGI program terms, include provisions that address how the participation payment will be determined. These provisions also exclude those EV site installations that are sited in disadvantaged communities from being charged a participation payment. In developing the size of the participation payment, the considerations "include, but are not limited, to the following: customer commitment, avoiding adverse impacts to deployment, total VGI Facility cost and customer segment." After consulting with the PAC, SDG&E will then file a Tier 2 advice letter requesting approval of the proposed participation payment. Parties can raise concerns about the size of the participation payment in a protest to the advice letter filing.

As described above, some of the criteria and considerations for deciding the size of the participation payment are already known. Another consideration is the various EVSE that may be offered, and their varying capabilities. In addition, the participation payment will undergo review by the PAC, will be subject to protest by parties during the advice letter process, and will be reviewed by Commission staff during the advice letter process.

TURN recommends in its comments on the proposed decision that the Commission set the participation payment in this decision by requiring workplace locations to pay for 75% of the costs of the charging stations installed at their sites, and requiring MUDs to pay for 50% of the costs of the charging stations. TURN contends that this is consistent with what was adopted in the EV pilot program of Southern California Edison Company in D.16-01-023. UCAN

suggests that the PAC be chaired by the Energy Division representative, and that the PAC develop the participation fee.

As described above, there are a number of competing concerns regarding the participation payment. These concerns should be addressed through the PAC and the advice letter process, with the Commission's Energy Division taking the lead on the development of the participation payment, and to resolve disputes under the delegated authority provided in this decision. The development of the participation payment should consider what was done in D.16-01-023, as well as the criteria and considerations expressed in the Alternative VGI Program Terms in Attachment 2 of this decision. This process will ensure that the amount of the participation payment will not be set in a unilateral manner by SDG&E or any other party.

The comments on the proposed decision also seek clarification on whether the participation payment should offset the capital costs, or the O&M costs. UCAN recommends that the participation payment be used to reduce the capital expense, which would reduce the ratebase. TURN and some of the other parties recommend that the participation payment be used to offset the O&M costs.

In the SCE EV pilot program, we treated the charging station rebate as an expense, rather than including the rebate into ratebase. (*See* D.16-01-023, at 18-20.) For that reason, we will direct SDG&E to use the participation payments it receives from the 2016 VGI Pilot Program to offset the O&M costs incurred, and for SDG&E to establish a memorandum account to achieve this purpose.

5.7.12. Education and Outreach

Several parties contend that a lot more education and outreach is needed as part of SDG&E's VGI program in order to do the following: encourage property owners of MUDs and workplaces to sign-up for the VGI program;

educating the public about the benefits of transportation electrification; and educating potential EV owners about the benefits of owning an EV. We also note that the GPI and JMP recently filed a joint motion in these proceedings requesting that the Commission open a new track in early 2016 to focus on education and outreach for increasing EV adoption.

We note that the Proposed Settlement already contains provisions to conduct education and outreach, which have been incorporated into the alternative VGI program terms. One of the Guiding Principles is to support the goals to install a grid-integrated infrastructure to support one million ZEVs by 2020, and to accelerate the adoption of 1.5 million ZEVs by 2025. In addition, the Proposed Settlement provides for preapproved third party vendors to market and sign-up site hosts. Additionally, SDG&E will work with CBOs to assist with education and outreach, and to prequalify and sign-up site hosts. Also, as part of the alternative VGI program terms, we added the Guiding Principle that the VGI program must complement other utility clean energy programs, and other non-utility programs such as the Charge Ahead California Initiative. We have also added further direction to coordinate outreach with existing low-income and limited English proficiency programs such as the Community Help and Awareness of Natural Gas and Electricity Services program. We also note that in D.11-07-029, the Commission ordered the electric utilities to adhere to the education and outreach principles pertaining to PEVs adopted in that decision.

Accordingly, there is no need to require that a certain percentage of the approved VGI program budget be used for education and outreach efforts. As for the joint motion of GPI and JMP, that will be addressed in a separate ruling.

5.7.13. Bidirectional Power Flow

Vote Solar contends that the VGI program does not explore whether the EV charging equipment will have the capability for bidirectional power flow, from the grid into the EV battery, and from the EV battery into the grid. Although this bidirectional use of EV batteries was identified as "vehicle to grid" (V2G) in R.13-11-007 (*see* R.13-11-007 at 14-16), the SDG&E VGI program is focusing on managing PEV charging to incentivize EV charging customers to charge their EVs during non-peak periods, and to maximize the use of renewable generation that is generated during non-peak periods. Although SDG&E's VGI program is not designed to explore how the batteries of EVs can be used as grid storage and to discharge energy back into the grid, we recognize that certain EV service providers may wish to provide this as a "complementary service" that might include onsite photovoltaics or energy management systems.

In connection with SDG&E's 2016 VGI Pilot Program, V2G will be permitted as a complementary service that may be offered by third party vendors of EVSE in the ongoing RFI and RFP qualification processes, subject to the following two guidelines that ensure consistency with the 2016 VGI Pilot Program.

The first guideline, as recognized in the Energy Division's Whitepaper on VGI, is that V2G represents an additional step toward enabling the use of EVs as storage devices in a fully integrated electric and transportation system. Allowing V2G discharging could facilitate this type of service, and could lead to the development of new products and innovation by EV service providers for their EV charging customers. For example, in Resolution E-4595, the Commission authorized the development of a V2G project that tests the provisioning of ancillary services to the CAISO through the use of a PEV fleet.

The second guideline is that the cost of this V2G complementary service will not be borne by ratepayers unless the service is necessary to support the VGI program objectives. That is because the cost of bidirectional power flow equipment was not included as part of SDG&E's VGI proposal, the cost of such equipment is not known at this point, and we do not yet know the extent of the demand for this type of service.

In the modifications to the alternative VGI program terms, we have included V2G as an example of a complementary service that could be offered by EVSE providers.

5.7.14. Line Extension Issue

TURN contends that SDG&E's VGI program violates Public Utilities Code Sections 453 and 783 because SDG&E is not charging for the line extension costs (contained in SDG&E's electric Rules 15 and 16) that may be needed to provide electric service at the EV site installations. TURN contends that not charging the customer for such a line extension violates Public Utilities Code Section 453 because it grants a preference as to a rate or charge. TURN also contends that the Commission must make the written findings required in Public Utilities Code Section 783 before allowing such line extensions to be built.

SDG&E contends that its electric Rules 15 and 16, and the two Public Utilities Code sections, do not apply to SDG&E's proposed deployment of the EV site installations. SDG&E contends that since it will be the owner of the EV site installations, that the line extension rules do not apply.

We agree with SDG&E on the line extension issue. Before SDG&E constructs anything on the site host's property, SDG&E will require that it be provided with an easement from the property owner so that SDG&E can construct and install the EV site installation, the EVSE, and any wiring or service

drop that may be needed. Since SDG&E will be the owner of the EV site installations and the EV charging stations, under the terms of SDG&E's electric Rules 15 and 16, and Public Utilities Code Section 783, SDG&E is not extending service to a customer. Accordingly, Public Utilities Code Sections 454 and 783, and SDG&E's electric Rules 15 and 16, do not apply to these EV site installation deployments.

5.7.15. Electricity From Direct Access Providers

Marin Clean Energy and Shell Energy raise the issue of whether the EV site installations should be able to obtain their electricity from direct access providers. Shell Energy contends that if SDG&E is the owner of the EV site installation, that SDG&E should be required to obtain the electricity from an ESP.

We decline to require as part of the alternative VGI program terms that SDG&E obtain the electricity for its EV site installations from an ESP. We decline to do so because SDG&E's VGI rate will be designed using several different factors. If SDG&E is required to obtain the electricity for the EV site installations from a third party provider, this will add another layer of complexity to the design of the VGI rate since SDG&E would need to factor in the cost of the ESP's electricity.

5.7.16. Request for GHG Funding Eligibility

SDG&E requests in its application that the Commission make a determination that SDG&E's VGI pilot program be found eligible, pursuant to D.12-12-033, to receive funding from the revenues generated by the sale of the cap-and-trade allowances consistent with Public Utilities Code Section 748.5(c). The nine settling parties who filed briefs in support of the adoption of the Proposed Settlement support SDG&E's request that it be allowed to seek funding from the GHG revenues for this pilot program.

TURN opposes SDG&E's request that it be allowed to receive funding from the revenues generated through the sale of cap-and-trade allowances. TURN contends that SDG&E has not demonstrated that the VGI program meets the regulatory requirements that govern the use of cap-and-trade revenues.

We have reviewed D.12-12-033, D.14-10-033, and Public Utilities Code Section 748.5(c). Public Utilities Code Section 748.5(c) provides in part that the GHG revenues may be allocated "for clean energy and energy efficiency projects established pursuant to statute that are administered by the electrical corporation and that are not otherwise funded by another funding source."[37] Based on this provision, SDG&E's request does not meet the requirements to receive funding from the GHG revenues. That is because the monies for the VGI program that we approve in the alternative VGI program terms will be funded from "another funding source," i.e., from ratepayers of SDG&E. In addition, D.14-10-033 at 28 requires that when seeking approval of a project using GHG revenues, the utility is to explain why the project qualifies under Public Utilities Code Section 748.5(c), and why the project is best funded with GHG allowance revenues instead of ordinary recovery through rates. No explanations have been provided in that regard. Accordingly, we conclude that the VGI program approved in today's decision is not eligible for funding from the GHG revenues.

5.7.17. Safety Considerations

The safety-related considerations for the VGI program are ensuring that the EV site installation and the associated EVSE infrastructure are installed safely

[37] D.14-10-033 at 27 also cites Public Utilities Code Section 748.5(c) regarding funding by another funding source.

and in accordance with applicable codes and regulations, and that the electricity dispensed from the EV charging stations is safely delivered.

These safety-related considerations are addressed in the Proposed Settlement, which have been incorporated into the alternative VGI program terms. For those contractors who construct, install, and maintain the EV site installations and charging stations, all of them will be required to have EVITP certification. The EVITP provides training and certification to licensed electricians who plan to install EVSE.

In addition, the Proposed Settlement provides that:

> SDG&E will require that all the construction, installation and maintenance of VGI Facilities that is not performed by employees of SDG&E shall be performed by contractors signatory to the [International Brotherhood of Electrical Workers (IBEW)] who hold a valid C-10 contractor's license, as defined in the governing labor agreement between SDG&E and the IBEW.[38]

As discussed before, the Proposed Settlement is based on SDG&E's original VGI proposal as modified by the Proposed Settlement. As part of SDG&E's planning for each of the EV site installations, SDG&E will prepare an engineering design and electrical load calculations, and submit that to the local permitting agencies to obtain the necessary permits. (*See* Exhibit SDG&E-2 at 10-11.) In addition, all of the EVSE must meet SDG&E's specifications. (*Id.* at 18-19.)

[38] According to the Contractors State License Board of the California Department of Consumer Affairs, a C-10 contractor's license allows an electrical contractor to place, install, erect or connect any electrical wires, fixtures, appliances, apparatus, raceways, conduits, solar photovoltaic cells or any part thereof, which generate, transmit, transform or utilize electrical energy in any form or for any purpose.

All of the above requirements have been retained in the alternative VGI program terms as set forth in Attachment 2 of this decision. Those requirements will ensure that the construction, installation, and operation of the EV site installations and charging stations comply with all the applicable safety regulations and codes. We also note that for those EV site installations being installed pursuant to Civil Code Section 1952.7, subdivision (d) of that code section provides that those site installations "shall meet applicable health and safety standards and requirements imposed by state and local authorities as well as all other applicable zoning, land use, or other ordinances, or land use permit requirements."

As part of the RFI and RFP processes, SDG&E needs to consider and ensure that the metering data, and other data, transmitted from the EVSE is secure.

5.7.18. SB 350 and Future VGI Rollout if Warranted

SB 350 will affect all future actions of the Commission regarding transportation electrification activities. Public Utilities Code Section 740.12(d) excludes SDG&E's VGI application from Public Utilities Code Section 740.12 because that code section applies to all applications for transportation electrification programs and investments filed on or after January 1, 2016.

The enactment of SB 350 raises the issue about the means in which SDG&E's VGI pilot program can be expanded, if warranted, in the future. Public Utilities Code Section 740.12(b) clearly contemplates that all future applications "for programs and investments to accelerate widespread transportation electrification" should be reviewed based on the policies expressed in Public Utilities Code Section 740.12. Instead of keeping A.14-04-014 open to consider a possible expansion of SDG&E's VGI program sometime in the future,

A.14-04-014 will be closed through today's decision. Thus, any future request of SDG&E to expand the 2016 VGI Pilot Program, or to apply the lessons learned from the 2016 VGI Pilot Program to other transportation electrification programs or investments, is to be filed in a new application.

Today's decision does not direct the electrical corporations to file the new "applications for programs and investments to accelerate widespread transportation electrification" as set forth in Public Utilities Code Section 740.12(b) as a result of SB 350. That direction will come in a future ruling or decision after the Commission has consulted with ARB and the Energy Commission as contemplated in Public Utilities Code Section 740.12(b).

5.7.19. CARE Discount

The JMP contends that since only 10% of the EV site installations will be located in disadvantaged communities, and because low income ratepayers will be least able to afford an EV and are unlikely to use the EV site installations, JMP recommends that the SDG&E ratepayers who live in disadvantaged communities should only pay 10% of the VGI program costs. Alternatively, JMP recommends that all low income ratepayers be responsible for only 10% of the costs, and those enrolled in the California Alternate Rates for Energy (CARE) be completely exempt.

We are not persuaded by the argument that since disadvantaged communities will host only 10% of the EV site installations, that the ratepayers living in such communities should only pay 10% of the VGI program costs. Our reason for not adopting that recommendation is twofold. First, the long run societal benefit of transportation electrification benefits society as a whole because GHG emissions are lowered, and air quality is improved. To apply a discount based on how many EV site installations are being located in a

particular community is not appropriate when the societal benefits are considered. Second, such a recommendation would be difficult to administer because of the added billing complexity of determining 10% of the VGI program costs, and then billing the ratepayers living in those disadvantaged communities at that reduced cost.

We are, however, persuaded by the argument that low income ratepayers are more unlikely to own an EV and to use the EV site installations, even though the Charge Ahead California Initiative is geared toward increasing access to disadvantaged, low-income and moderate-income communities.

The CARE program provides low income households with discounts on their energy bills. Public Utilities Code Section 382(b) provides as follows:

> In order to meet legitimate needs of electric and gas customers who are unable to pay their electric and gas bill and who satisfy eligibility criteria for assistance, recognizing that electricity is a basic necessity, and that all residents of the state should be able to afford essential electricity and gas supplies, the commission shall ensure that low-income ratepayers are not jeopardized or overburdened by monthly energy expenditures. Energy expenditure may be reduced through the establishment of different rates for low-income ratepayers, different levels of rate assistance, and energy efficiency programs.

Furthermore, Public Utilities Code Section 382(c) provides that "Nothing in this section shall be construed to prohibit electric and gas providers from offering any special rate or program for low-income ratepayers that is not specifically required in this section." In addition, Public Utilities Code Section 739.1(g) provides that "It is the intent of the Legislature that the commission ensure CARE program participants receive affordable electric and gas service that does not impose an unfair economic burden on those participants."

Thus, if SDG&E decides to accept the alternative VGI program terms, and because this is a pilot program, CARE customers will be excluded from paying the costs associated with the 2016 VGI Pilot Program. Should SDG&E seek to expand the VGI program in the future, we will revisit the issue in that new application of whether CARE customers should be excluded from having to pay the costs of an expanded VGI program.

5.7.20. Balancing Account

SDG&E requests that it be allowed to recover the costs of its VGI program from its ratepayers through the establishment of a two-way interest-bearing VGI Balancing Account (VGIBA). SDG&E proposes that the VGIBA record the authorized revenue requirement and the actual O&M and capital-related costs.

As part of the alternative VGI program terms in the proposed decision, it was recommended that SDG&E be authorized to establish a two-way interest-bearing VGIBA subject to the $45 million budget limit set forth in the proposed decision. In the comments to the proposed decision of ORA, TURN, and UCAN, they recommended the use of a one-way balancing account instead of the two-way balancing account to ensure that costs associated with the 2016 VGI Pilot Program are limited.

Since we are authorizing a pilot program that is limited in scope and cost, we are persuaded that a one-way interest-bearing VGIBA is more appropriate under the circumstances. If SDG&E accepts the terms of the alternative VGI program, it will have 30 days from the date of SDG&E's acceptance to file a Tier 2 advice letter to establish the one-way interest-bearing VGIBA.

As discussed in section 5.7.11 of this decision, SDG&E shall also establish a memorandum account to apply the participation payments that it receives from the 2016 VGI Pilot Program to offset the program's O&M costs.

5.7.21. Acceptance of Alternative VGI Program Terms

For all of the reasons that we discussed about the alternative VGI program terms, we conclude that these alternative terms, as discussed in today's decision and summarized in Attachment 2 of this decision, are acceptable to the Commission if SDG&E decides to pursue the 2016 VGI Pilot Program.

We find that the alternative VGI program terms: (1) are more reasonable and responsive to the concerns of the parties representing a ratepayer perspective; and (2) balance the interests of SDG&E, its ratepayers, and all the other parties, with the societal interests of reducing GHG emissions and promoting the use of renewable resources through the integration of a VGI rate for EV charging. Based on all of the discussion in this decision, we conclude that the alternative VGI program terms, and the 2016 VGI Pilot Program contained therein, are reasonable in light of the record developed in these proceedings, consistent with the law, and is in the public interest.

The approved 2016 VGI Pilot Program will help move the San Diego region towards the goal of transportation electrification and to meet the societal objectives of reducing GHG emissions and promoting the use of renewable sources of energy. This pilot will also allow for the testing of the VGI rate concept, and its acceptance by potential site hosts and by the EV owners in the San Diego area. For all of those reasons, we find pursuant to Public Utilities Code Sections 740.3(c) and 740.8 that the 2016 VGI Pilot Program is in the ratepayers' interests, and does not unfairly compete with nonutility enterprises.

Since today's decision does not grant SDG&E's request concerning its original VGI proposal, and denies the Settlement Motion to adopt the Proposed Settlement, it is up to SDG&E to decide if it wants to accept the alternative VGI program terms and to proceed with the 2016 VGI Pilot Program. SDG&E shall have 30 days from today's date to accept the alternative VGI program terms, and to proceed with the 2016 VGI Pilot Program as discussed in today's decision, and as described in Attachment 2 of this decision. To accept these alternative terms, SDG&E shall send a letter of acceptance to the Commission's Executive Director, which shall also be served on the service list in these consolidated proceedings, accepting the alternative VGI program terms and stating that it will implement the 2016 VGI Pilot Program on the terms and conditions set forth in Attachment 2 of this decision, and as described in today's decision.

If SDG&E decides to accept and to implement the 2016 VGI Pilot Program, SDG&E shall within 30 days of its letter of acceptance, file a Tier 2 advice letter establishing the 2016 VGI Pilot Program, and the pricing formula that will go into calculating the VGI rate.

As SDG&E pointed out in its comments on the proposed decision, and as explained in this decision and in Attachment 2 of this decision, a number of steps will need to be followed and taken before the first VGI site host can sign up for the VGI rate. Today's decision will pave the way for that process to begin. The three year sign up for the 2016 VGI Pilot Program shall begin after the advice letters described in this Ordering Paragraph 3 of this decision have been approved by the Commission.

We recognize that since the VGI rate will be constantly changing, it will not be possible to have the actual VGI rates in SDG&E's VGI tariff. In order to assist the decision making processes of EV charging customers and EVSE

vendors, and for the Commission to track and resolve any disputes regarding the actual VGI rates being charged, SDG&E shall maintain a publicly available website that includes a database and circuit-level map of all the hourly VGI rates being charged on all of its circuits participating in the 2016 VGI Pilot Program. SDG&E is to maintain the database to include, at a minimum, the most recent 17,520 hours, as available, of the VGI rates being charged on each circuit. This database of the VGI rates being charged by SDG&E to those customers and site hosts participating in the 2016 VGI Pilot Program shall be made available to the Commission upon demand.

The consent of the other settling parties who signed on to the Proposed Settlement is not needed because this decision denies the motion to adopt the Proposed Settlement. Although we favor the support of the Proposed Settlement's settling parties, as well as the support of the other parties who did not agree to the Proposed Settlement, it is up to SDG&E to decide if it wants to accept the 2016 VGI Pilot Program on the alternative VGI program terms. If SDG&E decides against proceeding with this program as approved and authorized in today's decision, then SDG&E will need to file a new application if it seeks to deploy EV charging infrastructure.

Since all of the issues raised in connection with SDG&E's VGI proposal in A.14-04-014 have been addressed by today's decision, A.14-04-014 shall be closed and no longer consolidated with R.13-11-007. R.13-11-007 shall remain open as there are other issues to address in that Rulemaking.

6. Comments on Proposed Decision

The proposed decision of Administrative Law Judge (ALJ) John S. Wong in this matter was mailed to the parties in accordance with Public Utilities Code Section 311, and comments were allowed pursuant to Rule 14.3 of the

Commission's Rules of Practice and Procedure. Opening comments were filed on January 12, 2016, and reply comments were filed on January 19, 2016.

Those comments have been reviewed and considered, and appropriate changes have been made to the decision.

7. Assignment of Proceeding

Carla J. Peterman is the assigned Commissioner and John S. Wong is the assigned ALJ in this proceeding.

Findings of Fact

1. Governor Brown's Executive Order B-16-2012 set a target of creating infrastructure to support up to one million ZEVs by 2020, and to have 1.5 million ZEVs on California's roads by 2025.

2. A.14-04-014 was consolidated with R.13-11-007 on September 29, 2014.

3. The August 5, 2015 ruling denied the request of some of the parties to hold additional hearings on the Proposed Settlement.

4. The August 5, 2015 ruling also directed the parties to file opening and reply briefs on whether the Proposed Settlement, SDG&E's original VGI proposal, or a variant of those proposals should be adopted or not.

5. Among other things, SB 350 added provisions to the Public Utilities Code to promote the widespread use of electricity as a transportation fuel in order to achieve the goals of the Charge Ahead California Initiative as set forth in the H&S Code.

6. H&S § 44258.4(b) states in part that the goal of the Charge Ahead California Initiative is to place in service at least one million ZEVs and near-ZEVs by January 1, 2023.

7. Public Utilities Code Section 740.12(d) specifically excludes SDG&E's application from the provisions of SB 350.

8. SDG&E's VGI pilot program is based in part on SDG&E's experience with a VGI prototype site installation that was installed for the use of its employees.

9. SDG&E's VGI rate will vary throughout the day to reflect the expected changes in energy prices and grid conditions, and PEV owners using the EV site installations will be sent day-ahead price signals to encourage PEV charging during off-peak periods.

10. SDG&E's VGI pilot program proposes that the sign-up and contracting take place over four years, and that the installations take place over a period of four to five years, with a total of 550 EV site installations and 5,500 EV charging stations being deployed in accordance with the following schedule: Year 1 – 50 site installations with up to 10 charging stations each; Year 2 – 100 site installations with up to 10 charging stations each; Year 3 – 200 site installations with up to 10 charging stations each; and Year 4 – 200 site installations with up to 10 charging stations each.

11. SDG&E's VGI pilot program is capped at $103 million.

12. SDG&E requests that it be allowed to recover the VGI pilot program costs from its ratepayers through the establishment of a two-way interest-bearing VGIBA.

13. SDG&E's circuits have different characteristics including the following: the number of residential and commercial customers on each circuit; the amount of solar generation of each circuit; the load factor of the circuit; and the peak demand hours of the circuit.

14. The circuit characteristics are expected to affect the calculation of the VGI rate's hourly prices across the more than 1,000 distribution circuits.

15. Under SDG&E's VGI pilot program, all of the EV charging infrastructure located at each site installation would be owned by SDG&E.

16. SDG&E considers its VGI program to be a pilot project because of the following: the unique VGI rate; the targeting of MUDs and workplaces only; and the four year enrollment period for the VGI program.

17. SDG&E's day-ahead hourly VGI rates will correspond with the expected changing hourly price of electricity and will be designed to encourage EV charging at times of the day that will minimize incremental peak loads on the electrical distribution system, integrate high levels of renewable energy use, and avoid charging on system peaks.

18. The Proposed Settlement is based on, and would accept with certain modifications, SDG&E's original VGI proposal as set forth in its application.

19. The Proposed Settlement is based on 11 Guiding Principles that are to guide the VGI program implementation, and the 16 modifications made to SDG&E's original VGI proposal.

20. Among the Proposed Settlement's 16 modifications are the following: site hosts will have the choice of two billing options, the VGI Rate-to-Driver, and the VGI Rate-to-Host, and if the VGI Rate-to-Host option is chosen the site host will be required to submit a load management plan; site hosts will be able to choose EVSE and related services from a list of prequalified vendors; SDG&E will assess a VGI program participation payment on VGI facility site hosts that elect to participate in the program, and the participation payment will be waived for VGI facilities located at sites in disadvantaged communities; at least 10% of the VGI facilities will be installed in disadvantaged communities as identified by the CalEnviroScreen; SDG&E will solicit participation from the PAC in planning and implementing the VGI program following its approval by the Commission; metering at the EVSE level must be compatible with the SDG&E billing and metering requirements; and two years after the VGI program is launched,

SDG&E will provide an interim progress report to the Commission, which will include the data described in Appendix B of the Proposed Settlement.

21. At the evidentiary hearings, some of the parties presented testimony as to why SDG&E's VGI proposal should be adopted, while other parties proposed a variety of changes to SDG&E's original VGI proposal.

22. A review of the Proposed Settlement reveals that many of the modifications to SDG&E's VGI proposal incorporate certain positions taken by some of the parties before the Proposed Settlement was agreed upon.

23. The overarching objective of SDG&E's VGI program, as set forth in SDG&E's original VGI proposal, and in the Proposed Settlement, is to help implement the goals set by the Governor and the State of California to deploy EV charging infrastructure to support a growing number of PEVs, to reduce GHGs, and to increase the use of renewable sources of energy.

24. The objective and goals behind SDG&E's VGI program are set forth in the Governor's Executive Order, and in various California statutes, as described in § 5.2. of today's decision.

25. The legislative direction to encourage the development of an EV charging infrastructure and to promote the widespread adoption of EVs so as to reduce GHG emissions, and to promote the use of renewable energy resources, must not be ignored.

26. The deployment of EV charging infrastructure will help assure potential purchasers of EVs that EV charging will be available.

27. The VGI rate is designed to optimize the use of the energy on the electric grid by offering lower electricity rates to EV drivers and site hosts of the EV site installations to encourage EV charging during off-peak electricity periods, and to

maximize the use of energy generated from renewable resources during off-peak periods.

28. The VGI rate will be made available on a day-ahead basis so that the EV drivers and site hosts are aware of the price of electricity on an hourly basis for their EV charging needs.

29. The VGI rate for different hours of the day will be calculated by SDG&E, taking into account the amount of electricity that will be generated during the various hours of the day, the price of electricity, and anticipated congestion conditions on the grid and circuits.

30. If the VGI Rate-to-Host option is selected, the site host or its selected vendor will be required to supply SDG&E with a plan for managing the EV charging load.

31. Although some of the parties may disagree with the cost, size, or scope of the VGI program, none of the parties disagree with the goal of the VGI program to optimize the use of the energy on the electric grid by offering lower electricity rates to EV drivers and site hosts of the EV site installations to encourage EV charging during off-peak electricity periods, and to maximize the use of energy generated from renewable resources during off-peak periods.

32. The electrification of vehicles used for transportation offer opportunities to reduce air pollution and GHGs.

33. The goal of SDG&E's original VGI proposal, and as modified in the Proposed Settlement, is a reasonable concept to pursue because it responds to the call in R.13-11-017 for utility activities that support VGI initiatives.

34. The VGI proposal is consistent with R.13-11-007 because it will evaluate the potential and value of VGI activities that capture the benefits of PEV battery

storage for managed charging, and for providing demand response ancillary services to the grid and power markets.

35. The VGI proposal addresses the concerns in Public Utilities Code Section 740.2 about: (1) the widespread use of PEVs and EVs and the role and development of public charging infrastructure; (2) the impact of EVs and PEVs on grid stability and the integration of renewable energy resources; and (3) the widespread use of PEVs and EVs to achieve the state's goals regarding the reduction of GHGs, obtaining more electric generation from renewable sources of energy, and the shifting of emissions reductions responsibilities from the transportation sector to the electric industry.

36. The cost and size are the two largest disagreements that the non-settling parties have with SDG&E's original VGI proposal, and with the Proposed Settlement.

37. For the cost of SDG&E's original VGI proposal, and the Proposed Settlement, SDG&E and the settling parties are requesting the same amount, almost $103 million.

38. Under SDG&E's original VGI proposal, and the Proposed Settlement, SDG&E and the settling parties are requesting authorization for up to 550 EV site installations, and up to 5,500 EV charging stations, to be deployed over a four to five year period, and that SDG&E would be the owner of the EV site installations and the EV charging stations.

39. The cost of the VGI program under SDG&E's original VGI proposal, and the Proposed Settlement, will be nearly $103 million over the 22 year recovery period, which exceeds the cost of typical pilot programs, or research, development, and demonstration projects, that the Commission has authorized in the past.

40. The societal benefits of the VGI program must be weighed with who will receive the direct benefits of the VGI program, who will end up paying for the program, and whether potential site hosts and potential EV owners will respond as SDG&E and others predict.

41. With the challenges of convincing consumers to switch from gasoline fueled vehicles to EVs, and the uncertainties about how the projected EV adoption rate was derived, we are not as certain about the EV adoption rate.

42. In order to secure the sites needed to locate the EV site installations and associated EVSE, the property owners of prospective MUD and workplace sites will need to consent, provide an easement, and pay a participation fee under the Proposed Settlement.

43. Getting sufficient property owners to agree to the preconditions of siting an EV site installation and associated EVSE at a MUD or workplace may prove more difficult to obtain than in theory.

44. There are still many unknowns regarding the EV market, and how potential site hosts and EV owners will respond to the VGI program.

45. We do not want to approve and authorize a pilot project that will cost $103 million without being able to timely review and evaluate the progress of the VGI program.

46. It would be foolhardy to authorize a VGI pilot program of $103 million, using ratepayer money, without some assurance that EV drivers will be using these site installations and charging stations on a frequent basis, and that such a deployment will result in a widespread adoption of EVs for everyday transportation.

47. In applying the balancing test, the Commission stated in D.14-12-079 that the Commission will assess the likely competitive impact on the market segment

targeted, and whether any anticompetitive impacts can be prevented or adequately mitigated through the exercise of existing rules or conditions.

48. Under the Proposed Settlement, the site hosts or their designees, have two options that were not offered as part of SDG&E's original VGI proposal: (1) the site host or designee can choose to take service under the VGI Rate-to-Host billing option, and (2) they can choose the EVSE and related services that they want from preapproved vendors under either the VGI Rate-to-Driver or the VGI Rate-to-Host billing options.

49. These two options appear to mitigate some of the concerns about anticompetitive impacts by offering the site host two billing options under the VGI rate, and allowing preapproved third party providers to offer EVSE and related services to site hosts, which promotes competition and innovation.

50. Under SDG&E's original VGI proposal, and the Proposed Settlement, if the EV market does not develop as projected after four to five years, SDG&E will be one of the leading providers of EV charging in the San Diego region at the end of that period.

51. Public Utilities Code Section 740.8 defines the "interests" of ratepayers as it is used in Public Utilities Code Section 740.3(c).

52. We find merit in adopting some of CESA's recommendations to mitigate possible anticompetitive impacts.

53. Under SDG&E's original VGI proposal, the 100% ownership of the EV site installations, combined with the SDG&E prescribed specifications for the EVSE, and providing the EVSE infrastructure to site hosts at no cost, may result in anticompetitive impacts on EV charging operators and EVSE manufacturers.

54. Under the Proposed Settlement, the anticompetitive impacts would be reduced because site hosts would be allowed to choose the EVSE and related

services from preapproved vendors, the site hosts could choose the VGI Rate-to-Host option, and the site host would be obligated to pay a participation fee.

55. If the cost and the size of the VGI program is reduced from what is being offered in the Proposed Settlement, that would strengthen the reasoning for finding that a scaled down VGI program will not result in SDG&E unfairly competing with nonutility enterprises because the number of EV site installations and charging stations owned by SDG&E would be reduced.

56. Rejecting SDG&E's original VGI proposal and the Proposed Settlement outright without the adoption of an alternative program will delay efforts to reach the state's goals and targets.

57. Pursuant to Rule 12.4, when the Commission rejects a settlement, one of the steps it can take is to propose alternative terms that are acceptable to the Commission and allow the parties reasonable time within which to elect to accept such terms or to request other relief.

58. We find merit in authorizing and adopting an alternative VGI program similar to the Proposed Settlement, but on a reduced scale.

59. The alternative VGI program terms that are acceptable to this Commission are attached to this decision as Attachment 2.

60. The Proposed Settlement serves as a template for the alternative VGI program terms because it offers a viable framework to deploy the VGI rate at EV charging infrastructure located at MUDs and workplaces, which allow site hosts to choose the VGI Rate-to-Host option, and to choose the EVSE and related services from preapproved vendors, and has procedures in place to encourage involvement by the PAC and CBOs.

61. There is value in SDG&E retaining 100% ownership of the EV charging stations for this pilot program to ensure that all of these ratepayer-funded charging stations are working and remain available for EV charging.

62. Along with other EV pilot program results and available market data, the ownership of the EV charging stations by SDG&E may inform future Commission action on EV charging infrastructure ownership, and related transportation electrification issues.

63. The alternative VGI program terms do not require SDG&E to install stand-alone make ready stubs.

64. We decline to set aside part of the VGI program funds approved in today's decision to help fund the deployment of EV charging infrastructure by third parties because the alternative VGI program terms contains provisions that will encourage third party competition.

65. Due in part to the uncertainty of how site hosts and potential EV purchasers will respond to the large scale deployment of 550 site installations, and 5,500 charging stations, a scaled down version of the Proposed Settlement is warranted.

66. The alternative VGI program terms agreeable to the Commission include the following: allow SDG&E to install approximately 350 EV site installations, with approximately 3,500 charging stations, over a three year sign-up period, with charging infrastructure installations allowed to continue for one additional year; allow SDG&E to rate base and to justify and recover the capital and O&M costs and associated revenue requirements of the site installations and charging stations over their useful lives in future general rate case proceedings; and this alternative VGI program shall be subject to a maximum start-up budget of $45 million.

67. The $45 million budget limit is based on the total cost of 350 EV site installations and 3,500 EV charging stations over the first three years of the VGI program (plus a fourth year to complete the installation of the VGI facility infrastructure at host sites enrolled within the three year sign up period of the program) as originally proposed in Exhibit SDG&E-4, Table JBA-5.

68. It is reasonable under the start-up budget for SDG&E to install at least 3,000 EV charging stations at a minimum of 300 sites, and budget permitting, to install 3,500 EV charging stations or more at a minimum of 350 sites or more.

69. The cost, size, and duration of the alternative VGI program terms is more reflective of a pilot program.

70. The alternative VGI program terms shall require SDG&E to select site host locations that represent a diversity of circuits.

71. SDG&E's site selection in the 2016 VGI Pilot Program should coordinate and leverage the work being performed in R.14-08-013.

72. To ensure that the budget approved for the alternative VGI program is spent wisely, two additional Guiding Principles have been incorporated into the alternative VGI program terms.

73. The alternative VGI program terms shall require that between 40% and 60% of all pilot program site installations and charging stations are to be sited at MUDs, and shall establish a target of 50%.

74. Pursuant to Civil Code Section 1947.6, a tenant of a residential rental property can make a request of the landlord to install an EV site installation.

75. Since the VGI rate is based on a time-differentiated hourly rate, it may be more advantageous to use a slower charging method such as Level 1 and Level 2 charging.

76. The alternative VGI program terms shall not require the use of DC fast chargers.

77. The alternative VGI program terms shall require SDG&E to work with the CBOs to identify disadvantaged communities that could benefit the most from the deployment of EV site installations.

78. It is reasonable to require at least 10% of charging stations be deployed in disadvantaged communities, using either a service territory-based or a state-wide definition of the term, whichever is broader.

79. More frequent monitoring and reporting of the VGI program is needed.

80. The alternative program terms shall include the following: SDG&E shall have quarterly check-in meetings with the Commission's Energy Division to provide the staff with updates concerning the information set forth in today's decision; SDG&E shall file semi-annual reports in R.13-11.007, or a successor proceeding, containing the information described in today's decision, and in the manner described in today's decision; and parties may file and serve opening and reply comments on the semi-annual reports in the manner described in today's decision.

81. All of the data that is being required through the alternative VGI program terms will be useful in evaluating SDG&E's VGI program, to decide if any changes need to be made, and to help decide whether the VGI pilot program should be expanded or if other EV programs should be launched.

82. Under the VGI Rate-to-Driver option, SDG&E will be engaged in submetering when it provides billing to each individual EV charging customer using an EV charging station on the VGI Rate-to-Driver option.

83. The alternative VGI program terms has included a reference to D.13-11-002 as an example of the submetering protocol for SDG&E's analogous multiple customers of record submetering pilot.

84. The alternative VGI program terms does not adopt specific interoperability standards for the VGI pilot program.

85. The alternative VGI program terms makes a change to the PAC regarding the possible involvement of the San Diego Association of Governments.

86. The Proposed Settlement already contains provisions to conduct education and outreach, which have been incorporated into the alternative VGI program terms.

87. There is no need to require that a certain percentage of the approved VGI program budget be used for education and outreach efforts.

88. EVSE providers or vendors who are prequalified as part of the 2016 VGI Pilot Program will be permitted to provide V2G as a complementary service if it is consistent with the guidelines described in this decision.

89. Since SDG&E will be the owner of the EV site installations and the EV charging stations, the line extension rules and Public Utilities Code Sections 454 and 783 do not apply because SDG&E is not extending service to a customer.

90. We decline to require as part of the alternative VGI program terms that SDG&E obtain the electricity for its EV site installations from an ESP because such a requirement would add another layer of complexity to the design of the VGI rate.

91. The requirements in Attachment 2 of this decision will ensure that the construction, installation, and operation of the EV site installations and charging stations comply with all applicable safety regulations and codes.

92. The long run societal benefit of transportation electrification benefits society as a whole, which makes it difficult to apportion 10% of the program costs to those customers living in disadvantaged communities.

93. The alternative VGI program terms are: (1) more reasonable and responsive to the concerns of the parties representing a ratepayer perspective; and (2) balances the interests of SDG&E, its ratepayers, and all the other parties, with the societal interests of reducing GHG emissions and promoting the use of renewable resources through the integration of a VGI rate for EV charging.

Conclusions of Law

1. D.14-12-079 adopted rules to expand the utilities' role in the development and ownership of EV infrastructure by using a case-specific approach, and also set aside the prohibition adopted in D.11-07-029 that electric utilities could not own EV charging infrastructure.

2. In deciding whether the Proposed Settlement regarding SDG&E's VGI proposal should be approved or not, and in deciding whether SDG&E's original VGI proposal or a scaled down version of the proposal should be adopted, the following four considerations are to be adhered to: (1) Public Utilities Code Section 451 which provides that the charge to ratepayers must be just and reasonable; (2) the directive set forth in D.14-12-079 regarding utility ownership of PEV charging infrastructure and the balancing test set forth in D.11-07-029; (3) the various applicable code sections, and the Governor's Executive Order and ZEV Action Plan; and (4) Rule 12.1(c) regarding approval of a settlement.

3. Since the Proposed Settlement is based on SDG&E's original VGI proposal, as modified by the Proposed Settlement, we need to analyze the elements of SDG&E's underlying VGI proposal, together with the modifications that the Proposed Settlement would make, applying the four considerations.

4. Although SB 350 specifically exempts SDG&E's VGI application from the transportation electrification provisions of newly added Public Utilities Code Section 740.12, many of the provisions of that code section are instructive as to why the Commission should forge ahead with projects such as a VGI pilot program.

5. There is sufficient legal authority for the Commission to approve and authorize some form of a VGI program to be implemented by SDG&E.

6. In considering what action we need to take in terms of promoting EVs and EV charging infrastructure, that needs to be balanced with the statutory requirement in Public Utilities Code Section 451 of having just and reasonable rates.

7. The environmental concerns and interests of some of the parties are reflected in Public Utilities Code Sections 740.2, 740.3, and 740.8.

8. Before EV program costs can be passed on to SDG&E's ratepayers, the requirements in Public Utilities Code Sections 740.3(c) and 740.8 must be met.

9. It would not be a wise use of ratepayer monies to authorize a pilot project of the cost and size contemplated in SDG&E's original VGI proposal and in the Proposed Settlement.

10. The cost and size of the VGI pilot project should be reduced.

11. The charges SDG&E's ratepayers would have to pay for SDG&E's original VGI proposal, or the VGI program in the Proposed Settlement, would be unjust and unreasonable under Public Utilities Code Section 451.

12. In D.14-12-079, the Commission set aside the prohibition adopted in D.11-07-029 that electric utilities could not own EV charging infrastructure.

13. The rules adopted in D.14-12-079 regarding utility ownership of EV charging infrastructure consist of using a case-specific approach to assess any

proposed utility program based upon the facts of specific requests, and to use the balancing test adopted in D.11-07-079.

14. The balancing test adopted in D.11-07-079 weighs the benefits of utility ownership of the EV charging infrastructure against the competitive limitation that may result from that ownership.

15. Applying the balancing test in D.14-12-079 and D.11-07-029, the ratepayers' interests and benefits as described in Public Utilities Code Sections 740.3 and 740.8, and the concern of unfair competition in Public Utilities Code Section 740.3(c), the EVSE ownership by SDG&E should be permitted in a scenario as proposed by SDG&E in the Proposed Settlement, or in a scaled down VGI pilot program patterned after the Proposed Settlement, and that such ownership would be in the ratepayers' interests and outweigh the disadvantages that could result from a lack of competition.

16. Applying the same tests to SDG&E's original VGI proposal, the tests would not be met, and SDG&E should not be allowed to own the EVSE infrastructure.

17. Before the costs of the VGI program can be passed on to SDG&E's ratepayers, the Commission must, pursuant to Public Utilities Code Section 740.3(c), find and determine: (1) that the program is in the ratepayers' interests; and (2) that the utility does not unfairly compete with nonutility enterprises.

18. Public Utilities Code Section 740.8, as well as Public Utilities Code Sections 701.1, 740.2, and 740.3, rebut CFC's contention that the VGI pilot program is outside the scope of SDG&E's provisioning of utility service.

19. For the reasons stated in the decision, we do not agree with TURN's original interpretation of Public Utilities Code Section 740.8.

20. Under the ratepayers' interests test, as set forth in Public Utilities Code Sections 740.3(c) and 740.8, the VGI program would be in the ratepayers' interest.

21. If SDG&E's original VGI proposal were to be adopted by the Commission, it is questionable whether the costs of such a program could be passed on to ratepayers because of the anticompetitive impacts.

22. If the Proposed Settlement were to be adopted by the Commission, the anticompetitive impacts would be less of a concern for passing on the costs of such a program to ratepayers.

23. A scaled down version of the Proposed Settlement would meet the criteria passing those costs on to SDG&E's ratepayers.

24. In authorizing and approving an alternative program, the Commission needs to be cognizant of existing code sections, including Public Utilities Code Section 451, and to weigh and balance the state's policy objectives, and the cost and benefits of such an alternative.

25. SDG&E's request in A.14-04-014 to adopt its original VGI proposal should be denied.

26. The Proposed Settlement is unreasonable in light of the whole record, and is inconsistent with the law because the charges to SDG&E's ratepayers for the Proposed Settlement would be unjust and unreasonable under Public Utilities Code Section 451.

27. The Settlement Motion's request to adopt the Proposed Settlement should be denied.

28. The May 28, 2015 ruling that denied ORA's motion to consolidate the three electric utilities' applications and to hold hearings on ORA's Cal EVIP proposal, is affirmed.

29. Today's decision does not adopt ORA's Cal EVIP proposal.

30. The Energy Division should monitor how Civil Code Section 1947.6 may affect the placement of EV site installations, and to bring this to the attention of the California Energy Commission and the ARB and to cooperate with those agencies regarding this issue.

31. The Commission should delegate to the Commission's Energy Division the authorization to resolve disputes, and to modify and approve modifications to the 2016 VGI Pilot Program that are minor in nature and which are not specified in this decision to be submitted by an Advice Letter.

32. The revenue generated from the participation payments from the 2016 VGI Pilot Program shall be used to offset the O&M costs of the program, and SDG&E should be directed to establish a memorandum account to achieve this purpose.

33. SDG&E's request that the VGI program be found eligible for funding from the GHG revenues does not meet the requirements set forth in Public Utilities Code Section 748.5 and D.14-10-033.

34. SB 350 will affect all future actions of the Commission regarding transportation electrification activities.

35. Public Utilities Code Section 740.12(d) excludes SDG&E's VGI application from Public Utilities Code Section 740.12 because that code section applies to all applications for transportation electrification programs and investments filed on or after January 1, 2016.

36. Public Utilities Code Section 740.12(b) clearly contemplates that all future applications for programs and investments to accelerate widespread transportation electrification should be reviewed based on the policies expressed in Public Utilities Code Section 740.12.

37. Any future request of SDG&E to expand the 2016 VGI Pilot Program, or to apply the lessons learned from the 2016 VGI Pilot Program to other

transportation electrification programs or investments, is to be filed in a new application.

38. If SDG&E decides to accept the alternative VGI program terms, CARE customers should be excluded from paying the costs associated with the 2016 VGI Pilot Program.

39. As part of the alternative VGI program terms, SDG&E should be authorized to establish the one-way interest-bearing VGIBAwhich shall be subject to the $45 million budget limit for the 2016 VGI Pilot Program.

40. SDG&E is authorized to justify and seek recovery of its capital and O&M costs for the 2016 VGI Pilot Program in its general rate case proceedings.

41. The alternative VGI program terms, and the 2016 VGI Pilot Program contained therein, is reasonable in light of the record developed in these proceedings, consistent with the law, and is in the public interest

O R D E R

IT IS ORDERED that:

1. The June 3, 2015 "Joint Motion for Adoption of Settlement Agreement" is denied, and the "Settlement Agreement Regarding San Diego Gas & Electric Company's Vehicle-Grid Integration Pilot Program Application, A.14-04-014" is not adopted.

2. The request of San Diego Gas & Electric Company (SDG&E) in Application (A.) 14-04-014 for authority to implement a pilot program for electric vehicle-grid integration is granted on the terms and conditions specified in Ordering Paragraph 3 of this decision. However, SDG&E's request for authority to

implement the pilot program described in A.14-04-014, and which was the subject of evidentiary hearings, is denied.

3. Pursuant to Rule 12.4(c) of the Commission's Rules of Practice and Procedures, the Commission proposes alternative vehicle-grid integration (VGI) program terms to replace the rejection of the "Settlement Agreement Regarding San Diego Gas & Electric Company's Vehicle-Grid Integration Pilot Program Application, A.14-04-014" (Proposed Settlement) as described in Ordering Paragraph 1.

a. The alternative terms acceptable to the Commission for a VGI pilot program is described in this decision, and is summarized in Attachment 2 of this decision. The alternative terms are referred to in this decision and in Attachment 2 as the "alternative VGI program terms." The alternative VGI program terms authorizes and approves a $45 million start-up budget, plus cost recovery through future general rate case proceedings for justified capital and operations and maintenance expenses, for San Diego Gas & Electric Company (SDG&E) to implement the "2016 Vehicle VGI Pilot Program," which is patterned after the Proposed Settlement, with the additional modifications made by this decision. These additional modifications include targeting 350 electric vehicle (EV) site installations (with a minimum of 300), and targeting 3,500 EV charging stations (with a minimum of 3,000), over a three year target sign-up period. Sign-ups may extend beyond three years budget permitting, and the installation period shall extend one additional year after the sign-up period.

b. SDG&E shall have 30 days from today's date to accept the alternative VGI program terms, and to proceed with the 2016 VGI Pilot Program. To accept these alternative VGI program terms, SDG&E shall send a letter of acceptance to the Commission's Executive Director, which shall also be served on the service list in these proceedings, accepting the alternative VGI program terms, and stating that it will implement the 2016 VGI Pilot Program on the terms and conditions set forth in Attachment 2 of this decision, and as described in this decision.

c. If SDG&E decides to accept and to implement the 2016 VGI Pilot Program, SDG&E shall within 30 days of its letter of acceptance, file a Tier 2 advice letter establishing the 2016 VGI Pilot Program, and the pricing formula that goes into calculating the VGI rate.

d. If SDG&E decides to accept and to implement the 2016 VGI Pilot Program, SDG&E shall within 30 days of its letter of acceptance, file a Tier 2 advice letter to establish its one-way, interest bearing, Vehicle-grid Integration Balancing Account (VGIBA) which shall be capped by the authorized start up budget amount of $45 million.

e. If SDG&E decides to accept and to implement the 2016 VGI Pilot Program, the customers in SDG&E's service territory who are on the California Alternate Rates for Energy program shall be excluded from paying for the costs of the 2016 VGI Pilot Program.

f. If SDG&E decides to accept and to implement the 2016 VGI Pilot Program, SDG&E shall within 120 days of its letter of acceptance, file a Tier 2 advice letter to establish the criteria upon which the participation payment to be paid by the site host is to be calculated.

g. If SDG&E decides to accept and to implement the 2016 VGI Pilot Program, SDG&E shall within 120 days of its letter of acceptance, file a Tier 2 advice letter to establish a memorandum account to apply the participation payments it receives from the 2016 VGI Pilot Program to offset the operations and maintenance costs incurred from this program.

h. If SDG&E decides to accept and to implement the 2016 VGI Pilot Program, SDG&E shall within 30 days of its letter of acceptance, file a Tier 1 advice letter concerning the use of the broader definition for determining the eligible disadvantaged communities that are to be targeted.

i. The three year sign-up period for the 2016 VGI Pilot Program, as established by this decision, shall commence after the advice letters described in this Ordering Paragraph 3 have been approved by the Commission.

j. If SDG&E decides to accept and to implement the 2016 VGI Pilot Program, SDG&E shall in accordance with this decision, maintain a publicly available website of a database of all the hourly vehicle-grid integration (VGI) rates being charged on all of its circuits that have a VGI rate, and a circuit map, and this database of the VGI rates shall be made available to the Commission upon demand.

k. If SDG&E decides to accept and to implement the 2016 VGI Pilot Program, SDG&E shall comply with all the meeting and reporting requirements as set forth in this decision and in Attachment 2.

4. If the 2016 VGI Pilot Program is implemented by San Diego Gas & Electric Company, the Commission's Energy Division shall monitor the program, and carry out the activities described in this decision.

a. The Energy Division of the Commission is delegated the authority to resolve disputes, and to modify and approve modifications to the 2016 VGI Pilot Program that are minor in nature and which are not specified in this decision to be submitted by an Advice Letter.

5. Any future request of San Diego Gas & Electric Company to expand the 2016 VGI Pilot Program, or to apply the lessons learned from the 2016 VGI Pilot Program to other transportation electrification programs or investments, shall be filed in a new application.

6. Application 14-04-014 is closed, and shall no longer be consolidated with Rulemaking 13-11-007.

7. Rulemaking 13-11-007 remains open.

This order is effective today.

Dated January 28, 2016, at San Francisco, California.

MICHAEL PICKER
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
LIANE M. RANDOLPH
Commissioners

ATTACHMENT 1

ATTACHMENT 1

ABBREVIATIONS

Term	Abbreviation
Administrative Law Judge	ALJ
Air Resources Board	ARB
Alternative-fuel vehicle	AFV
Americans with Disabilities Act	ADA
California Alternate Rates for Energy	CARE
California Electric Vehicle Infrastructure Pilot	Cal EVIP
California Energy Storage Alliance	CESA
ChargePoint, Inc.	ChargePoint
Community based organization	CBO
Consumer Federation of California	CFC
Distributed energy resources	DER
Distribution Resource Plan	DRP
Diversified business enterprise	DBE
Electric service provider	ESP
Electric Vehicle Infrastructure Training Program	EVITP
Electric vehicle service provider	EVSP
Electric vehicle supply equipment	EVSE
Environmental Defense Fund	EDF
Federal Executive Agencies	FEA
Geographic information systems	GIS
Greenhouse gas	GHG
Green Power Institute	GPI
Health & Safety Code	H&S
International Brotherhood of Electrical Workers	IBEW
Joint Minority Parties	JMP
Kilowatt hour	kWh
KnGrid, LLC	KnGrid
Low carbon fuel standard	LCFS
Multi-unit dwelling	MUD
Natural Resources Defense Council	NRDC
Office of Ratepayer Advocates	ORA

Operations and maintenance	O&M
Order Instituting Rulemaking	Rulemaking or R.
Plug In America	PIA
Plug-in electric vehicle	PEV
Prehearing conference	PHC
Program Advisory Council	PAC
Ratepayer Impact Measure	RIM
Request for information	RFI
Request for proposal	RFP
San Diego Gas & Electric Company	SDG&E
Senate Bill	SB
Shell Energy North America (US), L.P.	Shell Energy
Siemens AG	Siemens
Time of use	TOU
The Utility Reform Network	TURN
Utility Consumers' Action Network	UCAN
Vehicle grid integration	VGI
Vehicle grid integration balancing account	VGIBA
Vehicle to grid	V2G
Zero emission vehicle	ZEV

(End of Attachment 1)

ATTACHMENT 2

ATTACHMENT 2
Alternative VGI Program Terms

The California Public Utilities Commission (Commission) authorizes and approves a 2016 Vehicle Grid Integration (VGI) Pilot Program (2016 VGI Pilot Program), and cost recovery, for San Diego Gas & Electric Company (SDG&E).

This approved 2016 VGI Pilot Program is based on the VGI framework that SDG&E proposed in Application (A.) 14-04-014 on April 11, 2014, and on the modifications that were made to SDG&E's VGI framework in the "Settlement Agreement Regarding San Diego Gas & Electric Company's Vehicle-Grid Integration Pilot Program Application, A.14-04-014" (Settlement Agreement). SDG&E's VGI framework as proposed in A.14-01-014, and the Settlement Agreement which was attached to the June 3, 2015 "Joint Motion for Adoption of Settlement Agreement," were not adopted in Decision (D.) 16-01-045. However, in D.16-01-045, the Commission authorizes and approves the 2016 VGI Pilot Program, which is patterned after the Settlement Agreement, but is reduced in cost, size and scope, as well as other changes as described in D.16-01-045. The changes made in D.16-01-045 to the 2016 VGI Pilot Program are reflected in this Attachment, which reflect the Alternative VGI Program Terms that are acceptable to the Commission, as provided for in Rule 12.4(c) of the Commission's Rules of Practice and Procedure. The approved 2016 VGI Pilot Program shall be governed by the terms and conditions as set forth in D.16-01-045, and in this Attachment. SDG&E shall adhere to the terms and conditions of the 2016 VGI Pilot Program as set forth in this Attachment.

Definitions

As used in this Attachment, which is entitled "Alternative VGI Program Terms", the following definitions apply:

"Air Resources Board" means the California Air Resources Board of the California Environmental Protection Agency.

"Alternative VGI Program Terms" means Attachment 2 to D.16-01-045, and which sets forth the terms and conditions of the 2016 VGI Pilot Program.

"Application" means SDG&E's Application A.14-04-014 filed with the Commission April 11, 2014.

"Attachment" means Attachment 2 to D.16-01-045, which reflects the Alternative VGI Program Terms that are acceptable to the Commission as provided for in Rule 12.4(c) of the Commission's Rules of Practice and Procedure.

"Commission" means the California Public Utilities Commission.
"DBE" means a disadvantaged business enterprise certified by The Supplier Clearinghouse pursuant to Commission General Order 156.
"DC Fast Charging" means a method of quickly charging certain electric vehicles with a high power direct current (DC) charging source.
"Disadvantaged Communities" means disadvantaged communities as identified by the California Environmental Protection Agency's Enviroscreen tool developed pursuant to SB 535 (de León, 2013).
"Energy Division" means the Energy Division of the California Public Utilities Commission.
"EV Driver" means a person using VGI Facilities to charge an EV.
"EV" means an electric vehicle that is capable of being charged using EVSE.
"EVSE" means electric vehicle supply equipment used for charging EVs (SDG&E Rebuttal Testimony Ex. SDG&E 8, p. JPA-4, footnote 6).
"Guiding Principles" means those guiding principles set forth in this document.
"MUD" means multi-unit dwelling.
"PAC" means the VGI Program Advisory Council.
"SDG&E" means San Diego Gas & Electric Company, a California regulated public utility.
"Settlement Agreement" means the Settlement Agreement that was reached between some of the parties to these proceedings, which the settling parties filed a June 3, 2015 motion requesting that the Commission adopt the Settlement Agreement, and in which the motion to adopt the Settlement Agreement was denied in D.16-01-045.
"VGI Facility" means a group of EVSE or charging stations installed with a separate electric service.
"VGI Program Advisory Council" means the stakeholder advisory council formed pursuant to this Attachment.
"VGI Rate" means the dynamic hourly EV charging rate described in SDG&E's direct testimony, Ex. SDG&E-3 (Fang).
"VGI Rate-to-Driver" means the VGI Rate billing plan option where the VGI Rate is offered directly to the EV driver as originally proposed in SDG&E's Application.
"VGI Rate-to-Host" means the VGI Rate billing option where the VGI Rate is billed to the VGI Facility site host as outlined in this Attachment.
"2016 VGI Pilot Program" means the scaled down Vehicle-Grid Integration Pilot Program as proposed by SDG&E in Application 14-04-014, as modified by the Settlement Agreement, and as further modified by Decision 16-01-045.

Guiding Principles

The following Guiding Principles shall guide SDG&E's 2016 VGI Pilot Program implementation.

1. Must support the Governor's and California state goals to:
   a. Achieve installation of grid-integrated infrastructure to support 1 million zero emission vehicles (ZEVs) by 2020;
   b. Accelerate the adoption of 1.5 million ZEVs by 2025;
   c. Support clean air and climate change objectives.
2. Must be structured to provide net benefits to all ratepayers.
3. Must protect ratepayers by ensuring that assets continue to be used and useful.
4. Must provide electric vehicle (EV) drivers the opportunity to maximize fuel cost savings relative to conventional transportation fuels.
5. Must provide equitable deployment of services to all ratepayers, including statutory requirements and directives to serve disadvantaged communities and increase access to clean transportation.
6. Must provide customer choice.
7. Must support broad-based investment in EV charging equipment and services by public, private and utility entities and avoid anticompetitive impacts on the markets for EV charging equipment and related services.
8. Must manage program costs.
9. Must incorporate learning-by-doing and make adjustments to the 2016 VGI Pilot Program as needed.
10. Must provide data to help inform State policy.
11. Must utilize rate design and load management practices to facilitate the integration of renewable energy resources, as well as deliver other grid benefits.
12. Must align with SDG&E's companywide Diversified Business Enterprise ("DBE") goal of 40% and request subcontractors to provide proposals in support of the 40% goal.
13. Must complement other utility clean energy programs and other non-utility programs, such as those being implemented pursuant to the Charge Ahead California Initiative (Stats. 2014, Ch. 530), which will build consumer demand for clean energy and zero emission vehicles.

Modifications To SDG&E's VGI Framework

The following modifications are made to SDG&E's VGI framework as originally proposed in A.14-04-014.

1. Total start-up funding of SDG&E's 2016 VGI Pilot Program shall be $45 million, which shall be paid for by the electric ratepayers of SDG&E, unless excluded by the terms of this document. SDG&E is authorized to

seek cost recovery of its ongoing capital and operations and maintenance expenses, and associated revenue requirement, that are justified in its future general rate case proceedings.

2. The total number of charging sites to be deployed under the 2016 VGI Pilot Program shall be approximately 350, and the total number of charging stations to be deployed shall be approximately 3500. The minimum number of sites to be deployed shall be 300, and the minimum number of charging stations to be deployed shall be 3000. Budget permitting, the sign-up period can be extended past the three-year sign-up period to sign-up and install additional charging sites and charging stations. The installation period shall continue for one year after the end of the sign-up period.

   Over the three-year sign-up period, between 40% and 60% of the EV charging stations, and between 40% and 60% of the site installations, shall be located at MUDs. SDG&E shall strive to deploy approximately 50% of all installations at MUDs.
3. SDG&E's 2016 VGI Pilot Program shall exclusively target multi-unit dwellings (MUDs) and workplaces to site the EV charging stations. The overall percentage distribution of EV charging stations sited at MUDs and workplaces should be approximately 50/50, and SDG&E shall try to achieve this percentage distribution throughout the sign-up period to become a site host. The distribution may not be less than 40% or more than 60% of charging stations (or sites) located at MUDs.

4. As part of the site selection criteria for the EV charging stations, SDG&E shall select site host locations that represent a diversity of circuits so that the 2016 VGI Pilot Program can be tested in a variety of circuit types and conditions.

5. SDG&E's site selection in the 2016 VGI Pilot Program should coordinate and leverage the work being performed in R.14-08-013.

6. The VGI facility site hosts (e.g., property manager/owner of a MUD or workplace setting) will have the choice of two billing options:[39]
    a. VGI Rate-to-Driver – the VGI Rate offered directly to the EV driver (as originally proposed), or
    b. VGI Rate-to-Host – the VGI Rate offered to the site host.

7. SDG&E shall endeavor to enroll a significant number of EV site installations under both VGI billing options.

8. Where the VGI Facility site host opts to receive the VGI Rate (i.e., the VGI Rate-to-Host pricing plan), the site host, or its selected vendor, will be required to submit to SDG&E the load management tactics it will implement at its VGI Facility, including the incremental costs and equipment required to implement the load management tactics, the prices or fees that it intends to levy on VGI Facility users (EV drivers)[40], and any vehicle or EVSE communication systems necessary to implement the load management tactics. Site hosts that do not submit load management plans consistent with the Guiding Principles will be asked by SDG&E to revise accordingly and will be ineligible to participate in the 2016 VGI Pilot Program until SDG&E determines that the load management plan is consistent with the Guiding Principles. Participation in the VGI Rate-to-Host option will not be unreasonably withheld. As with VGI Facility site hosts that opt for the VGI Rate-to-Driver pricing plan, site usage patterns will be monitored, and in addition, site host determined prices or fees (to use the VGI Facility) will be tracked for those site hosts that opt for the VGI Rate-to-Host pricing plan. These data will be used to inform Commission policy.

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[39] VGI facility site host refers to any MUD or workplace site host entity or person that has decision making authority at such site, such as, but not limited to a third party, property manager, or property owner of a MUD or a workplace setting or similar site (i.e., with frequently used, long duration parking). For purposes of clarification, this 2016 VGI Pilot Program is not available to single family residential customers, and public parking locations that do not serve and support MUD or workplace settings.

[40] SDG&E recognizes that site hosts on the VGI Rate-to-Host pricing plan may want the flexibility to change prices or fees over time, as appropriate.

9. VGI Facility site hosts will choose electric vehicle supply equipment ("EVSE") and related services from a list of vendors pre-qualified by SDG&E to provide such services for the 2016 VGI Pilot Program. SDG&E's 2016 VGI Pilot Program does not include the installation of DC Fast Charging equipment.

10. SDG&E will assess a 2016 VGI Pilot Program participation payment on VGI Facility Site Hosts that elect to participate in the 2016 VGI Pilot Program. The participation payment must be used to offset the pilot program operation and maintenance costs, which shall be tracked in a memorandum account established for that purpose. The participation payment will be waived for VGI Facilities at sites located in Disadvantaged Communities. SDG&E shall file for approval of the proposed participation payment, after consulting with the VGI Program Advisory Council (as described below), by way of a Tier 2 advice letter. In developing the proposed participation payment, factors that will be considered include, but are not limited, to the following: customer commitment, avoiding adverse impacts to deployment, total VGI Facility cost and customer segment. While the participation payment approach adopted in D.16-01-023 satisfies these criteria, other approaches and payment magnitudes may also be considered.

11. After the first year of participation in the 2016 VGI Pilot Program, the VGI Facility site host shall have an annual option to switch VGI Rate plans (i.e., the VGI Rate-to-Driver pricing plan or VGI Rate-to-Host pricing plan). In the event that ownership or control of a VGI Facility site changes, the new site host shall have the option to select a VGI Rate plan, consistent with current utility tariff and billing practices.

12. Third party vendors of EVSE and services pre-qualified by SDG&E for the 2016 VGI Pilot Program may offer and contract with the VGI Facility site host to provide any additional or complementary services, such as vehicle to grid, as long as these services do not interfere with the objectives of the 2016 VGI Pilot Program. Specifically, such services may not include activities, agreements, arrangements, policies or procedures that inhibit the ability of the EV driver or VGI Facility site host to respond to the pricing signal of the VGI Rate. The costs of these additional services will not be borne by the 2016 VGI Pilot Program, unless they are complementary services necessary to support the VGI Program objectives. As such, as

noted in Appendix C, SDG&E will encourage discussions during the RFI process that allow vendors to explore with SDG&E the funding of innovative opportunities that may exceed the minimum implementation requirements of the 2016 VGI Pilot Program, and have the potential to enhance and improve the grid-integration outcomes of the 2016 VGI Pilot Program overall.

13. Third party vendors pre-qualified by SDG&E for the 2016 VGI Pilot Program, in coordination with SDG&E customer contact personnel, will market and sign-up potential VGI Facility site hosts to participate in the 2016 VGI Pilot Program in the two targeted customer segments (MUD and workplace settings), and in any other customer sub-segments identified in this Attachment (e.g., Disadvantaged Communities and housing or sites that support car-sharing entities). Responses to the RFP should reflect this requirement (see SDG&E's prepared direct testimony, Ex. SDG&E-2 (Schimka) p. 18 lines 7-20). Competitively neutral descriptions of the VGI Rate plans will be prepared by SDG&E and shall be used by third parties; third parties shall be permitted to develop and utilize their own marketing materials at their own expense, consistent with and subject to SDG&E's Co-branding Policy and approval process. In order to create and maintain a positive customer experience with the 2016 VGI Pilot Program, the third parties will be required to describe how they will share the initial and ongoing customer relationships with SDG&E and the VGI Facility host and EV driver. Vendors will be permitted to contract directly with site hosts for services as long as these services do not interfere with the objectives of the 2016 VGI Pilot Program (as stated above).
    a. SDG&E will solicit participation from multiple third parties to provide equipment, install, maintain and operate the VGI System in a manner consistent with SDG&E's Supply Management policy and procedures.[41] Construction, installation and maintenance contractors will have Electric Vehicle Infrastructure Training Program (EVITP) certification, and SDG&E will require that all construction, installation and maintenance of VGI Facilities that is not performed by employees of SDG&E shall be performed by contractors

[41] See references to SDG&E's Supply Management policy and procedures as outlined in SDG&E's prepared direct testimony Exhibit SDG&E-2 (Schimka) p. 8 line 1 – p. 9 line 20.

signatory to the IBEW who hold a valid C-10 contractor's license, as defined in the governing labor agreement between SDG&E and the IBEW.

14. The 2016 VGI Pilot Program will be included within SDG&E's companywide Diversified Business Enterprise goal of 40%. (See SDG&E prepared testimony, Ex. SDG&E-2, pages RS-8, 9 and RS-19). The RFP and contract will contain a DBE subcontracting plan, which requires the bidder/contractor to list its expected annual DBE spend and list any subcontractors it plans to use to achieve its DBE goal. Bidders will be requested to provide proposals in support of SDG&E's 40% goal.

15. At least 10% of VGI Facilities will be installed in Disadvantaged Communities that are defined as the census tracts scoring in the top 25% of Cal EPA's Enviroscreen tool developed pursuant to SB 535 (de León, 2013). This top quartile shall be calculated on either a state-wide or a service territory basis, whichever is broader. SDG&E will work with community based organizations to assist with education and outreach, identifying the disadvantaged communities that could benefit the most from the deployment of EV charging stations, as well as pre-qualifying and signing-up site hosts for participation in the 2016 VGI Pilot Program. In addition, SDG&E will:
    a. Scale up deployment of VGI Facilities at qualified locations above the 10% target (in line with screening criteria identified in SDG&E's prepared direct testimony, Ex. SDG&E-2 (Schimka) p. RS 7 lines 4-18) to support accelerated EV adoption in Disadvantaged Communities.
    b. SDG&E will complement and coordinate with federal, state and locally funded programs, such as those being developed by the Air Resources Board pursuant to SB 1275, that are expected to grow the demand for EVs in Disadvantaged Communities (e.g., EV car-sharing services), and Commission authorized programs that target low income customers and limited English proficiency customers.
    c. SDG&E will report to the Commission on whether a state-wide or a service territory basis for calculation of the top quartile in Enviroscreen is broader by submitting the number of census tracts qualifying as disadvantaged communities under both methodologies. This information shall be submitted by SDG&E in

a Tier 1 advice letter. In that advice letter, SDG&E shall request authorization to use the methodology that results in a larger number of qualifying census tracts.

16. All contractors shall have hiring goals to support opportunities to increase hiring from Disadvantaged Communities, including first-source hiring and targeted-hiring goals for projects in Disadvantaged Communities. The PAC will also monitor and provide recommendations, including specific numerical targets for meeting hiring targets, to contractors or subcontractors associated with the increase of hiring from Disadvantaged Communities, including best practices for hiring in Disadvantaged Communities.

17. SDG&E will solicit the participation of a broad and diverse stakeholder advisory group (the "VGI Program Advisory Council" or "PAC") in planning and implementing the VGI Program following its approval by the Commission. The VGI PAC will include representatives from local and state government (including representation from the Energy Division), industry, labor and other stakeholder participants, ratepayer and environmental advocates, and representatives of Disadvantaged Communities. SDG&E shall also seek the participation of the San Diego Association of Governments on the PAC. Details regarding the roles, responsibilities and frequency of meetings are described in Appendix A of this document.

18. With guidance from the VGI Program Advisory Council, SDG&E will make programmatic changes as needed during the course of the 2016 VGI Pilot Program in line with the Guiding Principles noted above. Certain programmatic changes may require filings with the Commission for approval. Programmatic changes will be made on an on-going basis, running concurrent with the 2016 VGI Pilot Program, so as not to impact its overall progress. Data collection and program assessment criteria used to determine the need for any programmatic change are identified in SDG&E's prepared direct testimony, Ex. SDG&E-6 (Martin) p. 35 line 9 – p. 37 line 13, and will be supplemented pursuant to this document as further described in Appendix B. Information will be provided to the PAC in a manner similar to SDG&E's Procurement Review Group. Data will be provided to the PAC and Commission to assess the need for programmatic changes.

SDG&E shall work with the VGI Program Advisory Council to select a geographic information system tool to track the progress and attributes of the 2016 VGI Pilot Program deployment.

19. Metering at the EVSE level must be compatible with SDG&E billing and metering requirements (i.e., tolerances, accessibility, testability, and re-calibration, as needed), and/or submetering protocol if and as approved by the Energy Division (for example, see D.13-11-002). SDG&E reserves the right to make exceptions as conditions of the 2016 VGI Pilot Program warrant. Minimum acceptable metering tolerance is anticipated to be 1% and if needed to meet meter testing and re-calibration requirements, removal (and replacement) of the entire EVSE will be acceptable.

    VGI bills will be sent directly to the SDG&E EV driver (SDG&E customer, as originally proposed) receiving the VGI Rate or to the VGI Facility site host receiving the VGI Rate under the VGI Rate-to-Host pricing plan. Data will be provided to SDG&E by the qualified third party to SDG&E's specifications in a manner acceptable to both parties to allow for this billing (see SDG&E's prepared direct testimony, Ex. SDG&E-2 (Schimka) p. 20 lines 1-19). Billing specifications per SDG&E's prepared testimony, Ex. SDG&E-7 (Schimka, Martin) p. ST-42 lines 8-13, are to send VGI rate on a day-ahead basis, allow customer (site host or EV driver) to set charging needs, meet these charging needs, collect usage data and send data to SDG&E for billing processing. For exceptional instances when a non-SDG&E customer is allowed by the VGI Facility site host at a site that is on the VGI Rate-to-EV Driver pricing plan to use the VGI Facility for vehicle charging temporarily, the site host will have the option to be the VGI Rate customer (i.e., enrolled in the VGI Rate), and will be billed for this usage, similar to how the site host is billed under the VGI Rate-to-Host pricing plan.

20. Unless directed otherwise by the Commission or budget permitting, SDG&E will cease marketing the VGI Program and will not sign-up any additional sites as of the end of the third year of 2016 VGI Pilot Program implementation, except for the limited exception described in this paragraph. Installation of VGI Facilities may continue into year four for sites signed up within the three year program, but for which installation has not been completed by the end of year three.

21. SDG&E will allow for flexibility in the design of the VGI Facility configuration to meet the needs of a host site. The costs of any incremental configuration needs will not be funded within the VGI Program (see SDG&E's prepared direct testimony, Ex. SDG&E-2 (Schimka) p. RS-7 lines 4-18). Implementation and site screening process will accommodate host site construction, tenant improvement timelines and situational needs. Some sites may be rejected due to physical limitations, unusually large construction costs and/or level of difficulty.

22. As stated throughout SDG&E's VGI Program proposal, SDG&E will contract with one or more third parties to provide operating systems and related hardware to control EVSE networks to implement the VGI system. It is SDG&E's aim to specify "what" is required to be achieved per the objectives of the VGI Program, and not "how" these requirements are met. This is intended to foster innovation and enhancement to the customer's experience. Although described in SDG&E's prepared direct testimony, Ex. SDG&E-2 (Schimka) p. RS-8 line 1 to p. RS-9, lines 1-20, further clarification of the RFI and RFP processes, in light of this document's modifications to SDG&E's VGI Program proposal, are further described in Appendix C of this document.

23. In order to provide an assessment of the 2016 VGI Pilot Program consistent with the Guiding Principles, six months after the 2016 VGI Pilot Program is launched, and every six months thereafter until February 1, 2021. SDG&E shall file an interim progress report in R.13-11-007 or in a successor proceeding, and shall post the report on its website and serve a notice of availability on the service lists in A.14-04-014 and R.13-11-007. The interim progress report shall include the information described in D.16-01-045, the data as described in Appendix B of this Attachment, and a description of any programmatic changes implemented by SDG&E prior to the date of the report. Parties may then file and serve opening comments on each semi-annual report within 30 days of the service of the report in R.13-11-007, and may file and serve reply comments within 50 days of the service of the report.
    a. SDG&E shall be required to have a check-in meeting (in person or by telephone) with the Commission's Energy Division staff every three months to provide the staff with updates regarding the information described in D.16-01-045.

24. In order to prevent and mitigate potential anticompetitive activities, SDG&E will: (1) create appropriate firewalls to ensure that any non-utility EV site installations performed by SDG&E, or its contractors, that use third party charging platforms and applications, are not shared with or disclosed to personnel at SDG&E engaged in EV-related activities; (2) adopt policies and procedures to ensure that third party EV site installations are queued fairly for the interconnection process, and that the SDG&E EV site installations are not given priority or any preference; and (3) provide third party EV charging developers with information about the distribution system upgrade costs and load data for potential EV site installations. To discharge these mitigation measures, SDG&E should (1) accept the condition that none of its Clean Transportation staff will solicit, obtain, or pass on any proprietary data when engaged in assisting service connections for third party EV charging; (2) include language protecting such proprietary data when contracting with such third party EV charging vendors, and (3) for distribution system upgrade cost data, adhere to its current tariffed and Commission-approved policies and procedures that prioritize load and generation interconnections on a queued basis by data of application, and under which SDG&E provides cost and schedule data to developers when they apply to interconnect new load or generation.

25. Customers of SDG&E who are in the California Alternate Rates for Energy program shall be excluded from paying for the costs of the 2016 VGI Pilot Program.

26. SDG&E is authorized to establish a one-way, interest-bearing, VGI Balancing Account (VGIBA). The VGIBA shall be subject to the $45 million start-up budget limit that we approve in D.16-01-045 for the 2016 VGI Pilot Program. If SDG&E accepts the terms of the alternative VGI program terms, it will have 30 days from the date of SDG&E's acceptance to file a Tier 2 advice letter to establish the VGIBA.

Appendix A

Roles, Responsibilities of the VGI Program Advisory Council

SDG&E will solicit the participation of a broad and diverse stakeholder VGI Program Advisory Group ("VGI Program Advisory Council" or "PAC") in the planning and implementing the 2016 VGI Pilot Program, once it has been approved by the Commission. This independent advisory council will include representatives from local and state government (including representation from the Energy Division), industry and other stakeholders, ratepayer and environmental advocates, and representation from Disadvantaged Communities. Participation in the PAC will not be funded by the 2016 VGI Pilot Program. The PAC does not have formal decision-making authority. The PAC will make recommendations and/or provide key information and materials to the VGI Program Managers at SDG&E, who will organize and chair PAC meetings. Information will be provided to the PAC in a manner similar to SDG&E's Procurement Review Group.

Overall, the key role and purpose of the PAC will be to provide input to SDG&E for programmatic changes as needed during the course of the 2016 VGI Pilot Program (e.g., VGI Rate - as originally proposed, or with VGI host site prioritization for an equitable deployment of VGI Facilities), to improve the performance of the 2016 VGI Pilot Program, in line with the Guiding Principles and consistent with any applicable Commission orders, tariff rules, regulations, etc. SDG&E will give careful consideration to all programmatic modifications recommended by the PAC at their meetings and implement such changes deemed feasible and necessary. Programmatic changes will be made on an on-going basis, running concurrent with the 2016 VGI Pilot Program, so as not to impact its overall progress.

The VGI PAC will employ a process for examining the data described in Appendix B to determine if a program modification should be implemented to improve the performance of the 2016 VGI Pilot Program.

In line with input from the VGI PAC, SDG&E will make programmatic changes as needed during the course of the 2016 VGI Pilot Program (e.g., VGI Rate - as originally proposed, or with VGI host site prioritization for an equitable deployment of VGI Facilities). Programmatic changes will be made on an on-going basis, running concurrent with the 2016 VGI Pilot Program, so as not to impact its overall progress. The VGI PAC and SDG&E will consider before the conclusion of the VGI Program, and when there is sufficient data, a shareholder reward/risk mechanism that is contingent on delivery of proposed benefits.

To fulfill this role, the VGI Program Advisory Council and its members will have the following responsibilities:

1. Attend all VGI Program Advisory Council meetings, planned to take place at least twice per year over the 2016 VGI Pilot Program period (however, year one will include additional organizational and planning meetings to launch the PAC, as appropriate). Members' individual representatives will be authorized by the sponsoring member

organization to accurately represent the member's position or perspectives. There will be only one representative per member organization. Participation in the PAC will not affect a member's right to speak individually.

2. Examine the 2016 VGI Pilot Program data and findings presented by SDG&E and PAC members in order to make informed recommendations.
3. Timely vet recommendations for 2016 VGI Pilot Program modifications.
4. Actively participate in PAC meetings, and related assignments; contribute resources (e.g., data, expertise, and related) to the PAC where applicable.
5. VGI PAC meeting locations will alternate between San Diego and San Francisco, as determined by the VGI PAC.

Appendix B

Supplemental Data Collection Objectives, Requirements and 2016 VGI Pilot Program Assessment Criteria

Data collection and 2016 VGI Pilot Program assessment criteria used by the VGI Program Advisory Council to determine the need for any programmatic change are identified in the Research Plan (Data Collection and Analysis) described in SDG&E's prepared direct testimony Ex. SDG&E-6 (Martin) p. JCM-35 line 9 – p. 37 line 13, and will be supplemented as described below pursuant to the modifications to SDG&E's VGI Program proposal as a result of D.16-01-045. Data collection identified in this testimony specifically relate to measuring 2016 VGI Pilot Program performance and cost-effectiveness. With the addition of the VGI Rate-to-Host option, there is a need for additional data collection in order to compare and contrast the performance of the two VGI options (i.e., VGI Rate-to-Driver and VGI Rate-to-Host). To accomplish this, the data collection in the Research Plan will include, but will not be limited to:

- Customer (EV drivers and site Hosts) enrollment by site and VGI pricing plan (i.e., VGI Rate-to-Driver and VGI Rate-to-Host)
- Under the VGI Rate-to-Host, load management plans and pricing or fees, including those measures taken that encourage the facilitation of the integration of renewable energy
- Estimates of fuel cost savings through the use of the VGI Facility, under both the VGI Rate-to-Driver and VGI Rate-to-Host pricing plans
- VGI Facility utilization rates
- Deployment of VGI Facilities within or adjacent to a Disadvantaged Community, including EV car-sharing deployment

There is also a need for data collection adequate to provide a description of the 2016 VGI Pilot Program's status and activities, and an assessment of the 2016 VGI Pilot Program's progress consistent with the Guiding Principles in the Interim Progress Report. To accomplish this, additional data collection will include, without limitation, data related to:

- Status of program implementation to date
- Comparing the installations of non-utility EVSE to VGI EVSE
- Surveys of customer and driver decisions to adopt PEVs
- Rate of achievement of supplier diversity and workforce objectives

The VGI PAC will have the flexibility to determine if additional 2016 VGI Pilot Program related measurement and evaluation objectives are of interest and will help to inform Commission policy. The VGI PAC will then articulate the purpose behind these objectives, specify these additional data collection requirements, and determine how they will be funded and resourced.

Appendix C

RFI and RFP Process Clarification

In light of the modifications in Decision 16-01-045 to SDG&E's VGI Program proposal, the following are clarifications of the RFI and RFP processes.

With respect to the selection process and selection criteria for pre-qualifying vendors who will be authorized to provide VGI operating systems and related hardware to control EVSE networks to implement the VGI system, SDG&E prefers generally functional requirements per the objectives of the 2016 VGI Pilot Program, and not "how" these requirements are met. This is intended to foster innovation and enhance the customer's experience and ensure customer choice of vendor, equipment and services. Vendors will be permitted to contract directly with site hosts for services, as necessary, as long as these services do not interfere with the objectives of the 2016 VGI Pilot Program. SDG&E will use a multi-faceted approach to evaluating RFI responses and RFP bid proposals. All responses will be evaluated based on, but not limited to, the following criteria (not listed in order of importance):

- Total cost of ownership over the lifecycle of the EVSE and its operating system, including all indirect and direct costs
- Responsiveness to the RFI and RFP (including response to SDG&E's Terms and Conditions included in the RFP)
- Overall product and service offering including cost, quality, warranty and capability
- Ability to meet safety, reliability, operational and 2016 VGI Pilot Program requirements
- Demonstrated ability to provide innovative functionality to enhance the 2016 VGI Pilot Program experience for the customer while meeting program objectives
- Minimum requirements met for EVSE and operating systems
- 2016 VGI Pilot Program value-added features
- Performance history
- Proposed schedule/time required to complete the required deliverables
- Prior experience in providing EVSE services as described in the RFI/RFP
- Financial strength of the service provider
- Sustainability ("green")
- DBE proposals and plans to achieve stated targets

SDG&E reserves the right to investigate the references and past performance of any bidders/vendors with respect to, among other factors, compliance with specifications, safety, completion or delivery on schedule, and lawful payment of suppliers, sub-suppliers, and workers prior to any contract award. It is anticipated that vendors meeting all the selection criteria will be qualified to participate in providing equipment and services under the 2016 VGI Pilot Program. Except as otherwise set forth in Appendix C, it is anticipated and preferred that multiple vendors will be selected as an outcome of this bidding event however SDG&E reserves the right to accept or reject any or all proposals on the basis of

any reason, and although SDG&E is under no obligation to disclose the reason for rejection, SDG&E will provide feedback to any vendor whose proposal was rejected, if requested.

With respect to the installation and maintenance of the VGI Facilities, SDG&E plans to seek the most effective form of VGI Facility development, installation and maintenance, consistent with utility standards and practices. Construction, installation and maintenance contractors will have Electric Vehicle Infrastructure Training Program (EVITP) certification, and SDG&E will require that all construction, installation and maintenance of VGI Facilities that is not performed by employees of SDG&E shall be performed by contractors signatory to the IBEW who hold a valid C-10 contractor's license, as defined in the governing labor agreement between SDG&E and the IBEW.

Finally, the RFI and RFP process and vendor qualification process will remain open throughout the duration of the 2016 VGI Pilot Program to allow for and encourage participation from qualified third parties over time. SDG&E will encourage discussions during the RFI process that allow vendors to explore with SDG&E the funding of innovative opportunities that may exceed the minimum implementation requirements of the 2016 VGI Pilot Program, and have the potential to enhance and improve the grid-integration outcomes of the 2016 VGI Pilot Program overall.

(End of Attachment 2)

ATTACHMENT 3

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Last Updated on 21-DEC-2015 by: JVG

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Last Updated on 21-DEC-2015 by: JVG

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COM/CR6/smt **Date of Issuance 11/21/2022**

Decision 22-11-040 November 17, 2022

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification.	Rulemaking 18-12-006

DECISION ON TRANSPORTATION ELECTRIFICATION POLICY AND INVESTMENT

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DECISION ON TRANSPORTATION ELECTRIFICATION POLICY AND INVESTMENT

Summary

This decision adopts a long-term transportation electrification policy framework that includes a third-party administered statewide transportation electrification infrastructure rebate program and directs the California electrical corporations, specifically, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities (CalPeco Electric) LLC, Bear Valley Electric Service Inc., and PacifiCorp d/b/a Pacific Power to jointly fund the program and associated activities.

The transportation electrification framework and rebate program further state policy promoting decarbonization and will continue to do so, as the supporting technology and policy mechanisms continue to mature. The adopted program prioritizes investment in low-income, underserved, and tribal communities to ensure participation from customers that lack access to the benefits of transportation electrification.

This decision resolves the transportation electrification framework policy and program design topics that have been under consideration since 2020 and adopts the most important elements of the statewide infrastructure rebate program. Additional program guidelines will be established in a subsequent decision and Advice Letters, as described herein.

This proceeding remains open.

1. Background

In December 2018, the California Public Utilities Commission (Commission) established this proceeding through an Order Instituting Rulemaking (OIR). Following party protests and responses to the OIR, a prehearing conference on March 1, 2019, addressed the potential issues, scope,

and schedule of the proceeding. The assigned Commissioner issued a Scoping Memo and Ruling (Scoping Ruling) on May 2, 2019, setting the issues to be considered throughout this proceeding. Among other things, the Scoping Ruling held that a Transportation Electrification Framework was needed to address a multitude of issues related to transportation electrification (TE) investments made by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Liberty Utilities (CalPeco Electric) LLC (Liberty), Bear Valley Electric Service Inc. (Bear Valley), and PacifiCorp d/b/a Pacific Power (PacifiCorp), collectively referred to as the investor-owned utilities (IOUs).

The Governor and the Legislature have directed state agencies to accelerate TE. The Commission works closely with our sister state agencies on TE policy, program design, and deployment. The California Energy Commission (CEC) studies electric vehicle (EV) charging needs across the state and distributes funding for certain charging use cases. The California Air Resources Board (CARB) regulates vehicles in the state and sets requirements for the transition to zero-emission vehicles (ZEVs). Numerous other public agencies including Air Quality Management Districts, the Governor's Office of Business and Development, and local governments engage in TE planning processes with the Commission, the CEC, and the CARB.

1.1. Draft Transportation Electrification Framework

One of the goals of the instant proceeding is to provide a framework for the Commission to consider utility investments and rates related to ZEVs. As such, the OIR authorized the Commission's Energy Division (ED) staff to develop a framework for utility TE investments moving forward. After months

of stakeholder engagement, on February 3, 2020, an Administrative Law Judge (ALJ) ruling in this proceeding issued a Transportation Electrification Framework proposal (Draft TEF) and requested party comments.[1]

Given the number of unique topics within the Draft TEF, the Commission required parties to file comments in stages. Because of the length and technical nature of the Draft TEF, parties requested more time between opening and reply comment rounds, and the ALJ subsequently issued several rulings superseding the procedural schedules previously adopted for commenting on the various chapters of the Draft TEF.[2]

On March 6, 2020, the following parties filed opening comments on Chapters 2-5 of the Draft TEF: Alliance for Transportation Electrification (ATE), Advanced Energy Economy (AEE), BNSF Railway (BNSF), California Independent System Operator Corporation (CAISO), Public Advocates Office at the California Public Utilities Commission (Cal Advocates), California Transit Association, California Energy Storage Alliance (CESA), ChargePoint, Inc. (ChargePoint), City of Long Beach, California Large Energy Consumers Association (CLECA), Connect California LLC, Environmental Defense Fund (EDF), Electrify America LLC (Electrify America), Enel X North America Inc. (Enel X), Envoy Technologies Inc., Energy Producers and Users Coalition (EPUC), EVgo Services LLC (EVgo), Community Environmental Council/ Green

[1] ALJ's Ruling Adding Staff Proposal for a Draft Transportation Electrification Framework to the Record and Inviting Party Comments (Feb. 3, 2020).

[2] The docket for this proceeding contains a complete list of rulings modifying the comment schedule for the Draft TEF.

Power Institute (GPI),[3] Plug In America, Joint Automakers,[4] Joint Commenters,[5] Joint EV Technology Providers,[6] Joint Parties,[7] Liberty, PacifiCorp, PG&E, San Diego Association of Governments (SANDAG), Small Business Utility Advocates (SBUA), SCE, SDG&E, Tesla Inc. (Tesla), the Utility Reform Network (TURN), Utility Consumers' Action Network (UCAN), and Vehicle-Grid Integration Council (VGIC).[8] On April 27, 2020, the following parties filed reply comments on Chapters 2-5 of the Draft TEF: Alliance for Automotive Innovation (Auto Innovators), ATE, BNSF, Cal Advocates, CALSTART, California Hydrogen Business Council, ChargePoint, Center for Sustainable Energy (CSE), Ecology Action,[9] EDF, Electrify America, Enel X, EVgo, GPI, the Greenlining Institute (Greenlining),[10] Greenlots, Joint CCAs,[11] Joint Commenters, Joint Parties,[12] National Diversity Coalition (NDC), Peninsula Clean Energy

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[3] GPI refers to both Community Environmental Council and Green Power Institute.

[4] Joint Automakers consist of the Alliance for Automotive Innovation, Ford Motor Company, General Motors LLC, Hyundai Motor Company, and Kia Motors Corporation.

[5] Joint Commenters consist of Center for Community Action and Environmental Justice, East Yard Communities for Environmental Justice, Sierra Club, Union of Concerned Scientists, and Center for Biological Diversity.

[6] The Joint EV Technology Providers consist of Greenlots and Siemens eMobility (Siemens).

[7] Joint Parties here refers to Natural Resources Defense Council (NRDC), Coalition of California Utility Employees (CUE), Greenlots, Enel X, EVBox North America Inc. (EVBox), and Siemens.

[8] Citations to "Opening Comments on Draft TEF Chapters 2-5" refer to these comments.

[9] Ecology Action filed these reply comments on May 8, 2020.

[10] Greenlining filed these reply comments on May 6, 2020.

[11] Joint CCAs here refers to Marin Clean Energy (MCE), Sonoma Clean Power Authority (SCP), California Choice Energy Authority (CalChoice), Silicon Valley Clean Energy Authority (SVCE), East Bay Community Energy (EBCE), Redwood Coast Energy Authority (RCEA), the City of San José, and Monterey Bay Community Power (MBCP).

[12] Joint Parties here refers to Siemens, NRDC, CUE, Greenlots, and EVBox.

Authority (PCE), PG&E, Sacramento Municipal Utility District (SMUD), SBUA, SCE, SDG&E, Siemens, Silicon Valley Leadership Group (SVLG), Tesla, TURN, UCAN, and VGIC.[13]

On July 14, 2020, the following parties filed opening comments on Chapters 7 and 8 of the Draft TEF: Bear Valley, BNSF,[14] CAISO, Cal Advocates, CALSTART, ChargePoint, City of Long Beach, CUE, EDF, Electrify America, Enel X and Nuvve, EVBox, EVgo, Joint Commenters, Joint Parties,[15] Liberty, NDC, PCE, PG&E, SCE, SDG&E, Tesla, UCAN, and VGIC.[16] On August 7, 2020, the following parties filed reply comments on Chapters 7 and 8 of the Draft TEF: AEE, BNSF, Cal Advocates, ChargePoint, CUE, EDF, Electrify America, Enel X and Nuvve, EVgo, Greenlots, Joint Parties,[17] NDC, PacifiCorp, PG&E, SCE, SDG&E, Tesla, TURN, UCAN, and VGIC.[18]

On August 21, 2020, the following parties filed opening comments on Chapters 6 and 11 of the Draft TEF: AEE, BNSF, Cal Advocates, CALSTART, California Association of Small and Multi-Jurisdictional Utilities (CASMU),[19] ChargePoint, Clean Energy Fuels, CSE, EDF, Electrify America, Greenlining, GPI,

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[13] Citations to "Reply Comments on Draft TEF Chapters 2-5" refer to these comments.

[14] BNSF filed these comments on July 7, 2020.

[15] Joint Parties here refers to NRDC, CUE, Plug in America, Auto Innovators, Enel X, Siemens, EVBox, and Auto Innovators.

[16] Citations to "Opening Comments on Draft TEF Chapters 7 and 8" refer to these comments.

[17] Joint Parties here refers to NRDC, CUE, Plug in America, Greenlots, Enel X, Siemens, EVBox, and Auto Innovators.

[18] Citations to "Reply Comments on Draft TEF Chapters 7 and 8" refer to these comments.

[19] CASMU is comprised of Bear Valley, Liberty, and PacifiCorp.

GRID Alternatives (GRID), Joint CCAs,[20] Joint Commenters, Joint Parties,[21] NDC, PG&E, Plug In America, SANDAG, SBUA, SCE, SDG&E, Tesla, TURN, UCAN, and VGIC.[22] On September 4, 2020, the following parties filed reply comments on Chapters 6 and 11 of the Draft TEF: AEE, ATE, Cal Advocates, ChargePoint, City and County of San Francisco, Clean Energy Fuels, CLECA, EDF, Electrify America, EVgo, Greenlining, GPI, GRID, Joint CCAs,[23] Joint Commenters, NDC, PG&E, SBUA, SCE, SDG&E, Tesla, TURN, UCAN, and VGIC.[24]

On September 11, 2020, the following parties filed opening comments on Chapters 9, 10, and 12 of the Draft TEF: AEE, BNSF, Cal Advocates, ChargePoint, CLECA, EDF, Electrify America, EVgo, GPI, Joint CCAs,[25] Joint Commenters, Joint Parties,[26] Lyft Inc., PacifiCorp, PCE, PG&E, SANDAG, SBUA, SCE, San Diego Airport Parking Company (SDAP), SDG&E, Tesla, TURN, Uber Technologies Inc. (Uber), UCAN, and VGIC.[27] On September 25, 2020, the following parties filed opening comments on Chapters 9, 10, and 12 of the Draft TEF: AEE, ATE, BNSF, Cal Advocates, ChargePoint, Clean Energy Fuels,

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[20] Joint CCAs here refers to PCE, RCEA, EBCE, the City of San José, MCE, SVCE, and SCP.

[21] Joint Parties here refers to NRDC, CUE, Plug in America, Greenlots, Enel X, Siemens, EVBox, and Auto Innovators.

[22] Citations to "Opening Comments on Draft TEF Chapters 6 and 11" refer to these comments.

[23] Joint CCAs here refers to PCE, RCEA, EBCE, the City of San José, MCE, SVCE, SCP, CalChoice, and Clean Power Alliance of Southern California (CPA).

[24] Citations to "Reply Comments on Draft TEF Chapters 6 and 11" refer to these comments.

[25] Joint CCAs here refers to MCE, SCP, CalChoice, SVCE, EBCE, RCEA, the City of San José, and CPA.

[26] Joint Parties here refers to NRDC, CUE, Plug in America, Greenlots, Enel X, Siemens, EVBox, and the Auto Innovators.

[27] Citations to "Opening Comments on Draft TEF Chapters 9, 10, and 12" refer to these comments.

CLECA, EDF, GPI, GRID, Joint CCAs,[28] NDC, PCE, PG&E, SCE, SDAP, SDG&E, Tesla, TURN, Uber, and UCAN.[29]

Three workshops held after the issuance of the Draft TEF sought stakeholder feedback on how to move forward with the Draft TEF. On March 23, 2020, a remote workshop addressed topics related to Chapters 3.1, 4, and 5 of the Draft TEF. On April 20, 2020, a remote workshop addressed Chapter 4, and on June 8 and 9, 2020, a remote workshop addressed Chapter 3.4.

On October 13, 2021, the Commission convened an en banc session with other state agencies to discuss the role of ratepayer funding in accelerating TE. To date, the Commission has authorized approximately $1.8 billion to be invested in various TE programs and pilots. The en banc session encouraged public dialogue regarding the appropriate level of ratepayer investments in TE, including the availability of other funding sources to promote TE and how that level of investment would help California meet its EV adoption goals.

1.2. Utility Investments on the Distribution Side of the Meter and Implementation of Assembly Bill (AB) 841

On September 30, 2020, the Governor signed AB 841 (Stats. 2020, ch. 372). AB 841 directed the utilities and the Commission to establish new rules that authorize each utility to "design and deploy all electrical distribution infrastructure on the utility side of the customer's meter for all customers installing separately metered infrastructure to support charging stations, other

[28] Joint CCAs here refers to MCE, SCP, CalChoice, SVCE, EBCE, RCEA, the City of San José, and CPA.

[29] Citations to "Reply Comments on Draft TEF Chapters 9, 10, and 12" refer to these comments.

than those in single-family residences."[30] In February 2021, the IOUs filed Advice Letters to implement the legislation. The Advice Letters requested the establishment of new EV Infrastructure Rules and requested memorandum accounts to track the associated costs. The Commission approved these Advice Letters with modifications in Resolutions (Res.) E-5167 and E-5168.

The EV Infrastructure Rules represent a major policy shift since the issuance of the Draft TEF. Before implementation of AB 841, the Commission approved both utility-side and customer-side TE investments associated with programs through specific, one-off IOU TE applications, and the IOUs tracked the costs for recovery through balancing accounts associated with the individual TE programs. Outside of programs before implementation of AB 841, customers would take service under Rule 16, which would determine the amount of utility-side costs the customer versus ratepayers would pay.

Pursuant to the new EV Infrastructure Rules, the IOUs socialize across all ratepayers the costs of service line extensions and electrical distribution infrastructure for EV charging—for customers other than those in single-family residences. Single-family residences already receive similar treatment under existing permanent exemptions from the Rules 15 and 16, governing customer contributions for new infrastructure.[31]

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[30] Public Utilities (Pub. Util.) Code Section 740.19(c).

[31] Residential EV customers in single-family homes have received exemptions from Rule 16 since 2011. Under Rule 16, ratepayers cover costs up to an allowance, but the customer is responsible for other costs, such as construction, trenching, and other expenses. Rule 16 covers fewer costs associated with utility-side service line extensions and electrical distribution infrastructure than the new rules. Decision (D.) 21-12-033 made the interim policy on Common Treatment for Excess PEV Charging the standard Commission policy, pending determination that a new policy is necessary to ensure just and reasonable rates for ratepayers.

Under the new approach, investments associated with EV infrastructure on the utility side of the meter are now part of the IOUs' overall distribution system upgrade plans.[32] As defined in AB 841, make-ready infrastructure includes poles, vaults, service drops, transformers, mounting pads, trenching, conduit, wires, cables, meters, other equipment, and associated engineering and civil construction work on the utility side of the meter that enable the installation of an EV charger.[33] The IOUs track all EV Infrastructure Rule costs through their EV Infrastructure Rule Memorandum Accounts and seek recovery of recorded costs through their general rate cases (GRCs). This is intended to allow for more rapid and predictable utility investment in TE infrastructure for EV customers. The Commission continues to review and shape distribution investment plans so that they align with California's electrification goals and do not lead to unreasonable or unnecessary ratepayer costs.

Pursuant to AB 841, the Commission and stakeholders will begin evaluating the effectiveness of the EV Infrastructure Rules in accelerating TE and protecting the interests of ratepayers in 2025. As required by the resolutions, the utilities will report data via the annual EV Cost and Load Report to enable analysis and evaluation of the new EV Infrastructure Rules.[34]

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[32] These include ongoing efforts in various venues and proceedings (*e.g.*, Rulemaking (R.) 20-05-003, R.21-06-017, and working groups such as the Joint Agency Steering Committee, which is comprised of the Commission, CARB, CAISO, and CEC, with direct IOU coordination).

[33] Pub. Util. Code Section 740.19(b).

[34] As of issuance of this decision, the most recent EV Cost and Load Report is for 2021. PG&E, SCE, and SDG&E, Joint IOU Electric Vehicle Load Research and Charging Infrastructure Cost Report (Mar. 31, 2022), available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M464/K783/464783120.PDF.

For each utility, the new rules cannot be modified until the completion of its next GRC cycle, with new GRC cycles beginning between 2027 and 2029.[35] The Commission may then use the data collected on costs and the effectiveness of the new rules to determine whether to require any customer contributions for costs incurred on the utility side of the meter.

The Commission is undertaking several efforts related to EV infrastructure investments, including ensuring that customers installing EV chargers do not wait in long interconnection queues. In the proceeding to modernize the electric grid for a high distributed energy resources future, the Commission oversees the IOUs' plans to upgrade the distribution grid to meet the new load EV charging will create.[36] Additionally, the Commission's Integrated Resource Planning (IRP) proceeding, which focuses on resource procurement, is using load forecasts that include more EV charging demand.[37] By doing so, it is incorporating expected EV load into planning for both generation and transmission resources.

Additionally, on May 27, 2022, pursuant to Res. E-5167 and E-5168, SDG&E filed Advice Letter 4011-E,[38] containing the joint IOUs' proposed electric vehicle supply equipment (EVSE) service energization timelines. The

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[35] Pub. Util. Code Section 740.19(c) ("The commission may revise the policy . . . after the completion of the general rate case cycle of the electrical corporation following the one during which the advice letter was filed if a determination is made that a change in the policy is necessary to ensure just and reasonable rates for ratepayers.").

[36] R.21-06-017.

[37] R.20-05-003.

[38] PG&E Advice Letter 6607-E; SCE Advice Letter 4803-E; Bear Valley Advice Letter 444-E; Liberty Advice Letter 192-E; PacifiCorp Advice Letter 685-E.

Advice Letter proposed an average 160-day timeline for all EVSE installed via the IOUs' EV Infrastructure Rules.

The distribution system on the utility side of the meter will require substantial upgrades in the long term to handle significant growth in EV load and to support increased deployment of high-capacity fast chargers. It will be especially important for the system to expand at a pace and in locations that support the medium- and heavy-duty (MDHD) fleet needed to meet California's air quality regulations. The efforts described above are intended to ensure that the IOUs strategically pursue cost-effective upgrade opportunities that do not overload the grid. The IOUs will continue to collaborate with the relevant state agencies including the Commission, the CEC, and CAISO in distribution grid planning to support EV charging.

1.3. Additional Changes Since Issuance of the Draft TEF

Since the issuance of the Draft TEF, the Commission has adopted the following decisions in this proceeding: D.20-09-025, clarifying the status of electric vehicle service providers (EVSPs) as public utilities; D.20-12-027, providing direction for the Low-Carbon Fuel Standard (LCFS) holdback revenue utilization; D.20-12-029, implementing Senate Bill (SB) 676 (Bradford, 2019) and vehicle-grid integration strategies; D.21-07-028, setting near-term priorities for TE investments by the IOUs; D.21-12-030, revising the near-term priority TE Investment decision; D.21-12-033, extending the interim policy on common treatment for excess plug-in EV charging costs; and D.22-08-024, adopting the Plug-in Electric Vehicle Submetering Protocol and EVSE communication protocols.

In addition to the decisions issued in this proceeding since February 2020, the Commission adopted several decisions in specific TE ratesetting proceedings. Decisions authorizing TE investments since the issuance of the Draft TEF include D.20-08-045—authorizing $436 million for SCE's Charge Ready 2 infrastructure and market education programs—and D.21-04-014—authorizing $43.5 million for SDG&E's Power Your Drive Extension program. The Commission also issued Res. E-5175 to clarify EVSE communication requirements and other details related to the EVSE qualification processes for SCE's Charge Ready 2 program. Related to EV rates, D.21-11-017 required PG&E to offer an optional day-ahead, hourly real-time rate to customers who have enrolled or are eligible to enroll in its existing Business EV Rate, and D.22-08-002 considered a study on the marginal generation capacity costs that PG&E should use when calculating its rates, including its real-time pricing rate.

In September 2020, Governor Newsom issued Executive Order N-79-20 requiring that all new light-duty (LD) vehicle sales be zero emission by 2035 and all new MDHD vehicle sales be zero emission by 2045. As of August 25, 2022, the CARB approved the Advanced Clean Cars II (ACCII) regulation, establishing this target as a compliance requirement for all automakers.[39] Pursuant to this same Executive Order and AB 2127 (Ting, 2018), the CEC issued its inaugural Electric Vehicle Charging Infrastructure Assessment, or the AB 2127 Charging Assessment, in July 2021.[40]

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[39] CARB Resolution 22-12 adopted the Advanced Clean Cars II regulation and amended the CARB ZEV regulation to require an increasing number of ZEVs to support EO N-79-20, which requires all new passenger vehicles sold in California to be zero emission by 2035.

[40] The CEC will biennially issue updated AB 2127 Charging Assessment reports.

Through the initial AB 2127 Charging Assessment, the CEC estimates that by 2030 California may need up to 1.2 million EV chargers to support an estimated eight million LD EVs and an additional 157,000 chargers to support MDHD EVs.[41] There are currently over 1.2 million LD EVs in California and significantly fewer chargers than the number the CEC identified as potentially needed in 2030.

Additionally, shortly after the Draft TEF was issued, California declared a state of emergency due to the COVID-19 pandemic. Since then, transportation and other social patterns have changed significantly.

As noted, the Commission has authorized more than $1.8 billion in ratepayer dollars for TE investments to date. This amount does not include the significant utility-side investment we expect to result from the implementation of AB 841 and other necessary utility-side upgrades, and the significant investment from LCFS revenue.[42] Of the $1.8 billion that the Commission has authorized, the IOUs have spent approximately $333 million to date, or approximately 17.5 percent—meaning a significant amount of funding is still available.

In addition to substantial ratepayer investments, billions of dollars in approved federal and state funds will support California's TE infrastructure. As

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[41] CEC AB 2127 Charging Assessment at 31, "An update to the model, EVI-Pro 2, expands infrastructure projections to support nearly 8 million ZEVs by 2030 and incorporates evolving technology and market conditions. This level of ZEV adoption is derived from CARB's *Draft 2020 Mobile Source Strategy* and is the trajectory needed to achieve the Executive Order N-79-20 target of 100 percent light-duty ZEV sales by 2035."

[42] The IOUs' LCFS funding, while confidential, is estimated to be in the tens of millions of dollars per year range. *See* D.20-12-027 at 7. We cannot accurately predict the amount of ratepayer funding that will support the EV Infrastructure Rules, but we expect the rules to cover an average of 15 to 20 percent of a site's total installation costs (*i.e.*, utility- and customer-side costs).

a result of the federal Infrastructure Investment and Jobs Act of 2021, for instance, California will receive $383 million in funding for TE infrastructure. The Act authorizes an additional $2.5 billion for ZEV infrastructure available in competitive grants nationwide.[43]

In November 2021, the CEC approved $1.4 billion for TE and hydrogen vehicle charging infrastructure to be spent over three years, increasing the previous budget by more than six times. California's 2021 Budget Act committed $3.9 billion towards ZEV acceleration through 2024. The budget included an additional $6.1 billion one-time expenditure over five years to accelerate the state's transition to ZEVs, with much of the funding dedicated to supporting MDHD fleets and disadvantaged and low-income communities.

With the signing of the federal Inflation Reduction Act in August 2022, an additional $1.7 billion in tax credits for EV chargers and other alternative fuel equipment will be available for eligible customers beginning January 1, 2023, through the Alternative Fuel Vehicle Refueling Property Credit.[44]

1.4. Staff Proposal

On February 25, 2022, an Assigned Commissioner's Ruling issued and requested comments on the Energy Division Staff Proposal to Establish Transportation Electrification Funding Cycles and Statewide Behind-the-Meter

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[43] *See* U.S. Dept. of Energy, Bipartisan Infrastructure Law (Infrastructure Investment and Jobs Act of 2021), https://afdc.energy.gov/laws/infrastructure-investment-jobs-act.

[44] The Alternative Fuel Vehicle Refueling Property Credit is a general business tax credit that offsets 30 percent of the total costs to purchase and install charging equipment, excluding permitting and inspection costs, up to $100,000 per charger. Eligible customers must be located in a census area where the poverty rate is at least 20 percent or the median family income in the area is equal to or less than 80 percent of the statewide median family income. *See* U.S. Dept. of Energy, Alternative Fuel Infrastructure Tax Credit, https://afdc.energy.gov/laws/10513.

Program (Staff Proposal). The following parties submitted opening comments on the Staff Proposal by the April 25, 2022 deadline: AEE, ATE, Auto Innovators, BNSF, Cal Advocates, California Efficiency + Demand Management Council (CEDMC), ChargePoint, CLECA, CSE, Port of Long Beach, Clean Energy Fuels, EDF, EDF Renewables Inc. (EDF Renewables), Electrify America, EPUC, EVgo, GPI, Greenlining, GRID, Joint CCAs,[45] Joint Commenters,[46] Joint Parties,[47] NDC, Nuvve, PG&E, SBUA, SCE, SDG&E, Tesla, TURN, UCAN, VGIC, and Weave Grid Inc (Weave Grid).[48] The following parties submitted reply comments on the Staff Proposal by the May 16, 2022 deadline: AEE, Cal Advocates, ChargePoint, CLECA, CSE, EDF, Electrify America, EPUC, EVgo, Fermata Energy LLC

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[45] Joint CCAs here refers to CalChoice, CPA, EBCE, MCE, PCE, RCEA, San Diego Community Power (SDCP), SCP, and San José Clean Energy (SJCE), which is the City of San José's CCA program that the San José Community Energy Department administers.

[46] Joint Commenters here refers to Center for Community Action and Environmental Justice, East Yard Communities for Environmental Justice, Sierra Club, and Union of Concerned Scientists. Parties included in the Joint Commenters' filings on the Staff Proposal differ from the parties included on the Joint Commenters' earlier filings on the Draft TEF.

[47] Joint Parties here refers to NRDC, CUE, Ecology Action, Siemens, Shell EV Charging Solutions America (formerly Greenlots), and Enel X. in a census area where the poverty rate is at least 20 percent or the median family income in the area is equal to or less than 80 percent of the statewide median family income. *See* U.S. Dept. of Energy, Alternative Fuel Infrastructure Tax Credit, https://afdc.energy.gov/laws/10513.

[47] Joint CCAs here refers to CalChoice, CPA, EBCE, MCE, PCE, RCEA, San Diego Community Power (SDCP), SCP, and San José Clean Energy (SJCE), which is the City of San José's CCA program that the San José Community Energy Department administers.

[47] Joint Commenters here refers to Center for Community Action and Environmental Justice, East Yard Communities for Environmental Justice, Sierra Club, and Union of Concerned Scientists. Parties included in the Joint Commenters' filings on the Staff Proposal differ from the parties included on the Joint Commenters' earlier filings on the Draft TEF.

[48] Citations to "Opening Comments on Staff Proposal" refer to these comments.

(Fermata), GPI, Greenlining, GRID, Joint CCAs,[49] Joint Commenters, NDC, Nuvve, PG&E, SCE, SDG&E, TURN, UCAN, VGIC, and Weave Grid.[50]

The Staff Proposal responds to stakeholder comments on the Draft TEF and recent developments in the TE market and proposes a modified approach to TE funding through the remainder of the decade and beyond. The proposal aims to accelerate behind-the-meter (BTM) EV charging deployment to support California's ambitious goals and the CEC's projected EV charger need, while limiting costs to ratepayers, promoting equity, minimizing administrative burden, and maximizing third-party participation. In light of the developments described above, the Staff Proposal does not address investments on the utility side of the meter. In this decision, the Commission addresses both the outstanding issues from the Draft TEF and the Staff Proposal.

2. Issues Before the Commission

Because this proceeding encompasses highly complex and interrelated issues, the scoping memo designates general topic areas with examples of issues that the Commission may address in the proceeding. This decision addresses issues associated with all seven topics included in the scoping memo: (1) issues related to the TEF; (2) cost recovery mechanisms for TE investments; (3) rates for ZEVs and hydrogen-fueled vehicles; (4) vehicle-grid integration; (5) coordination with existing EV programs; (6) safety; and (7) other (*e.g.*, additional policies or issues related to TE that other Commission proceedings do not address).[51] We consider the extensive record in this proceeding in our resolution of the issues.

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[49] Joint CCAs here refers to CalChoice, CPA, EBCE, MCE, PCE, RCEA, SCP, SDCP, and SJCE.

[50] Citations to "Reply Comments on Staff Proposal" refer to these comments.

[51] Assigned Commissioner's Scoping Memo and Ruling at 2-7 (May 2, 2019).

3. Issues from the Draft TEF Not Included in the Staff Proposal

This section resolves outstanding issues from the Draft TEF not included in the Staff Proposal discussion below.

3.1. Draft TEF Chapter 3: Transportation Electrification Plans

Chapter 3 of the Draft TEF includes recommendations on the Transportation Electrification Plan (TEP) framework.[52] The Draft TEF recommends that the Commission direct each IOU to develop a ten-year TEP to complete more holistic TE portfolio and grid planning and to create a roadmap for ratepayer-supported TE investment programs moving forward. To create the TEP framework, the Draft TEF recommends that the Commission direct the IOUs to:

1. File and serve ten-year strategic TEPs;
2. Engage in ongoing state energy forecasting efforts and resource planning proceedings and use the most recent TE adoption projections from the CARB's regulatory timelines, the CEC's infrastructure needs assessment, and the IOUs' Integrated Capacity Analysis maps to develop infrastructure targets and proposed budgets in the TEPs;
3. Include specified necessary and relevant information in the TEPs;
4. Submit pilot proposals via Advice Letters;
5. Submit large-scale program proposals via applications in the first quarter of every odd numbered year;
6. Provide full TEP updates every four years; and

[52] Draft TEF at 16-33.

7. Align TEP updates with any new issues and/or program priorities identified through the five-year TEF update process.

In comments on this chapter of the Draft TEF, parties provide differing views on the TEP framework. UCAN argues the TEPs should include a ten-year forecast of anticipated TE loads and hourly load shapes.[53] Tesla urges the Commission to balance the need for near-term TEPs focused on five-year evaluations with a ten-year strategic vision.[54] ChargePoint claims the ten-year TEP timeline would not allow for accurate program design and budgeting.[55] Relatedly, SDG&E urges the Commission to adopt a single application for a five-year TE plan and associated funding, with one-off interim applications to fill any market gaps.[56] PG&E and SCE also argue that the TEPs should cover a five-year instead of ten-year period.[57]

Parties also provide comments on IOU engagement with other forecasting and planning processes needed to develop the TEPs. SCE argues that the TEPs consider state and local policies and regulations that drive EV adoption and the corresponding TE infrastructure needs, including regional air quality plans and regulations, the San Pedro Bay Ports Clean Air Action Plan, the California Sustainable Freight Action Plan, and municipal TE plans.[58] ChargePoint

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[53] UCAN Opening Comments on Draft TEF Chapters 2-5 at 7.

[54] Tesla Reply Comments on Draft TEF Chapters 2-5 at 10.

[55] ChargePoint Opening Comments on Draft TEF Chapters 2-5 at 7.

[56] SDG&E Opening Comments on Draft TEF Chapters 2-5 at 15.

[57] PG&E Opening Comments on Draft TEF Chapters 2-5 at 3; SCE Opening Comments on Draft TEF Chapters 2-5 at 9.

[58] Opening Comments on Draft TEF Chapters 2-5 at 12.

recommends that the TEPs reflect coordination with Caltrans, the California Green Building Standards (CALGreen) Code, the Division of the State Architect, and the Department of Housing and Community Development.[59]

UCAN supports leveraging the CEC's, CARB's and other state agencies' existing processes.[60] In addition to state agencies, EVgo proposes that the IOUs consider TE infrastructure deployments directed by the settlement between the Commission and NRG Energy.[61] The Joint Commenters caution against an overly prescriptive TEP process.[62] Cal Advocates recommends the TEPs incorporate lessons learned from previous TE programs and consider data on costs from other entities, including the national laboratories and other state agencies.[63] PG&E suggests that the TEPs should leverage IOU planning processes that account for utility TE infrastructure needs, such as the IRP proceeding, the distribution capacity plans in each IOU's GRC, and the Distribution Resources Plan proceeding.[64]

Additionally, parties present arguments for whether to establish the TEP budget as a cap on an IOU's investments or a forecast of the programmatic costs. The Joint Commenters caution against the creation of cost caps because the TE regulatory and technological terrain is changing too rapidly to justify restricting

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[59] ChargePoint Opening Comments on Draft TEF Chapters 2-5 at 4.

[60] UCAN Opening Comments on Draft TEF Chapters 2-5 at 7.

[61] EVgo Opening Comments on Draft TEF Chapters 2-5 at 3-4.

[62] Joint Commenters Opening Comments on Draft TEF Chapters 2-5 at 12.

[63] Cal Advocates Opening Comments on Draft TEF Chapters 2-5 at 6.

[64] PG&E Opening Comments on Draft TEF Chapters 2-5 at 11-12.

investments based on quickly dated assumptions.[65] SCE recommends the TEPs provide a cost forecast, which would become a cap following Commission authorization.[66] UCAN supports establishing budgets as a cap and not merely using forecasts.[67] Conversely, ChargePoint and BNSF recommend establishing budgets based on a forecast of programmatic costs instead of creating a cap.[68] TURN argues against viewing TEP budgets as a forecast or cap because parties would need to fully vet costs.[69] The California Transit Association supports TEP budgets reflecting a forecast of programmatic costs, including low-to-high cost projections to account for varying levels of state funding.[70] Cal Advocates supports establishing budgets through forecasts, which would require the IOUs to make long-term planning decisions while allowing for flexibility as actual costs become more definite.[71] SBUA similarly recommends that budgets be based on forecasts and that the IOUs justify increased spending if needed.[72]

In this decision, we decline to adopt the TEP framework and the associated proposals. The Staff Proposal takes parties' comments on the proposed TEPs into consideration of its design of the funding cycle framework. Parties persuasively argue that the lengthy planning process envisioned in the TEP proposal would

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[65] Joint Commenters Opening Comments on Draft TEF Chapters 2-5 at 13.

[66] SCE Opening Comments on Draft TEF Chapters 2-5 at 12.

[67] UCAN Opening Comments on Draft TEF Chapters 2-5 at 8-9.

[68] ChargePoint Opening Comments on Draft TEF Chapters 2-5 at 5; BNSF Opening Comments on Draft TEF Chapters 2-5 at 4.

[69] TURN Opening Comments on Draft TEF Chapters 2-5 at 9.

[70] California Transit Association Opening Comments on Draft TEF Chapters 2-5 at 4.

[71] Cal Advocates Opening Comments on Draft TEF Chapters 2-5 at 7.

[72] SBUA Opening Comments on Draft TEF Chapters 2-5 at 3.

not adequately account for or best serve the rapidly accelerating TE marketplace. Further, the Commission and its staff currently engage in a number of updated TE planning efforts. Leveraging the existing interagency coordination and planning framework, staff at the Commission, CAISO, CEC, and CARB are working closely to ensure that our processes are planning for the expected growth in EV adoption over the next decade. This work includes, but is not limited to:

1. Recent adoption of the 2021 CEC's Integrated Energy Policy Report (IEPR) demand forecast—the starting point for all generation and infrastructure planning within the CAISO footprint—which reflects higher TE adoption consistent with CARB's ACCII and proposed Advanced Clean Fleets (ACF) regulations;
2. The IRP proceeding's 2021 Preferred System Plan, reflecting the CEC's 2021 IEPR forecast, to the CAISO for study in its 2022-2023 transmission planning process (TPP base case);[73]
3. The proceeding to modernize the electric grid for a high distributed energy resources future, authorizing the IOUs to use a variation of the CEC's 2021 IEPR forecast to better study the distribution impact of high TE in their respective 2023 Grid Needs Assessments;[74] and
4. The Commission's new proceeding to advance demand flexibility through electric rates which considers developing dynamic rates available for EV charging that may facilitate broader EV load management and grid support.[75]

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[73] R.20-05-033.

[74] R.21-06-017.

[75] R.22-07-005.

Furthermore, the Commission works to coordinate internal and interagency TE infrastructure planning efforts with IOU planning. Consequently, much of the planning work that the TEP proposal envisioned is underway. While we do not find it necessary to move forward with the TEP planning proposal as initially envisioned, we may find it appropriate to adopt some of the elements of the TEP proposal in the future to leverage these processes and inform IOU TE infrastructure programs, targets, and budgets.

3.2. Draft TEF Chapter 4: IOU Role in Accelerating TE Infrastructure Deployment

Chapter 4 of the Draft TEF includes four recommendations on the role the IOUs should have in deploying TE infrastructure.[76] The Draft TEF recommends that the Commission direct the IOUs to:

1. Actively engage their subject matter experts in ongoing state agency planning and modeling efforts, including the CARB's Mobile Source Strategy update and the CEC's Infrastructure Deployment Strategy analysis, and summarize TE infrastructure gaps based on state planning processes and other resources;
2. Provide information and participate in the development of a Market Maturity Assessment;
3. Explain in their TEPs each market barrier that each IOU program is intended to address and how the program(s) will address the barrier; and
4. Explain in their TEPs any market barrier(s) that IOU TE programs are not suited to address.

Regarding the first recommendation for the Commission to order the IOUs to engage in ongoing state agency planning and modeling efforts, parties observe

[76] Draft TEF at 33-42.

that state planning and modeling efforts can provide important information.[77] However, many parties caution that these efforts are not comprehensive, and therefore many parties argue that the IOUs should account for other information sources, such as input from local governments and transit agencies.[78] Other parties note that the Commission should refrain from adopting overly prescriptive requirements.[79]

We agree that additional planning and modeling is useful. For example, the CEC's AB 2127 Charging Assessment does not provide sufficient detail on where TE infrastructure is most needed and what role the IOUs should take. Additionally, while the CEC's report pursuant to SB 1000 (Lara, 2018) identifies some gaps in charging infrastructure based on income disparity and location, it does not provide specific detail on where to install charging infrastructure to address these gaps.[80] The Commission currently engages in a number of processes to coordinate internal and interagency TE infrastructure planning efforts with IOU planning, as discussed above. Although we decline to direct the IOUs to engage in specific efforts, the IOUs should continue to participate in

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[77] *See, e.g.*, BNSF Opening Comments on Draft TEF Chapters 2-5 at 5.

[78] Joint Commenters Opening Comments on Draft TEF Chapters 2-5 at 17; SCE Opening Comments on Draft TEF Chapters 2-5 at 14; Cal Advocates Opening Comments on Draft TEF Chapters 2-5 at 12; City of Long Beach Opening Comments on Draft TEF Chapters 2-5 at 3; California Transit Association Opening Comments on Draft TEF Chapters 2-5 at 5; ChargePoint Opening Comments on Draft TEF Chapters 2-5 at 17.

[79] SDG&E Opening Comments on Draft TEF Chapters 2-5 at A-3; TURN Opening Comments on Draft TEF Chapters 2-5 at 12.

[80] *See* CEC, California Electric Vehicle Infrastructure Deployment: Senate Bill (SB) 1000 Report (Dec. 2020), available at: https://efiling.energy.ca.gov/getdocument.aspx?tn=236189.

processes like those described above to continue to improve upon TE planning efforts.

Second, the Draft TEF recommends that the IOUs participate in the development of a "market maturity assessment," which would determine the level of market maturity for different TE segments, and the IOUs would use the analysis to evaluate investments to overcome market barriers. Many parties claim that the proposed market maturity assessment would be an overly complex process that would not provide sufficient information to understand the nascent TE market.[81] Other parties caution against using the assessment to justify IOU ownership of EVSE.[82]

We decline to adopt the market maturity assessment proposal because most, if not all, TE market segments are not yet mature. We agree with parties' arguments that the proposal is premature because the assessment would require significant modifications and effort to provide an effective and reliable tool. However, the program evaluation described later in this decision may include metrics to analyze market conditions, and these metrics could help to justify adjustments to the adopted rebate program during the Mid-Cycle Assessment, as discussed in more detail later in this decision. Further, although we decline to adopt the market maturity assessment proposal, this decision provides guidance

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[81] SCE Opening Comments on Draft TEF Chapters 2-5 at 9;, Tesla Opening Comments on Draft TEF Chapters 2-5 at 6-7; PG&E Opening Comments on Draft TEF Chapters 2-5 at 17; SDG&E Opening Comments on Draft TEF Chapters 2-5 at A-4; AEE Opening Comments on Draft TEF Chapters 2-5 at 13; Greenlots Opening Comments on Draft TEF Chapters 2-5 at 3; SDG&E Reply Comments on Draft TEF Chapters 2-5 at 9; SBUA Reply Comments on Draft TEF Chapters 2-5 at 3-4; ChargePoint Reply Comments on Draft TEF Chapters 2-5 at 11.

[82] *See, e.g.*, ChargePoint Opening Comments on Draft TEF Chapters 2-5 at 15.

on the appropriate role of the IOUs in deploying TE infrastructure. The discussion in Section 4 of this decision provides that guidance.

We decline to adopt the third and fourth recommendations to include a discussion of market barriers in the IOUs' TEPs. This decision does not adopt the proposed TEP framework, and we therefore find it unnecessary to adopt any requirements concerning the contents of the TEPs.

In comments on this chapter of the Draft TEF, parties also present arguments regarding whether the IOUs' role should include IOU ownership of BTM TE infrastructure. The Joint EV Technology Providers argue "making a declaration on ownership models without testing different business models, such as utility residential BTM ownership, would not only jeopardize the state's ability to achieve its goals, but is also entirely unfounded."[83] The Joint CCAs assert "IOU ownership of TE infrastructure should be limited, and IOU investment should generally be focused on the utility side of the meter."[84] UCAN cautions that IOU ownership of TE infrastructure should be limited.[85]

We take these comments into account in evaluating the Staff Proposal's recommendation that the IOUs should not have the option to own BTM TE infrastructure moving forward. In recent Commission decisions, we are clearly

[83] Joint EV Technology Providers Opening Comments on Draft TEF Chapters 2-5 at 10.

[84] Joint CCAs Reply Comments on Draft TEF Chapters 2-5 at 2.

[85] UCAN Opening Comments on Draft TEF Chapters 2-5 at 15.

moving away from the IOU-ownership model, concluding that it is often more expensive for ratepayers.[86]

3.3. Draft TEF Chapter 5: Near-Term Priorities

The Draft TEF recommends that the Commission limit consideration of new IOU applications or Advice Letters that address near-term TE barriers and/or regulatory priorities.[87] The recommendations seek to address any gaps in program offerings prior to 2025, while the Commission evaluates whether to adopt the Draft TEF and TEP framework.

The Commission addressed the Draft TEF's recommendations on near-term TE priorities in D.21-07-028 and D.21-12-030, resolving all issues related to this part of the Draft TEF.[88] These decisions provided specific guidance to the IOUs on high priority areas for which the IOUs can submit Advice Letter proposals prior to further Commission guidance on the Draft TEF. The decisions also created an expedited application review process for IOU proposals that seek to extend existing or recently completed TE programs. Those decisions did not preclude the IOUs from submitting applications for TE proposals that are not

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[86] *See, e.g.*, D.21-07-028; D.21-04-014; D.20-08-045; SDG&E, Compliance Filing of San Diego Gas & Electric Company (U902E) of Independent Audit Report Pursuant to Decision 21-04-014 (Jan. 31, 2022), available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M445/K599/445599617.PDF.

[87] Draft TEF at 58-59.

[88] D.21-12-030 revises two elements of D.21-07-028: (1) one criterion for the new building investment area and (2) language describing the expedited review process for applications to extend existing TE programs.

within the established near-term priority areas. As of October 2022, only SDG&E had submitted a near-term priority Advice Letter for consideration.[89]

As the Commission adopted D.21-07-028 to provide "guidance to the [IOUs] in the event that they choose to submit proposals for transportation electrification investments prior to [adoption of the TEF],"[90] and this present decision addresses the TEF, we find it is reasonable to establish a sunset date for the near-term TE priorities pathways and the authorized near-term TE priority funds not yet approved or not currently under Commission review. The IOUs shall file any near-term TE priority applications or Advice Letters no later than May 31, 2023. The IOUs shall not accept customer applications or agreements within any approved near-term TE priority programs after December 31, 2026, unless specifically directed otherwise by the Commission. This corresponds with the end of the current funding cycle and transitional grace period discussed below.

3.4. Draft TEF Chapter 6: Equity

We address equity considerations in Section 4.3.5 of this decision to ensure that the benefits of TE and ratepayer funded investments in EV charging fully reach all segments of the California population, particularly underserved communities.

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[89] SDG&E's Advice Letter 4021-E, submitted on June 8, 2022, proposes a new near-term TE priority program, Power Your Drive for Communities. The Advice Letter seeks approval of $20 million over three-years to install a mix of 174 direct current fast chargers (DCFC) and Level 2 EVSE to support charging needs of customers without access to home charging.

[90] D.21-07-028 at 2.

3.5. Draft TEF Chapter 7: Safety

As part of the Commission's responsibility to assure the safety of all IOU operations, the Safety Policy Statement and the Safety Action Plan seek to improve the safety culture within the Commission and across the industries it regulates.[91] The IOUs and EV charging installers must comply with all local, state, and federal safety requirements. In addition, the TE Safety Checklists seek to better inform the IOUs' compliance requirements regarding safety considerations specifically related to TE programs.[92] As part of the Commission's further development of safety standards for the TE programs, the Draft TEF evaluates changes to the following safety-related areas: (1) IOU program requirements to ensure consumer and installer safety and (2) workforce training.

3.5.1. Consumer and Installer Safety

The Draft TEF includes four recommendations to improve consumer and installer safety with respect to TE programs. These recommendations consist of direction by the Commission to the IOUs to:

1. Include comprehensive safety rules in their TEPs;
2. Continue to report on safety procedure implementation and best safety practices for various TE program types;
3. Identify one IOU as lead to review existing safety procedures and determine whether revisions are needed prior to the initial TEP filings and each subsequent TEP

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[91] California Public Utilities Commission, Safety Policy and Action Plans, https://www.cpuc.ca.gov/regulatory-services/safety/safety-policy-and-action-plans.

[92] California Public Utilities Commission, Safety Requirements Checklist for CPUC-Approved Transportation Electrification Programs, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/s/6442458882-safety-requirements-checklist-final-draft-.pdf (for PG&E, SCE, and SDG&E), https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/s/6442462124-safety-requirements-checklist-for-d1809034-final-.docx (for Bear Valley, Liberty, and PacifiCorp).

update. The lead IOU should also consider whether to adopt safety procedures to ensure IOU-funded TE infrastructure is safely maintained or decommissioned once the program term has ended; and

4. Consider limited roles for IOU pilot programs to evaluate pre-commercial technologies and associated safety needs.[93]

Regarding the first recommendation, PCE expresses support for the inclusion of safety requirements "in the context of an IOU's infrastructure upgrades and TE programs that require connection of new EVSE to the grid."[94] However, PCE also clarifies that the TEF should clarify that the safety requirements are not one size fits all and should allow Program Administrators to apply only the relevant sections of the safety requirements in their TEPs.[95]

We decline to adopt a requirement in this decision that the IOUs include comprehensive safety rules in their TEPs. Since this decision will not direct the development of TEPs, this recommendation is no longer relevant.

No party's comments address the second recommendation for the Commission to direct IOUs to continue to report on safety procedure implementation and best safety practices for various TE program types.

Due to the lack of comment on this recommendation and the general support in comments for the continued use of the current TE Safety Checklists, we find that a change to this procedure is not warranted at this time. The IOUs and Program Administrator should continue to utilize and report on safety procedures, based on the TE Safety Checklists. As part of the Program Handbook

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[93] Draft TEF at 75.

[94] PCE Opening Comments on Draft TEF Chapters 7 and 8 at 4.

[95] *Ibid.*

development process, Mid-Cycle Assessment, and/or program evaluations, the IOUs and Program Administrator should examine whether any modifications to the TE Safety Checklists are needed and propose those to the Commission.

Regarding the third recommendation, Tesla asserts that the current safety standards in the TE Safety Checklists adopted in D.18-01-024 and D.18-05-040 are reasonable and effective for ensuring safety and do not see a need to revise those standards at this time.[96] Tesla supports a periodic review of the safety requirements in the checklist based on new technology entering the market or feedback under the existing programs, via a transparent stakeholder process.[97] SDG&E contends that a specific reevaluation of TE-related safety practices is not necessary for TEPs and that the IOUs should determine the necessity of revisions to existing safety rules.[98]

The IOUs also express support for following existing procedures for maintenance and decommissioning of IOU TE infrastructure. SCE argues that TE infrastructure, like non-TE utility infrastructure, is industrial in nature and built to last decades.[99] PG&E indicates that no new policies or procedures are necessary because PG&E's current safety and asset management standards also apply to TE equipment and facilities as well.[100] Liberty asserts that any contracts

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[96] PG&E Opening Comments on Draft TEF Chapters 7 and 8 at 2; SCE Opening Comments on Draft TEF Chapters 7 and 8 at 2; Bear Valley Opening Comments on Draft TEF Chapters 7 and 8 at 3; Liberty Opening Comments on Draft TEF Chapters 7 and 8 at 1; Tesla Opening Comments on Draft TEF Chapters 7 and 8 at 2.

[97] Tesla Opening Comments on Draft TEF Chapters 7 and 8 at 2.

[98] SDG&E Opening Comments on Draft TEF Chapters 7 and 8 at 2.

[99] SCE Opening Comments on Draft TEF Chapters 7 and 8 at 3.

[100] PG&E Opening Comments on Draft TEF Chapters 7 and 8 at 3.

signed with third parties for TE equipment installed on its system will include maintenance and decommissioning requirements.[101]

We find that the IOUs should continue to comply with the checklist for all utility-side work. Where applicable, the IOUs and Program Administrator must confirm compliance with the checklist for the Funding Cycle 1 (FC1) program, discussed in detail in Section 4 below, and require that all program participants in FC1 comply with all local codes and receive relevant local and state permits from the Authorities Having Jurisdiction. The Program Handbook development process, described below, shall determine compliance and verification details for these requirements.

Regarding the fourth safety recommendation, both VGIC and PCE support the TEPs including an appropriate role for IOUs to evaluate pre-commercial equipment and identify special safety requirements.[102] However, VGIC recommends that the Commission provide guidance in the TEF to establish a "uniform program and process by which market participants could request to conduct pre-commercial technology demonstrations and evaluations."[103] Bear Valley asserts that there is no need for any specific procedures or specific safety rules because EV vendors are relied on to ensure the charging technology complies with all industry standards.[104]

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[101] Liberty Opening Comments on Draft TEF Chapters 7 and 8 at 2.

[102] VGIC Opening Comments on Draft TEF Chapters 7 and 8 at 2; PCE Opening Comments on Draft TEF Chapters 7 and 8 at 4.

[103] VGIC Opening Comments on Draft TEF Chapters 7 and 8 at 2.

[104] Bear Valley Opening Comments on Draft TEF Chapters 7 and 8 at 3.

We decline to adopt any pilot programs associated with pre-commercial technologies and safety needs. The record does not reflect sufficient need for this type of pilot program.

3.5.2. Workforce Training

To scale up TE and achieve state climate and reliability goals, California needs a well-trained workforce to support its safety requirements. Accordingly, the IOUs must address any workforce training necessary to ensure safe installation of IOU-funded TE infrastructure. If special training is necessary for specific TE programs or technology, the IOUs have an important role to ensure that the appropriate training is available. Additionally, the Commission's Environmental and Social Justice Action Plan adopts an objective to promote high road career paths and economic opportunity for residents of environmental and social justice communities.[105]

To achieve these workforce development goals, the Draft TEF recommends that the IOUs should: (1) coordinate with the California Labor & Workforce Development Agency to address workforce development needs and opportunities to create high-quality jobs that support IOU TE programs and (2) evaluate whether any additional installer safety-related training is necessary beyond state licensing requirements.

The IOUs are generally supportive of the workforce development recommendations but present different perspectives on their roles and

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[105] California Public Utilities Commission, Environmental and Social Justice Action Plan, https://www.cpuc.ca.gov/news-and-updates/newsroom/environmental-and-social-justice-action-plan. The Commission's Environmental and Social Justice Action Plan emphasizes the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of laws, regulations, and policies.

requirements regarding coordination with state agencies. SCE states that coordination with the California Labor & Workforce Development Agency could help the IOUs identify development needs and opportunities to create high-quality jobs that support IOU TE programs.[106] PG&E indicates that the California Labor & Workforce Development Agency, the California Workforce Development Board, and other relevant state/regional workforce development organizations should lead the workforce development efforts.[107] SDG&E calls for flexibility regarding the IOUs' development of their workforces and the omission of an overly prescriptive requirement for IOUs to coordinate with statewide bodies.[108]

D.21-07-028 addresses some of the Draft TEF's workforce development recommendations by directing the IOUs to, within all future program applications, further the principles of economic equity and promote access to high quality jobs for residents of underserved communities.[109] Section 4.3.5.6 of this decision expands on the workforce development requirements for FC1.

As to the recommendation for the IOUs to evaluate whether any additional installer safety-related training is necessary beyond state licensing requirements, parties generally agree that ensuring specialized training is important, while differing on the role of the IOU in that process. Both PCE and the Joint Commenters emphasize the importance of the availability of specialized safety workforce training to reduce barriers and ensure that charging infrastructure

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[106] SCE Opening Comments on Draft TEF Chapters 7 and 8 at 3.

[107] PG&E Opening Comments on Draft TEF Chapters 7 and 8 at 3-4.

[108] SDG&E Opening Comments on Draft TEF Chapters 7 and 8 at 4-5.

[109] D.21-07-028 at 33-34.

installation occurs within all parts of the IOUs' service territories.[110] EVgo recommends specific safety certifications to increase speed of installations.[111] NDC states that the IOUs should coordinate with community-based organizations (CBOs) in addition to unions to ensure training of electricians from diverse and underserved communities.[112] ChargePoint recommends a clear delineation of the responsibilities within the workforce training section, while EDF asserts that the IOUs should not have sole responsibility for workforce development.[113]

Because the Commission established near-term workforce training requirements for the IOUs in D.21-07-028, this decision does not address near-term workforce training requirements. However, Section 4.3.5.6 discusses workforce development and safety-related training requirements for the Program Administrator to implement.

3.6. Draft TEF Chapter 8: Technology and Standards

Chapter 8 of the Draft TEF recommends that the IOUs ensure that TE programs include the requisite technology and meet existing standards to ensure TE infrastructure deployment meets state TE goals and is coordinated with other state TE investments.[114]

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[110] PCE Opening Comments on Draft TEF Chapters 7 and 8 at 6; Joint Commenters Opening Comments on Draft TEF Chapters 7 and 8 at 2.

[111] EVgo Opening Comments on Draft TEF Chapters 7 and 8 at 10.

[112] NDC Opening Comments on Draft TEF Chapters 7 and 8 at 3.

[113] ChargePoint Opening Comments on Draft TEF Chapters 7 and 8 at 1; EDF Opening Comments on Draft TEF Chapters 7 and 8 at 4.

[114] Draft TEF at 77-96.

3.6.1. EVSE Standards

Regarding EVSE standards, the Draft TEF proposes aligning IOU TE infrastructure requirements with minimum requirements of other public agencies. Specifically, the Draft TEF recommends the Commission direct the IOUs to:

1. Establish program requirements that ensure publicly accessible, ratepayer-funded EVSE meet all existing state regulatory requirements; and
2. Require that EVSE funded through their TE programs contain networking capabilities and can implement International Organization for Standardization (ISO) standard 15118 and other communication enabling requirements adopted by the CECCEC.

Parties express differing views on adopting EVSE standards. To ensure accessibility and transparency, Cal Advocates supports requiring all IOU programs to incorporate CARB payment access regulations and consumer information regulations from the California Department of Food and Agriculture's Division of Measurements and Standards, requiring all publicly available EVSE display the unit price of electricity on their face or, in the case of two or more EVSE installed at one location, at a single primary element.[115] VGIC cautions that the opportunity cost of requiring all ratepayer-funded EVSE to meet ISO 15118 would be significant.[116] EVgo asserts that unintended consequences may result from the inappropriate application of certain technology requirements to use cases with long dwell times.[117]

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[115] Cal Advocates Opening Comments on Draft TEF Chapters 7 and 8 at 2.

[116] VGIC Opening Comments on Draft TEF Chapters 7 and 8 at 6.

[117] EVgo Opening Comments on Draft TEF Chapters 7 and 8 at 2-3.

The Joint Commenters recommend requiring utilization of open communication protocols to: (1) insure against stranded assets; (2) support competition, innovation, and customer choice through customer hardware- and software- switching ability; and (3) ensure ratepayer-funded EVSE is fully interoperable.[118] ChargePoint supports use of ISO 15118 and a requirement for ratepayer-funded EVSE to have networking capabilities, while encouraging the Commission to allow global discussions on standard development to continue before prematurely requiring ISO 15118.[119] PG&E does not oppose use of ISO 15118 but also recommends exploring other communication protocols.[120] Tesla cautions against adopting ISO 15118 as the key communication protocol for publicly accessible EVSE deployed through the Commission's or the CEC's TE programs.[121]

Over two years have passed since the Commission received comments on the Draft TEF's recommendations regarding EVSE standards. In the meantime, the Commission adopted requirements and the CEC issued recommendations on specific EVSE communication standards.[122] Most recently, D.22-08-024 adopted the following standards:

1. All alternating current (AC) conductive EVSE deployed on or after July 1, 2023, for LD use cases in ratepayer-funded

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[118] Joint Commenters Opening Comments on Draft TEF Chapters 7 and 8 at 1-3.

[119] ChargePoint Opening Comments on Draft TEF Chapters 7 and 8 at 7-8.

[120] PG&E Opening Comments on Draft TEF Chapters 7 and 8 at 6.

[121] Tesla Opening Comments on Draft TEF Chapters 7 and 8 at 5.

[122] *See* D.21-04-014 (adopting SDG&E's Power Your Drive Extension program); Res. E-5175 (directing SCE to revise its Charge Ready 2 program requirements); CEC, Recommendation for Deployment of ISO 15118-Ready Chargers (Feb. 22, 2022), available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=241955.

or utility-administered TE infrastructure programs must be equipped with a Society of Automotive Engineers (SAE) J1772 connector;

2. All direct current (DC) conductive EVSE deployed on or after July 1, 2023, for LD use cases in ratepayer-funded or utility-administered TE infrastructure programs must be equipped with a Combined Charging System (CCS) connector;

3. All ratepayer-funded or utility administered TE programs implemented on or after July 1, 2023, must ensure communications and controls between a network service provider and the EVSE are capable of operating on Open Charge Alliance (OCA) Open Charge Point Protocol (OCPP) 1.6 or later, and similar communication standards may be implemented in addition to OCPP; and

4. All EVSE deployed on or after July 1, 2023, for ratepayer-funded or utility-administered TE infrastructure programs must be ISO 15118 ready. ISO 15118-ready chargers are equipped with onboard hardware that enable high-level communications with the vehicle using ISO 15118. An ISO 15118-ready charger is capable of, at minimum, the following: (a) powerline carrier based high-level communications as specified in ISO 15118-3; (b) secure management and storage of keys and certificates; (c) Transport Layer Security (TLS) version 1.2, with additional support for TLS 1.3 or subsequent versions recommended to prepare for future updates to the ISO 15118 standard; (d) receiving remote updates to activate or enable ISO to prepare for future updates to the ISO 15118 standard; (e) connecting to a backend network; and (f) selecting the appropriate communication protocol used by the vehicle.[123]

[123] D.22-08-024 at Ordering Paragraph 6.

To ensure interoperability and open standards, these requirements apply to all future ratepayer-funded BTM TE infrastructure programs. We clarify here that the FC1 rebate program adopted in this decision is one such ratepayer-funded BTM TE infrastructure programs.

3.6.2. Cybersecurity

The Draft TEF includes several recommendations related to cybersecurity, including that the IOUs propose cybersecurity standards to implement and identify any gaps in available standards that could cause issues from increased deployment of networked EVSE.[124]

The Commission addressed these issues in D.20-12-029, which directed SCE to propose cybersecurity standards and file a workplan with a cybersecurity gaps analysis.[125] Pursuant to D.20-12-029, SCE filed Advice Letter 4521-E requesting approval to implement the workplan and proposing a budget. The Commission approved the Advice Letter via a disposition letter on March 30, 2022.

SCE requests that the Commission authorize the implementation of the cybersecurity workplan, approved through Advice Letter 4521-E. SCE also seeks authority to establish a memorandum account to track workplan-related costs for review and recovery.[126] Based on ED's approval, we authorize SCE to implement the cybersecurity workplan approved in Advice Letter 4521-E, according to the estimated budget specified confidentially in that Advice Letter. With this qualification, we authorize SCE to establish a memorandum account to track and

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[124] Draft TEF at 85-87.

[125] D.20-12-029 at 62-63, Ordering Paragraph 19.

[126] SCE Reply Comments on Staff Proposal at 8.

record costs associated with the workplan implementation. SCE should seek reasonableness review for recovery of the recorded expenditures within a GRC.

3.6.3. EVSE Interconnection and Energization

The Draft TEF recommends that the Commission adopt streamlined processes to expedite load-only EV charging installations and to provide transparent timelines and processes to determine whether utility service upgrades are needed to support the installation of EV chargers.[127] Res. E-5167 and E-5168 address this topic and parties' comments. These resolutions adopt an average service energization timing for the new EV Infrastructure Rules, while acknowledging that additional analysis is necessary to implement timeline requirements.

The resolutions direct the IOUs to: (1) within 180 days of the resolutions' approval, host a public workshop to discuss the barriers to timely energization of TE infrastructure[128] and (2) within 60 days of hosting the workshop, file a joint Tier 2 Advice Letter to propose an average timeline between 90 to 160 days, identify the processes within the IOUs direct and indirect control, identify processes that are not within the IOUs control, processes for the IOU to improve service energization timing for items within their direct and indirect control, a description of how the IOUs can contribute to improve service energization for responsibilities not in their control, and incorporate the party feedback provided during the public workshop.

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[127] Draft TEF at 95-96.

[128] The IOUs jointly hosted this workshop on March 31, 2022.

On May 27, 2022, SDG&E filed Advice Letter 4011-E, containing the joint IOUs' EV charging service energization timing proposal. As of the mailing of this decision, the joint IOUs' proposal is under review; however, the Commission recently took steps to streamline the interconnection process for EV charging and improve communication of interconnection timelines between IOUs and their customers.[129] We acknowledge parties' requests for discourse and continued focus on energization. While we do not direct any specific process in this decision, Energy Division staff may address these issues through future forums and/or workshops, and the Commission may address this topic through other venues.

3.6.4. Submetering

The Draft TEF indicates that the Commission will address submetering for EV charging within this proceeding.[130]

On January 23, 2020, an ALJ Ruling directed the IOUs to jointly develop, with input from parties, and file a submetering protocol. In D.22-08-024, we adopted the Plug-in Electric Vehicle (PEV) Submetering Protocol, which allows a customer to avoid having to install a separate utility meter and instead use a submeter to measure and bill EV charging separately from the customer's primary utility meter. The decision required the IOUs to implement the protocol for customers with PEVs who own their submeters, thereby addressing this section of the Draft TEF.

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[129] Res. 5165-E at Findings of Fact 6-7, Ordering Paragraph 2; D.20-09-035 at Ordering Paragraph 23; Res. E-5172 at App. D.

[130] Draft TEF at 93-94.

3.6.5. Emerging Technology

The Draft TEF recommends that the Commission consider whether a TE emerging technologies program would be appropriate for IOU administration.[131]

In D.20-12-029, the Commission considered comments on this topic in response to the Draft TEF and directed the IOUs to file an Advice Letter to request approval of a Vehicle-Grid Integration Emerging Technology Program with a maximum budget of $5 million annually for two years, thereby addressing this section of the Draft TEF.[132] Pursuant to the decision, SCE filed Advice Letter 4610-E on behalf of the joint IOUs, proposing an emerging technologies program. The Commission issued Draft Res. E-5224 to address the request in SCE Advice Letter 4610-E.

3.7. Draft TEF Chapter 9: TE and Customer Rates

Chapter 9 of the Draft TEF includes various recommendations regarding TE and customer rates.

3.8. Electric Vehicle Rate Evolution Plans

The Draft TEF recommends requiring each IOU's TEP to contain an Electric Vehicle Rate Evolution (EVREV) plan, which would include a collaborative, stakeholder guided strategy for improving the customer experience in paying for EV fueling and potentially providing compensation to customers for discharging their EV batteries at times of grid congestion. The Draft TEF proposes that EVREV plan topics include dynamic rates, EV-specific rates, and residential EV rates, along with any other proposed rate design issues.

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[131] Draft TEF at 94-96.

[132] D.20-12-029 at 34-39, Ordering Paragraph 11.

The Draft TEF recommends that the IOUs separately propose EVREV plans or that one lead IOU's TEP contain a joint-IOU plan. The Draft TEF also proposes that the EVREV plans reflect full coordination across the IOUs and feedback from stakeholders.[133] Various parties comment on the EVREV proposal.[134]

Several events occurred since the issuance of the EVREV proposal that impact its consideration in this proceeding. On May 25, 2021, ED staff hosted a workshop to discuss ideas for advancing distributed energy resources (DERs) and flexible load management, leveraging new system-wide retail rate reforms, and load modifying demand response (DR) proposals. To identify policy and program ideas that would further the May 2021 proposals, ED staff released the "unified, universal, dynamic, economic" (UNIDE) concept paper, followed by a June 22, 2022 white paper and staff proposal that adopted the term California Flexible Unified Signal for Energy (CalFUSE) for the proposal.[135] Following the

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[133] Draft TEF at 106.

[134] BNSF Comments on Draft TEF Chapters 9, 10, and 12 at 4; PG&E Opening Comments on Draft TEF Chapters 9, 10, and 12 at 3; SBUA Comments on Draft TEF Chapters 9, 10, and 12 at 12; Joint Commenters Comments on Draft TEF Chapters 9, 10 at 3; NRDC Comments on Draft TEF Chapters 9, 10, and 12 at 1-3; SDG&E Comments on Draft TEF Chapters 9, 10, and 12 at 3; SCE Comments on Draft TEF Chapters 9, 10, and 12 at 1-2; UCAN Comments on Draft TEF Chapters 9, 10, and 12 at 9; CLECA Comments on Draft TEF Chapters 9, 10, and 12 at 9; Clean Energy Fuels Reply Comments on Draft TEF Chapters 9, 10, and 12 at 2; GPI Comments on Draft TEF Chapters 9, 10, and 12 at 3; Electrify America Comments on Draft TEF Chapters 9, 10, and 12 at 4; SDAP Comments on Draft TEF Chapters 9, 10, and 12 at 13, 18-19; Tesla Reply Comments on Draft TEF Chapters 9, 10, and 12 at 2; ATE Reply Comments on Draft TEF Chapters 9, 10, and 12 at 2.

[135] *See* California Public Utilities Commission, Energy Division, Advanced Strategies for Demand Flexibility Management and Customer DER Compensation (June 22, 2022), available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/ed-white-paper---advanced-strategies-for-demand-flexibility-management.pdf.

release of this white paper, in July 2022, the Commission opened R.22-07-005 to advance demand flexibility through electric rates—with one of the major objectives of the rulemaking being enablement of widespread TE to meet the state's climate goals.

We do not find it appropriate to pursue the TEF's EVREV proposal at this time due to the efforts in R.22-07-005, which aims to achieve many of the same objectives as the EVREV proposal. Therefore, we do not require a proposed scope and schedule of EVREV development as contemplated in the Draft TEF.[136] However, we reaffirm the vision of EVREV for rates to become technology-neutral in order to promote fairness in electricity pricing and export compensation among various DERs.

The Draft TEF also recommends the initiation of a collaborative process among IOUs and stakeholders to develop EVREVs that explore the various EVREV-related topics in the proposal. The proposal envisages a process that builds off ongoing proceedings and identifies straightforward solutions that can be implemented prior to the submission of EVREVs. The Draft TEF encourages utilization of longer-term strategies flowing from those solutions into the EVREVs. The Draft TEF further recommends that the IOUs propose revised rates as part of regular TEP revisions to align with the EVREV process and plans.

CLECA comments that collaboration is beneficial for developing best practices and consistency for program design, but cautions that each IOU has a different cost of service that must be considered in each IOU's GRC Phase 2 to set

[136] Draft TEF at 106.

actual rates.[137] UCAN indicates that collaboration will help simplify new EV rates and create consistency in rate design.[138] AEE notes that the unique characteristics of EV drivers charging within its service territory and different charging use cases should be considered.[139]

We agree that a collaborative process between the IOUs and stakeholders is worthwhile. Partly to achieve these aims, we direct creation of a forum on vehicle-grid integration. We describe this forum in more detail below, along with a discussion of specific strategic focus areas, to advance the collaborative process goals outlined in the Draft TEF. Additionally, we decline to adopt the recommendation to require the IOUs to propose revised TE rates due to the opening of R.22-07-022 and recent Commission decisions.[140]

The Draft TEF additionally recommends that the Commission direct the IOUs to increase enrollment in residential EV time-of-use (TOU) rates via enhanced education and outreach to maximize grid benefits and customer savings. The Draft TEF proposes requiring customers with home smart chargers to enroll in a separately metered EV rate when submetering is available. Various parties' comments address this recommendation.

ChargePoint cautions against mandatory enrollment in dynamic or TOU rates for all EV use cases, because it claims both tools are limited and do not

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[137] CLECA Opening Comments on Draft TEF Chapters 9, 10, and 12 at 12.

[138] UCAN Comments on Draft TEF Chapters 9, 10, and 12 at 2.

[139] AEE Opening Comments on Draft TEF Chapters 9, 10, and 12 at 2.

[140] D.20-12-023 (addressing SDG&E's Electric Vehicle High Power (EV-HP) Charge Rate); D.21-11-017 (addressing PG&E's Optional Day-Ahead Real-Time Rate for Commercial EV Customers); D.22-08-002 (addressing Phase 2 of PG&E's Dynamic, Real-Time, Hourly Pricing Rate).

capture all EV charging use cases.[141] EVgo contends that meaningful price signals may not automatically translate into more optimal grid conditions, and highlights that demand for a direct current fast charger (DCFC) is relatively inelastic and already takes place during hours of solar generation without price signals.[142] Tesla recognizes the need to send appropriate price signals to customers to optimize charging with grid needs, but urges the Commission to consider the various use cases.[143] NRDC agrees that plans should increase enrollment in residential EV TOU rates via enhanced education and outreach to maximize grid benefits and customer savings, but also recommends the establishment of target enrollment levels for IOU EV rates.[144]

We find that rate education is an important component of the Commission's TE program goals and should be a key objective of the FC1 program's marketing, education, and outreach component. Section 4.3.4 of this decision addresses rate education.

Finally, the Draft TEF asks whether the Commission should explore using rate design and/or customer bill credits to offset the cost of public charging for customers who do not have access to residential off-peak charging rates. Cal Advocates indicates that it may be necessary to offset the cost of public charging for communities of concern to promote equity.[145] The Joint Commenters assert that the Commission should differentiate between low-income and other

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[141] ChargePoint Opening Comments on Draft TEF Chapters 9, 10, and 12 at 2.

[142] EVgo Opening Comments on Draft TEF Chapters 9, 10, and 12 at 5.

[143] Tesla Opening Comments on Draft TEF Chapters 9, 10, and 12 at 4.

[144] NRDC Opening Comments on Draft TEF Chapters 9, 10, and 12 at 3.

[145] Cal Advocates Opening Comments on Draft TEF Chapters 9, 10, and 12 at 5-6.

customers facing a lack of home charging, because low-income customers likely have fewer choices to optimize their needs and preferences than more affluent customers.[146]

We agree with both parties and note that portable fuel cards, which decrease the cost of charging for low-income customers who lack access to off-peak charging at home, may be an important solution to promote equity. The CARB provides fuel cards for low-income EV customers as a component of several programs including the Financing Assistance Program, the Clean Vehicle Rebate Project, and Clean Cars 4 All. These programs are not currently available to the majority of Californians and EV fueling costs are a major barrier to EV adoption by low-income customers. We direct that the Mid-Cycle Assessment for FC1, described in Section 4.2.4 of this decision, include consideration of the need for and potential designation of a portion of FC1 funds for fuel cards for low-income customers. It should also examine availability of fuel cards to low-income customers in other programs, including the CARB's offerings, and data on whether fueling costs still pose a barrier to EV adoption by low-income customers.

3.8.1. TE Program Cost Recovery and Allocation

The Draft TEF requests comment on whether IOUs should recover TE program costs through the distribution rate component of the customer's bill. The Draft TEF also proposes to address the allocation factor for TE program costs through Phase 2 of the IOUs' GRCs.

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[146] Joint Commenters Opening Comments on Draft TEF Chapters 9, 10, and 12 at 2.

UCAN and Cal Advocates both disagree with recovering TE program costs through distribution rates. They argue for allocation of the costs on an equal cents per kilowatt-hour (kWh) basis through the Public Purpose Program (PPP) surcharge because the TE program serves a broader social interest and its costs are direct subsidies by ratepayers who do not use the charging infrastructure to those who do.[147] UCAN and Cal Advocates assert that the Commission should determine cost recovery through the program's application proceeding because these costs are outside the focus of the GRC. SBUA also opposes recovery of TE program costs through distribution rates and supports recovery through the PPP surcharge.[148] SBUA contends that few, if any, of the TE program's goals are to improve the reliability of the distribution system and the placing of the programs' costs in distribution rates is misaligned with the goals established in legislation.[149] NDC argues that although TE infrastructure deployments are referred to as distribution upgrades, they do not provide distribution benefits to the grid in the traditional sense; therefore, TE program costs should not be recovered through the distribution rates.[150]

The Joint Commenters indicate that IOUs should generally recover TE program costs through PPP surcharges but should recover utility-side infrastructure costs through distribution rates.[151] ATE generally agrees with the

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[147] UCAN Opening Comments on Draft TEF Chapters 9, 10, and 12 at 12; Cal Advocates Opening Comments on Draft TEF Chapters 9, 10, and 12 at 7-8.

[148] SBUA Opening Comments on Draft TEF Chapters 9, 10, and 12 at 13.

[149] *Ibid.*

[150] NDC Reply Comments on Draft TEF Chapters 9, 10, and 12 at 2.

[151] Joint Commenters Opening Comments on Draft TEF Chapters 9, 10, and 12 at 2.

proposed mechanism for recovery of TE program costs, but notes there are potential exceptions.[152] ATE indicates that make-ready investments or ownership and operation of charging stations should be recovered through distribution rates because they provide benefits to customers and involve changes to the distribution system. However, ATE emphasizes that the Commission provide special consideration to recovery of costs in environmental and social justice communities where subsidies or rate discounts may be more appropriate.

SCE argues that the Commission's allocation of TE program costs must recognize the various categories of costs contained within a single TE program to equitably allocate these costs.[153] SCE argues that allocating all TE programs costs through a PPP surcharge increases rates unnecessarily in the rate classes expected to adopt MDHD technologies. However, SCE indicates that 100 percent allocation of costs to distribution rates may place too much of a burden on segments that adopt LD EV technologies. PG&E and CLECA both support the recommendation to recover costs through distribution rates.[154]

Concerning the allocation factor, TURN argues that the Commission should decide TE program cost allocation in the TEF rather than relitigating it in each GRC Phase 2 proceeding.[155] TURN asserts that deferring this issue to the GRC Phase 2 proceedings is inconsistent with the TEF's goal to establish a structured process to reduce the time and resources needed to resolve

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[152] ATE Reply Comments on Draft TEF Chapters 9, 10, and 12 at 5.

[153] SCE Reply Comments on Draft TEF Chapters 9, 10, and 12 at 2.

[154] CLECA Opening Comments on Draft TEF Chapters 9, 10, and 12 at 11; PG&E Opening Comments on Draft TEF Chapters 9, 10, and 12 at 6.

[155] TURN Opening Comments on Draft TEF Chapters 9, 10, and 12 at 1-2.

controversial issues that were previously addressed on a case-by-case basis. TURN also notes that the TEF is the appropriate proceeding because other proceedings' participants may not possess adequate expertise with TE programs.[156] PG&E and CLECA both support the recommendation to allocate costs in Phase 2 of the GRCs.[157]

We find that moving forward the IOUs should record all BTM TE program costs in either one-way subaccounts within the IOUs' individual TE Balancing Accounts or through separate one-way balancing accounts and recover them through distribution rates. This method of cost recovery is consistent with past TE program decisions, the majority of which require the IOUs to recover costs in either a one-way Balancing Account or one-way subaccount within their TE Balancing Accounts. Additionally, the IOUs recover costs for all existing utility-side and BTM TE programs through distribution rates. The EV Infrastructure Rules also direct cost recovery through distribution rates, with review during the IOUs' GRCs.

Should the adopted amounts exceed actual costs, each IOU shall refund excess funds to customers at the end of its GRC cycle in distribution rates through its next consolidated electric revenue requirement and rate change advice letter, or through another advice letter as approved by the Commission. The IOUs shall not record excess funds in the new one-way balancing account or subaccount. At the end of its GRC cycle, each IOU shall transfer any over-collected balance to its distribution revenue adjustment balancing account as part

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[156] *Ibid.*

[157] CLECA Opening Comments on Draft TEF Chapters 9, 10, and 12 at 11; PG&E SCE Opening Comments on Draft TEF Chapters 9, 10, and 12 at 6.

of its annual year-end revenue requirement and rate change consolidated advice letter process for rates effective January 1 of the following year, or through another advice letter process as authorized by the Commission. Each IOU shall include in distribution rates the forecasted revenue requirement approved in this decision, and thus its distribution rates will recover program revenues, which it will record to its corresponding distribution revenue adjustment balancing account.

We also require the IOUs to allocate FC1 program costs and all BTM TE program costs moving forward on an equal cents per kWh basis. This helps ensure that costs are distributed across all customer classes equitably. Further, parties' comments described above do not account for the new EV Infrastructure Rules and, therefore, address both BTM and utility-side costs. As utility-side costs are not included in the program contemplated here, it is even more appropriate to adopt the equal cents per kWh approach.

3.8.2. Alternative Financing

As to the issue of alternative financing, the Draft TEF recommends that the IOUs host a public workshop to discuss their capacity to administer an on-bill financing or tariff-based recovery program as well as the potential structure(s) for such programs.

Several parties' comments address alternative financing. PG&E asserts that the Commission should not adopt any specific alternative financing requirements at this time, while allowing the IOUs to propose alternative financing mechanisms in future TEPs to aid TE deployment cost-effectively

without excessive costs to non-benefiting customers.[158] NDC supports the workshop proposal to explore options to reduce financial barriers to individual EV adopters and relieve ratepayer burdens related to funding the TE program.[159] NRDC also agrees with the workshop proposal, but states that the Commission should revise the language in the TEF to clarify that the IOUs can still come forward with applications proposing these programs if they see sufficient justification and need.[160] Cal Advocates supports the workshop proposal, indicating it would facilitate input from stakeholders on mechanisms that incentivize the greatest amount of TE at the lowest cost to ratepayers.[161] TURN supports the concept of on-bill financing and agrees with the workshop proposal to discuss the potential structure of IOU on-bill financing programs.[162]

EDF asserts that exploration of innovative financing mechanisms, particularly for smaller commercial fleets with less access to capital and that operate in low-income communities, is a crucial component to ensure widespread TE. However, EDF expresses disappointment in the delay in approval of an on-bill financing or tariff-based recovery program.[163] AEE disagrees with delaying approval of an on-bill financing or tariff-based recovery program and argues that the IOUs have the capital and ability to make these

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[158] PG&E Opening Comments on Draft TEF Chapters 9, 10, and 12 at 7.

[159] NDC Reply Comments on Draft TEF Chapters 9, 10, and 12 at 4.

[160] NRDC Opening Comments on Draft TEF Chapters 9, 10, and 12 at 13.

[161] Cal Advocates Opening Comments on Draft TEF Chapters 9, 10, and 12 at 8.

[162] TURN Reply Comments on Draft TEF Chapters 9, 10, and 12 at 2.

[163] EDF Reply Comments on Draft TEF Chapters 9, 10, and 12 at 5.

investments now.[164] SBUA argues that the Commission should address alternative financing efforts in R.20-08-022, the proceeding to investigate and design clean energy financing options for electricity and natural gas customers.[165]

We decline to take further action on alternative financing programs in this proceeding as we are addressing that topic in R.20-08-022, which focuses on the investigation and design of alternative financing programs for all clean energy technologies. That proceeding addresses outstanding issues that need further discussion, including the IOUs' proposals on TE alternative financing pilots.[166] Our consideration of alternative financing mechanisms for TE in R.20-08-022 ensures consistency in alternative financing program design and efficiently utilizes stakeholders' and the Commission's resources.

3.9. Draft TEF Chapter 10: Partnerships

Chapter 10 of the Draft TEF recommends that the IOUs leverage relationships and complement ratepayer investment with public-private partnerships, collaboration on building code enhancement, regional coordination, and community choice aggregator (CCA) coordination.[167]

3.9.1. Public-Private Partnerships

Regarding public-private partnerships, the Draft TEF recommends the Commission direct the IOUs to:

1. Host a roundtable discussion between the vehicle manufactures, EVSPs, and other stakeholders to discuss

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[164] AEE Opening Comments on Draft TEF Chapters 9, 10, and 12 at 6.

[165] SBUA Opening Comments on Draft TEF Chapters 9, 10, and 12 at 14.

[166] *See* R.20-08-022, Assigned Commissioner's Amended Scoping Memo and Ruling at 6 (Nov. 19, 2021).

[167] Draft TEF at 115-35.

potential partnership opportunities and ensure broad, expert input; and

2. To demonstrate in their program applications and pilot Advice Letters that the IOUs have created public-private partnerships that incorporate best practices from national and international models, including cost sharing, market benefits, data sharing, clearly defined goals, outreach, and education, and leveraging grant opportunities.[168]

Many parties support an IOU-hosted roundtable discussion and the formation of public-private partnerships.[169] However, other parties caution against mandating the IOUs to form partnerships with industry as it may slow down the process of deploying TE infrastructure.[170]

The Staff Proposal provides an updated framework for incorporating industry feedback; therefore, these Draft TEF recommendations are no longer directly applicable. We generally agree with parties that IOU TE programs benefit from industry input. Thus, we direct the IOUs to seek industry feedback in developing the Program Handbook, which is discussed below.

3.9.2. CALGreen Building Code Enhancements

The Draft TEF recommends that the IOUs cooperate with the Building Standards Commission and the other state agencies that develop the California Green Building Standards (CALGreen) Code, which includes a range of green building requirements that apply to new residential and non-residential

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[168] *Id.* at 119-20.

[169] *See, e.g.*, ChargePoint Opening Comments on Draft TEF Chapters 9, 10, and 12 at 7; Cal Advocates Opening Comments on Draft TEF Chapters 9, 10, and 12 at 12; Tesla Opening Comments on Draft TEF Chapters 9, 10, and 12 at 7.

[170] *See, e.g.*, Electrify America Opening Comments on Draft TEF Chapters 9, 10, and 12 at 9-10; PG&E Opening Comments on Draft TEF Chapters 9, 10, and 12 at 9; SCE Opening Comments on Draft TEF Chapters 9, 10, and 12 at 8-9.

buildings. The Draft TEF recommends that the IOUs' TEPs address this opportunity to encourage installation of lower-cost TE infrastructure at new buildings.[171]

NRDC et al. agreed with the goal of promoting installation of lower-cost infrastructure and with the recommendation to have the IOUs cooperate with Building Standards Commission and the other state agencies to develop CALGreen.[172] PG&E argues that the IOUs' Energy Efficiency Business Plans adequately provide funding for these activities.[173] SCE similarly argues that IOUs' existing Codes and Standards Programs within their Energy Efficiency Portfolios provide sufficient resources to support the CALGreen and the development of building standards related to TE infrastructure.[174]

Since the issuance of the Draft TEF, the Commission has advanced these efforts without the existence of the proposed IOU TEPs. We have directed the IOUs to support building code enhancements for any new construction multi-unit dwelling (MUD).[175] Further, in D.21-07-028, we authorized the IOUs to submit proposals to support new construction MUDs that exceed code.

This decision provides no additional funding or guidance to support CALGreen or TE-related codes and standards development because the Energy Efficiency proceeding, and related efforts, already provide funding

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[171] Draft TEF at 120-126.

[172] NRDC *et al*. Opening Comments on Draft TEF Chapters 9, 10, and 12 at 15.

[173] PG&E Opening Comments on Draft TEF Chapters 9, 10, and 12 at 12.

[174] SCE Opening Comments on Draft TEF Chapters 9, 10, and 12 at 9.

[175] For example, the SCE Charge Ready 2 program supports EV charging at new construction MUDs by providing rebates for installations that go above the CALGreen code. (D.20-08-045 at 77-81, Ordering Paragraphs 5, 12, 13.)

sources. Further, the consolidated Energy Efficiency applications proceeding considers parties' comments on how codes and standards advocacy programs should expand their scope to address additional clean energy goals, such as TE and decarbonization; therefore, that proceeding will likely address funding for codes and standards work in areas other than energy efficiency (*e.g.*, EV charging, BTM storage, etc.).[176]

3.9.3. Regional Coordination

With local governments continuing to develop their own TE plans, the Draft TEF recommends that the IOUs coordinate with municipalities to develop holistic strategies that address unique regional barriers.[177] Specifically, the Draft TEF recommends that the Commission direct the IOUs to:

1. Coordinate with the state's 35 Air Districts and Metropolitan Planning Organizations when developing their TEPs and TE pilots, programs, and rates, where appropriate;
2. Include metrics to show how their TEPs and TE programs provide incremental air quality improvements related to state and federal air quality goals;
3. Refer to the CEC's Infrastructure Deployment Strategy and state, local, and federal air quality management plans in their program applications to identify and design TE programs that address EV charging infrastructure gaps throughout their service territories;
4. Align with and support other available Air District and Metropolitan Planning Organizations grant funding opportunities to design TE programs that can help the state meet federal air quality standards; and

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[176] Application 22-02-005 *et al.*

[177] Draft TEF at 126-30.

5. Designate IOU staff time to participate in the regional EV Coordinating Councils within their service territories.

PG&E supports the overarching recommendation for the IOUs to coordinate with the Air Districts and Metropolitan Planning Organizations in developing the TEPs, while cautioning against a prescriptive coordination requirement that would not account for differences in regional needs or political structures.[178] PG&E also claims that due to resource constraints, PG&E might be unable to work with each local government to develop their TE plans.[179] SCE argues against the Commission creating a strict analytical framework with a set of prioritization criteria and, instead, proposes that the IOUs' TEPs demonstrate that proposed programs address the core goal of overcoming barriers to and accelerating EV adoption.[180] SANDAG urges the Commission to prioritize sites that achieve the greatest air quality improvements and greenhouse gas (GHG) emissions reductions in hard-to-reach markets and underserved areas.[181]

As we are not adopting the proposed TEPs in this decision, some of the Draft TEF's recommendations on this topic are no longer relevant. Instead, we adopt a streamlined approach to regional coordination. The IOUs shall conduct outreach to Air Districts and Metropolitan Planning Organizations in their service territories to inform them of and request their participation in the development of the Program Handbook. These entities can share details on other funding opportunities and help influence program implementation details (*e.g.*,

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[178] PG&E Opening Comments on Draft TEF Chapters 9, 10, and 12 at 13.

[179] *Ibid.*

[180] SCE Opening Comments on Draft TEF Chapters 9, 10, and 12 at 10-11.

[181] SANDAG Opening Comments on Draft TEF Chapters 9, 10, and 12 at 4.

rebate levels, outreach tactics, etc.). This outreach can help ensure that the FC1 program addresses regional TE plans, leverages additional outreach support from Air Districts and Metropolitan Planning Organizations, leverages funding sources and incentive stacking, and supports the equitable geographic distribution of charging infrastructure.

Regarding the development of air quality improvement metrics, the FC1 program evaluation, discussed in detail below, addresses this topic. Finally, we expect IOUs to participate in regional EV Coordination Councils within their service territories.

3.9.4. Coordination with CCAs

We address coordination with the CCAs in Section 4 below regarding the Staff Proposal.

3.10. Draft TEF Chapter 11: Additional Policy Guidance

Chapter 11 of the Draft TEF provides recommendations on three disparate topics: (1) vehicle-grid integration (VGI); (2) marketing, education, and outreach (ME&O) issues; and (3) the IOUs' LCFS programs.[182]

3.10.1. VGI

To advance VGI and help ensure that the IOUs integrate incremental load from an increasing number of EVs in a manner that provides grid benefits, the Draft TEF recommends the Commission direct the IOUs to:

1. Ensure their TEPs include strategies to meet the requirements of SB 676;
2. Integrate VGI considerations across all relevant business activities;

[182] Draft TEF at 135-49.

3. Address SB 676 definitions and guidance in any applications;
4. Provide consistent reporting on TOU rate and VGI use case implementation among utility program participants including to help track progress toward meeting SB 676 requirements; and
5. Collaborate with ED staff to hold a workshop(s) aligning VGI strategies within the IOUs' TEPs with SB 676 implementation guidance.[183]

Parties offer varying levels of support for the Draft TEF's VGI recommendations. Electrify America asserts that TE should remain the Commission's primary objective, while pursuing VGI flexibly as a second priority.[184] ATE cautions against complicating or delaying the TEF by including VGI goals and requirements.[185] PG&E and SCE request that the Commission not adopt VGI portfolios until parties complete further research and evaluation, including through pilot programs.[186] SCE also recommends that the Commission align VGI implementation by integrating strategies developed by the Joint Agency VGI Working Group[187] convened in 2019 into the TEF.[188] AEE

[183] Draft TEF at 139-40.

[184] Electrify America Opening Comments on Draft TEF Chapters 6 and 11 at 6; Electrify America Reply Comments on Draft TEF Chapters 6 and 11 at 4-5.

[185] ATE Reply Comments on Draft TEF Chapters 6 and 11 at 7.

[186] PG&E Reply Comments on Draft TEF Chapters 6 and 11 at 2; SCE Reply Comments on Draft TEF Chapters 6 and 11 at 5-6.

[187] Gridworks, Vehicle Grid Integration Working Group, https://gridworks.org/initiatives/vehicle-grid-integrationwg/.

[188] SCE Opening Comments on Draft TEF Chapters 6 and 11 at 5.

recommends, and the Joint Commenters support, keeping VGI efforts standalone and not relying on TEF/TEP development to avoid undue delay.[189]

EDF argues the IOUs should make progress on VGI before the Commission approves the TEPs, including developing requirements for standards, equity, pilots, resiliency, and submetering.[190] ChargePoint recommends advancing SB 676 implementation in parallel with the TEF.[191] GPI requests that the Commission require the IOUs to address SB 676 in their draft TEPs as soon as 2024.[192] UCAN recommends that VGI be the "primary focus" of the IOUs' TEPs, and consequently the Commission should provide VGI guidance to the utilities prior to the first TEP cycle, pursuant to SB 676.[193] The Joint Parties assert that the Commission should expeditiously issue a decision directing the IOUs to develop VGI portfolios designed to meet the requirements of SB 676.[194] SDG&E advocates for selecting SB 676-related metrics cautiously, given the nascency of the EV market and the lack of consensus on the costs of VGI use cases.[195] VGIC urges the Commission to issue VGI guidance containing a model VGI portfolio and a directive for the IOUs to implement portfolios beginning in 2021.[196]

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[189] AEE Opening Comments on Draft TEF Chapters 6 and 11 at 3; Reply Comments on Draft TEF Chapters 6 and 11 at 2-3.

[190] EDF Opening Comments on Draft TEF Chapters 6 and 11 at 10.

[191] ChargePoint Opening Comments on Draft TEF Chapters 6 and 11 at 6.

[192] GPI Opening Comments on Draft TEF Chapters 6 and 11 at 4.

[193] UCAN Opening Comments on Draft TEF Chapters 6 and 11 at 5.

[194] Joint Parties Opening Comments on Draft TEF Chapters 6 and 11 at 9.

[195] SDG&E Opening Comments on Draft TEF Chapters 6 and 11 at 11.

[196] VGIC Opening Comments on Draft TEF Chapters 6 and 11 at 3.

We take these comments into consideration in pursuing VGI strategies. A December 2020 decision adopts a definition of VGI and guidance for the IOUs to address SB 676 requirements in any future applications.[197] In Section 4.3.8.1 of this decision, we provide further guidance and vision to advance VGI efforts beyond D.20-12-029.

3.10.2. ME&O

To establish clear requirements for the IOUs' TE ME&O campaigns, the Draft TEF recommends that the Commission direct the IOUs to:

1. Focus TE-related ME&O efforts on building awareness and participation interest for individual IOU programs;
2. Develop ME&O plans within their TEPs, including focused outreach targeting Environmental and Social Justice communities and collaboration with CBOs, Environmental Justice organizations, and local governments;
3. Propose a single budget and overarching ME&O plans within their TEPs focused on EV rates, EV charging behavior, and the electric grid; and
4. Work with ED staff and stakeholders to develop portfolio-wide and program-specific ME&O targets and metrics.[198]

In comments, some parties advocate for the IOUs playing a broad role in ME&O efforts. ATE recommends that the IOUs play a leading role in ME&O efforts.[199] SCE asserts that the IOUs are able to perform broad ME&O coordinated with other ME&O efforts.[200] ChargePoint argues for the IOUs playing an active role in educating customers about the benefits of EVs,

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[197] D.20-12-029.

[198] Draft TEF at 145-46.

[199] ATE Reply Comments on Draft TEF Chapters 6 and 11 at 9.

[200] SCE Opening Comments on Draft TEF Chapters 6 and 11 at 5.

encouraging utilization of EV charging stations, and engaging with prospective site hosts.[201] The Joint Parties and SDG&E recommend the IOUs leverage their core competencies and customer relationships to play a broad role in ME&O.[202] GPI asserts that ME&O efforts are critical to increase charger utilization and recommends the IOUs pursue a collaborative ME&O strategy with CBOs, customers, and EVSPs.[203] EDF and the Joint Commenters recommend the IOUs support efforts to disseminate information about EVs and engage in a collaborative approach to ME&O.[204] PG&E asserts that the IOUs should be able to propose program-specific ME&O as well as overarching TE ME&O.[205] Plug In America recommends increasing the investment in ME&O and not limiting the IOUs' role.[206] CASMU supports the IOUs conducting ME&O rather than providing a budget for a third party to complete the work.[207]

Other parties, instead, argue for narrowing the IOUs' ME&O role. Cal Advocates urges the Commission not to authorize the IOUs to adopt broad EV awareness programs, arguing that such programs would duplicate existing TE ME&O efforts.[208] Clean Energy Fuels recommends restricting utility ME&O

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[201] ChargePoint Opening Comments on Draft TEF Chapters 6 and 11 at 8.

[202] Joint Parties Opening Comments on Draft TEF Chapters 6 and 11 at 10; SDG&E Opening Comments on Draft TEF Chapters 6 and 11 at 13-15.

[203] GPI Reply Comments on Draft TEF Chapters 6 and 11 at 4-5.

[204] EDF Opening Comments on Draft TEF Chapters 6 and 11 at 14; EDF Reply Comments on Draft TEF Chapters 6 and 11 at 9-10; Joint Commenters Reply Comments on Draft TEF Chapters 6 and 11 at 4.

[205] PG&E Opening Comments on Draft TEF Chapters 6 and 11 at 15.

[206] Plug In America Opening Comments on Draft TEF Chapters 6 and 11 at 6.

[207] CASMU Opening Comments on Draft TEF Chapters 6 and 11 at 4.

[208] Cal Advocates Reply Comments on Draft TEF Chapters 6 and 11 at 1-3.

efforts to individual IOU programs and prohibiting the IOUs from using ratepayer funds for general EV marketing.[209] Electrify America asserts the IOUs should defer to third parties for broad EV awareness campaigns.[210]

Parties also comment on the need to promote collaboration within ME&O efforts. SBUA recommends the Commission direct the IOUs to engage with small businesses through improved ME&O campaigns because utility TE ME&O activities have generally overlooked small businesses, which constitute the majority of businesses in California and provide roughly half of the state's jobs.[211] SANDAG urges the Commission to encourage the IOUs to develop public-private partnerships to advance ME&O efforts.[212] VGIC similarly asserts that EVSPs could provide a valuable avenue for direct customer education on rates, programs, and ME&O focused on VGI.[213] ChargePoint also recommends that IOU ME&O efforts leverage outreach by EVSPs and vendors to educate customers (*e.g.*, IOUs sponsoring joint webinars with EVSPs and vendors).[214]

Section 4.3.4 of this decision provides direction for ME&O activities, but we make certain findings here based on feedback received on the Draft TEF's ME&O proposal. We agree that ME&O efforts are critical to EV charger utilization and find that post-energization ME&O may help to increase charger utilization rates. We discuss metrics to track ME&O's efficacy in increasing

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[209] Clean Energy Fuels Opening Comments on Draft TEF Chapters 6 and 11 at 4.

[210] Electrify America Opening Comments on Draft TEF Chapters 6 and 11 at 8.

[211] SBUA Opening Comments on Draft TEF Chapters 6 and 11 at 8-13.

[212] SANDAG Opening Comments on Draft TEF Chapters 6 and 11 at 4.

[213] VGIC Reply Comments on Draft TEF Chapters 6 and 11 at 9.

[214] ChargePoint Opening Comments on Draft TEF Chapters 6 and 11 at 8.

charger utilization in the discussion on the FC1 Program Handbook below. In response to several parties' support of narrowing the IOU role on ME&O to ensure ratepayer funds do not duplicate broad EV awareness campaigns, we find that the FC1 program should not replicate statewide efforts promoting EV awareness, including the $5 million program to promote ZEV awareness funded by the Governor's Office of Business and Economic Development.

We also agree with parties' arguments that public-private partnerships can advance ME&O efforts; therefore, we find that the ME&O performed within the FC1 rebate program would benefit from public-private partnerships. Finally, we agree that small businesses and small fleets have been overlooked in TE ME&O activities, and we therefore find that the FC1 rebate program's ME&O efforts should target small businesses as their participation is needed to achieve California's EV adoption goals.

3.10.3. IOU LCFS Programs

The Draft TEF proposes guidance on how the IOUs would spend the portion of the LCFS credits known as "holdback" credits or funds.

Since the issuance of the Draft TEF, D.20-12-027 authorized the large utilities to spend the holdback funds or credits in accordance with guidance and regulations established by the CARB, as well as additional guidance outlined in that decision. The decision also directed the large utilities to file Tier 2 Advice Letters with plans for the expenditure of these funds. An ED disposition letter approved PG&E's implementation plan on December 24, 2021, and the Commission issued Resolution E-5236 on November 4, 2022, approving SCE's implementation plan with modifications. SDG&E's request is under review.

3.11. Draft TEF Chapter 12: Emerging Transportation Trends

Chapter 12 of the Draft TEF contains recommendations for how the IOUs should approach three emerging transportation sectors: Transportation Network Companies (TNCs), micromobility (*e.g.*, electric bikes and scooters), and autonomous electric vehicles (AEVs).[215]

3.11.1. Transportation Network Companies

The Draft TEF includes several recommendations and questions related to TNCs' role within the Commission's TE activities.[216] For example, the Draft TEF recommends that if the IOUs propose a program involving TNCs, the IOUs should secure TNC co-funding or substantial fund matching. The Draft TEF further notes the Commission is coordinating with CARB to implement the California Clean Miles Standard pursuant to SB 1014 (Skinner, 2018), which requires TNCs to meet annual GHG emission targets and goals beginning in 2023.[217] Additionally, the Commission now has an open proceeding to implement the California Clean Miles Standard.[218]

Parties' comments address ED's TNC recommendations and other aspects of the Commission's role related to TNCs and TE. Uber argues that the Commission should wait to take action until CARB finalizes its Clean Miles Standard regulation.[219] ChargePoint states that rather than establishing a

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[215] Draft TEF at 150.

[216] Draft TEF at 150-52.

[217] *See* CARB, Clean Miles Standard Regulation, https://ww2.arb.ca.gov/rulemaking/2021/cleanmilesstandard.

[218] R.21-11-014.

[219] Uber Opening Comments on Draft TEF Chapters 9, 10, and 12 at 3.

minimum contribution mechanism, the TEF should support collaboration and coordination between IOUs and TNCs to ensure that IOU TE programs complement and encourage TNC investment in EVs.[220] EDF notes that load associated with increasingly electrifying TNCs will quickly be problematic if not well managed.[221] The Joint Parties argue that TNC companies should provide substantial matching or co-funding and be required to share transparent TNC data with the IOUs and their research partners to help inform IOU program design and strategic planning.[222]

We decline to adopt the Draft TEF's recommendations related to TNCs in this decision. We are addressing issues related to TE and TNCs in the proceeding implementing the Clean Miles Standard. We should also note that several of the types of rebates that will be available under the FC1 program, including those for charging at MUDs and for public charging, can fund chargers that will be available to TNC drivers. Therefore, no additional direction on this topic is needed here.

3.11.2. Micromobility

Parties provide limited comments on the Draft TEF's recommendations related to micromobility, such as requiring coordination to determine the grid impact of charging micromobility equipment and ensure equipment charging utilizes the correct electric tariff.[223] The IOUs caution that they do not have authority over the micromobility companies' charging providers and are not

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[220] ChargePoint Opening Comments on Draft TEF Chapters 9, 10, and 12 at 11.

[221] EDF Opening Comments on Draft TEF Chapters 9, 10, and 12 at 20.

[222] Joint Parties Opening Comments on Draft TEF Chapters 9, 10, and 12 at 17.

[223] Draft TEF at 152-56.

responsible for policing or enforcing micromobility companies' actions.[224] Uber generally opposes regulatory action and IOU intervention in the micromobility market, arguing that it is preemptive and will risk chilling the nascent market, interfering with innovation, and confusing the IOUs' near- and mid-term TE efforts.[225]

The Commission takes no position on these issues in this decision. The Commission may address matters related to micromobility in a future proceeding.

3.11.3. Autonomous EVs

Few parties provide comments on the Draft TEF's recommendations related to autonomous EVs, including direction for the IOUs to coordinate with the appropriate Commission staff to track autonomous EV deployments and trends and describe how the development and growth of autonomous EVs could impact future TE infrastructure needs.[226] PG&E urges the Commission not to require tracking of autonomous EV deployment and trends.[227] Cal Advocates supports requiring the IOUs to track the progress of autonomous EVs but recommends minimizing IOU-staff time spent on tracking efforts until more considerable progress on technology development and deployment occurs.[228]

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[224] PG&E Opening Comments on Draft TEF Chapters 9, 10, and 12 at 23; SCE Opening Comments on Draft TEF Chapters 9, 10, and 12 at 14.

[225] Uber Opening Comments on Draft TEF Chapters 9, 10, and 12 at 4.

[226] Draft TEF at 156-57.

[227] PG&E Opening Comments on Draft TEF Chapters 9, 10, and 12 at 24.

[228] Cal Advocates Opening Comments on Draft TEF Chapters 9, 10, and 12 at 20.

SANDAG supports allowing the IOUs to file emerging technology feasibility studies and pilots in their TEPs and TE applications.[229]

We decline to adopt any requirements related to autonomous EVs in this decision. The Commission's Transportation Licensing and Analysis Branch addresses all issues related to autonomous EVs, including the implementation of the Commission's decision authorizing deployment of autonomous vehicle passenger service in R.12-12-011.[230]

4. Staff Proposal

This section discusses and resolves issues presented in the Staff Proposal.

4.1. Staff Proposal Section 3: Proposed Changes to the Draft TEF

With the policy and market landscape having changed significantly since the issuance of the Draft TEF, the Staff Proposal recommends a modified approach to accelerating TE.[231] The Staff Proposal only pertains to BTM TE investments because the new EV Infrastructure Rules—constituting a major policy shift since the issuance of the Draft TEF—address utility-side TE investments. Considering parties' comments on the Draft TEF, the IOUs' implementation of Commission-approved programs, additional TE funding allocations, and the state's EV charging needs, the Staff Proposal properly updates the following areas of the Draft TEF, discussed in detail below:

[229] SANDAG Opening Comments on Draft TEF Chapters 9, 10, and 12 at 5.

[230] D.20-11-046.

[231] Staff Proposal at 3-5.

timelines, program guidance, rebate structure, budget, scope, implementation process, and administration.[232]

In particular, the Staff Proposal shifts away from the Draft TEF's proposed ten-year TEP planning approach and recommends adopting a funding cycle approach to TE moving forward. The simplified funding cycle structure would establish and reevaluate the nature of and need for ratepayer support of BTM TE activities on a periodic basis.

The Staff Proposal recommends that Funding Cycle 1 (FC1) begin in 2025 to allow for exhaustion of currently approved TE funding. FC1 would consist of a statewide rebate program for BTM make-readies and EVSE, as well as ME&O and TA programs. The FC1 rebate program would provide support to MUDs, MUD-serving public locations, and MDHD sectors. As proposed, Funding Cycle 2 (FC2) would start in 2030, after FC1 completes at the end of 2029, and would be based on an assessment of FC1, and analysis of the policy and market needs.

Prior to the start of FC1, the Staff Proposal recommends that the current array of TE programs, pending applications and ALs, and forthcoming near-term priority proposals be grouped together as Funding Cycle 0 (FC0). This is the culmination of programs and funding opportunities initiated following the passage of SB 350 and as such represents the Commission's initial approach that this proceeding and the Draft TEF sought to evolve beyond.

4.1.1. Improving Administrative Efficiency

To address the current ad hoc approach the IOUs have pursued to address the state's TE needs, the Draft TEF intended to establish a structured ten-year

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[232] *Id.* at 5-8.

planning process that would reduce the time and resources needed to resolve controversial issues that were previously addressed on a case-by-case basis. The Draft TEF's goal was to streamline the process and resources needed to establish and review TE funding, avoid inconsistency in program offerings and policy across IOU territories, decrease administrative cost and burden of each IOU administering numerous separate programs, and minimize resources associated with participation in numerous proceedings.

The Draft TEF recommends that the IOUs file ten-year forward-looking TEPs. The Staff Proposal provides a simplified five-year funding cycle approach that would establish and reevaluate the nature of and need for ratepayer support of BTM TE activities on a periodic basis. IOU TE programs that support BTM infrastructure serve as a critical accelerant of TE in the state, but there is a need to move beyond the current piecemeal application and approval processes. We therefore adopt the more nimble and focused funding cycle approach recommended in the Staff Proposal to account for party feedback on the Draft TEF discussed above, updated direction from the Legislature, recent Commission decisions and resolutions, and an evolving TE policy and market landscape.[233]

4.1.2. Role of IOUs

The Staff Proposal asserts that the "IOUs are aware of and executing on their core responsibility to serve as both the infrastructure and fuel providers for one of the most ambitious technological transitions in history and are providing

[233] *See, e.g.*, AB 841; Res. E-5167; Res. E-5168.

essential customer support in the process."[234] In comments on the Role of the IOUs within Chapter 4 of the Draft TEF, PG&E argues that "[i]t is important for utilities to provide appropriate broad and targeted support for the TE market within the context of their core capabilities and the roles they play in the wider TE ecosystem. These capabilities include infrastructure, developing appropriate rates for electric fueling, customer education, and programs. . . . PG&E supports the TE market and customers but cannot drive demand for it."[235]

The IOUs are executing their core responsibilities to serve as both the infrastructure and fuel providers to support TE. With the passage of AB 841 and the resulting EV Infrastructure Rules governing recovery of utility costs related utility-side distribution infrastructure investments that support EV charging, the scope and magnitude of the IOUs' role is clear. We agree with the Staff Proposal that the IOUs' core role in TE is supporting and enabling the TE market by acting as utility-side infrastructure and fuel providers. This includes providing transparent and current data to state agencies and the public on grid capacity to support TE growth. If the IOUs properly perform their core responsibilities of supporting utility-side infrastructure and serving as fuel providers, they will accelerate TE and customer investment by providing reliable infrastructure, rates, and technical expertise.

Given the immensity and importance of the core IOU responsibilities, the role of IOU ratepayers in subsidizing BTM TE infrastructure requires careful and ongoing consideration. Although indefinite ratepayer support may not be

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[234] Staff Proposal at 10.

[235] PG&E Opening Comments on Draft TEF Chapters 2-5 at 8.

warranted, we find merit in authorizing ratepayer funding for TE investments through FC1. The CEC's initial AB 2127 Charging Assessment demonstrates that there is significant need for more charging infrastructure in the near-term, and we find it reasonable to establish a role for ratepayers in supporting this charger buildout in the near-term. While recognizing the significant need for TE investment and the availability of non-ratepayer funding sources, we must act prudently in the context of very significant ratepayer pressures impacting the affordability of utility services. Therefore, additional analysis—provided in part through the FC1 evaluation—and stakeholder feedback is needed before the Commission considers authorizing BTM TE funding beyond FC1.

4.2. Staff Proposal Section 4: Funding Cycle Proposal

4.2.1. Five-Year Funding Cycle Structure

The Staff Proposal includes a proposal for a five-year funding cycle structure for FC1, which will begin January 1, 2025, and end December 31, 2029, to allow for the exhaustion of currently approved TE funding. ED staff intends for the proposed funding cycle structure to provide the Commission and parties a simplified approach to determine the continued need for ratepayer support of BTM TE activities. PG&E and ChargePoint support the five-year funding cycle rather than a ten-year cycle.[236] Electrify America supports the five-year funding cycle, but requests that the Commission clarify that "other policy prerogatives and regulatory requirements and rate designs may be revised within this period."[237]

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[236] PG&E Comments on Staff Proposal at 3; ChargePoint Comments on Staff Proposal at 6.

[237] Electrify America Opening Comments on Staff Proposal at 7.

NDC and ATE support the five-year funding cycle provided there is a Mid-Cycle Assessment within FC1 to evaluate the program and refine the rebate program priorities.[238] GPI suggests two different timelines: (1) five-year funding cycles for IOU ratepayer investment and (2) ten-year strategies for meeting TE goals, as described in the Draft TEF via the IOU TE plans or TEPs, updated every five years.[239]

We adopt a five-year funding cycle structure, finding it an appropriate period over which to authorize investments in TE to stimulate the market and foster private investment from 2025 through 2029. Our adoption of a five-year funding cycle provides clarity and certainty as to policy and program design that is easy to understand for customers and stakeholders. It will also provide a reasonable timeframe for the periodic evaluation of BTM TE investments. Furthermore, there is widespread support for this funding cycle approach and the five-year time period.

4.2.2. Extension of Current IOU Programs in FC0

The Staff Proposal proposes that FC0 encompasses the current array of programs, pending applications and Advice Letters, and forthcoming near-term priority programs. In other words, FC0 is the culmination of all programs and funding opportunities that were initiated following the passage of SB 350, and as such, represents the Commission's initial approach that this proceeding and the Draft TEF sought to evolve beyond. Together, the portfolio of approved programs to date represents approximately $1.48 billion of remaining ratepayer

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[238] ATE Comments on Staff Proposal at 4; NDC Comments on Staff Proposal at 3.

[239] GPI Opening Comments on Staff Proposal at 5.

funding to be exhausted. The Staff Proposal requests comment as to whether the near-term priorities decision's authority for extension of current IOU programs adequately addresses potential gaps in funding within the remainder of the FC0 timeline.

Several parties agree that the near-term priorities decision's authority is adequate during FC0.[240] ATE agrees, but contends that since it is currently unknown if IOU programs in FC0 have sufficient funding to keep up with the need through 2025, the Commission should allow IOUs to use the flexibility mechanisms in the near-term priorities decision for the traditional application pathway and program extensions to 2025.[241] Joint Commenters generally agree that the current programs and mechanisms are adequate, but request assurances that that there are no explicit or implied limits to what the IOUs may request during FC0 given the rapidly changing market.[242] NDC also agrees, but emphasizes that it is more likely that the Commission will have to address the issue of unspent funds rather than funding gaps due to the existing substantial amount of unspent funding.[243]

Several parties indicate that the Commission should allow the IOUs to propose additional programs and/or pilots during FC1, if merited, to meet

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[240] SCE Opening Comments on Staff Proposal at 14.

[241] ATE Opening Comments on Staff Proposal at 3.

[242] Joint Commenters Opening Comments on Staff Proposal at 3.

[243] NDC Opening Comments on Staff Proposal at 2.

California's clean transportation goals.[244] PG&E contends that IOUs need the ability to expand VGI pilots.[245] The Joint Parties and ChargePoint assert that the Commission should allow IOUs to submit complementary programs during FC1 similar to the near-term priority decision's programs.[246] The Joint Parties and PG&E indicate that the Commission must approve programs if they are consistent with the criteria set forth in SB 350.[247] Several parties advocate for an extension of the near-term priorities decision's framework to FC1.[248]

We find that the recently adopted near-term priorities decision adequately addresses IOU funding opportunities for the remainder of FC0. We do not find it necessary to extend the near-term priorities decision authorization to allow for Advice Letters and expedited applications through FC1. The near-term priorities decision addresses critical near-term priorities in the period prior to the adoption

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[244] ChargePoint Opening Comments on Staff Proposal at 4; Weave Grid Opening Comments on Staff Proposal at 5; PG&E Opening Comments on Staff Proposal at 12; SDG&E Opening Comments on Staff Proposal at 12; Fermata Opening Comments on Staff Proposal at 10; EDF Opening Comments on Staff Proposal at 2; Joint Commenters Opening Comments on Staff Proposal at 3; GPI Opening Comments on Staff Proposal at 3.

[245] PG&E Opening Comments on Staff Proposal at 5.

[246] Joint Parties Opening Comments on Staff Proposal at 2; ChargePoint Opening Comments on Staff Proposal at 5.

[247] Joint Parties Opening Comments on Staff Proposal at 5; PG&E Opening Comments on Staff Proposal at 7.

[248] Weave Grid Opening Comments on Staff Proposal at 8; PG&E Opening Comments on Staff Proposal at 11; SCE Opening Comments on Staff Proposal at 11.

of further long-term TEF guidance.[249] Given that focus, the pathways and guidance authorized in that decision are no longer relevant beyond FC0.

4.2.3. Transition Between FC0 and FC1

The Staff Proposal highlights that the IOUs collectively have approximately $1.48 billion in unspent Commission-authorized funding, which is nearly five times as much as the IOUs have spent since 2016. As the Commission seeks to have FC1 begin in 2025, which intends to create a simple, statewide approach to ratepayer funded TE investments, the Staff Proposal proposes pathways to wind down FC0 program implementation and requests comment on: (1) how the Commission should structure the transition between FC0 and FC1 and (2) how to deal with any FC0 funding remaining at the beginning of FC1.

Several parties call for the completion or near completion of FC0 programs prior to FC1 programs commencing. NDC argues for the completion of all current FC0 programs prior to FC1 so the data from FC0 program can inform FC1 policies and priorities.[250] NDC indicates that such a requirement is necessary to protect ratepayers. NDC contends that each FC0 program should have a specific justification to continue beyond 2025 and be addressed through the

[249] D.21-07-028 at 24-25 ("In light of the overwhelming interest of the parties in maintaining flexibility for Electrical Corporation TE investment proposals *before the approval of a TEP*, and the urgent need to meet the state's TE policy goals *by 2025*, this decision clarifies that Electrical Corporations may file three forms of *near-term* requests for TE investments." (emphasis added)).

[250] NDC Opening Comments on Staff Proposal at 2.

authorizing decision.[251] Cal Advocates asserts that FC1 should start just prior to equivalent FC0 programs exhausting their budgets.[252]

ATE supports a grace period to wind down FC0 that provides an overlap in program implementation and spending. ATE calls for the grace period to be at least two years with the IOUs allowed to request a longer transition period depending on the use case.[253] BNSF also supports a two-year grace period, citing the potential for supply chain issues to cause delay.[254] GPI recommends a default one-year grace period with the option to submit a request for an additional one-year extension to wind down FC0.[255]

Several parties support allowing all TE pilots and programs approved in FC0 to run until the approved budgets are exhausted.[256] SDG&E asserts that California's TE goals will benefit from some overlap between existing utility FC0 programs and the new FC1 program due to the necessary ramping up period of the rebate program.[257] SCE argues that adopting a process that requires SCE to end its TE programs early would essentially be retroactive ratemaking because it would result in changes to a previous Commission decision.[258]

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[251] *Ibid.*

[252] Cal Advocates Opening Comments on Staff Proposal at 7.

[253] ATE Opening Comments on Staff Proposal at 3.

[254] BNSF Opening Comments on Staff Proposal at 3.

[255] GPI Opening Comments on Staff Proposal at 4.

[256] ChargePoint Opening Comments on Staff Proposal at 4-5; PG&E Opening Comments on Staff Proposal at 2; SCE Opening Comments on Staff Proposal at 15; SDG&E Opening Comments on Staff Proposal at 9; EDF Opening Comments on Staff Proposal at 18.

[257] SDG&E Opening Comments on Staff Proposal at 10.

[258] SCE Opening Comments on Staff Proposal at 16.

The Joint Commenters and the City of Long Beach support rolling over any approved unexpended funding for FC0 programs to FC1.[259] Several parties stress that the Commission should avoid the eligibility gaps and start/stop issues that have characterized some previous IOU programs and that a hard stop on program implementation and funding would undermine program continuity and a positive customer experience.[260]

We agree with the need of an overlap between FC0 and FC1 to allow for a grace period while FC1 ramps up and FC0 programs ramp down. We adopt a default two-year grace period for FC0 to overlap with FC1 in order to allow the IOUs to spend previously authorized FC0 funds—meaning the IOUs shall not accept customer applications or agreements within FC0 programs after December 31, 2026, unless the governing program decision directs another end date. This grace period provides sufficient flexibility to allow for the effective completion of FC0 programs and allocation of the associated funding.

As discussed in Section 3.3 above, D.21-07-028 prevents gaps in program offerings between the issuance of the Draft TEF and a TEF decision. Any near-term priority expedited application or Advice Letter filed after the issuance of this decision shall be filed no later than May 31, 2023, and the IOUs must not accept customer applications or agreements within any approved near-term priority program after December 31, 2026. This deadline does not impact the general authorization to file applications under SB 350.

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[259] Joint Commenters Opening Comments on Staff Proposal at 2; City of Long Beach Opening Comments on Staff Proposal at 5.

[260] ChargePoint Opening Comments on Staff Proposal at 4; PG&E Opening Comments on Staff Proposal at 7; Weave Grid Opening Comments on Staff Proposal at 3.

4.2.4. Mid-Cycle Assessment

The Staff Proposal includes a Mid-Cycle Assessment of the funding allocation to ensure the investments sufficiently serve the market and contribute to state goals.

SCE, ATE, and ChargePoint support a Mid-Cycle Assessment as appropriate.[261] Several parties contend that a single Mid-Cycle Assessment is inadequate. Cal Advocates supports an annual assessment, while GPI supports an assessment every two years.[262] EDF indicates that a Mid-Cycle Assessment should be the minimum interval and is supportive of more frequent assessments.[263] NDC calls for an assessment at the two-year mark and another assessment at the 4.5-year mark.[264] Tesla supports two Mid-Cycle Assessments.[265] PG&E advocates for including a process to assess and adjust funding.[266]

We find that a single Mid-Cycle Assessment in 2027, the third year of FC1, is appropriate to ensure flexibility in program implementation, sufficient review of FC1, and confirmation of whether investments are adequately serving the market and contributing to state goals. We also adopt an annual review to allow for program adjustments based on feedback from annual roundtables. This annual adjustment process shall be initiated via Tier 2 Advice Letter following

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[261] SCE Opening Comments on Staff Proposal at 16; ATE Opening Comments on Staff Proposal at 4; ChargePoint Opening Comments on Staff Proposal at 6.

[262] Cal Advocates Opening Comments on Staff Proposal at 8; GPI Opening Comments on Staff Proposal at 5.

[263] EDF Opening Comments on Staff Proposal at 17.

[264] NDC Opening Comments on Staff Proposal at 4.

[265] Tesla Opening Comments on Staff Proposal at 7.

[266] PG&E Opening Comments on Staff Proposal at 3.

the roundtable. We find that the combination of these two processes provides sufficient flexibility for the FC1 program, while not overburdening stakeholders, the IOUs, and the Program Administrator.

The Commission will initiate the Mid-Cycle Assessment in Quarter 1 of 2027 to assess the FC1 program. The Commission will issue a ruling with questions for stakeholders regarding any potential necessary modifications to the FC1 program, based on lessons learned from implementation, evaluation results, overall market needs assessment, and the continued role of ratepayer support for BTM infrastructure.

The scope of the Mid-Cycle Assessment will include, but is not limited to, the following issues:

1. Whether to modify the Program Administrator contract, including a partial or full extension until end of 2029;
2. Whether to modify the Program Administrator, including whether to direct ratepayer funds to the CEC for administration;
3. Whether to adjust the allocation of funding among MDHD, LD, and allowable use cases;
4. Whether to authorize the IOUs to collect the remaining 40 percent of the authorized $1 billion budget if additional funding, based on the criteria established in this decision, is necessary;
5. Whether to modify the IOUs' funding contribution levels and changes to funding contribution methodology;
6. Whether to modify or eliminate any FC1 program elements (*i.e.*, ME&O, Technical Assistance, rebates);
7. Whether to modify the underserved community funding levels based on review of data on underserved community outreach and adoption; and
8. Whether to modify the underserved community requirements, including changes to the allocation—any

underserved community requirement changes should be based on an evaluation of deployment, outreach, and equity data.

We anticipate that any FC1 program modifications resulting from the Mid-Cycle Assessment will take effect in January 2028. The following three key areas of evaluation for the Mid-Cycle Assessment shall help determine whether FC1 should continue beyond the mid-cycle point, and, if so, what modifications are needed:

1. **Program and Process Evaluation**—how well is the Program Administrator implementing the FC1 program?

   Based on the findings of the evaluations, assessments, and Commission-led audit, discussed later in this decision, the Commission will assess progress of the FC1 program toward targets adopted in the Program Handbook decision, reasonableness of expenditures, and effectiveness of program design in meeting program objectives.

2. **Market Progress** – how has the market and available funding for EV charging progressed by mid-cycle; has the need for ratepayer funding for BTM changed in any way; and are the identified target customer segments still the appropriate ones for ratepayer funding?

   Via funding through the ED-managed evaluation budget, ED staff and technical consultants should carry out at least one study, to be completed by the end of the second program year to assess funding availability and market needs, including but not limited to:

   - Assessment of all public funding available to support FC1 target sectors or any new sectors;
   - Assessment of the FC1 target sectors along with any new sectors, number of chargers deployed to date based on CEC's AB 2127 charging assessments, planned charger deployments, IEPR projections, and remaining FC0 and FC1 program funding; and

- Additional market performance data available to inform continued ratepayer support for BTM TE infrastructure.

3. **Rate Pressure** – how does the continuation of FC1 impact affordability of rates?

   Through the Mid-Cycle Assessment process, ED staff should develop a rate impact assessment based on the impact on rates of all TE related costs—inclusive of FC0 programs, EV Infrastructure Rules, and the ongoing FC1 program—using applicable affordability metrics (*i.e.*, affordability ratio), as discussed in the Commission's affordability proceeding. D.20-07-032, the Phase I decision in the affordability proceeding,[267] sought to "apply the affordability metrics in ratesetting proceedings in as widespread a manner as the current methodology allows." The subsequent Phase 2 decision, D.22-08-023, further refined the affordability metrics and established a methodology for forecasting future values of the affordability ratio metric for a set of hypothetical essential usage bills, thus allowing for measurement of affordability impacts in future years based on expected rate and bill impacts. As part of the analysis, ED staff should consider the increase in electricity sales TE may create and how that may factor into overall impact on electric rates. The TE affordability assessment should consider market needs and whether there are other sources of funding that would reduce or eliminate the need for ratepayer subsidies of BTM TE infrastructure.

The Commission will use the findings of this process to inform a future decision to determine if the program should be extended for an additional two years, and if so, provide recommendations for improvements.

[267] R.18-07-006.

4.2.5. Annual Roundtables

The Staff Proposal further recommends the IOUs and Program Administrator host annual roundtables to review the program's efficacy in addressing equity, with participation from stakeholders, including CBOs, environmental justice organizations, tribal communities, Commission representatives, CCAs, the Disadvantaged Communities Advisory Group, and other stakeholders. Based on party feedback and program data presented during the roundtable, the Staff Proposal recommends the Program Administrator shall propose any necessary modifications to the program to address outstanding equity concerns.

Cal Advocates and UCAN support roundtables, indicating that an annual roundtable involving agencies such as CEC and CARB, stakeholders, CBOs, and the IOUs, will be an essential part of evaluating the program, especially with regard to equity.[268] ATE indicates a mid-cycle evaluation during FC1 will be sufficient and appropriate.[269] NDC comments that annual reviews with mechanisms to quickly implement program modifications would be beneficial to help measure and achieve the actual public benefits anticipated from the investments.[270]

Based on party comment, we adopt a single annual roundtable, as opposed to separate data- and equity-focused roundtables. The annual roundtables shall occur in July of each year of FC1 and will be led by the IOUs and the

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[268] Cal Advocates Opening Comments on Staff Proposal at 17; UCAN Opening Comments on Staff Proposal at 6.

[269] ATE Opening Comments on Staff Proposal at 9.

[270] NDC Opening Comments on Staff Proposal at 18.

Program Administrator, with ED staff input on the agenda. The scope of the roundtables shall include stakeholder input and review of program data and evaluation results to inform any proposed modifications to the Program Handbook, such as adjustments to the rebate levels and changes to better reach underserved communities. The roundtables should emphasize review of equity considerations. The IOUs shall file a Tier 2 Advice Letter by August 1 of each year of FC1 with the proposed modifications to the Program Handbook, and those modifications shall take effect on January 1 the following year.

4.2.6. Development of FC2 Guidance

The Staff Proposal requests comments as to whether the Commission should define a timeline for development of FC2 guidance at the same time as the adoption of FC1 or wait until a later time.

PG&E supports development of FC2 guidance one year before the end of FC1, while ChargePoint suggests after the FC1 Mid-Cycle Assessment.[271] NDC stresses the need for evaluation of FC0 and FC1 prior to the development of FC2, which it recommends should occur in the last year of FC1.[272] The Joint Commenters assert that development of guidance for FC2 should begin at least 18 months prior to its start.[273] ATE and GPI support adoption of FC2 guidance

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[271] PG&E Opening Comments on Staff Proposal at 3; ChargePoint Opening Comments on Staff Proposal at 5.

[272] NDC Opening Comments on Staff Proposal at 3.

[273] Joint Commenters Opening Comments on Staff Proposal at 5.

along with the adoption of FC1, with GPI indicating that this would help avoid any gaps between the programs.[274]

We find it appropriate to adopt a timeline and process for the development of FC2 guidance. The development of FC2 shall be based on the evaluation of the FC1 program, additional BTM infrastructure needs, and an assessment of the continued role of IOUs in supporting BTM infrastructure. Any FC2 funding should consider findings from program evaluations, market studies and, to the extent feasible, infrastructure planning analyses. The FC2 development process should commence in early 2027 via ruling, which should provide adequate time for an effective process since the initiation of any potential FC2 program would likely commence on January 1, 2030. Following the issuance of a ruling and subsequent party comments, the Commission would issue guidance, if needed, by the end of 2027.

4.2.7. Funding Cycle Timeline

The table below provides a summary of the timelines for the funding cycles.

Event	Date
FC0	Present – December 31, 2024
FC0 Grace Period	January 1, 2025 – December 31, 2026
FC1 Begins	January 1, 2025
FC1 Mid-Cycle Assessment	2027
Development of FC2 Guidance	2027
FC2 Tentatively Begins	January 1, 2030

[274] ATE Opening Comments on Staff Proposal at 4; GPI Opening Comments on Staff Proposal at 4.

4.2.8. Supplemental Program/Pilot Applications

Several parties raise the issue of whether the IOUs should be allowed to file additional applications for supplemental and pilot programs during FC1. These parties, including Fermata, PG&E, ChargePoint, Weave Grid, SCE, EDF, and Joint Commenters, support the idea of adding additional application pathways. Other parties, including CLECA, Cal Advocates, EPUC, Clean Energy Fuels, NDC, and TURN, raise affordability concerns with authorizing additional TE funding beyond the FC1 program.

We find that the existing Commission application pathway per SB 350 is sufficient. Any application, including for supplemental programs or pilots, submitted via that pathway will be reviewed in the context of the funding the Commission has authorized to date. Additionally, any application for funding should sufficiently demonstrate that the IOUs are best suited for that role and that it fills a market need that is not otherwise addressed by the FC1 program, any other state agency administered TE programs,[275] and any other funding available from local or federal entities. The application should also evaluate the impact of any funding authorized on the affordability of utility services, using the metrics in our affordability decisions.

4.3. Staff Proposal Section 5: FC1 BTM Rebate Program

4.3.1. FC1 Budget

4.3.1.1. Total FC1 Budget

The Staff Proposal proposes a total budget of $1 billion over five years for FC1 and seeks comments as to the appropriate budget level. A number of parties

[275] These TE programs include, but are not limited to, CALeVIP, EnergIIZE, or successor programs, and the potential Clean Cars and Clean Air Ballot Initiative program.

find the proposed $1 billion budget excessive and premature given ongoing developments in the market and the need to evaluate the performance of the current TE programs.

TURN argues that the budget proposal does not adequately reflect that future state, private, and public commitments could "substantially or completely offset the need for ratepayer expenditures from 2025-2029."[276] TURN recommends a maximum budget of $500 million over five years or 50 percent of the state's allocation to the CALeVIP program, whichever is least.[277]

NDC contends that the budget is excessive due to the large amount of non-ratepayer funds already committed to TE. NDC cites the "inability of the market and IOUs to utilize approved funding expeditiously" as well as ratepayer affordability concerns in recommending a FC1 budget of $75 million annually or $375 million over five years.[278]

Cal Advocates asserts that the budget is unreasonable, and that ratepayer funding should only be used as a last resort, limited to specific areas such as underserved communities.[279] Cal Advocates recommends capping the budget at $100 million for the first year and determining the budgets for subsequent years based on program performance and market needs.[280]

Several parties argue that the Commission should wait to set the budget. CLECA, UCAN and EPUC all support waiting until a review of the TE program

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[276] TURN Comments on Staff Proposal at 3.

[277] *Id.* at 6.

[278] NDC Comments on Staff Proposal at 5.

[279] Cal Advocates Comments on Staff Proposal at 8.

[280] *Id.* at 4.

costs and benefits before approving such a large level of ratepayer funding.[281] CLECA and EPUC also argue that all unspent ratepayer funds and other funding sources should be exhausted prior to approval of more ratepayer funds.[282]

The Joint Commenters and ChargePoint oppose a delay in funding authorization, with ChargePoint emphasizing that "the slow drawdown of funds to date has reasonable explanations" and that a clear regulatory direction as to TE programs is important.[283] PG&E counters that the Commission should not limit ratepayer funding to a last resort, but rather target it to fill gaps in programs.[284] Additionally, Auto Innovators argues for flexibility to adjust funding levels.[285]

Several parties find the proposed budget level reasonable, ChargePoint, CSE and GPI support the $1 billion budget.[286] CSE acknowledges that private sector funding is increasing but asserts that the maturity of the TE market is still at a point where significant public funding is necessary for California to reach its ambitious TE goals. Additionally, both ChargePoint and CSE call for a mechanism to review and adjust the budget and program design.[287]

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[281] CLECA Comments on Staff Proposal at 2; EPUC Comments on Staff Proposal at 3; UCAN Comments on Staff Proposal at 5.

[282] CLECA Comments on Staff Proposal at 3; EPUC Comments on Staff Proposal at 3.

[283] Joint Commenters Comments on Staff Proposal at 4; ChargePoint Comments on Staff Proposal at 3.

[284] PG&E Comments on Staff Proposal at 4.

[285] Auto Innovators Opening Comments on Staff Proposal at 17.

[286] ChargePoint Comments on Staff Proposal at 8; CSE Comments on Staff Proposal at 2; GPI Comments on Staff Proposal at 5.

[287] ChargePoint Comments on Staff Proposal at 8; CSE Comments on Staff Proposal at 2.

Lastly, a number of parties find the proposed level of funding insufficient. Several parties argue that the $1 billion budget is insufficient to meet the level of needed charging identified in the first CEC AB 2127 Charging Assessment.[288] ATE, SCE, AEE, GPI and Joint Commenters support the ability to increase the budget if a mid-cycle review demonstrates that the $1 billion budget is insufficient to meet the program goals due to decreased outside funding streams or impacts from market and policy developments.[289]

We adopt the proposed $1 billion budget for FC1. We find that this level of funding appropriately balances the benefits of increased access to TE and the costs of continued ratepayer investment. It also takes into account the significant investments in TE infrastructure in the recently approved state budget—more than $10 billion dedicated to ZEVs and ZEV infrastructure over five years. In addition, the federal Infrastructure Investment and Jobs Act of 2021 dedicates almost $383 million in TE infrastructure to California with another $2.5 billion for clean vehicle infrastructure available in competitive grants nationwide. Finally, the federal Inflation Reduction Act provides an additional $1.7 billion in Tax credits for EV chargers and other alternative fuel equipment. The funding structure we adopt provides flexibility to modify the program via the Mid-Cycle Assessment if the market or outside funding levels change in the future.

Of the authorized $1 billion program budget, the IOUs may only access up to 60 percent of the budget within the first three years. During the Mid-Cycle

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[288]SCE Comments on Staff Proposal at 2; EDF Comments on Staff Proposal at 2; Fermata Comments on Staff Proposal at 10.

[289] ATE Comments on Staff Proposal at 5; GPI Comments on Staff Proposal at 2; AEE Comments on Staff Proposal at 13; SCE Comments on Staff Proposal at 2; Joint Commenters Opening Comments on Staff Proposal at 2.

Assessment, the Commission will assess the progress of the BTM program in meeting its objectives and the need for continued ratepayer support for BTM infrastructure given available resources, especially in view of the primary role of ratepayers to fund utility-side infrastructure upgrades. The Commission may modify or terminate the program if ratepayers are unduly burdened. This provides flexibility to determine if the full $1 billion is reasonable over the five-year period.

In order to accommodate fluctuations in annual spending, such as higher administrative start-up costs in early years and the acceleration of rebate payment as the program progresses, all funding caps are applied towards the total accessible funds. Therefore, the funding caps over the first three years shall be calculated based on their respective percentage of $600 million in initial funding.

4.3.1.2. Portion of Budget Each IOU Contributes

The Staff Proposal requests comment on what portion of the FC1 budget each IOU should contribute. Several parties comment on this issue. GPI supports a proportional contribution based on service territory population.[290] SCE and the Joint Commenters support IOU proportional contributions based on electric sales, as done in other statewide programs.[291] NDC supports a funding contribution level proportional to the amount of internal combustion engine vehicles in an IOU service territory since the purpose of the TE program is to

[290] GPI Comments on Staff Proposal at 6.

[291] SCE Comments on Staff Proposal at 17; Joint Commenters GPI Comments on Staff Proposal at 2.

transition away from these vehicles, consistent with state policy.[292] Auto Innovators support an allocation based on geographic distribution need since the market for EVs is statewide.[293] GPI recommends a review of the allocation based on performance and subsequent changes, if necessary, to optimize the allocation.[294]

We adopt a funding allocation that is based on each IOU's percentage of electric sales for 2024. We find that this methodology is the most efficient and equitable way to determine each IOUs' budget allocation. Each IOU shall file a Tier 2 Advice Letter within 60 days of this decision to establish a one-way sub-account within their existing TE balancing account or a separate one-way balancing account. Each sub-account or balancing account shall be capped based on the approved FC1 budget and the percentage of electric sales for the IOU in 2024.

4.3.1.3. Funding Amount Dispersed in Each IOU Territory

The Staff Proposal requests comment on whether the funding dispersed in each IOU territory be limited to each IOU's funding contribution to the program. SCE opposes such limitations and asserts that funding should be dispersed on a first-come, first-served basis as managed by the Administrator.[295] Several parties support limiting the funding to each IOU's service territory, arguing that it

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[292] NDC Comments on Staff Proposal at 6.

[293] Auto Innovators Comments on Staff Proposal at 17.

[294] GPI Comments on Staff Proposal at 6; NDC Comments on Staff Proposal at 6.

[295] SCE Comments on Staff Proposal at 17.

unreasonable and inequitable for ratepayer of one IOU to subsidize ratepayers in a different IOU.[296]

We find that funding dispersed in each IOU territory must be limited to each IOU's funding contribution to the FC1 Program. Allowing ratepayers of one IOU to fund another IOU's customers' participation in this program would unjustly and unreasonably raise rates without commensurate benefits.

4.3.1.4. Annual Funding Cap

The Staff Proposal requests comment on whether the Commission should place an annual cap on program funding. The Staff Proposal also requests that parties that support an annual cap comment as to: (1) how the unspent funds in each period should be treated and (2) what should happen if the annual funds are fully committed before the end of the annual funding period.

Numerous parties indicate that there should be no annual cap. Several parties assert that an annual cap could lead to frustration and confusion regarding funding availability, waitlists, and stop/start cycles.[297] Other parties emphasize that the budget should be flexible in case annual spends are uneven and levels of spending beyond a cap could increase program impact.[298] Several parties also support an annual cost cap, arguing it will ensure ratepayers are not unduly burdened with unnecessary costs and provide stability on rate

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[296] Cal Advocates Comments on Staff Proposal at 9; ATE Comments on Staff Proposal at 5; NDC Comments on Staff Proposal at 7.

[297] ChargePoint Comments on Staff Proposal at 5, 8; CEDMC Comments on Staff Proposal at 3; EDF Reply Comments on Staff Proposal at 3, 10; AEE Comments on Staff Proposal at 5, 13; ATE Comments on Staff Proposal at 5.

[298] ChargePoint Comments on Staff Proposal at 3, 5, 8; The Council Comments on Staff Proposal at 3; EDF Reply Comments on Staff Proposal at 3, 10; CSE Comments on Staff Proposal at 2.

increases.[299] Cal Advocates asserts that a cost cap will maintain rebate availability for lower income participants, who may be more likely to be later adopters.[300]

We do not adopt an annual cap on program funding. We find that the imposition of an annual cap would impede overall program effectiveness and that continual access to authorized program funding will lead to better IOU customer experience, consistent infrastructure investment and deployment and overall program administration. The Mid-Cycle Assessment shall determine if additional funds are necessary beyond the initial three years and whether other changes, such as annual caps, are necessary.

4.3.1.5. Administrative Costs Cap

As stated in the Staff Proposal, the goal of a statewide third-party implemented program is to minimize administrative costs and complexity, reduce the number of administrators customers must consider, create consistency across the state, and maximize customer and technology provider participation. To ensure the FC1 Program is able to minimize administrative costs, the Staff Proposal requests comment on the appropriateness of an eight percent cap for program administration.

CSE supports the eight percent cap for program administration as consistent with other statewide incentive programs.[301] GPI supports the eight percent cap but cautions that the Commission should clarify that programs

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[299] TURN Opening Comments on Staff Proposal at 8; NDC Opening Comments on Staff Proposal at 7.

[300] Cal Advocates Opening Comments on Staff Proposal at 10.

[301] CSE Opening Comments on Staff Proposal at 3.

costs are not automatically approved and must be justified.[302] TURN asserts that the administration cost budget is excessive absent additional context and detail and that responses to request for proposals (RFPs) should address exact amounts.[303] NDC finds that the program administration cap is too high given the large budget for FC1 and the relative simplicity of program administration.[304]

We find a cap of up to eight percent for administrative costs is reasonable. The eight percent cap on administrative costs shall apply over the total amount authorized for collection (*i.e.*, 60 percent for first three years) to allow for flexibility in program administration. The eight percent cap includes both IOU and Program Administrator administrative expenses, which is consistent with our approach in prior programs that similarly rely on program administrators, including the Self-Generation Incentive Program and the Solar on Multifamily Affordable Housing program. The IOUs and the Program Administrator shall determine the proper allocation of funding between the entities. We expect IOU costs to be minimal as they are responsible for RFP issuance, contract management, program reporting, limited data management, and evaluation. The Commission shall reassess the eight percent administrative funding cap in the Mid-Cycle Assessment to determine if adjustments are necessary.

Additionally, we find it is appropriate to audit the Program Administrator to confirm that spent administrative funds do not exceed the cap. This audit or review shall occur prior to the Mid-Cycle Assessment and be conducted by the Commission's Utility Audit, Risk, and Compliance Division. ED staff, in

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[302] GPI Opening Comments on Staff Proposal at 7.

[303] TURN Opening Comments on Staff Proposal at 9.

[304] NDC Opening Comments on Staff Proposal at 8.

consultation with the Commission's Utility Audit, Risk, and Compliance Division, may request additional audits or broaden the scope of the audit.

4.3.1.6. ME&O and Technical Assistance Services Funding Cap

The Staff Proposal requests comment on the appropriateness of the six percent aggregate cap for ME&O and TE advisory services, or TA.

Several parties find the ME&O and TA caps too low. PG&E claims that ME&O costs will be immense, especially for hard-to-reach and underserved communities and that the ME&O budget should be higher due to need for initial brand-building and multiple marketing strategies.[305] SCE and Fermata advocate for expansion of the TA program funding, while the Joint Commenters recommend disaggregating the ME&O and TA budgets.[306] GPI and NDC advocate for a ten percent cap for ME&O due to concerns about low utilization rates for chargers as well as difficulty reaching low-income, minority, and other underserved communities.[307] CSE recognizes that the six percent cap for ME&O and TA budget caps are somewhat higher than for other programs but asserts that the allocations are reasonable.[308]

We find merit in the arguments that the budget for both ME&O and TA should be higher, especially to ensure adequate outreach and engagement with and participation from hard-to-reach and underserved communities. Therefore,

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[305] PG&E Opening Comments on Staff Proposal at 3.

[306] SCE Opening Comments on Staff Proposal at 10; Fermata Opening Comments on Staff Proposal at 11; Joint Commenters Opening Comments on Staff Proposal at 2.

[307] GPI Opening Comments on Staff Proposal at 7; NDC Opening Comments on Staff Proposal at 8.

[308] CSE Opening Comments on Staff Proposal at 3.

we find that ME&O and TA shall each have a budget of up to six percent of the total budget. We shall evaluate these caps in the Mid-Cycle Assessment to determine if adjustments are necessary and if the minimum expenditure requirement for underserved communities, described in Section 4.3.4.1 below, is being met.

4.3.1.7. Program Evaluation

The Staff Proposal recommends a program evaluation budget of two percent of the FC1 program budget, to be split between ED and the IOUs. In addition, it proposes $3 million for ED staff to manage.

Several parties' comments address the funding proposal. NDC argues for one percent and supports $3 million for ED evaluation budget, arguing that this figure is consistent with authorized evaluation budgets in recent Commission decisions on SDGE's Power Your Drive 2 and SCE's Charge Ready 2.[309] SCE posits that the proposed data collection and program evaluation funding may be excessive because it is difficult to evaluate the full amount allocated to evaluation without additional context regarding need, objectives, and potential duplication of efforts.[310] PG&E contends that additional detail and justification is needed for the allocation to ED for management. PG&E requests clarification as to what additional evaluation needs ED anticipates and if it is appropriate for funding to be collected through the FC1 program.[311]

Due to the potential for changes to the rebate program during the Mid-Cycle Assessment and to ensure adequate technical support is available for

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[309] NDC Opening Comments on 2022 TE Staff Proposal at 23.

[310] SCE Opening Comments on Staff Proposal at 23.

[311] PG&E Opening Comments on Staff Proposal at A8.

ED staff up to and throughout FC1, we adopt a slightly modified evaluation budget structure consisting of two separate budgets: (1) IOU managed and (2) ED managed.

For the IOU-managed evaluation budget, we allocate $3 million for the first three years of the funding cycle and up to $5 million for the full five years of FC1. The scope of the IOUs' evaluation funding includes: (1) a third-party evaluation of the FC1 program and (2) development and maintenance of program progress reporting and analytical tools under the guidance of ED staff based on findings from the Data Assessment. The third-party evaluation should include, but not be limited to, a general evaluation of cost and progress toward program goals, program process evaluation, and equity and location-specific implementation.

For the ED-managed evaluation budget, we adopt an annual expenditure limit of $3 million from 2023 through 2029 for technical consulting and support funding, totaling $21 million. ED staff may carry forward the funds from year to year. The Commission's Executive Director will approve the expenditures and seek reimbursement from PG&E, SCE, and SDG&E. Reimbursement will be sought from these three IOUs on a proportional basis in relationship to their annual retail sales as reported at inception of the contract.

This budget amount is necessary because the level of program reporting requirements and analysis necessary to assess TE program progress, will require technical consultant support. The funding for the ED-managed evaluation budget will be sought pursuant to the California Legislature's Annual Budget Act, which gives the Commission certain specific and limited ongoing

reimbursable expenditure authority.[312] Prior to exercising such authority, the Commission must issue a decision that identifies the contracting activities that will be undertaken and the costs subject to reimbursement by IOUs.[313] This decision serves that purpose.

ED staff anticipate technical support and consulting on tasks including, but not limited to:

1. Program reporting assessment, analysis, and recommendations for process improvement: This task includes supporting ED staff on the Data Assessment filing, discussed below, and developing recommendations to streamline existing reporting processes and create new ones. This task could also include development of reporting templates, processes, and ongoing reporting management.
2. Reporting quality assurance/control (QA/QC) and analytical support: This task includes performing QA/QC analysis of ongoing reporting and troubleshooting reporting issues with the IOUs as well as performing ad hoc analyses of reported accomplishments based on ED staff direction to inform decision making.
3. Electrification planning: This task includes identifying, analyzing, and developing recommendations to inform TE inputs, assumptions, and analytical frameworks for the various planning processes, including but not limited to IRP, Distribution Resource Planning, GRCs, and IEPR demand forecast, as well as expert support and necessary facilitation of stakeholder processes to develop and vet inputs and assumptions needed for infrastructure planning.

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[312] *See* Budget Act of 2010, Stats. 2010, Ch. 712, Item 8660-001-0462(6).

[313] *See* D.18-02-018 at 147.

4. FC1/Mid-Cycle Assessment/FC2 recommendations: This task includes identifying research needs and carrying out necessary research to inform recommendations for FC1, the Mid-Cycle Assessment, and subsequent guidance for any FC2 funding, including but not limited to market assessment studies, assessment of VGI activities and practices, and additional program evaluations.

ED staff in collaboration with the IOUs and stakeholders should develop and maintain a Research and Evaluation Plan to document the Commission's and the IOUs' research priorities. ED staff should serve the initial Research and Evaluation Plan on the service list of this or a successor proceeding no later than 180 days after executing the contract.

4.3.1.8. Potential Need for Additional Funding in FC1

The Staff Proposal requests comment on how to address a potential need for additional funding in FC1.

Several parties assert that any concern for funding gaps is unwarranted. TURN argues that any gaps in IOU program offerings likely indicate a robust market that has sufficient public and private funding to function independently.[314] EPUC and NDC stresses that any additional funds beyond existing program funds should be covered by private industry, not ratepayers, and the exhaustion of program funds signals a fulfillment of ratepayer obligation to TE efforts.[315]

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[314] TURN Opening Comments on Staff Proposal at 9.

[315] EPUC Opening Comments at Opening Comments on Staff Proposal at 5; NDC Opening Comments on Staff Proposal at 9.

SCE suggests a process where IOUs submit a joint Tier 2 Advice Letter or an expedited Tier 3 Advice Letter to request any funding or program revisions needing during FC1.[316] Cal Advocates opposes any Advice Letter process for increasing funds, arguing that a full review in a rate setting rulemaking proceeding is necessary prior to any funding increases.[317] ATE proposes an evaluation of funding in the FC1 mid-cycle evaluation and allow IOUs to apply for additional funding at any point during the FC1 if need is demonstrated.[318] ChargePoint and CSE support a process for fund reallocation, with lower amounts via an Advice Letter process and over 25 percent via an application or petition for modification.[319]

We do not adopt any process to authorize additional funds for FC1. We agree with TURN and NDC that any gaps would indicate a robust market. Furthermore, the IOUs can submit applications to request additional funding if needed, which would provide the appropriate setting to evaluate the request and impact on ratepayers.

4.3.1.9. Ownership of BTM Equipment

The IOUs currently have programs that offer varying degrees of infrastructure ownership. For example, all of the IOUs' LD programs allow the IOU to own up to 100 percent of the BTM make-ready infrastructure, but some also allow IOU ownership of the EVSE for certain customer segments.

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[316] SCE Opening Comments on Staff Proposal at 4.

[317] Cal Advocates Opening Comments on Staff Proposal at 7.

[318] ATE Opening Comments on Staff Proposal at 6.

[319] ChargePoint Opening Comments on Staff Proposal at 8; CSE Opening Comments on Staff Proposal at 2.

Several parties support the move away from IOU ownership of BTM TE charging infrastructure. TURN identifies the move away from unnecessary, costly, and risky utility ownership of BTM charging infrastructure assets toward a rebate structure as "the most important ratepayer protection provided in the proposal."[320] TURN also asserts that utility ownership of customer-side assets only benefits utility shareholders.[321] UCAN reiterates its argument that utility ownership of EVSE stifles competition, is not a cost-effective approach to attain California's goals and that third-party investment and a rebate structure is a more cost-effective option for ratepayers.[322]

Cal Advocates also supports transition away from IOU ownership of BTM infrastructure, noting that IOU ownership of BTM charging infrastructure "unnecessarily increases rates to all ratepayers, which disproportionally hurts low-income communities because electric rate funded programs are inherently regressive."[323] Cal Advocates emphasizes that using concerns regarding underserved communities to argue for utility ownership is misplaced because of programs like the CEC's proposed $300 million program for Equitable At-Home Charging is a better way to address that concern. Cal Advocates also disputes the survey data cited by the Joint Commenters, arguing that "IOU ownership of BTM should not be approved without random surveys to obtain charging

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[320] TURN Opening Comments on Staff Proposal at 1.

[321] *Ibid.*

[322] UCAN Opening Comments on Staff Proposal at 1.

[323] Cal Advocates Opening Comments on Staff Proposal at 8.

behavior data from EV adopters and potential behavior from those who have not yet adopted EVs."[324]

EVgo supports the move away from IOU ownership, emphasizing that there are many other ways to ensure equitable EVSE deployments, overcome market barriers, and maximize program flexibility, other than IOU ownership.[325] EVgo cites to CEC's CALeVIP programs as an example.[326]

Several parties disagree with the move away from IOU ownership of BTM infrastructure or indicate that the FC1 program should adopt a more flexible ownership model. AEE argues a categorical exclusion of IOU ownership is premature because barriers to EVSE deployment will persist in many areas, including MUDs, if IOUs ownership is not an option.[327] EDF urges the Commission to consider preservation of IOU ownership of charging stations as an option, contending that small businesses or other customers may experience more difficulty transitioning to ZEVs.[328]

ATE opposes the complete elimination of IOU ownership for BTM, indicating that even with rebates, there will be situations where private third parties do not come forward to build needed infrastructure, especially in underserved or rural areas.[329] The Joint Parties oppose the change as well contending that "[p]rohibiting participants from choosing their preferred

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[324] *Id.* at 7.

[325] EVgo Reply Comments on Staff Proposal at 4.

[326] *Ibid.*

[327] AEE Opening Comments on Staff Proposal at 10.

[328] EDF Opening Comments on Staff Proposal at 7.

[329] ATE Opening Comments on Staff Proposal at 14.

ownership option . . . could have undesirable consequences for underserved markets."[330]

We find it appropriate to eliminate all IOU ownership of BTM infrastructure beginning with FC1. Such a shift in the ownership paradigm allows for technology and construction flexibility, while reducing the cost burden that capitalized IOU expenditures impose on ratepayers.

While we acknowledge the concerns regarding the potential need for flexibility to support low-income, DAC, and small business customers for whom the rebate model may be challenging, we believe there are other ways in which the program can help address these needs while still maintaining the rebate model. Through the Program Handbook development process, the Program Administrator shall provide an option for an up-front rebate. Through the Program Handbook development process, the Commission and stakeholders should additionally explore the feasibility of the following options:

1. Providing bridge loans or any other assistance to mitigate the up-front cost barrier for certain targeted customers beyond solely up-front rebates;
2. Leveraging TA to support small business and underserved community customers, with support for customers establishing their own ongoing maintenance and operations plans/contracts;
3. Exploring public-private partnerships that could help ease the burden of ongoing maintenance and operations of charging stations; and
4. Providing higher levels of rebates for small fleets and businesses, as detailed later in this decision.

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[330] Joint Parties Opening Comments on Staff Proposal at 4.

4.3.1.10. Capitalization of BTM Funds

Past TE programs have allowed limited capitalization of BTM equipment costs. However, the Staff Proposal moves away from this approach and proposes eliminating the option for the IOUs to capitalize any BTM equipment costs.

In response, SCE proposes that the Commission still allow capitalization of the statewide BTM rebate program costs, indicating that such treatment would help facilitate the acceleration of TE by distributing incurred costs over a longer period of time and minimizing near-term rate spikes.[331] SCE also claims that capitalization would better align the recovery of costs with the long-term benefits provided by the statewide BTM rebate program.[332] Fermata, PG&E, GPI, and ATE support SCE's capitalization proposal.[333]

TURN opposes the capitalization of the BTM rebate costs, arguing that capitalizing costs is significantly more expensive over time and is a primary reason for current high rates.[334] TURN also indicates that there are other tools to ensure that DACs and low-income customers can access electrification.[335] EPUC and NDC also oppose the capitalization proposal.[336]

We do not adopt the proposal from SCE to capitalize BTM rebate costs. While expense treatment of the BTM rebate costs may result in somewhat higher

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[331] SCE Opening Comments on Staff Proposal at 4-5.

[332] *Id.* at 5.

[333] ATE Opening Comments on Staff Proposal at 15; Fermata Reply Comments on Staff Proposal at 9; GPI Reply Comments on Staff Proposal at 3; PG&E Reply Opening Comments on Staff Proposal at 2.

[334] TURN Opening Comments on Staff Proposal at 4.

[335] TURN Reply Comments on Staff Proposal at 4-6.

[336] EPUC Reply Opening Comments on Staff Proposal at 4; NDC Reply Comments on Staff Proposal at 4.

upfront costs, we agree with TURN that capitalizing these costs will be significantly more expensive for ratepayers over time. This approach is consistent with recent decisions and with our directives in those decisions to limit the amount of utility ownership of BTM infrastructure and thus capitalization of those assets. One of the main objectives of the funding cycle proposal and the FC1 structure is to reduce total costs to ratepayers. Allowing the capitalization of BTM infrastructure costs runs counter to this objective because it unnecessarily adds costs for ratepayers. The Mid-Cycle Assessment shall provide an opportunity to examine, and if needed modify, the program.

4.3.1.11. Use of General Fund

Several parties urge the Commission to consider use of the General Fund for the Program.[337] SCE, SDG&E and Cal Advocates indicate that if the legislature allocated a portion of state's general fund to support the statewide BTM rebate, it would be reasonable for the CEC or CARB to administer those funds.[338] AEE contends that it would be more appropriate to fund a statewide EVSE rebate program, but cites uncertainty as to the sufficiency of funding amounts without a clear understanding of potential EVSE incentive levels.[339]

Greater reliance on general fund revenues can reduce pressure on ratepayers, but we cannot adopt any allocation of general funds for the FC1 program budget as such an allocation is outside of the Commission's authority.

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[337] SDG&E Opening Comments on Staff Proposal at 5, 8; Cal Advocates Opening Comments on Staff Proposal at 6, PG&E Opening Comments on Staff Proposal at 1; CLECA Opening Comments on Staff Proposal at 5.

[338] SDG&E Opening Comments on Staff Proposal at 8; Cal Advocates Opening Comments on Staff Proposal at 4; SCE Opening Comments on Staff Proposal at 7.

[339] AEE Opening Comments on Staff Proposal at 4.

We note that this decision takes into account the significant amount of state funding for TE. However, we encourage the consideration of alternatives to ratepayer funding for IOU led EV charging infrastructure programs to reduce the burden on ratepayers.

4.3.1.12. Securitization

SCE and PG&E propose that if costs cannot be capitalized that the Commission should authorize the IOUs to securitize those costs.[340] SCE argues that it would allow costs to go into rates at a significantly lower amount compared to traditional operations and maintenance. TURN contests SCE's and PG&E's securitization proposal, arguing that while the initial rate impact would be reduced, securitization would result in ratepayers paying more over time due the costs of the transaction and the interest paid.[341]

We decline to adopt the proposal to securitize costs. We agree with TURN that securitization would increase ratepayer costs more over time and therefore is not warranted at this time.

4.3.1.13. New Construction

The Staff Proposal recommends phasing out ratepayer support for new construction programs starting in 2025, as other funding sources or requirements—particularly state budget investments and CALGreen building requirements—will be available to support this area. We resolve this issue in Section 3.8.2. above.

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[340] SCE Opening Comments on Staff Proposal at 6; PG&E Reply Comments on Staff Proposal at 2.

[341] TURN Reply Comments on Staff Proposal at 5-6.

4.3.2. FC1 Rebates

The Staff Proposal suggests fixed rebate amounts that are revisited periodically and allow for increased rebates for targeted underserved community customers.

Parties expressed various opinions regarding a rebate program. Cal Advocates recommends a declining rebate program.[342] Electrify America argues that a rebate limit may create bias against certain types of chargers and AEE recommends the program have safeguards in place to consider capacity of the chargers, among other considerations.[343] Nuvve proposes a rebate based on fixed percentage of costs.[344] In contrast, PG&E, EDF, and GPI support alternatives to a rebate program such as on-bill financing.[345]

We find that the rebate program provides a suitable solution to accelerating TE infrastructure development. The rebate amount may be fixed for the duration of FC1, assessed via the roundtables, and reevaluated mid-cycle. Rebates may also vary according to certain parameters. A stakeholder process led by the Program Administrator should set the rebate levels.

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[342] Cal Advocates Opening Comments on Staff Proposal at 11.

[343] Electrify America Opening Comments on Staff Proposal at 11; AEE Opening Comments on TE Staff Proposal at 14.

[344] Nuvve Opening Comments to Staff Proposal at 3.

[345] PG&E Opening Comments to Staff Proposal at A5; EDF Reply Comments to Staff Proposal at 10; GPI Reply Comments to Staff Proposal at 1-2.

4.3.2.1. Fixed, Variable, and Declining Block Rebates

The Staff Proposal requests stakeholder comment on whether rebates should decline in blocks based on deployment instead of being fixed for the duration of FC1.

Auto Innovators opposes declining block rebates, contending that the technology and market conditions relevant to the Million Solar Roofs program do not translate to deployment of EV charging infrastructure.[346] ChargePoint also does not support declining block rebates in FC1 because: (1) demand in the EV charging infrastructure market is below desired levels, (2) customers' response to new EV infrastructure rules is unknown, (3) the costs of BTM make-ready infrastructure are unlikely to decline regardless of demand and (4) declining block rebates place an undue emphasis on costs.[347] AEE does not support use of declining block rebates because it claims that EVSE deployment costs are not expected to decrease.[348]

EDF supports declining block rebates, asserting that programs that use such a structure "generally install more capacity, have greater incentive longevity, and provide more market certainty as compared to programs that have a fixed incentive rate."[349] TURN also argues for declining block rebates that decline based on the deployment in each market segment over the course of the

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[346] Auto Innovators Opening Comments on Staff Proposal at 18.

[347] ChargePoint Opening Comments on Staff Proposal at 10.

[348] AEE Opening Comments on Staff Proposal at 6.

[349] EDF Reply Comments on Staff Proposal at 3.

five-year period due to the rapid development in marketplace.[350] TURN indicates that declining block rebate structure for charging infrastructure is not based on expected cost declines in the underlying technology, but on the market's ability to shoulder an increasing amount of costs over time as the FC1 program develops and TE markets mature.[351] TURN emphasizes that the goal of the program should be to "ramp down customer-side ratepayer funded rebates to zero as quickly as possible, not to provide indefinite subsidies for the markets."[352]

NDC supports declining block rebates and emphasizes that any declines should occur on a predetermined schedule to provide simplicity and important market data.[353] Cal Advocates indicates that declining block rates are a reasonable approach and recommends a survey of a representative sample of potential participants to assess their willingness to pay for the equipment.[354] Tesla asserts that any timelines for adjusting rebate levels may need to vary by vehicle segments depending on scale and speed of adoption.[355]

We decline to adopt a declining block structure. We agree that the technology and market conditions that inspired declining incentives for the solar market do not translate to deployment of EV charging infrastructure. It is uncertain at this time that the costs of BTM infrastructure will decline in the same

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[350] TURN Opening Comments on Staff Proposal at 9.

[351] *Id.* at 10.

[352] *Ibid.*

[353] NDC Opening Comments on Staff Proposal at 5, 11.

[354] Cal Advocates Opening Comments on Staff Proposal at 11.

[355] Tesla Opening Comments on Staff Proposal at 4.

manner as equipment in the solar sector. Furthermore, we can still achieve an overall phasing out of the incentives over time without this approach. If the Mid-Cycle Assessment finds that a declining block structure would be beneficial, given new information available, then we may modify the program.

4.3.2.2. Stacking Rebates

The Staff Proposal requests stakeholder comment on: (1) whether FC1 program participants should be allowed to stack rebates offered by other agencies and/or programs and (2) if rebate stacking is allowed, what conditions should the Commission impose.

Cal Advocates supports the ability to stack rebates, but calls for safeguards, such as a joint website hosted by the Commission and the CEC centralized customer relationship management website, to prevent overspending.[356] AEE also supports rebate stacking and recommends that the Commission identify all potential major sources of complementary program funding to help ensure that rebate stacking does not delay rebate application processing.[357]

Nuvve supports rebate stacking because it may help make an otherwise unattainable project become attainable.[358] GRID asserts that the Commission should allow all necessary project costs to qualify for rebate support provided that the total stacked rebate amount is not greater than the total project cost, including the installation cost.[359] Several parties support stacking, but indicate

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[356] Cal Advocates Opening Comments on Staff Proposal at 12.

[357] AEE Opening Comments on Staff Proposal at 13.

[358] Nuvve Opening Comments on Staff Proposal at 5.

[359] GRID Opening Comments on Staff Proposal at 4.

that the Commission should ensure that the same equipment is not funded twice and that allowed rebates do not exceed costs.[360] ATE recommends a requirement that all rebate recipients certify that all funds received through rebates are used to pay for the proposed infrastructure.

We find it appropriate to allow the stacking of rebates, provided that the total received rebates do not exceed 100 percent of the installation and equipment costs. The ability to stack rebates allows for the installation of a broader and larger amount of TE infrastructure, thereby promoting the California's TE goals. A customer's application must include a full disclosure of costs and other rebates that have been received or that are pending. Any stacking must also comply with the other rebate providers' rules and requirements. Lastly, the Program Administrator shall develop a process within the Program Handbook to confirm the total received rebates do not exceed 100 percent of costs, as well as consider a process to claw back rebate amounts that exceed the limit.

4.3.2.3. Determining Appropriate Rebate Levels

The Staff Proposal requests comment on what is the most important information in determining appropriate rebate levels for FC1.

Both the CEDMC and PG&E recommend against setting rebate levels in this decision. The CEDMC indicates that the Commission should determine only guiding principles and goals at this time, while PG&E states that the details of

[360] ChargePoint Opening Comments on Staff Proposal at 11; Tesla Opening Comments on Staff Proposal at 5; SCE Opening Comments on Staff Proposal at 18; Auto Innovators Opening Comments on Staff Proposal at 19; NDC Opening Comments on Staff Proposal at 11.

the program design and implementation should be determined through a stakeholder process and finalized in future decisions or processes.[361]

EDF recommends the program focus on small businesses and low-income/DAC customers in order to ensure funds are equitably distributed.[362]

The City of Long Beach contends that it is premature to determine whether rebates and the design of rebates should be the sole implementation technique for 2025-29 and that any rebate program should be flexibly designed rather than a one rebate fit all approach.[363]

Tesla presents the following areas of importance: (1) identifying average and median EVSE equipment cost as well as cost reduction patterns; (2) assurance to the EVSE market of some level of longer-term certainty of rebate amounts; and (3) identifying power level of EVSE and what customer segment and vehicle type it is intended to serve.[364] ChargePoint emphasizes the importance of information as to: (1) total customer cost for deployment, operation and maintenance of EVSE; (2) customer's eligibility for other incentive funding or revenue sources such as DR; and (3) segment-specific needs.[365]

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[361] PG&E Opening Comments on Staff Proposal at 4; CEDMC Opening Comments Staff Proposal at 3.

[362] EDF Opening Comments Staff Proposal at 7.

[363] City of Long Beach Opening Comments Staff Proposal at 6.

[364] Tesla Opening Comments Staff Proposal at 3, 5.

[365] ChargePoint Opening Comments Staff Proposal at 9.

Cal Advocates stresses the importance of: (1) status of statewide charger installation compared to policy objectives; (2) availability levels of other program rebates in the state; (3) whether current programs are oversubscribed; and (4) avoiding the use of willingness-to-pay data collected through self-report surveys due to bias and non-representative nature of current participants.[366]

TURN asserts the importance of information on the cost to install infrastructure and charging stations compared with the willingness and ability of private companies, individuals, and the state to absorb those costs rather than ratepayers.[367] NDC argues the Commission should consider: (1) the average per port costs for BTM EVSE deployment; (2) the value of the benefits customers will receive; (3) customer willingness and ability to pay; (4) the existence and amount of other subsidies; (5) the need for financial support and air quality improvement at the customer's location; and (6) fair additional incentives to counter historical inequity.[368]

AEE urges consideration of: (1) the capacity of the EV charger incentivized; (2) the potential for incremental VGI functionality; (3) whether a customer is located in an underserved community; and (4) the expected BTM make-ready costs for different types of customer sites.[369] ATE emphasizes the need for a discussion of the process for developing a single rebate as well as the multiple

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[366] Cal Advocates Opening Comments Staff Proposal at 10.

[367] TURN Opening Comments Staff Proposal at 9.

[368] NDC Opening Comments Staff Proposal at 10.

[369] AEE Opening Comments Staff Proposal at 14.

factors, including traditional costs and ratemaking and policy measures.[370] ATE also supports flexibility to allow for either a single rebate or multiple programs.

Auto Innovators indicates that important information is the potential and actual level of EV adoption in the community to be served and the current level of EVSE deployment by EVSPs.[371] Electrify America asserts the importance of whether a rebate promotes a robust and competitive marketplace, while CSE calls for the use of periodic surveys to assess consumer preferences and behavior to inform the rebate.[372]

We do not find it appropriate to set rebate levels at this time for either the LD or MDHD components of the FC1 program. Determination of the appropriate rebate level would benefit from additional stakeholder input and analysis. However, we do adopt guidelines for setting rebate levels to cover a percentage of project costs via the Program Handbook development process discussed below.

4.3.2.3.1. LD Rebates

For LD infrastructure rebates, the following guidelines shall apply in setting rebate levels:

1. Include higher rebates for certain underserved community customers (*i.e.*, MUDs with a majority low-income residents), as described in this decision;
2. Maintain flexibility, including exploring new ideas in promoting participation of small businesses, as defined in

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[370] ATE Opening Comments Staff Proposal at 7.

[371] Auto Innovators Opening Comments Staff Proposal at 18.

[372] Electrify America Opening Comments Staff Proposal at 7; CSE Opening Comments Staff Proposal at 4.

the Program Handbook, and underserved community customers;

3. Identify an average or median EVSE and make-ready equipment/installation cost as a "base cost" on which to base rebate levels;
4. Consider the ability to leverage customers' and companies' contributions;
5. Vary rebate levels based on power capacity (*i.e.*, Level 2 vs. DCFC);
6. Establish maximum percentage of costs to be covered by the rebate, with higher maximums for certain targeted underserved community customers (*i.e.*, MUDs with a majority low-income residents);
7. Establish a maximum project cost, if applicable;
8. Consider the overall program average per port cost;
9. Consider other programs' rebate levels, such as CALeVIP and others, and align with other publicly funded rebates to prevent the stacking of rebates to a level above 100 percent of costs;
10. Consider customers' eligibility for other incentives;
11. Differentiate between customer segments (*e.g.*, MUDs and public MUD-serving locations) where appropriate; and
12. Avoid any BTM TE rebates for Fortune 1000 companies.

Stakeholders should discuss LD rebate levels during a workshop in the Program Handbook development process. Prior to the workshop, the IOUs shall distribute data on incentive levels for past and current IOU TE programs to the service list of this or any successor proceeding. The workshop report addressed below shall reflect the discussion. The workshop should include a presentation of data from FC0 to inform the development of rebate levels. The Program Handbook development process should establish upfront rebates for targeted underserved community customers and design this rebate approach to

reduce customer costs and protect ratepayer investments. The Program Handbook should establish procedures and penalties for non-compliance with the Program Handbook requirements.

Any necessary rebate level adjustments shall occur though the annual roundtable and corresponding Tier 2 Advice Letter process. This includes any specialized rebates/rebate approaches for targeted underserved community customers.

4.3.2.3.2. MDHD Rebates

For MDHD infrastructure rebates, the following guidelines shall apply in setting rebate levels:

1. Higher rebates for customers in DACs and primarily operating in DACs;
2. Creativity in addressing the needs of small fleet customers, potentially providing higher rebates;
3. Consideration of customer's eligibility for other incentive funding;
4. Differentiation between customer segments where appropriate;
5. Ability to leverage customer and private company contributions;
6. Vary rebate levels based on power capacity (*i.e.*, Level 2 vs. DCFC);
7. Consideration of minimum power level thresholds;
8. Consideration of average per port cost;
9. Alignment with other public funded rebates to avoid over-subsidization by ratepayers;
10. Establishment of a maximum percentage of costs to be covered by the rebate, including additional incentives for DAC customers;

11. Identify an average or median EVSE and make-ready equipment/installation cost as a "base cost" on which to base rebate levels, if appropriate;
12. Exclusion of Fortune 1000 companies from receiving rebates; and
13. Establishment of a maximum project cost, if applicable. Stakeholders should also discuss MDHD rebate levels during a workshop during the Program Handbook development process. Any necessary rebate level adjustments shall occur through the annual roundtable and Tier 2 Advice Letter process.

4.3.2.4. Reevaluating Rebate Levels During FC1

The Staff Proposal requests comments concerning whether to fix FC1 rebate levels for the program's five-year term or whether to periodically reevaluate rebate levels.

CSE cautions against fixing rebate levels for the entire five-year period, indicating that setting rebate level too high or too low could result in funding being exhausted too early or not at all. CSE supports reevaluating rebate levels during the Mid-Cycle Assessment.[373] ATE, ChargePoint, and Auto Innovators also do not support fixing the rebate levels for the entire program term and support reevaluating the rebate levels and adjusting, if necessary, during the Mid-Cycle Assessment.[374] Cal Advocates recommends reevaluating the rebate levels annually, while Weave Grid calls for flexible rebate levels.[375]

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[373] CSE Opening Comments on Staff Proposal at 5.

[374] ChargePoint Opening Comments on Staff Proposal at 9; ATE Opening Comments on Staff Proposal at 8; Auto Innovators Opening Comments on Staff Proposal at 18.

[375] Cal Advocates Opening Comments on Staff Proposal at 12; Weave Grid Opening Comments on Staff Proposal at 6.

We find that allowing rebate levels to change annually would provide program flexibility and account for changing market conditions. A yearly assessment of the appropriate rebate level shall occur via the annual roundtables adopted in this decision. Any modification to the rebate level or structure shall occur through the associated Tier 2 Advice Letter process.

4.3.3. FC1 Technical Assistance

4.3.3.1. IOU Administration

The Staff Proposal recommends only one entity be the administrator of each program component, with third-party administrators overseeing the rebate and ME&O components and the IOUs maintaining administration of the technical assistance (TA) portion. The Staff Proposal reasons that providing TA to customers, especially fleets, that are electrifying is a core utility role that the IOUs already perform in some form. The Staff Proposal requests comment on whether the IOUs should directly manage the TA programs, as proposed, or whether the Commission should adopt some other administrative structure.

A number of parties support IOU, rather than third-party, management of the TA programs, asserting that TA is a core utility role that the IOUs are in the best position to manage.[376] Auto Innovators specifies that IOUs should manage aspects of the TA programs that relate to interconnection, billing, rates, and utility-managed charging and DR programs.[377] Several parties also state that TA

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[376] ChargePoint Opening Comments on Staff Proposal at 11; SDG&E Opening Comments on Staff Proposal at 10; PG&E Opening Comments on Staff Proposal at 6, 13; SCE Opening Comments on Staff Proposal at 19; ATE Opening Comments on Staff Proposal at 8.

[377] Auto Innovators Opening Comments Staff Proposal at 19.

should be available to customers who do not participate in rebate program.[378] ChargePoint emphasizes that IOUs providing TA should be held to a strict standard of technology and product neutrality to ensure competitive markets and customer choice.[379]

Several parties comment that it would be appropriate for EVSPs to have a role in TE along with IOUs, indicating that EVSPs could complement the IOU and Program Administrator functions.[380] EDF and ChargePoint contend that DR program administrators and third-party DER providers can also assist with TA due to their technical expertise.[381] The Joint CCAs assert that CCAs should also be involved in TA, indicating that in many cases, CCAs are already effectively providing TA in support of existing CCA TE programs and filling a gap in the IOUs' TE programs.[382] The Joint CCAs also argue that designating the IOUs as the exclusive TA administrator for FC1 incentives may raise anti-competitive concerns and may limit TA services available to some customers due to the constraints on IOU discussion of CCA rates and services with customers.[383]

We find it appropriate for the IOUs to maintain administration of TA. The IOUs are best positioned to administer the current scope of the program, and TA is part of their core role. We do not find merit in the Joint CCAs' argument that IOU administration of TA would raise anti-competitive issues because

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[378] ChargePoint Opening Comments Staff Proposal at 12; PG&E Opening Comments on Staff Proposal at 13; SDG&E Opening Comments on Staff Proposal at 2.

[379] ChargePoint Opening Comments on Staff Proposal at 11.

[380] *Id.* at 12; NDC Opening Comments on Staff Proposal at 13.

[381] ChargePoint Opening Comments on Staff Proposal at 12.

[382] Joint CCAs Opening Comments on Staff Proposal at 10.

[383] *Id.* at 11.

TA functions involve helping customers with rates. D.12-12-036 indicates that IOU administration of TA would not violate the Code of Conduct for CCAs. That decision includes an exception to marketing limitations for communications that are part of a Commission-authorized program.[384] The FC1 TA program clearly falls under the exception because it is a specific program authorized by the Commission. However, the IOUs should coordinate with the CCAs on TA and CCA-specific offerings for their customers (*e.g.*, DR programs).

Additionally, we find that the Joint CCAs have not sufficiently demonstrated the benefits of CCA administration of TA, especially in light of the potential for customer confusion. One of the key objectives of TA is to create an easy-to-understand process for customers seeking to electrify their transportation by providing a single point of contact for the customers through the process of choosing between types of chargers, planning for load management, selecting rates, and energization. While all CCA customers receive distribution service through an IOU, not all IOU customers are also CCA customers. As such, a split CCA- and IOU-administered TA structure would cause confusion for customers when determining with whom they should work. Moreover, it is unclear whether the Commission could award TA funding to individual CCAs without putting the contract out for competitive bid, thus making it possible that TA would be administered by another entity entirely, not the CCAs.

However, we do recognize that that CCAs may be best suited to speak to their customers about their rate structures. Therefore, in the Program Handbook development process, and a workshop discussed below, the IOUs and

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[384] D.12-12-036 at A1-1 (Code of Conduct and Expedited Complaint Procedure).

stakeholders shall discuss and determine appropriate clear and defined channels of communication between the IOUs' TA efforts and the CCAs in their service territories. This communication should occur in a manner that minimizes confusion for customers.

Additionally, we agree that TA efforts would benefit from the involvement of EVSPs and automated load management (ALM) and DR providers. The Program Handbook development process should determine a clear method for IOU TA engagement with EVSPs and providers of ALM and DR.

4.3.3.2. TA Program Scope

The Staff Proposal recommends TA services, at a minimum, include: (1) basic technical assistance; (2) planning load management and other VGI considerations; (3) help with choosing rates; (4) and support with walking through the IOU energization and/or interconnection process. The Staff Proposal requests comment on whether this proposed scope of the TA programs is appropriate.

Parties generally agree that the proposed scope is appropriate, but some parties recommend additions to the scope.[385] SBUA recommends targeted outreach to small businesses.[386] PG&E and SCE support the scope, but recommend expansion to include more comprehensive support and advisory services during the planning, installation, and post-deployment stages of

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[385] ATE Opening Comments on Staff Proposal at 8; Auto Innovators Opening Comments on Staff Proposal at 20; GPI Opening Comments on Staff Proposal at 10; AEE Opening Comments on Staff Proposal at 15.

[386] SBUA Opening Comments on Staff Proposal at 19.

customer projects, especially for underserved communities.[387] SCE asserts that any TA scope expansion should include enhanced analytical tools and resources for customers as well as sector-based education.[388]

The Joint CCAs recommend that the scope of TA should expressly target underserved customer segments, and that CCAs have the appropriate resources and expertise to provide it.[389] SCE counters that while some CCAs may have experience providing technical support, the IOUs can provide more comprehensive TA and support smaller and less experienced customers.[390]

We find that the scope of TA services that the Staff Proposal recommends is appropriate, but make several additions based on party comments. TA services shall include, at minimum: (1) basic technical assistance; (2) planning load management and other VGI considerations; (3) help with choosing rates; (4) support with walking through the IOU energization and interconnection process; (5) support and advisory services during planning, installation, and post-deployment; (6) operations post-deployment, like route optimization, load management, and future fleet electrification; and (7) available ALM and DER options to lower deployment costs. In providing TA, the IOUs must adhere to a strict standard of technology and product neutrality to avoid interfering with competitive markets and ensure customer choice. Additionally, TA should be

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[387] PG&E Opening Comments on Staff Proposal at 14; SCE Opening Comments on Staff Proposal at 9.

[388] SCE Opening Comments on Staff Proposal at 10, 19.

[389] Joint CCAs Opening Comments on Staff Proposal at 15.

[390] SCE Opening Comments on Staff Proposal at 3-5.

available to all IOU customers, including FC0, FC1, and non-program participants, as well as bundled and unbundled customers.

Because additional development of TA and its scope is necessary prior to program launch, we direct the IOUs to host a workshop prior to adoption of the Program Handbook, including, but not limited to, the EVSPs, DR providers, environmental justice organizations, fleet customers, small business, and CCA representatives to better build out the scope of TA. This workshop shall inform the Program Handbook development process, which will adopt a final TA scope. We clarify that EVSPs may submit project applications and interface with the IOU and Program Administrator if authorized to do so by the site host. The Program Handbook development process should examine whether to allow other entities to file project applications on behalf of site hosts. The Program Handbook should provide guidance for the applications, including documentation needed to demonstrate site host authorization.

4.3.4. FC1 Marketing, Education & Outreach

4.3.4.1. Administration

The Staff Proposal requests comments on ME&O administration. While no party recommends specific ME&O administration details beyond coordination with CBOs and CCAs, we find it appropriate to take an approach similar to the Solar on Multifamily Affordable Housing program, which puts the onus on the Program Administrator to develop much of the ME&O program administration.[391] The Program Handbook development process should establish

[391] D.17-12-022.

ME&O administration details to allow for additional stakeholder feedback. Therefore, the Program Administrator shall:

1. Develop and manage the ME&O marketing plan;
2. Develop and manage the program's outreach materials and efforts;
3. Develop a detailed budget that describes the ME&O efforts and directs at least 65 percent of ME&O funds towards ME&O for underserved communities;
4. Work with CBOs, tribal communities, and other stakeholders to reach eligible customers, and to develop material and outreach strategies for underserved communities and other equity targets;
5. Develop ME&O data collection strategies; and
6. Develop and implement any additional efforts needed to ensure the success of the FC1 ME&O efforts.

4.3.4.2. Scope

Several parties provide recommendations regarding the scope of ME&O activities. CSE supports targeted and localized ME&O due to different community needs.[392] PG&E recommends the development of an ME&O plan, including a customer engagement strategy, once the statewide rebate program has established goals, objectives, and defined priority communities. PG&E also contends that IOUs are important partners and potential implementers of the statewide rebate program ME&O due their prior experience with other programs.[393] SBUA emphasizes the importance of small business outreach, recommending that IOUs provide targeted, streamlined information on their

[392] CSE Opening Comments on Staff Proposal at 5-6.

[393] PG&E Opening Comments on Staff Proposal at 5.

website and through small-business account representatives.[394] SBUA recommends a structure similar to existing energy efficiency consultations. GPI emphasizes the need for enhanced post-energization ME&O in underserved communities to drive higher EV adoption.[395]

We find that the scope of ME&O work should include targeted outreach to: (1) underserved communities; (2) rural communities; (3) small businesses; and (4) tribal communities; and (5) workforce development, job training and placement, and certification organizations. The Program Administrator should leverage the CEC's SB 1000 assessments to best reach customers throughout the IOUs' service territories, including rural regions. The roundtables and Mid-Cycle Assessment should examine the program's progress in reaching rural regions and addressing gaps in the SB 1000 assessments for the charging areas that this program covers.

The scope of the ME&O component should largely focus on acquiring FC1 customers and education on charging from the grid and load management options. Post-energization ME&O should also be included in the scope. Lastly, we agree that more work is necessary to finalize the ME&O scope; therefore, the Program Administrator should include discussion of the ME&O scope at a workshop within the Program Handbook development process.

The annual roundtables should include check-ins on the scope and progress of ME&O to reach targeted customers, garner program participation, effectively educate on load management, and address equity concerns. Any

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[394] SBUA Opening Comments on Staff Proposal at 18.

[395] GPI Opening Comments on Staff Proposal at 2.

necessary modifications shall occur through the annual roundtable and associated Tier 2 Advice Letter process.

4.3.4.3. Consultation with Community-Based Organizations

The Staff Proposal requests comment on requirements for consultation and/or coordination with CBOs. Several parties call for early CBO involvement. GRID advocates for early-stage, paid consultation with CBOs, indicating their participation is critical to remove locally known obstacles.[396] PG&E also supports incorporating the CBOs into development and implementation so they can leverage their close relationships with customers to provide efficient and effective ME&O.[397] GPI contends that IOUs should be required to consult with the appropriate CBOs at stakeholder meetings during program design and implementation.[398]

Cal Advocates recommends that the Commission require the third-party ME&O administrator to do interviews and a community needs survey in collaboration with CBOs to understand where to target program activities to provide the most benefit to communities.[399] CSE calls for at least 25 percent of the ME&O budget to go to CBOs, indicating that it is consistent with D.21-07-028.[400] EDF also calls for the participation of CBOs, stating they need to be part of the

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[396] GRID Opening Comments on Staff Proposal at 5.

[397] PG&E Opening Comments on Staff Proposal at 6.

[398] GPI Opening Comments on Staff Proposal at 10.

[399] Cal Advocates Opening Comments on Staff Proposal at 13.

[400] CSE Opening Comments on Staff Proposal at 4.

ME&O design and implementation, and the Program Administrator must develop a process to engage the CBOs and integrate their ideas.[401]

GPI also contends that CBOs and CCAs should be able to compete for contracts for post-energization ME&O.[402] NDC stressed the importance of the participation of CBOs in ME&O efforts because they are already integrated into low-income, minority communities and can help design outreach and partner on educational and information events.[403] Auto Innovators emphasizes that CBOs are an effective channel to reach customers.[404] ATE comments that CBOs should be involved in ME&O activities.[405]

We find that CBOs should be a part of the design and implementation of the FC1 program's ME&O component. We agree that their involvement will improve the effectiveness of ME&O efforts due to CBOs' extensive experience working closely with various communities and knowledge of successful outreach practices.

While some of the details of this engagement require further definition through the Program Handbook development process, the IOUs and the Program Administrator should begin engagement with the CBOs immediately after the issuance of this decision. Engagement should, at minimum, involve the following groups: (1) Disadvantaged Community Advisory Group; (2) CBOs that are already integrated into DACs and other underserved communities;

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[401] EDF Opening Comments on Staff Proposal at 8.

[402] GPI Opening Comments on Staff Proposal at 10.

[403] NDC Opening Comments on Staff Proposal at 13-14.

[404] Auto Innovators Opening Comments on Staff Proposal at 20.

[405] ATE Opening Comments on Staff Proposal at 9.

(3) non-English speaking community groups; (4) youth groups; and (5) workforce development, job training and placement, and certification organizations.

Prior to the adoption of the Program Handbook, the IOUs and Program Administrator should host a discussion at one of the workshops to determine how to effectively engage these groups in an ongoing fashion, including within the annual roundtables. Additionally, the other workshops held prior to the adoption of the Program Handbook should include participation from representatives of all the above listed communities and organizations. We require the Program Administrator to reflect their feedback in the Program Handbook workshop report discussed below to ensure their voices are part of the program development/design process. Following the establishment of the Program Handbook, the Program Administrator should develop a list of CBO and Environmental Justice organizations that the IOUs and Program Administrator can engage for future outreach.

Finally, we encourage the selected Program Administrator to subcontract with CBOs for local ME&O activities, which could include subcontracts to administer portions of the ME&O program on a local level. While we encourage this subcontracting, the Program Handbook development process shall determine any required percentage of budget allocated to local ME&O activities. Additionally, the Program Administrator and Program Handbook development process shall determine, at minimum: (1) roles of subcontractors; (2) the geographic reach of subcontractors; and (3) how the subcontractors will ensure consistent implementation of the ME&O program.

4.3.4.4. Role of CCAs in ME&O

Several parties, including Auto Innovators, GPI, GRID, PG&E, and the Joint CCAs, advocate for direct CCA involvement in developing and administering the ME&O component, with a portion of the ME&O budget allocated to CCAs.[406] While EDF supports the involvement of a variety of stakeholders, including CCAs, it expresses concern about a focus on the role of CCAs because not all customers are served by a CCA and that a misplaced reliance on CCAs may result in significant gaps in program ME&O.[407]

We find that the involvement of the CCAs in the design of the ME&O component would provide an important benefit to the program due their expertise working with customers and local communities. The CCAs should participate in the workshops and roundtables.

The Program Administrator may subcontract with CCAs, CBOs and other groups with experience working with local communities for local ME&O activities, including subcontracts to administer portions of the ME&O program on a local level. As with local ME&O subcontracting with CBOs, any required percentage of budget allocated to local ME&O activities should be determined through the Program Handbook development process. If there is agreement, the CCAs and IOUs can co-brand ME&O materials.

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[406] GPI Opening Comments on Staff Proposal at 10; Grid Opening Comments on Staff Proposal at 10; Auto Innovators Opening Comments on Staff Proposal at 22; PG&E Opening Comments on Staff Proposal at A6; Joint CCAs Opening Comments on Staff Proposal at 11.

[407] EDF Opening Comments on Staff Proposal at 7.

4.3.5. FC1 Equity

Since the release of the Draft TEF, the Legislature provided additional direction for TE funding in underserved communities through AB 841.[408] More recently, the Commission adopted requirements for IOU TE programs to increase funding for customers in underserved communities, requiring that up to 50 percent of all investments be in underserved communities.[409]

The Staff Proposal's revised recommendations concerning equity and underserved communities consider parties' comments on the Draft TEF, as well as goals one, two, five, and nine of the Commission's Environmental and Social Justice Action Plan.[410]

This decision prioritizes equity in every aspect of the TE programs it approves. As discussed below, we reserve at least 65 percent of the FC1 budget for underserved communities, along with 65 percent of the ME&O budget. ME&O must include targeted outreach to underserved and rural communities, small businesses, and tribal communities.

We recognize that tribal communities and enrolled members of California Tribes have unique barriers to TE that may require special attention. The Commission is committed to recognizing and respecting the sovereignty of the tribes and encouraging and facilitating their participation in Commission

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[408] Pub. Util. Code Section 740.12 (referencing definition of "underserved communities" in Pub. Util. Code Section 1601).

[409] D.21-07-028; D.21-04-014; D.12-02-027.

[410] Staff Proposal at 18-20.

programs.[411] Tribal communities have reported a lack of current information on TE options, a dearth of charging infrastructure in their communities, and a distrust of government incentive programs.[412]

In sum, the tribal communities are uniquely situated and require creative solutions to achieve meaningful TE adoption. The limitations of the FC1 program may hinder its success in tribal communities. Therefore, we direct the Program Administrator to determine and propose to the Commission a percentage of funding dedicated for tribal communities within the budget established for underserved communities, as part of the Program Handbook development process. The Program Administrator shall consider the unique needs of tribal communities and enrolled members of California Tribes and propose methods to reach these communities effectively, potentially including alternative use cases to provide rebates and higher rebate levels.[413]

We also limit the LD rebates available in FC1 to only MUDs and MUD-serving locations to ensure that these funds are used where they are most needed. Low-income MUDs can qualify for higher LD rebates. Higher rebates are

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[411] California Public Utilities Commission, Tribal Consultation Policy of the California Public Utilities Commission (April 26, 2018), available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M212/K861/212861685.PDF (adopted pursuant to Governor Brown's Executive Order B-10-11, which included direction to state agencies to "permit elected officials and other representatives of tribal governments to provide meaningful input into the development of legislation, regulations, rules, and policies on matters that may affect tribal communities").

[412] CARB, Low-Income Barriers Study, Part B: Overcoming Barriers to Clean Transportation Access for Low-Income Residents at 91 (Feb. 21, 2018), available at: https://ww2.arb.ca.gov/resources/documents/carb-barriers-report-final-guidance-document.

[413] If alternative use cases are permitted for tribal communities or members, those use cases may also be permitted in the Locally Invested Transportation Equity pilot program.

also available for MDHD customers located in DACs because MDHD electrification is a key measure to improve air quality and DACs, in particular, often suffer from poor air quality. The Locally Invested Transportation Equity pilot program discussed below is available only to low-income customers and small fleets located in DACs to ensure that these customers benefit most from this small, targeted fund for innovative TE rebates. Finally, we direct that that contractors in the FC1 program meet certain provisions including paying workers the prevailing wage, developing training standards, and ensuring workforce diversity.

We are specifying several check-ins to ensure the FC1 program achieves the equity objectives. This decision directs that an annual equity roundtable be held where stakeholders evaluate how well the program is meeting its equity goals. At the mid-point of the FC1 program, the Commission shall conduct a Mid-Cycle Assessment that will review and analyze equity considerations, including: (1) progress on spending and participation in targeted communities; (2) whether a fuel card program for low-income customers should be adopted as part of FC1; and (3) data on various equity metrics, including EV adoption by low-income customers.

4.3.5.1. Light-Duty Customer Types Eligible for Higher Rebates

The Staff Proposal includes recommendations to target certain underserved community customers within the LD segment.[414] Specifically, the Staff Proposal recommends higher rebates for the following customer types:

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[414] *Id.* at 19.

MUDs with a majority of "low-income" residents, MUDs located in DACs, and "MUD-serving public locations" that are located in DACs.[415]

In comments, some parties express support for authorizing higher LD rebates for the proposed customer types.[416] However, other parties caution against the proposed customer types. TURN argues for, and GRID supports, focusing on people not places and requiring the majority of the residents at a MUD site to have incomes at or below 80 percent of the area median income (AMI) in order to be eligible for higher rebates.[417] Greenlining agrees with providing additional consideration for the proposed customer types, while stressing the importance of ensuring higher rebates benefit low-income residents

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[415] Pub. Util. Code Section 1601(e) defines an "underserved community" as a community meeting one of the following criteria:

> (1) Is a "disadvantaged community" as defined by subdivision (g) of Section 75005 of the Public Resources Code.
>
> (2) Is included within the definition of "low-income communities" as defined by paragraph (2) of subdivision (d) of Section 39713 of Health and Safety Code.
>
> (3) Is within an area identified as among the most disadvantaged 25 percent in the state according to the California Environmental Protection Agency and based on the most recent California Communities Environmental Health Screening Tool, also known as CalEnviroScreen.
>
> (4) Is a community in which at least 75 percent of public school students in the project area are eligible to receive free or reduced-price meals under the National School Lunch Program.
>
> (5) Is a community located on lands belonging to a federally recognized California Indian tribe.

[416] *See, e.g.*, ChargePoint Opening Comments on Staff Proposal at 12; SCE Opening Comments on Staff Proposal at 19; ATE Opening Comments on Staff Proposal at 9.

[417] TURN Opening Comments on Staff Proposal at 13 (referencing work by Greenlining); GRID Reply Comments on Staff Proposal at 2.

and not contribute to potential displacement of low-income residents by providing incentives to luxury MUD rentals and condos.[418]

Cal Advocates and Greenlining support reserving a portion of the rebate program budget to serve specific underserved communities targeting people not places.[419] NDC argues for limiting higher rebates to MUDs with a majority of low-income residents, rather than also allowing MUDs located in underserved communities to qualify for higher rebates.[420]

Other parties support including additional customer types in the proposal. GRID asserts that the proposal is too limiting and that targeted rebates should not exclude the large fraction of low-income customers who reside in single-family homes.[421] EDF argues that the proposal fails to recognize that rural communities also require consideration and that there is a distinction between small and large businesses—proposing further intervention through ME&O, incentives, and additional TA for these customers.[422]

We adopt higher LD rebates for only one customer type in the proposal: MUDs with a majority low-income residents, defined as those customers with incomes at or below 80 percent of the AMI. In response to persuasive arguments from TURN, GRID, Greenlining, Cal Advocates, and NDC, this decision does not authorize higher rebates for all MUDs in DACs and MUD-serving public

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[418] Greenlining Opening Comments on Staff Proposal at 2-3.

[419] Greenlining Opening Comments on Staff Proposal at 18-19; Cal Advocates Reply Comments on Staff Proposal at 11.

[420] NDC Opening Comments on Staff Proposal at 15.

[421] GRID Opening Comments on Staff Proposal at 5-7.

[422] EDF Opening Comments on Staff Proposal at 9.

locations. Certain sites in DACs may not serve underserved communities or low-income residents, primarily or at all. Providing higher LD rebates only to MUDs with 50 percent or more low-income residents increases accessibility to TE for low-income utility customers. Further, higher rebates should primarily benefit low-income residents and not contribute to potential displacement of low-income residents.

We also agree with the proposed 80 percent of the AMI income threshold because this would better target low-income customers and accounts for income variances across the state. If this requirement is not reasonably administrable, the Program Handbook development process may explore and propose alternative criteria (*e.g.*, California Alternative Rates for Energy/Family Electric Rate Assistance eligibility). Finally, as discussed above, ME&O initiatives should include collaboration with and focus on underserved communities, including DACs, to respond to the unique needs and interests of the communities. We find that through inclusion of MUDs and MUD-serving locations as eligible FC1 recipients, through targeted ME&O in DACs, and through the program's additional spending requirement in underserved communities, discussed below, we sufficiently address this customer segment without providing increased incentives to customers who may not require them.

4.3.5.2. Medium-Duty and Heavy-Duty Customer Types Eligible for Higher Rebates

The Staff Proposal includes a recommendation to authorize higher rebates for certain underserved community customers within the MDHD segment.[423]

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[423] Staff Proposal at 19.

Specifically, the Staff Proposal recommends customers in DACs receive higher rebates because DACs suffer from poor air quality and the MDHD sectors have a disproportionate effect on air quality.

Several parties support increased MDHD rebates for customers in DACs.[424] SBUA recommends adjusting rebate amounts or eligibility criteria for end-use sectors or geographic regions that demonstrate poor cost-effectiveness (*e.g.*, small businesses in underserved communities).[425] NDC also supports more targeted support for smaller fleets/small businesses.[426] Greenlining cautions against providing additional subsidies to large corporations that operate warehouses, ports, and freight distribution.[427]

TURN argues there is a lack of evidence demonstrating why MDHD customers, likely comprised of large fleets and medium- and large-sized corporations, located in DACs require additional subsidies relative to customers in non-DACs.[428] CSE recommends higher rebates for customers whose vehicles are not only domiciled in DACs but also operate for significant periods in DACs.[429] EDF recommends dedicating a certain amount of funding to small fleets operating in DACs.[430]

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[424] Cal Advocates Opening Comments on Staff Proposal at 14; ATE Opening Comments on Staff Proposal at 9; GPI Opening Comments on Staff Proposal at 12; Greenlining Reply Comments on Staff Proposal at 5.

[425] SBUA Opening Comments on Staff Proposal at 11.

[426] NDC Opening Comments on Staff Proposal at 17.

[427] Greenlining Opening Comments on Staff Proposal at 3.

[428] TURN Opening Comments on Staff Proposal at 14.

[429] CSE Opening Comments on Staff Proposal at 7.

[430] EDF Opening Comments on Staff Proposal at 12.

We find merit in parties' support of this section of the Staff Proposal. We authorize higher MDHD rebates for customers in DACs because DACs suffer from poor air quality and the MDHD sectors have a disproportionate effect on air quality. Additionally, in light of the unique barriers to TE faced by tribal communities, we will also require that the Program Administrator consider higher MDHD rebates for tribal communities in the Program Handbook development process.

We also adopt certain requirements proposed in parties' comments. In response to Greenlining's arguments, we prohibit Fortune 1000 corporations-operating in DACs or elsewhere—from receiving any FC1 rebates because these large corporations do not require additional TE incentives funded by ratepayers. We also adopt CSE's recommendation to authorize higher rebates for customers whose vehicles are domiciled and operate for significant periods in DACs. The Program Handbook should determine the process for qualifying these customers for rebates, including the amount of time that must be spent travelling in DACs to qualify for higher rebates as well as the specific rebate levels. Finally, we find merit to the claims that small businesses and fleets currently require more targeted and continuous support, which would promote compliance with the CARB Advanced Clean Fleets regulation. Following stakeholder feedback, the Program Handbook shall develop approaches to better target these customers and provide definitions for small fleets and small businesses. At minimum, the definitions shall incorporate the definition of small business contained in Public Utilities Code Section 323.5(a)(2).

4.3.5.3. Minimum Spending in Underserved Communities

AB 841 requires IOU programs to direct a minimum of 35 percent of TE investments towards underserved communities.[431] The Staff Proposal goes beyond this requirement and recommends allocating at least 50 percent of FC1 funding to underserved communities, which mirrors requirements the Commission adopted for more recent utility TE decisions.[432]

Most parties endorse the Staff Proposal's recommendation to dedicate a minimum of 50 percent of FC1 funds to underserved communities.[433] Only GPI argues for a lower amount—35 percent—in order to better balance competing public policy interests of encouraging EV adoption, promoting higher charger utilization, and a focusing on undeserved communities.[434] In contrast, Cal Advocates, AEE, CSE, NDC, Greenlining, and TURN recommend at least a 50 percent allocation to support communities affected by both poverty and pollution.[435]

Instead of the Staff Proposal's 50 percent recommendation, we adopt a minimum FC1 funding allocation of 65 percent for underserved communities. Parties present convincing arguments that the proposed 50 percent requirement

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[431] Pub. Util. Code Section 740.12(b) (citing definition of "underserved communities" in Pub. Util. Code Section 1601).

[432] Staff Proposal at 19.

[433] Joint Commenters Opening Comments on Staff Proposal at 10.

[434] GPI Opening Comments on Staff Proposal at 12.

[435] Cal Advocates Opening Comments on Staff Proposal at 15; AEE Opening Comments on Staff Proposal at 15; CSE Opening Comments on Staff Proposal at 7; NDC Opening Comments on Staff Proposal at 17; Greenlining Opening Comments on Staff Proposal at 4; TURN Opening Comments on Staff Proposal at 12-14.

is the bare minimum the Commission should consider. We are persuaded that this increased allocation better serves the state's EV adoption goals, supports communities confronting greater barriers to EV adoption, and promotes equity, particularly given the extremely low level of EV adoption in underserved communities to date. Further, the 65 percent minimum requirement more effectively advances the goals of the Commission's Environmental and Social Justice Action Plan.

In addition, although tribal communities fall under the definition of "underserved communities" in AB 841, we want to ensure that tribal communities benefit from this program. We direct that during the Program Handbook development process, the Program Administrator propose a set-aside percentage of the 65 percent minimum spending in underserved communities requirement to specifically benefit tribal communities.

4.3.5.4. Annual Equity Roundtable

The Staff Proposal recommends that the IOUs and Program Administrator host an annual equity roundtable to review the progress of the FC1 program in addressing equity considerations.[436] Several parties support hosting an annual equity roundtable. Cal Advocates and UCAN assert the roundtable is essential to evaluate the program, especially with regards to equity.[437] NDC argues annual reviews, along with a mechanism to quickly implement program modifications, would be beneficial to measure and realize public benefits anticipated from the

[436] Staff Proposal at 19.

[437] Cal Advocates Opening Comments on Staff Proposal at 17; UCAN Reply Comments on Staff Proposal at 6.

investments.[438] ATE, on the other hand, claims a mid-cycle FC1 program evaluation would be sufficient.[439]

Parties' comments also include proposals to collect data related to equity. Greenlining recommends developing clear equity metrics and publishing deployment and resource data to identify where gaps exist and ensure investments target priority populations.[440] Greenlining and CSE note the lack of and need for centralized geospatial analysis of the locations of IOU TE investments and infrastructure.[441] Greenlining recommends the program collect equity-related data on land use, zoning, demographic trends and climate data on sea level rise and flood and fire risk in equity process.[442]

With parties' support, we adopt a requirement that the Program Administrator host an annual roundtable addressing equity. We discuss the requirements for the annual roundtable in Section 4.2.5. The annual review process, coupled with a mechanism to modify certain program elements, promotes equity considerations by allowing the Commission and stakeholders to measure the program's success and make any necessary changes. Instead of the Staff Proposal's recommendation to host a TE data summit and a separate equity roundtable, we consolidate these events into one annual roundtable to account for interrelated topics, such as data on the program's equity components and rebate levels. Because this may result in a combined, multi-day event, the

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[438] NDC Opening Comments on Staff Proposal at 18.

[439] ATE Opening Comments on Staff Proposal at 9.

[440] Greenlining Opening Comments on Staff Proposal at 9.

[441] *Id.*; CSE Reply Comments on Staff Proposal at 5.

[442] Greenlining Opening Comments on Staff Proposal at 12.

Program Administrator shall publish agendas in advance to allow stakeholders to participate in specific topics of their choosing. At a minimum, participation in these roundtables shall include CEC, CARB, CBOs, CCAs, ED staff, Disadvantaged Communities Advisory Group,[443] environmental justice organizations, EVSPs, IOUs, Low Income Oversight Board, and tribal community representatives.

The purpose of the annual roundtables is to review the progress of FC1 and the effectiveness of program requirements. At the roundtables, the Program Administrator shall present current program requirements, data on progress in achieving targets and rebate deployment, ME&O efforts, and TA activities. The data presented shall include equity metrics such as adoption of EVs by low-income customers, charger availability and operational status in low-income communities, and affordability of rates charged to drivers in low-income communities. While the roundtable is not the proper venue to modify the Program Administrator's contract or key terms of the program (*e.g.*, overall budget, MDHD vs. LD split, prohibition on IOU ownership of BTM charging infrastructure, etc.), this process may result in changes to program elements such as the rebate level, rebate design/delivery, ME&O strategies, customer targeting, or requirements to ensure participation of underserved communities.

The IOUs, in consultation with the Program Administrator, shall jointly file a Tier 2 advice after the roundtable proposing any changes to the program.

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[443] California Public Utilities Commission, Disadvantaged Communities Advisory Group, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/disadvantaged-communities/disadvantaged-communities-advisory-group/.

The Advice Letter shall contain a summary of the discussion at the roundtable. Stakeholders may comment on the Advice Letter filing before the Commission approves any modifications to the program.

4.3.5.5. Additional Equity Measures

The Staff Proposal recommends that the equity program elements work in tandem with ME&O initiatives that focus on reaching underserved communities.[444] The Staff Proposal further recommends significant collaboration with CBOs—reflected in the early design of the ME&O initiatives—to help the Program Administrator understand the unique needs and interests of local communities.[445] Further, the Draft TEF and the Staff Proposal recommend incorporating principles from the Commission's Tribal Consultation Policy into the TE equity efforts and the Program Handbook to ensure engagement with tribal communities.[446]

As discussed above, parties generally support increased outreach to underserved communities. More specifically, NDC urges the Commission to increase the budget for ME&O to include general EV education activities targeting underserved communities.[447] Greenlining encourages the Commission to create a set-aside program dedicated to DACs with meaningful stakeholder engagement processes.[448]

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[444] Staff Proposal at 19.

[445] *Ibid.*

[446] *Ibid.*

[447] NDC Opening Comments on Staff Proposal at 17.

[448] Greenlining Reply Comments on Staff Proposal at 3.

Recognizing stakeholder support for comprehensive equity strategies, we adopt the Staff Proposal's recommendations along with a requirement that at least 65 percent of ME&O funds be spent towards underserved communities, mirroring the FC1 funding allocation. Following stakeholder input, the Program Handbook shall propose ME&O initiatives specifically targeting underserved communities. The Program Handbook shall also incorporate principles from the Commission's Tribal Consultation Policy to advance efforts to engage with tribal communities and the Environmental and Social Justice Action Plan. Stakeholders should provide ongoing feedback on the effectiveness of ME&O efforts focused on underserved communities, as described in the roundtable discussion above.

4.3.5.6. Workforce Development

The Staff Proposal solicits party feedback on potential workforce development requirements related to equity and safety. Specifically, the Staff Proposal asks the following questions:

1. How can the FC1 rebate program ensure workforce development in underserved communities?
2. How can we ensure that this investment includes consideration for residents in these communities to have access to high-road jobs?
3. Beyond the EV Infrastructure Training Program (EVITP), are other workforce development measures necessary?
4. Are any additional workforce requirements needed to ensure safety?[449]

[449] Staff Proposal at 20, 24.

Additionally, Public Utilities Code Section 740.12(a)(1)(F) states: "[w]idespread transportation electrification should . . . create high-quality jobs for Californians."

Parties offer various opinions on this topic. ATE claims that simply providing rebates in underserved communities should result in workforce development.[450] NDC provides the following recommendations: (1) the Commission should partner with established CBOs focused on job training and employee development in underserved communities; (2) the Program Administrator should establish systems to connect the IOUs, EVSPs, and partner CBOs with job training organizations to hire workers from underserved communities; and (3) require data collection and reporting on the number of residents in underserved communities trained and employed in quality jobs related to the program.[451]

Greenlining argues that TE investments are a form of community development that should create high-road jobs for vulnerable communities.[452] Greenlining cited guidance in its Greenlined Economy Handbook concerning equitable community investment standards.[453] GRID recommends adopting requirements similar to the Commission's Solar on Multifamily Affordable Housing program, which contains job-training requirements and encourages

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[450] ATE Opening Comments on Staff Proposal at 10.

[451] NDC Opening Comments on Staff Proposal at 18.

[452] Greenlining Opening Comments on Staff Proposal at 23-24.

[453] *Id.* (citing Greenlining, Greenlining Economy Guidebook (2020), available at: https://greenlining.org/wp-content/uploads/2020/09/Greenlined-Economy-Guidebook-2020.pdf).

local and targeted hiring practices.[454] GRID also supports coordination with a variety of industry segment and training providers to develop incentives and standards for inclusive workforce development.[455]

We adopt program goals, requirements, and implementation strategies to help ensure TE investments create high-quality jobs, facilitate access to these jobs for targeted populations, and address the need for a skilled, trained, and diverse workforce. As GRID asserted, the Commission's Solar on Multifamily Affordable Housing program provides precedent for workforce training requirements. We adopt a similar approach here—to be finalized with stakeholder input through the development of the Program Handbook.

To ensure high-quality contractor participation in the program and to advance the state's workforce development and economic equity goals, the Program Administrator shall impose the following requirements in the Program Handbook on contractors and their subcontractors who install EVSE and any other electrical infrastructure under this program:

1. All workers under the program are paid the prevailing wage;
2. Contractors and subcontractors have no unresolved Contractors State License Board license citations in the previous five years;
3. Contractors and subcontractors have no unresolved safety violations with California Department of Occupational Health and Safety within the previous five years, nor compliance cases with the California Labor & Workforce Agency;

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[454] GRID Opening Comments on Staff Proposal at 7-8.

[455] *Ibid.*

4. Contractors and subcontractors have no unresolved Department of Industrial Relations wage claim violations in the previous five years; and
5. All work is done in compliance with relevant safety standards and local, state, and federal laws.

Additionally, the Program Administrator shall develop an FC1 program website for customers to view approved contractors and for prospective and approved contractors to access program information and eligibility requirements. The FC1 program website shall include a searchable list of contractors that allows customers to find approved contractors, including their contact information, all certifications held by the contractor, the services provided, and the geographic reach of the contractor (*i.e.*, zip code/counties served). The website shall also include a page for interested contractors to learn about participation requirements and how to submit an application to become an approved contractor. The application process should be quick and seamless. To provide a grace period to ensure sufficient contractors are on the approved list, customers are not required to use contractors on the approved list within the first six months of the program's launch. After six months, only contractors from the approved contractor list shall be eligible to install EVSE and related infrastructure under the FC1 program. The following are criteria for inclusion on the contractor list:

1. Job Quality: The Program Administrator shall assess and determine whether participating contractors recruit and retain a skilled and trained workforce. The Program Administrator should leverage, at minimum, high-quality workforce education and training guidance consistent with the Commission's Environmental and Social Justice Action Plan to develop these parameters.
2. Job Access: The Program Administrator shall assess and establish targeted hiring goals, and any other measures, to

address job access, increase workforce diversity, and improve the inclusion of "disadvantaged workers"[456] and other priority population segments and/or regions.

During the Program Handbook development process, the Program Administrator shall ensure sufficient public stakeholder opportunities are available to provide input on the inclusion of additional workforce development and economic equity metrics. In addition, the Program Administrator shall determine the appropriate methods to ensure contractor accountability with the labor, workforce, and contractor standards outlined here. The Program Administrator shall remove contractors from its approved contractor list if they no longer comply with the standards.

4.3.5.7. Locally Invested Transportation Electrification Pilot Program

We authorize funding for a pilot program for innovative equity-based locally or regionally appropriate incentives. The rebate program is an efficient streamlined method to fund TE infrastructure but may miss unique or innovative opportunities. The Locally Invested Transportation Equity (LITE) pilot program would provide an opportunity to test new rebate design approaches that may fill gaps in the statewide rebate program in a creative way. Due to their expertise working with customers and local communities, as well as experience and knowledge of successful outreach practices, we find it appropriate to limit the pilot program to CCAs, CBOs, and other entities demonstrating experience

[456] *See* Cal. Workforce Dev. Bd., Putting California on the High Road: A Jobs and Climate Action Plan for 2030 (June 2020), available at: https://cwdb.ca.gov/wp-content/uploads/sites/43/2020/09/AB-398-Report-Putting-California-on-the-High-Road-ADA-Final.pdf (defining "disadvantaged workers" as workers who reside in DACs based on CalEnviroScreen 3.0).

working with local communities. These pilot projects will provide the Commission with information to determine potential modifications to the statewide rebate program during the Mid-Cycle Assessment.

The objective of this pilot is to design and implement innovative approaches to rebates to support charging infrastructure for low-income customers,[457] including tribal members, or small fleets located within DACs (*i.e.*, census tracts in the top 25 percentile in CalEnviroScreen 4.0 on a statewide basis). The pilot should test innovative approaches for equity-focused rebates to potentially scale within the FC1 program. Thus, any pilot should be informed by the design, targeted customers, and guidelines of the FC1 program. The Mid-Cycle Assessment should evaluate any pilots to determine whether to implement the tested approach in the FC1 program. Any pilot should be innovative, and thus not duplicative of previous ratepayer-funded TE programs and pilots or the FC1 program (*e.g.*, rebate, ME&O, or TA funding). Any pilot must comply with all technical requirements the Commission has established for ratepayer funded EVSE.

We find that is appropriate for the IOUs to issue the RFP for the LITE pilot program and contract with any selected entities in order to allow the Program Administrator to focus on the statewide rebate program. We designate SDG&E as the lead IOU to conduct the RFP, coordinate with the other IOUs and ED staff to select shortlisted bidders, and file a Tier 3 Advice Letter describing the shortlisted bidders. We authorize Energy Division staff to approve the shortlisted bids and select approved bids among the shortlisted bids, based on

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[457] Low-income customers are those with incomes at or below 80 percent of the statewide AMI.

compliance with the required criteria. The winning bidders should coordinate contracts directly with the respective IOU(s) for their region, as each IOU shall execute and manage any contracts for pilots in its service territory. Only winning bidders must submit implementation plans and handbooks for their pilot proposals.

The budget of the pilot program will be up to $25 million total out of the FC1 budget. Individual pilots are capped at $4 million but can cost less, consistent with the SB 350 Priority Review Programs.[458] This will allow for at least six individual pilots to test various ways to address the stated equity objectives. Administrative costs associated with the pilots are capped at eight percent of the total pilot program budget, consistent the with FC1 program administrative cost cap. This should include both the contracted entity's administrative costs as well as the IOU's administrative costs. We limit the IOUs' costs for the LITE pilot program to those associated with their role in managing the RFP and subsequent contracts. As with the rest of FC1, any funding spent is limited to the amount of funding the service territory pays (*i.e.*, SDG&E ratepayers cannot fund pilots in PG&E's territory). If a contracted entity spans multiple IOU territories, it will need to account for funding differently in each region.

The pilot(s) should begin no later than the end 2025, concurrent with the FC1 rebate program. Per the process discussed below, this would mean that the RFP and selection process should begin by the end of 2023. As the purpose of these pilots is to identify innovative approaches to equity rebates for FC1, any

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[458] D.18-01-024.

pilot must be limited to an implementation period of up to three years, and the evaluation must occur concurrently with, and conclude no later than the end of, the Mid-Cycle Assessment. ED staff will be responsible for evaluating the pilots and developing recommendations for next steps based on findings.

CCAs, CBOs, and any other entities demonstrating experience working with local communities may apply for pilot program funding and file proposals in response to a competitive solicitation for implementation of a pilot that meets the above stated objective and the criteria outlined below. We require the following guidance and process for selecting pilots at the start of FC1:

1. A competitive RFP process run by the IOUs will identify innovative pilots totaling up to $25 million that address the stated objective above.
2. Following the RFP, the IOUs should submit the shortlisted pilots to the Commission via Tier 3 Advice Letter. This will ensure that the proposed pilots: (1) meet all criteria identified in this decision, (2) support the objective defined in this decision, (3) establish a process to coordinate with the Program Administrator, and (4) are fairly selected by the IOUs in a competitive process.
3. Within the Advice Letter filing, the IOUs should include an implementation plan and proposed pilot program handbook, which ED staff can leverage to support an evaluation of the pilot. Additionally, the IOUs should propose the establishment of one-way subaccounts to record the cost of the pilots in their TE balancing accounts.
4. Once the Commission authorizes the pilots, the IOU should hold the contract and serve as the point of contact with the selected entity and with the Commission.
5. Adopted pilots will be subject to a Commission-led audit or review, as is the case for the rest of FC1 funding. Contracted pilot administrators should submit quarterly reporting of expenditures and progress towards targets to the Commission.

6. Pilots selected for implementation should meet the following criteria:
    - Any entity submitting a proposal for pilot funding must provide previously all available administered TE program evaluation reports and cost data to demonstrate the entity's ability to efficiently and cost-effectively implement a pilot;
    - The pilots' design and objectives must support the objectives established in this decision for ratepayer support of BTM TE infrastructure, as well as the specific objective for this pilot funding outlined above;
    - Pilot proposals should clearly state the objectives of the pilot and how the proposed approach is adequate to meet the objectives;
    - Pilot proposals must include a data reporting plan that aligns with the overall reporting requirements for FC1; ED staff will leverage this reported data in its Mid-Cycle Assessment;
    - Pilots must treat bundled and unbundled customers equally;
    - Proposals must demonstrate that the pilot is designed to: (1) support the neediest regions of the state or (2) target low-income customers[459] or small fleets located within DACs;
    - Pilots must target the identified priority segments for FC1: MUDs, MUD-serving public locations, and MDHD customers;[460]
    - Pilots should not be redundant with other efforts (*e.g.*, they should not provide rebates that would be available under the larger program, existing programs or

[459] Customers with incomes at or below 80 percent of statewide AMI.

[460] Consistent with any exceptions adopted for tribal communities or tribal members.

duplicate ME&O efforts funded through FC1), and they should not be duplicative of each other;

- Pilot proposals must align with the Commission's Environmental and Social Justice Action Plan;
- Approval of these funds should not result in a reduction of funding from other CCA or CBO TE-related programs; and
- Once selected, the pilot administrator shall ensure no duplication of outreach efforts with the Program Administrator.

4.3.6. FC1 Priority Segments/Use Cases

The Staff Proposal contains a more focused approach to prioritizing certain sectors and use cases than the Commission has applied in previous IOU TE programs.[461] The proposed FC1 program focuses on the MDHD sectors and LD charging at MUDs and MUD-serving public locations. With the continued LCFS holdback funding, resiliency funding through other Commission proceedings,[462] other public EV charging funding, and the forthcoming adoption of new CALGreen requirements, the Staff Proposal recommends phasing out ratepayer funding for TE new construction, TE resiliency, panel upgrades, and workplace charging starting in 2025.

4.3.6.1. Allocation of Funds Between MDHD and LD

The Staff Proposal recommends allocating 70 percent of rebate funding for MDHD charging and 30 percent for LD charging at MUDs and MUD-serving

[461] Staff Proposal at 20-22.

[462] *See* D.20-05-051; D.20-06-017; D.20-12-027; D.20-12-029; D.21-01-018.

public locations.[463] The Staff Proposal argues that the Commission has approved less funding for the MDHD sectors and that fleet electrification often has higher installation costs and complexity compared to the LD sector. The Staff Proposal further justifies the funding allocation by referencing existing and forthcoming CARB regulations—including Advanced Clean Trucks, Advanced Clean Fleets, and Innovative Clean Transit—which will accelerate adoption of MDHD EVs. Finally, the Staff Proposal emphasizes the need to electrify the MDHD sectors to reduce air pollution disproportionately impacting DACs.

Many parties express support for the Staff Proposal's recommended allocation, with some suggesting modifications. BNSF argues existing and pending CARB regulations—including some absent from Staff Proposal (*e.g.*, Zero Emission Ports and Commercial Harbor Craft)—necessitate greater support for the MDHD sectors.[464] The Joint Commenters generally support the proposal but recommend including low- and moderate-income single-family residences as a target LD customer.[465] Similarly, CSE generally supports the proposal but urged the Commission to revisit the allocation of funding following additional data collection and analysis.[466] GPI also supports the proposal and recommends reassessing the allocation before the beginning of FC1 and during a Mid-Cycle Assessment.[467]

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[463] *Id.* at 20-21.

[464] BNSF Opening Comments on Staff Proposal at 4.

[465] Joint Commenters Opening Comments on Staff Proposal at 11.

[466] CSE Opening Comments on Staff Proposal at 9.

[467] GPI Opening Comments on Staff Proposal at 17.

Other parties propose modifying the Staff Proposal's allocation. EDF Renewables suggests a 50/50 split in funding.[468] NDC recommends allocating 70 percent of rebates to the LD sector and 30 percent to the MDHD sectors—with residential LD customers receiving at least 50 percent of total rebates—arguing that commercial and industrial customers operating MDHD vehicles profit from air polluting activities, have budgets to replace and upgrade vehicles, and receive brand and fuel cost benefits from fleet electrification.[469] Cal Advocates asserts the proposal requires additional cost-benefit analysis and justification given data showing operational cost parity between electrified and non-electrified MDHD vehicles.[470] EVgo urges the Commission to adopt a more nuanced and flexible approach that accounts for the regulatory landscape, vehicle availability, and other funding.[471] AEE recommends allocating funding based on updated EVSE data from the CEC and CARB.[472] Auto Innovators similarly advocates for flexibility in determining appropriate allocation amounts.[473]

We adopt the Staff Proposal's recommended allocation of 70 percent of FC1 funding for the MDHD sectors and 30 percent of FC1 funding for the LD sector. Parties present reasonable arguments for increasing the LD allocation;

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[468] EDF Renewables Opening Comments on Staff Proposal at 3.

[469] NDC Opening Comments on Staff Proposal at 19; NDC Reply Comments on Staff Proposal at 7-8.

[470] Cal Advocates Opening Comments on Staff Proposal at 18-20; Cal Advocates Reply Comments on Staff Proposal at 13.

[471] EVgo Opening Comments on Staff Proposal at 8.

[472] AEE Opening Comments on Staff Proposal at 12.

[473] Auto Innovators Opening Comments on Staff Proposal at 16.

however, we are more convinced by arguments for increased near-term funding for the MDHD sectors, which have historically received less Commission funding than the LD sector, and which provide greater air quality benefits. The 70 percent allocation for the MDHD sectors supports compliance with CARB regulations that will rapidly accelerate electrification of MDHD fleets.[474]

Additionally, we agree with parties advocating for additional flexibility because data collection and analysis may support a different allocation and circumstances may change over the course of FC1. For example, at the Mid-Cycle Assessment in 2027, analyses may justify additional LD sector funding to support CARB's ACCII and ACC regulations.[475] Therefore, we shall review the adequacy of the funding allocation during the Mid-Cycle Assessment, with stakeholder input.

4.3.6.2. Eligible LD Sectors

While recommending a larger proportion of funding for the MDHD sectors, the Staff Proposal recognizes a need for near- and medium-term LD-sector funding, especially for MUD residents who face increased barriers to EV adoption.[476] To increase access to EV charging for MUD residents, the Staff Proposal recommends limiting LD sector rebates to chargers sited at MUDs and public chargers located in areas of high MUD density, or "MUD-serving

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[474] *See, e.g.*, CARB, Advanced Clean Trucks, https://ww2.arb.ca.gov/our-work/programs/advanced-clean-trucks; CARB, Advanced Clean Fleets, https://ww2.arb.ca.gov/our-work/programs/advanced-clean-fleets; CARB, Innovative Clean Transit: https://ww2.arb.ca.gov/our-work/programs/innovative-clean-transit.

[475] CARB, Advanced Clean Cars II: https://ww2.arb.ca.gov/our-work/programs/advanced-clean-cars-program/advanced-clean-cars-ii.

[476] Staff Proposal at 21.

public locations." Further, it recommends excluding workplaces because IOU programs have made much more headway with installations at workplaces as compared to MUDs, the CEC's initial AB 2127 Charging Assessment's projection of less need throughout the state by 2030 in this segment as compared to MUDs and public charging, and the continued uncertainty around in-person work patterns and workplace charging due to the COVID-19 pandemic.

The Staff Proposal reasons that the projected charging needs identified in the CEC's AB 2127 Charging Assessment support these eligibility requirements. Finally, the Staff Proposal recommends the Program Handbook determine the definition of MUD-serving public locations, accounting for definitions utilized in SDG&E's Power Your Drive Extension and SCE's Charge Ready 2 programs.

Many parties agree with the Staff Proposal's recommended support of chargers sited at MUDs and MUD-serving public locations.[477] Other parties disagree and recommend support for other LD-sector chargers (*e.g.*, single-family residences, rideshare, and municipal fleets).[478] Several parties also emphasize the need to preserve flexibility and account for future market conditions in 2025 and beyond.[479] NDC asserts the Staff Proposal offers reasonable guidance to identify

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[477] SCE Opening Comments on Staff Proposal at 20; Cal Advocates Opening Comments on Staff Proposal at 20; Joint Commenters Opening Comments on Staff Proposal at 11; NDC Opening Comments on Staff Proposal at 20.

[478] EDF Renewables Opening Comments on Staff Proposal at 3; EVgo Opening Comments on Staff Proposal at 6; SBUA Opening Comments on Staff Proposal at 5; ChargePoint Reply Comments on Staff Proposal at 7.

[479] ATE Opening Comments on Staff Proposal at 10; AEE Reply Comments on Staff Proposal at 3; Auto Innovators Opening Comments on Staff Proposal at 21; Joint Commenters Opening Comments on Staff Proposal at 3; CEDMC Opening Comments on Staff Proposal at 2-3.

MUD-serving public locations.[480] Finally, some parties recommend extending eligibility to workplaces and to workplaces and other public locations.[481]

While we understand the need for other LD-sector charger locations that parties mention in comments (*e.g.*, single-family homes and workplaces), we must be prudent with limited ratepayer funding. This is especially true given the increasing role the IOUs have in supporting utility-side TE infrastructure. Thus, we find that MUDs and MUD-serving public locations are most critical to target due to the widespread lack of access to chargers for MUD residents. The CEC's initial AB 2127 Charging Assessment supports this finding.[482] We also agree that the Program Handbook should adopt a definition of MUD-serving public locations, following stakeholder feedback. In developing the Program Handbook, the Program Administrator and stakeholders should consider the Commission-adopted definition from SDG&E's Power Your Drive Extension program and the pending definition for SCE's Charge Ready 2 program.[483] Finally, similar to the funding split, we will revisit the eligibility requirements for LD-sector rebates during the Mid-Cycle Assessment, with stakeholder input.

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[480] NDC Opening Comments on Staff Proposal at 15-16.

[481] ChargePoint Opening Comments on Staff Proposal at 13; EDF Renewables Opening Comments on Staff Proposal at 3; SBUA Opening Comments on Staff Proposal at 6; VGIC Opening Comments on Staff Proposal at 15; SDG&E Opening Comments on Staff Proposal at 7; Fermata Reply Comments on Staff Proposal at 11; Joint Parties Reply Comments on Staff Proposal at 2; AEE Reply Comments on Staff Proposal at 8.

[482] CEC, Electric Vehicle Charging Infrastructure Assessment—AB 2127, https://www.energy.ca.gov/programs-and-topics/programs/electric-vehicle-charging-infrastructure-assessment-ab-2127.

[483] D.20-08-045; SDG&E Advice Letter 3809-E.

4.3.6.3. MDHD Definition

The Staff Proposal solicits party feedback on the MDHD definition.[484] The Joint Commenters support a definition consistent with the Commission's near-term priorities decision.[485] BNSF recommends the definition encompass all on-road and off-road MDHD vehicles or equipment subject to CARB zero-emissions regulation; on-road vehicles, such as MDHD vans, trucks, and transit vehicles; and off-road vehicles and equipment such as yard trucks, forklifts, side/top picks, cranes, locomotives, transport refrigeration units, and commercial vessels.[486] SCE cautions against including vehicle weight class in the definition, claiming this would exclude some small-business customers who utilize LD vans or pick-up trucks.[487]Auto Innovators recommend including vans and small trucks in the definition.[488]

For the FC1 program, we adopt the modified MDHD definition contained in D.20-09-025, which encompasses all EVs having a gross vehicle weight rating of 8,501 pounds or more, while also removing the exception of trains or locomotives, which BNSF identifies are also subject to CARB TE regulations.[489] We also adopt the following definition of off-road EVs and equipment as including: Locomotives, Construction or Agricultural Equipment, Small

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[484] Staff Proposal at 22.

[485] Joint Commenters Opening Comments on Staff Proposal at 3.

[486] BNSF Opening Comments on Staff Proposal at 4.

[487] SCE Opening Comments on Staff Proposal at 20.

[488] Auto Innovators Opening Comments on Staff Proposal at 21.

[489] D.20-09-025 at 9-10 (citing CARB LCFS regulations); BNSF Opening Comments on Staff Proposal at 4.

Off-Road Engines, and Off-Highway Recreational Vehicles.[490] This broad MDHD definition includes all vehicle categories parties recommend in comments, including off-road MDHD vehicles, vans, transit, yard trucks, forklifts, trains/locomotives, side/top picks, cranes, commercial vessels, and small trucks.

Similar to the funding allocation and eligibility requirements described above, we recognize that future circumstances may warrant modifying or updating the definition. Therefore, in response to stakeholder feedback, the Program Administrator may propose modifications to the MDHD definition through the post-roundtable Tier 2 Advice Letter filings.

4.3.6.4. Prioritizing MDHD Use Cases

The Staff Proposal requests input on whether to prioritize or deprioritize particular MDHD use cases (*e.g.*, quotas for number or rebates supporting transit, forklifts, etc.).[491] ATE cautions against prioritizing particular use cases.[492] SCE urges the Commission to provide increased rebates to use cases that require more assistance or that fulfill state objectives.[493] NDC proposes prioritizing small businesses.[494] SDG&E supports barring Fortune 1000 corporations from receiving rebates—in order to support equity goals—and ensuring MDHD rebates primarily benefit small fleets that lack the resources needed to electrify.[495]

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[490] D.20-09-025 at 24.

[491] Staff Proposal at 22.

[492] ATE Opening Comments on Staff Proposal at 11.

[493] SCE Opening Comments on Staff Proposal at 20.

[494] NDC Opening Comments on Staff Proposal at 20.

[495] SDG&E Opening Comments on Staff Proposal at 8.

Cal Advocates similarly recommends supporting small private entities, instead of corporations that already must transition to zero-emission fleets under the CARB's Advanced Clean Fleets regulation.[496] Cal Advocates and NDC additionally recommend conducting a cost-benefit analysis to identify pollution reduction opportunities with the lowest ratepayer costs.[497] Conversely, CSE supports prioritizing use cases subject to emissions reduction programs, such as the CARB's Advanced Clean Fleets and Innovative Clean Transit regulations.[498]

We direct the Program Administrator to prioritize small fleets because, as parties argued, they often lack the resources needed to electrify. The Program Handbook shall define "small fleets" and propose a process to prioritize them. If appropriate, the definition should align with those in the CEC's EnergIIZE, the CARB's Advanced Clean Fleets regulation, and other relevant MDHD regulations in California (*i.e.*, Drayage Trucks at Seaports and Railyards, Airport Shuttles, Transport Refrigeration Units, and Innovative Clean Transit). As discussed above, we find Fortune 1000 corporations ineligible to participate in the FC1 rebate program.

In creating the Program Handbook, the Program Administrator, IOUs, fleet operators, EVSPs, and other stakeholders should present data and findings from current MDHD programs to determine how the FC1 program can best account for the needs of differing MDHD fleet customers. The Program Administrator may propose program elements to address these needs.

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[496] Cal Advocates Reply Comments on Staff Proposal at 12.

[497] Cal Advocates Opening Comments on Staff Proposal at 21; NDC Opening Comments on Staff Proposal at 20.

[498] CSE Opening Comments on Staff Proposal at 10.

We further find that future conditions may justify different use case prioritization. To provide program flexibility, the annual roundtables should serve as a venue for stakeholders to provide input on both the need and potential methods to target specific MDHD use cases. During the Mid-Cycle Assessment, the Program Administrator and parties should evaluate whether fleets supported by FC1 rebates are achieving cost-effective GHG reductions and, if not, how to modify program requirements to target more cost-effective GHG reductions from the MDHD sectors. We authorize the Program Administrator to propose modifications to prioritize or deprioritize MDHD use cases through the pot-roundtable Tier 2 Advice Letters or during the Mid-Cycle Assessment.

4.3.6.5. MDHD Requirement for EV Purchase

The Staff Proposal asks parties whether the FC1 program should include a requirement for MDHD rebate recipients to purchase a certain number of EVs, as the Commission has adopted for existing IOU programs.[499] SBUA cautions against adopting a purchase mandate for small businesses because separate entities (*e.g.*, suppliers, contractors, customers) may finance, own, and control vehicles, property, and TE infrastructure.[500] SCE argues that a purchase requirement would not support public or site-hosted commercial vehicle charging, which is a current gap in IOU commercial charging programs.[501] ChargePoint supports a purchase mandate but recommends allowing leased

[499] Staff Proposal at 22.

[500] SBUA Opening Comments on Staff Proposal at 9.

[501] SCE Opening Comments on Staff Proposal at 21.

vehicles to fulfill the requirement as well.[502] In order to ensure ratepayer benefits, NDC proposes requiring the purchase of one MDHD EV for every MDHD charger port installed, with possible exceptions for government agencies and entities that purchase a large number of charger ports and EVs.[503] EDF rebuts NDC's proposal by arguing that many businesses have multiple EVs utilize a single charger and that a purchase requirement may effectively prevent small businesses from participating in the program.[504]

We find merit in parties' positions on both sides of the issue. However, to ensure FC1 rebates provide ratepayer benefits by encouraging the purchase and use of EVs, we adopt an MDHD EV purchase requirement. We require a minimum of one EV purchase, lease, or retrofit per charging port rebate. We also agree that there are scenarios that need additional consideration to implement an MDHD EV purchase mandate, including: (1) public or shared-charging ports and (2) small businesses. Therefore, we require the Program Handbook development process to finalize details of the purchase requirement for these contexts, including a possible exemption from the requirement and the process needed to request a waiver.

4.3.7. FC1 Program Administration

4.3.7.1. Administrator Structure

The Staff Proposal asks parties whether one administrator for both the MDHD and LD rebate components is appropriate.

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[502] ChargePoint Opening Comments on Staff Proposal at 14.

[503] NDC Opening Comments on Staff Proposal at 20-21.

[504] EDF Reply Comments on Staff Proposal at 9.

Several parties support one Program Administrator for both MDHD and LD components of the program to ensure simplicity, cost containment and a consistent customer experience.[505] ATE also supports one Program Administrator but cautions that MDHD may require focused attention by the administrator that will require adequate skills and experience in MDHD expertise.[506]

Other parties support separate program administrators for the MDHD and LD components. SCE contends that separate administrators will result in a more effective and competitive RFP process. SCE also indicates that the differing technology solutions and applications for EVSE between LD and MDHD supports separate administrators because one administrator may not be as "well-equipped in understanding both segments with as deep of expertise from a technical perspective."[507] GRID asserts that separate program administrators for the LD, MDHD, and low-income single-family home LD EV charging is appropriate because of the differences in vehicle types and distinct considerations for each component with regard to intended rebate recipients.[508] SDG&E and PG&E support multiple administrators due to the massive scale of

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[505] Tesla Opening Comments on Staff Proposal at 6; GPI Opening Comments on Staff Proposal at 18; CSE Opening Comments on Staff Proposal at 10; NDC Opening Comments on Staff Proposal at 21.

[506] ATE Opening Comments on Staff Proposal at 11.

[507] SCE Opening Comments on Staff Proposal at 21.

[508] GRID Opening Comments on Staff Proposal at 8.

the FC1 program, arguing that utilizing one administrator would risk the success of the program.[509]

We require a single third-party administrator for both the LD and MDHD components of the program to ensure simplicity and accessibility. All components of FC1, other than the IOU-administered TA programs, shall be administered by one entity resulting in one contract.

While we adopt a single Program Administrator, we do not impose restrictions on the program administration structure, including the Program Administrator's use of subcontractors to provide for flexibility in implementation and technical expertise. This could include subcontracts to separate entities supporting implementation of LD and MDHD rebates and to the CCAs, CBOs, or other entities to administer portions of the ME&O or rebate program on a local level. We further require the IOUs' contract with the selected Program Administrator, and any subcontracts with the Program Administrator, to comply with state contracting requirements, including the Commission's "Conflict of Interest" policies. Finally, we direct the Program Handbook to propose a name for the program that is easily understandable and effectively communicates the program's purpose.

In order to provide clarity regarding the roles of the Program Administrator and the IOUs, we specify their respective roles here. The role of the Program Administrator includes:

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[509] SDG&E Opening Comments on Staff Proposal at 7; PG&E Opening Comments on Staff Proposal at 7.

1. Administer the FC1 program rebate and ME&O;
2. Lead the development of the Program Handbook and implementation to meet the program's requirements and objectives;
3. Develop program and outreach materials, including naming the program;
4. Manage program administration, including application processing and verification, rebate payment, and installation verification;
5. Develop the website;
6. Collect and publicize data;
7. Lead and manage program reporting requirements; and
8. Lead annual roundtables and provide input to the IOUs in developing the annual Tier 2 Advice Letters.

The role of the IOUs includes:

1. Coordinate and cooperate with the Program Administrator as necessary to achieve program objectives;
2. Develop and manage Program Administrator RFP;
3. Execute and manage Program Administrator contract;
4. Manage relevant data collection and program evaluation;
5. Develop and manage LITE pilot program RFP;
6. Execute and manage contract(s) for the LITE pilot program;
7. Administer the TA program; and
8. Administer the ALM rebates, if implemented.

4.3.7.2. Program Advisory Council

The Staff Proposal requests comments on whether to leverage the Program Advisory Council (PAC) to discuss market and technological advances and propose any necessary changes annually. The Staff Proposal requests feedback on whether the PAC is an effective tool to address innovation throughout FC1.

Cal Advocates contends that the PAC is not designed to effectively gather stakeholder input in its current form. Cal Advocates recommends the use of the annual audit and roundtable process to gather this input with other agencies, IOUs, EV and EVSE manufacturers, CBOs, and advocacy groups.[510] NDC requests clarification from the Commission as to what actions the PAC can and should take if the administrator or the IOUs do not appropriately respond to PAC guidance.[511] Tesla asserts that leveraging the PAC is appropriate to review any annual market and technological process, but requests clarity as whether the separate PACs will be combined and whether any new entities need to be included in the discussions to ensure sufficient technology and market expertise.[512]

We find it appropriate to utilize the annual roundtables to discuss any programmatic and market developments, as well as potential modifications to the program. The quarterly PAC meetings can end at the conclusion of the FC0 programs.

4.3.7.3. Request for Proposals to Select Program Administrator

On the topic of the process for RFPs to select the Program Administrator, SCE recommends against the IOUs serving as a contracting agent for the Commission because it would: (1) not provide sufficient clarity of roles and responsibilities and (2) create potential unnecessary legal risks and barriers to

[510] Cal Advocates Opening Comments on Staff Proposal at 22.

[511] NDC Opening Comments on Staff Proposal at 22.

[512] Tesla Comments on Staff Proposal at 6.

efficient administration.[513] SCE recommends that the lead IOU issue the RFP, select the third-party administrator, and manage the vendor contract. SDG&E recommends that goals and metrics for the program be proposed as part of the Program Handbook and upon Commission approval, actual design and delivery would be the responsibility of the Program Administrator with ED holding the contract and executing evaluations.[514]

We find that it is appropriate for the IOUs to issue the RFP and contract with the selected Program Administrator.[515] However, we authorize ED to select the Program Administrator. The IOUs shall manage the contract with the Program Administrator, with input from ED staff. We designate SCE as the lead IOU to execute the contract. As the Commission must review the Program Administrator's contract, SCE shall file a Tier 2 Advice Letter to request approval of the contract language prior to finalization no later than May 1, 2023.

Further, the IOUs shall structure the initial Program Administrator contract for a three-year period, with the potential but not the guarantee of a two-year extension. The Commission shall have discretion to evaluate the performance of the Program Administrator at the mid-cycle point. At its discretion, the Commission may ask the IOUs to conduct an RFP for a new Program Administrator for the second half of FC1 or allow the initially contracted Program Administrator to continue.

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[513] SCE Opening Comments on Staff Proposal at 8.

[514] SDG&E Opening Comments on Staff Proposal at 8.

[515] This approach is consistent with the Commission's Solar on Multifamily Affordable Housing program.

The Program Handbook development process shall determine details of the program. The Program Administrator's contract must require establishment of back-end processes, as well as systems and procedures to meet the requirements of the Program Handbook and the objectives of: (1) distributing rebates to the market to maximize deployment of charging infrastructure; (2) maximizing program awareness and program-related customer education; and (3) coordinating with Veloz and other EV awareness campaigns to ensure ratepayer funds do not duplicate broad EV awareness and education.

4.3.8. Other FC1 Implementation Details

4.3.8.1. VGI

4.3.8.1.1. VGI Activities to Date

The Commission has significantly advanced VGI in California since the Draft TEF was issued. Much of this progress has occurred in response to SB 676, which "requires the Commission to establish strategies and quantifiable metrics to maximize the use of feasible and cost-effective EV integration into the electrical grid."[516] In December 2020, the Commission adopted D.20-12-029 to implement SB 676 and designated multiple VGI strategies and guiding principles, including, but not limited to:

1. Reforming retail rates and pursuing dynamic pricing structures;
2. Pursuing VGI pilots and demonstrations;
3. Accelerating the use of EVs for bi-directional non-grid-export power and Public Safety Power Shutoffs;

[516] D.20.12-029 at 2.

4. Reforming interconnection rules to allow for more efficient integration of EVs into the grid;[517]
5. Enhancing customer outreach on VGI and ALM through programs and rules; and
6. Adopting enhanced IOU reporting for VGI programs.

Since adopting D.20-12-029, the Commission has pursued these strategies by various means to advance VGI in California. In May 2022, the Commission approved three VGI pilots proposed by PG&E to address various VGI barriers and opportunities.[518]

The Commission's proceeding to advance demand flexibility through electric rates—initiated in July 2022—seeks to "establish demand flexibility policies and modify electric rates," in order to, among other objectives, "enable widespread electrification of buildings and transportation."[519] That proceeding serves as a focal point for reforming retail rates and pursuing dynamic pricing structures to facilitate, among other things, greater utilization of EVs as grid assets. That proceeding is also exploring opportunities for EVs to receive export credits, which D.20-12-029 established as a near-term objective to promote VGI.[520]

In addition to three other EV rates decisions, D.22-08-002 approved a real-time pricing pilot for residential and commercial EV customers in PG&E

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[517] *Id.* at 22 (describing this objective as "practically speaking [promoting the] use of EVs to provide bi-directional grid-export power").

[518] Res. E-5192.

[519] R.22-07-005, Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates at 7 (July 14, 2022).

[520] D.20-12-029 at 75.

territory with the goal of reducing peak capacity costs.[521] This pilot followed several other TOU-rate offerings for residential and commercial customers and supported VGI objectives by encouraging off-peak charging.[522]

As discussed above, in August 2022, the Commission approved the PEV Submetering Protocol via D.22-08-024, which requires the IOUs to allow customers to use compliant EVSE to separately meter electricity consumption in lieu of installing a separate utility-grade electricity meter. This decision lowered barriers and costs associated with enrollment in EV-specific rates. Critically, D.22-08-024 also adopts EVSE communication protocols. These include the adoption of: (1) SAE J1772 standard connector for all AC-conductive EVSE; (2) CCS standard connector for all DC-conductive EVSE; (3) OCA OCPP 1.6 or later; and (4) ISO 15118. These standards are consistent with those recommended by the CEC.

The use of SAE J1772 and CCS connectors allow for communications between an EV and the EVSE to support vehicle-to-charger communication.

OCPP allows for communication between the utility, charging operators, and site-hosts to provide site hosts and operators greater flexibility, choice, and control over the chargers.[523] OCPP also provides a centralized way for site hosts to connect and communicate with a portfolio of chargers. Adopting OCPP

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[521] *See* D.20-09-021; D.21-11-017; D.22-03-012.

[522] *See, e.g.*, D.19-10-055 (addressing PG&E's Commercial EV Subscription Rate); D.18-05-040 (addressing SCE's EV-specific Demand Charge Holiday Rate); D.18-01-024 (addressing SDG&E limited Public Grid Integration Rate); D.20-12-023 (addressing SDG&E's Electric Vehicle High Power (EV-HP) Rate).

[523] *See* CEC, Electric Vehicle Charging Infrastructure Assessment—AB 2127, https://www.energy.ca.gov/programs-and-topics/programs/electric-vehicle-charging-infrastructure-assessment-ab-2127 at 67.

ensures that the EVSE does not become a stranded asset if the EVSP goes out of business by enabling the seamless transition of network management from one EVSP to another.

ISO 15118 provides a standardized method for an EV and the EVSE to communicate information that enables authentication, automatic billing, and bidirectional charging.[524] This is a critical step forward as all EVSE will be able to securely exchange charging and customer information for authentication, billing, and charging parameters that allow for smart and bi-directional charging capabilities.

With the approval of D.22-08-024, by July 1, 2023, EVSE procured through TE programs that are either ratepayer funded, including the FC1 program discussed in this decision, or IOU administered (*e.g.*, LCFS holdback fund programs), must meet these standards.

4.3.8.1.2. VGI Strategy

Several parties submit comments regarding VGI strategy. Some parties emphasize the need for the Commission to better articulate a VGI strategy and create milestones in key areas of stakeholder concern, including technology enablement and price signals.[525] Auto Innovators encourages the development of an overarching roadmap for the deployment of VGI measures and supporting technologies over the next several years.[526] EDF argues there should be clear and comprehensive guidance on various issues, including managed charging, rate

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[524] *See id.*

[525] GPI Opening Comments on Staff Proposal at 10; Fermata Opening Comments on Staff Proposal at 6, 8.

[526] Auto Innovators Opening Comments on Staff Proposal at 6.

design, harnessing bidirectional capabilities of vehicles, and communication standards to ensure interoperability.[527] ChargePoint, EVgo, and the Joint Parties urge the Commission to continue to pursue the work envisioned by the EVREV Plans in the Draft TEF.[528]

We recognize the lack of clarity on VGI strategy and the need for this strategy to complement and inform FC1. Therefore, we find it appropriate to establish strategic focus areas for VGI: (1) rates and demand flexibility programs; (2) technology enablement; and (3) planning. We also adopt an annual VGI Forum to explore these strategic focus areas because successfully addressing VGI issues requires the involvement of multiple Commission divisions and state agencies. These actions lay the groundwork for further Commission guidance on VGI policy over the coming years.

For the first strategic focus area concerning rates and demand flexibility programs, parties have rightly noted that rates will be a core component of enabling VGI.[529] We agree that the primary venue for enabling customer participation in VGI will occur through proceedings and discussions on rates and demand flexibility programs. We therefore encourage stakeholder engagement in these proceedings. The VGI Forum discussed below will explore current and future approaches to utilizing rates as a core VGI strategy, reflecting the

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[527] EDF Opening Comments on Staff Proposal at 6.

[528] ChargePoint Opening Comments on Staff Proposal at 9; EVgo Opening Comments on Staff Proposal at 2; Joint Parties Opening Comments on Staff Proposal at 4.

[529] EVgo Opening Comments on the 2022 Staff Proposal at 2; Joint Parties Opening Comments on the 2022 Staff Proposal at 6; Auto Innovators Opening Comments on the 2022 Staff Proposal at 6, 11, 13; Joint Commenters Reply Comments on the 2022 Staff Proposal at 6; GPI Opening Comments on the 2022 Staff Proposal at 13; EDF Opening Comments on the 2022 Staff Proposal at 6.

Commission's intent to continue EV rate development in dedicated rate and demand flexibility proceedings, such as R.22-07-055. This component of the VGI strategy will build upon the EVREV strategy outlined in the Draft TEF. While we are not requiring the EVREV plan development outlined in the Draft TEF, we will continue to provide leadership on rate strategy via these proceedings and the VGI Forum.

Regarding the second strategic focus area, the IOUs will have a significant role to play in the enablement of VGI technology, including establishing interconnection standards and supporting the development of performance requirements for VGI equipment. The VGI Forum discussed below will explore the appropriate role of the IOUs, recognizing the IOUs are better positioned to enable rather than develop technology to advance VGI. The forum will also investigate whether ratepayer funds should support technology development in limited cases.

For the final strategic focus area of grid planning, the Commission, in conjunction with other state agencies, is currently working across various proceedings and processes to ensure that EV charging demand and VGI potential is properly accounted for in distribution, generation, and transmission system planning. As described earlier in this decision, the Commission and other state agencies are deeply engaged on this topic and are developing new analytical methods and processes to better account for VGI capabilities as technology evolves and becomes more widespread. The VGI Forum described below includes a discussion of these efforts and implications for Commission rates and programs.

The IOUs, in conjunction with ED staff, shall host annual VGI Forums. The primary purpose of the forums shall be to provide an opportunity for strategic

communication, information sharing, and discussion of relevant VGI issues, similar to the 2018 Commission ZEV Rate Design Forum.[530] Additionally, the required process shall provide an opportunity to incorporate learnings and developments on VGI into both the FC0 and FC1 programs, as well as other Commission venues (*e.g.*, interconnection, rate design, etc.). The two main topics for the forum will be:

1. Rates and Planning: This topic focuses on the linkages among planning, VGI, rate, and demand flexibility programs and proceedings. The forum should be held as a part of the Commission's Annual Rate Forum and include presentations on progress, gap assessments, and the need for EV-specific rates.
2. Technology Enablement: This focuses on technology enablement, VGI in existing IOU programs and pilots, and the incorporation of new technology developments into FC1. This forum should coordinate with the CEC's VGI staff to showcase recent developments (*e.g.*, emerging technology, ALM, coordination on VGI equipment certification, etc.).

The first of these forums, to be held in 2023, should include further discussion, input, and refinement of the framework to advance VGI strategy included in this decision. Additional areas for discussion could include revisiting the definition of VGI adopted in D.20-12-029, refinement or expansion of the three VGI strategic focus areas, and identification of milestones and deliverables to address high-priority barriers to VGI.

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[530] California Public Utilities Commission, CPUC ZEV Rate Design Forum, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/transportation-electrification/electricity-rates-and-cost-of-fueling/cpuc-zev-rate-design-forum.

Following each VGI Forum, the IOUs shall file a workshop report, which will ensure that the discussions and lessons identified are added to the record of this proceeding or its successor. The IOUs shall also distribute the workshop reports to the service lists for other relevant Commission proceedings. The IOUs shall propose any changes to the FC1 program based on the VGI Forum's discussion and the subsequent workshop reports through the Tier 2 Advice Letter filing following the annual roundtables. Changes could include, for example, incorporation of new technology or modifications to technology requirements. The IOUs may also file separate Tier 2 Advice Letters, where appropriate, to propose any changes to the FC0 programs.

4.3.8.1.3. VGI, Rates, and Load Management Directives for the FC1 Program

The Staff Proposal requests comment as to whether the FC1 program should include any requirements for customers to participate in DR programs or implement other load management tactics.

Many parties express general support for DR and load management requirements. Weave Grid supports tying rebates to DR and load management requirements to increase enrollment and participation in VGI programs.[531] VGIC recommends providing an upfront incentive to enroll in DR programs.[532] GPI and SBUA support the inclusion of incentives to encourage customers to participate in DR and implement other load management practices.[533] SCE and

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[531] Weave Grid Opening Comments on Staff Proposal at 9.

[532] VGIC Opening Comments on Staff Proposal at 6, 8.

[533] GPI Opening Comments on Staff Proposal at 19; SBUA Opening Comments on Staff Proposal at 16.

Cal Advocates emphasize that ME&O should focus on educating customers about on the benefits of load management and the IOUs' DR programs.[534] VGIC and Fermata assert that the ME&O administrator should present all DR options to participants and the IOUs should provide TA.[535]

Many parties argue that additional load management requirements are not necessary for FC1. They indicate that different load management strategies are appropriate in different charging applications and that the Commission should preserve customers' options to choose.[536] ATE emphasizes that load management requirements are unnecessary since most, if not all, rebates in FC1 will be for MUD applications where load management is difficult.[537] CSE asserts that the institution of requirements to participate in such programs could limit participation, particularly in DACs and underserved communities.[538] CSE recommends phasing in requirements and providing higher incentives to customers to participate in load management programs. Electrify America encourages the Commission to avoid adoption of mandatory participation in DR programs as a condition of taking service under a commercial tariff approved by the Commission.[539]

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[534] SCE Opening Comments on Staff Proposal at 22; Cal Advocates Opening Comments on Staff Proposal at 23.

[535] VGIC Opening Comments on Staff Proposal at 6; Fermata Opening Comments on Staff Proposal at 7.

[536] Tesla Opening Comments on Staff Proposal at 9; SCE Opening Comments on Staff Proposal at 22; Cal Advocates Opening Comments on Staff Proposal at 23; EVgo Opening Comments on Staff Proposal at 3.

[537] ATE Opening Comments on Staff Proposal at 13.

[538] CSE Opening Comments on Staff Proposal at 13.

[539] Electrify America Opening Comments on Staff Proposal at 11.

We find that a flexible approach is warranted because each customer will have specific constraints and a uniform approach to load management is not appropriate. Furthermore, the rapid evolution of technology and compensation mechanisms necessitates a flexible approach. Therefore, we do not adopt a requirement for FC1 program participants to enroll in any specific DR program or to adopt any specific load management strategy. Customers should have the option to choose based on their mobility needs and use cases. However, we require the IOUs to default all FC1 participants on to applicable time-varying EV-specific rates, with the ability to opt out for another time-varying rate. This is consistent with the requirements of the EV Infrastructure Rules. The IOUs, in conjunction with the CCAs in their service territories, should provide education to each customer on the most beneficial rates.

We also direct the IOUs to work with each customer to develop a load management plan, which the IOU should formally approve. The load management plan could include various options that ensure that charging load is flexible and responsive to price signals. As part of the load management plan development process, each IOU should work with customers to educate and provide guidance on various options for VGI and load management, including but not limited to enrollment in DR programs and deployment of ALM. This guidance should be competitively neutral and should not endorse any provider or technology. The Program Handbook should determine the requirements for the load management plans following discussion at one of the associated workshops.

4.3.8.1.4. Rebates for ALM in FC1

The role of ALM, requirements and potential incentives for ALM, and implementation details have been a key focus of this proceeding. In response to

the Staff Proposal, many parties present arguments regarding ALM and its implementation within FC1.

While many parties support encouraging ALM and DR, most agree that the Commission should not require ALM or DR because they may not be the right option for all use cases. EDF Renewables supports requiring ALM if it creates cost savings for a site.[540] Weave Grid supports ALM but argues the Commission should not require participation for all use cases.[541] VGIC maintains that ALM should always remain an optional strategy for customers.[542] VGIC and Fermata recommend offering an incremental incentive to host sites that voluntarily choose ALM that is linked to customer- and utility-side cost savings.[543] SCE and ChargePoint suggest requiring that funded hardware be ALM capable.[544]

We find it appropriate to establish a clear path to rigorously consider and decide whether to implement an incremental rebate for customers who choose to deploy ALM. First, to reduce ambiguity, we provide a definition of ALM for use throughout FC1: ALM refers to energy management systems that are deployed at a particular location to reduce aggregate EV charging load with the objective of reducing or eliminating the need for electrical capacity upgrades on the utility

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[540] EDF Renewables Opening Comments on Staff Proposal at 6.

[541] Weave Grid Opening Comments on Staff Proposal at 9.

[542] VGIC Opening Comments on Staff Proposal at 10.

[543] VGIC Opening Comments on Staff Proposal at 9, 12; Fermata Opening Comments on Staff Proposal at 7.

[544] SCE Opening Comments on Staff Proposal at 12; ChargePoint Opening Comments on Staff Proposal at 15.

and/or customer side of the meter.[545] Unless otherwise specified in other contexts (*e.g.*, rates, rules, etc.), this definition of ALM should apply.

Furthermore, it is important to develop a broader understanding of the costs and benefits of ALM to support a potential incentive design prior to large-scale deployment of an incentive. If a rebate amount is too low, it may not facilitate any additional ALM installations, but if it is too generous, it could result in misallocation of resources. Therefore, we require a study to assess ALM strategies and product offerings, barriers, equity impacts, and costs to determine whether rebates are necessary to incentivize ALM deployment, as well as how to best design potential rebates given outstanding implementation issues. Additionally, the study shall assess the IOUs' ALM education activities in deploying the EV Infrastructure Rules to provide insights on the current deployment of ALM. The study shall inform the appropriate structure of potential ALM rebates.

To complete this work, ED staff will manage an ALM study utilizing the technical consultant budget discussed above. Following the completion of this study at the end of Q1 2024, the Commission will issue the study along with staff recommendations on whether to pursue ALM rebates in the FC1 program via a ruling to allow for stakeholder comment. If ED staff recommends the Commission adopt ALM rebates, the ruling should also include recommendations for how to structure and implement the rebate program.

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[545] While D.20-12-029 refers to ALM as "software-based technology to manage EV charging load, also known as EV Energy Management Systems or load management," we find that this definition is overly broad and could be construed to mean any software that enables load flexibility (*e.g.*, original equipment manufacturer applications used to schedule EV charging).

If the Commission approves ALM rebates, the IOUs shall implement the rebates as part of their TA programs, as this is closely tied to the IOUs' role in educating customers under the EV Infrastructure Rules and load management plans. The FC1 infrastructure rebate budget shall provide funding for any ALM rebates, and we clarify that the funding shall not come out of the TA budget. The IOUs shall work with the Program Administrator to facilitate a streamlined, combined application process and rebate payment.

4.3.8.1.5. Outstanding Issues from D.20-12-029 Regarding ALM

D.20-12-029 ordered the IOUs to take specific actions to integrate consideration of ALM into all TE applications and "any future tariff or rule filed by a large electrical corporation for service line and/or distribution line upgrades to support transportation electrification."[546] These actions include:

> identify[ing] how it will deploy customer-side [ALM] at host sites through such programs, rule, and/or tariff where appropriate because this technology will support TE installation at equal or lesser costs than hardware-based electrical capacity while meeting TE charging needs; and describe[ing] its standard evaluation criteria to determine host sites where ALM would benefit ratepayers by reducing costs while meeting host site needs for electric vehicle charging.[547]

As discussed above, we continue to support ALM as an optional load management strategy for customers and require education on ALM both as part

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[546] D.20-12-029 at 28.

[547] D.20-12-029 at 79. This decision also directed ED staff to host a workshop to explore the referenced "standard evaluation criteria." This workshop was held on January 29, 2021. Following this workshop, ED staff declined to recommend additional guidance to the IOUs on standard evaluation criteria.

of the EV Infrastructure Rules and as part of the FC1 TA requirements. We further find that the above ALM requirements in D.20-12-029 are overly broad and create unnecessary ambiguity given the new funding cycle structure and the potential impact on future EV rate design.[548] In order to reduce ambiguity and to emphasize the importance of ensuring that IOU education on ALM includes thorough consideration of EV drivers' mobility needs, we modify Ordering Paragraphs 5 and 6 in D.20-12-029 as follows:

> 5. Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company shall, each, in any future transportation electrification (TE) programs to support TE infrastructure installation identify how it will educate customers on how Automated Load Management technology may support TE installation at equal or lesser costs than hardware-based electrical capacity while meeting host site and electric vehicle drivers' charging and mobility needs.
> 6. Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company shall each evaluate customer acceptance once Automated Load Management is installed at a host site as part of a ratepayer-funded transportation electrification program.

4.3.8.2. Aligning EVSE Qualification Process with the CEC's Process—LD and MDHD

The Staff Proposal requests comment on whether the Commission should align the qualification process for LD and MDHD EVSE with the CEC's process to reduce administrative burden and to harmonize program requirements.

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[548] D.20-12-029 indicated that "future Commission decisions may adopt additional VGI strategies or modify those adopted in this decision." D.20-12-029 at 6.

Parties generally support aligning the qualification process.[549] Tesla also agrees, but indicates that any process should take into account new block grants the CEC is developing.[550] SCE supports alignment and suggests using the Electric Power Research Institute's EVSE Qualification Working Group.[551] NDC supports alignment with the CEC process, but indicates that review and revision of qualifications is necessary as the market and technology develops to ensure that previously qualified EVSE continue to meet evolving standards.[552] GRID agrees recommends that the Commission should align its processes for public LD EVSE with those of other relevant CEC and Commission programs to ensure that customers can integrate solar PV and EVSE in a streamlined fashion.[553]

We find that alignment of the Commission's EVSE qualification process for LD and MDHD EVSE with the CEC's process is warranted for administrative efficiency and to harmonize program requirements. The product list should additionally aim to align with other state and federal charging requirements, where appropriate. The Program Administrator shall manage the approved product list and ensure that the list is accessible through the program website.

The IOUs should qualify EVSE on a rolling basis and automatically add equipment to the product list if it meets all of the technical requirements. These technical requirements should also be accessible through the program website

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[549] ChargePoint Opening Comments on Staff Proposal at 15; Auto Innovators Opening Comments on Staff Proposal at 22.

[550] Tesla Opening Comments on Staff Proposal at 8.

[551] SCE Opening Comments on Staff Proposal at 21.

[552] NDC Opening Comments on Staff Proposal at 22.

[553] GRID Opening Comments on Staff Proposal at 9.

and updated as changes to the requirements occur. The Program Handbook development process shall determine the initial technical requirements and must, at minimum, comply with the EVSE requirements adopted in D.22-08-024. Stakeholders should review the technical requirements at each annual roundtable and propose any necessary modifications.

4.3.8.3. EVSE and Technical Requirements

The Staff Proposal requests comment on whether the FC1 program should implement any other EVSE and technical requirements. SCE asserts that the Commission should require that EVSE are maintained for a set number of years and mandate the sharing of certain customer data with the IOUs. SCE recommends determining any requirements during Program Handbook development process.[554]

CSE supports requirements for rebate recipients to install EV infrastructure that is standardized, interoperable, and accessible. CSE's recommended requirements include standardized charging connectors, open standard communication protocols, and compliance with accessibility and payment requirements instituted under CARB's EVSE Standards regulation. CSE also supports a requirement that participants share data regarding charger utilization and uptime.[555] ChargePoint and Joint Commenters argue for requiring all EVSE to be networked, DR capable, and capable of performing load management. Electrify America does not support data collection requirements,

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[554] SCE Opening Comments on Staff Proposal at 22-23.

[555] CSE Opening Comments on Staff Proposal at 13.

expressing concern for the potential for such requirements to allow access to commercially sensitive information.[556]

We find that the adoption of some minimum EVSE requirements is necessary to ensure the effectiveness of the FC1 program. Therefore, we shall adopt minimum EVSE technical and data sharing requirements. The minimum EVSE technical requirements are:

1. A minimum EVSE maintenance period of eight years;
2. The uptime reliability must be consistent with the CEC and any relevant laws, including AB 2061 (Ting, 2022), for all ratepayer-funded EVSE in FC1;[557]
3. Consistent with D.22-08-024, all EVSE shall be interoperable, utilizing standardized charging connectors and open standard communication protocols, and should comply with accessibility and payment requirements per CARB's EVSE Standards regulation;
4. All EVSE funded through FC1 shall be networked and DR capable; and
5. All public MUD-serving EVSE shall be available to the public 24 hours per day, seven days a week.

The minimum EVSE data sharing requirements are:

1. EVSPs shall share uptime and utilization data;
2. For public and MUD charging, EVSPs shall share the price charged to customers;
3. EVSPs shall share, confidentially if needed, the cost of networking and maintenance packages they offer to customers; and

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[556] Electrify America Opening Comments on Staff Proposal at 12.

[557] AB 2061 (Ting, 2022) includes possible development of reliability/uptime requirements.

4. EVSPs shall provide the number and location of shared private chargers they have deployed or manage with the Commission and the CEC, upon request.

The EVSPs must share the data, confidentially if needed, with the Program Administrator and the Commission—but not with the IOUs. The Program Handbook shall describe the process for confidential data transfer and the level of detail and aggregation of data.

These EVSE technical and data sharing requirements are the minimum requirements and only apply to FC1 EVSP vendors and customers receiving ratepayer funds. The data will assist the Commission in understanding the total cost of ownership for the transition to electrified transportation and will inform the design of future incentives and educational materials. The Program Handbook may include additional requirements.

4.3.8.4. Ensuring Program Flexibility

The Staff Proposal requests comments on how the Commission should ensure that the FC1 program has sufficient flexibility to account for new technology and/or business models that may develop over the next several years.

Tesla supports an annual technology and cost review by either an independent third party or the Program Administrator, with an opportunity for stakeholder feedback.[558] PG&E and SDG&E support a mid-cycle review to identify where modifications are needed.[559] ATE recommends a review prior to the start of FC1 and a FC1 mid-cycle review. ATE also emphasizes that the IOUs

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[558] Tesla Opening Comments on Staff Proposal at 9-10.

[559] PG&E Opening Comments on Staff Proposal at A7; SDG&E Opening Comments on Staff Proposal at 11.

should be able to make filings during FC0, as needed, to account for new technology or business models.[560]

The Joint Commenters generally support the modification process within the proposal, request clarity on the venue for discussion.[561] The Joint Commenters also indicate a need for general flexibility that would allow the IOUs to act outside of the FC1 program in response to targeted TE needs. GPI supports the proposal to leverage existing PAC meetings to host an annual or biennial roundtable discussion to identify program modifications.[562] NDC comments that TA programs should be continually updated in order to help customers evaluate different technologies.[563]

We acknowledge the need for program flexibility and adopt annual roundtables and the Mid-Cycle Assessment to allow stakeholders the opportunity to flag any concerns with the implementation of the FC1 program. The roundtable process is described above. The roundtables and corresponding Advice Letter filing can resolve minor issues through edits to the Program Handbook. The Mid-Cycle Assessment shall address larger modifications to the program.

4.3.9. Targets

Several parties comment that the Commission should set targets to ensure IOUs are making measurable progress. Auto Innovators asserts that metrics and a scorecard are needed to ensure steady and timely process on the IOUs'

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[560] ATE Opening Comments on Staff Proposal at 13.

[561] Joint Commenters Opening Comments on Staff Proposal at 11-12.

[562] GPI Opening Comments on Staff Proposal at 21.

[563] NDC Opening Comments on Staff Proposal at 23.

TE initiatives. Auto Innovators encourages the Commission to set targets for each metric as a basis to assess the IOUs' performance of their core responsibilities such as distribution upgrades, implementing ratepayer funded programs, and developing EV rates and DR programs.[564] EDF also stresses the importance of target and metrics in ensuring: (1) EVs are successfully integrated into the grid and (2) IOUs are making measurable progress.[565] UCAN and GPI stress the importance of appropriate metrics and targets.[566]

We agree that program targets can improve program implementation and performance. Therefore, we establish a target development process and provide a list of minimum target categories for FC1. The Program Handbook development process shall include a workshop to address the development of targets, which the Program Handbook should adopt.

At a minimum, program targets shall address: (1) equity; (2) LD ports; and (3) MDHD vehicles electrified. To address equity, we would set targets for LD and MDHD programs in reaching target equity groups, including DACs and low-income customers. The LD ports category would set a minimum number of MUD and MUD-serving ports for the FC1 program to support, based on the rebate level established via the Program Handbook development process. The MDHD vehicles electrified category would set targets for a minimum number of vehicles electrified as a result of the MDHD program, based on the rebate level established via the Program Handbook development process and an assumption

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[564] Auto Innovators Opening Comments on Staff Proposal at 14.

[565] EDF Opening Comments on Staff Proposal at 3.

[566] UCAN Opening Comments on Staff Proposal at 2; GPI Opening Comments on Staff Proposal at 12.

of the minimum number of ports the program will fund. Sub-targets or program tracking metrics by vehicle type or fleet size may be established for the MDHD vehicles electrified category, as appropriate. We may approve final targets in the decision adopting the Program Handbook. We may consider modifications to the adopted targets as part of the Mid-Cycle Assessment.

4.3.10. Program Handbook Development Process

Several parties provide comments regarding the process for the development of the Program Handbook. The Joint Commenters request clarification that stakeholders can provide written input to the stakeholder process led by the third-party administrator as well as after any workshop that informs the Program Handbook.[567] EDF supports the development of the Program Handbook by stakeholders.[568] Tesla recommends delaying the development of the Program Handbook to "ensure it meets the needs of future equipment and customers in 2025 rather than being designed solely based on the current state of EVSE technology and deployment."[569]

TURN emphasizes that additional procedural vehicles, including workshops and party comments, are necessary to develop aspects of the Program Handbook.[570] SCE indicates that the timeline for the submission of the Tier 3 Advice Letter with the Program Handbook does not provide sufficient time for

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[567] Joint Commenters Opening Comments on Staff Proposal at 7.

[568] EDF Opening Comments on Staff Proposal at 17.

[569] Tesla Opening Comments on Staff Proposal at 7.

[570] TURN Opening Comments on Staff Proposal at 12.

appropriate stakeholder engagement and requests an extension of the submittal date to Q2 2023.[571]

As part of the Program Handbook development process, the Program Administrator and IOUs shall host a series of workshops. At a minimum, these workshops should cover the following topics: (1) TA scope; (2) TA engagement with EVSPs and ALM/DR providers; (3) establishment of clear communication channels with CCAs for TA; (4) load management plans; (5) ME&O; (6) CBO engagement in ME&O; (7) rebate levels; (8) establishment of an upfront rebate; (9) support for small fleets and small businesses; (10) effective support and outreach for underserved communities; (11) technical requirements; and (12) targets. The workshops can cover multiple topics as deemed appropriate.

By January 15, 2024, and no later than 60 days following the final workshop, the Program Administrator jointly with the IOUs shall serve on the service list of this or any successor proceeding, a draft Program Handbook and a workshop report covering all of the workshops held as part of the Program Handbook development process.

The Program Handbook development process will determine numerous significant details for the program, so an Advice Letter process is not appropriate. Following the submittal of the workshop report and the draft Program Handbook, the assigned ALJ may issue a ruling requesting comment on both documents. The Commission may subsequently adopt the Program Handbook, with any modifications.

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[571] SCE Opening Comments on Staff Proposal at 13.

The Program Handbook shall contain three main sections: (1) Rebate Program Rulebook; (2) Implementation Plan; and (3) Technical Assistance Rulebook. Through the annual roundtables and associated Tier 2 Advice Letter filings, we may adjust the Rebate Program Rulebook section of the Program Handbook. Additionally, through the Mid-Cycle Assessment and subsequent Commission decision, we may further adjust sections of the Program Handbook.

To ensure that the Program Handbook includes an appropriate scope of issues, we adopt the following minimum scope list for the Program Handbook.

1. Rebate Program Rulebook
    - Rebate guiding principles
    - Procedures and penalties for non-compliance with the Program Handbook requirements
    - Program targets
    - EVSE operating requirements (*e.g.*, minimum of 10 years)
    - Reporting requirements and reporting formats
    - TE Reporting Dictionary (*i.e.*, common definitions for of all data fields)
    - High-level ME&O objectives, scope, and budget
    - Subcontracting rules
    - Guidelines and rules for roundtables
    - EVSP data sharing requirements
    - Definition of MUD-serving

- Portion of underserved communities funding for tribal communities and any associated requirements[572]
- MDHD definition
- MUD definition
- Small fleet and small business definitions

2. Implementation Plan
    - Rebate levels and delivery methods, including upfront rebates and potential bridge loans or other assistance to mitigate up-front cost barriers for targeted customers
    - Customer application procedures
    - Applicant requirements and application procedures
    - Requirements for applicant documentation
    - Program budget that includes line items for rebates, ME&O, subcontracts, administrative activities, etc.
    - Contractor and electrician requirements
    - Vendor requirements
    - ME&O marketing plan
    - CBO engagement plan
    - List of key CBO and environmental justice organization partners
    - Targeted approach for rebates to tribal communities
    - Modified MDHD requirements for customers installing public/shared MDHD charging
    - Modified MDHD requirements for small business, for whom responsibility for financing, ownership, vehicle operations, property, etc. may belong to different entities

[572] Including unique use cases or exceptions proposed for tribal communities and members.

- EVSE technical requirements
- Customer troubleshooting procedures
- TE Safety Checklist requirements

3. Technical Assistance Rulebook
    - Scope of IOUs' TA programs
    - Joint requirements and processes for speaking with customers about TA
    - Defined channels of communication between each IOU's TA and each CCA in their territory
    - Established practices for how to work directly with each CCA in an IOU's territory in discussing rates and directing customers to a CCA when necessary
    - Defined channels of communication between each IOU's TA and the Program Administrator
    - Guidelines for how the IOUs' TA programs should engage with the private market of EVSPs and DR providers
    - Details and requirements for customer load management plans
    - Load management and VGI targets/metrics

The Program Administrator shall be responsible for the Rebate Program Rulebook and the Implementation Plan. The Rebate Program Rulebook shall contain information about the rebate and ME&O programs, customer rules, and program delivery rules. This is the practical information that the Program Administrator will use to implement the FC1 program.

The Implementation Plan shall describe how the Rebate Program Rulebook is implemented from a regulatory perspective, including contracting administrative details, information on targets, budget, and all program requirements. This section shall also establish the requirements for

documentation, including site verification forms, permits, and utility design submittals during the application process, as well as construction progress forms and final permits after funds have been reserved will be determined. These documentation requirements should be aligned with CALeVIP 2.0 requirements where appropriate. The Implementation Plan section shall provide background and an explanation of the program design.

The IOUs shall be responsible for the Technical Assistance Rulebook. It shall cover the program rules for the IOUs' implementation of the TA programs and shall serve as a guide for how the IOUs interact with each other, with the CCAs in their territory, and with the Program Administrator.

4.3.11. Data Assessment

Parties' comments on the Staff Proposal address whether to require a data audit. To avoid confusion with other audits directed in this decision, we refer to this activity as the Data Assessment.

UCAN and Cal Advocates support the proposal for a data assessment, indicating that it could help assess all information reported by the IOUs and identify any gaps in data reporting.[573] UCAN also emphasizes the importance of collecting charging load data. The Joint Commenters assert that the IOUs should report where and with what frequency data is made available.[574] The Joint Commenters also support an annual data summit. CSE generally supports an

[573] UCAN Opening Comments on Staff Proposal at 8; Cal Advocates Opening Comments on Staff Proposal at 23.

[574] Joint Commenters Opening Comments on Staff Proposal at 13.

assessment of data, indicating there are clear needs for data collection and evaluation regarding EV infrastructure accessibility, uptime, and utilization.[575]

Parties' comments also include proposals to collect data related to equity. Greenlining recommends developing clear equity metrics and publishing deployment and resource data to identify where gaps exist and to ensure investments target priority populations.[576] Greenlining and CSE note the lack of and need for centralized geospatial analysis of the locations of IOU TE investments and infrastructure.[577] Greenlining recommends the program collect equity-related data on land use, zoning, and demographic trends, as well as climate data on sea level rise and flood and fire risk.[578]

We adopt the Staff Proposal's structure because it is a reasonable methodology to inventory all IOU TE data and ensure funds are properly spent. The Data Assessment will inventory data the IOUs report under all directed TE reporting in order to streamline existing reporting requirements, minimize unnecessary or duplicative reporting, and inform FC1 program reporting requirements. Because the Data Assessment will inform the FC1 reporting requirements discussed below, the process must conclude prior to the launch of FC1.

We direct the IOUs to submit to ED staff a complete inventory of all TE-related data fields the IOUs are currently reporting under the various Commission TE reporting requirements, including under individual programs,

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[575] CSE Opening Comments on Staff Proposal at 13.

[576] Greenlining Opening Comments on Staff Proposal at 9.

[577] *Id.*; CSE Reply Comments on Staff Proposal at 5.

[578] Greenlining Opening Comments on Staff Proposal at 12.

SB 676, the Cost and Load Report, and LCFS. This reporting should itemize each individual data field reported and include a complete definition of each field, unit, frequency, and period.

By collecting and examining the data, the Data Assessment will facilitate an analysis of all information the IOUs report and help identify where there are gaps in data reporting. This will provide a basis to streamline TE data reporting and improve transparency. Additionally, the Data Assessment will identify data fields where the IOUs have differing definitions and propose universal definitions to allow for comparison across IOUs. These universal definitions will allow for comparison, when possible and applicable, between FC0 and FC1 programs.

The Program Handbook decision shall adopt, and update as needed, data field definitions—referred to as the TE Reporting Dictionary—and establish a process to align the definitions across IOUs. We adopt the timeline, process, and deliverables for implementation of the Data Assessment in Appendix B of this decision.

4.3.12. Reporting Requirements

The Staff Proposal requests comments on reporting requirements for FC1. CSE stresses the importance of robust data collection, evaluation, and reporting requirements.[579] CSE emphasizes the importance of the data to quantify equity benefits, forecast future needs, inform program design changes, and track progress towards state goals. CSE recommends that the Commission coordinate with CARB and CEC to develop standardized metrics and data collection

[579] CSE Opening Comments on Staff Proposal at 9.

methods. CSE also includes various categories of data that should be included in the reporting requirements.

We find reporting requirements will help monitor progress towards program goals, promote coordination with local, state, and federal programs, and provide transparency to the public. The decision adopting the Program Handbook will establish reporting requirements for FC1, including reporting format and frequency, as well as a process for revising reporting requirements. Reporting requirements will align with the CEC's data collection requirements and include energy forecasts and grid planning information where feasible and appropriate. The Program Handbook shall also establish standardized data transfer protocols, data request documents, and template data sharing agreements for the Program Administrator and the IOUs and for the Program Administrator and the EVSPs.

5. Conclusion

This decision adopts a funding cycle structure for TE and a third-party administered statewide TE infrastructure rebate program and directs the IOUs to jointly fund the program and associated activities. The decision addresses issues in the Draft TEF and the Staff Proposal. The adopted rebate program will accelerate BTM EV charging deployment to support California's ambitious climate goals, while limiting costs to ratepayers, promoting equity, minimizing administrative burden, and maximizing stakeholder participation.

6. Comments on Proposed Decision

The proposed decision of Commissioner Clifford Rechtschaffen in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. On November 3, 2022, the following parties

filed opening comments: Auto Innovators, ATE, Cal Advocates, CASMU, CEDMC, ChargePoint, Clean Energy Fuels, CLECA/EPUC,[580] City of Long Beach, CSE, EDF, EDF Renewables, Electric Vehicle Association, Electrify America, EVgo, FreeWire Technologies, Inc. (FreeWire), GPI,[581] Greenlining, GRID, Joint CCAs,[582] Joint Commenters,[583] NDC, NRDC, PG&E, SBUA, SCE, SDG&E, Siemens, Tesla, the Mobility House, TURN, VGIC, and Weave Grid. On November 8, 2022, the following parties filed reply comments: Auto Innovators, Cal Advocates, CASMU, ChargePoint, CSE, EDF, Electric Vehicle Association, Electrify America, FreeWire, GPI, Greenlining, Joint CCAs, Joint Commenters, NDC, NRDC, PG&E, SCE, SDG&E, Tesla, the Mobility House, TURN, and VGIC. We have considered parties' comments and made modifications to the decision as appropriate.

7. Assignment of Proceeding

Clifford Rechtschaffen is the assigned Commissioner, and Brian Korpics and Marcelo Poirier are the assigned ALJs in this proceeding.

Findings of Fact

1. The planning landscape has changed significantly since the issuance of the Draft TEF, and much of the planning work that the TEP proposal envisioned is underway.

2. The Commission currently engages in a number of processes to coordinate internal and interagency TE infrastructure planning efforts with IOU planning.

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[580] CLECA and EPUC filed joint opening comments.

[581] GPI filed its opening comments on November 2, 2022.

[582] Joint CCAs here refers to CalChoice, CPA, EBCE, MCE, PCE, RCEA, SDCP, SJCE, and SCP.

[583] Joint Commenters here does not include the Center for Biological Diversity.

3. Most, if not all, TE market segments are not yet mature.

4. The Commission adopted TE Safety Checklists in D.18-01-024 and D.18-05-040.

5. The Commission adopted EVSE communication standards in D.22-08-024.

6. Pursuant to D.20-12-029, SCE filed, and the Commission approved, SCE Advice Letter 4521-E, concerning a cybersecurity workplan, but the Commission did not authorize the requested budget.

7. Portable fuel cards that offset the cost of charging for low-income customers who lack access to off-peak charging at home may promote equity.

8. The majority of the Commission's prior TE program decisions require the IOUs to recover costs in either a one-way Balancing Account or one-way subaccount within their TE Balancing Accounts.

9. The Commission's prior TE program decisions and the EV Infrastructure Rules direct the IOUs to recover costs via distribution rates.

10. An equal cents per kWh allocation factor will ensure that costs are distributed across all customer classes equitably.

11. Air Districts and Metropolitan Planning Organizations can share details on other funding opportunities and help influence program implementation details (*e.g.,* rebate levels, outreach tactics, etc.).

12. IOU outreach on the FC1 program to Air Districts and Metropolitan Planning Organizations can help ensure that the program addresses regional TE plans, leverages additional outreach support from Air Districts and Metropolitan Planning Organizations, leverages funding sources and incentive stacking, and supports the equitable geographic distribution of charging infrastructure.

13. ME&O efforts post-energization can help to increase charger utilization rates.

14. Existing statewide efforts promote EV awareness, including the $5 million program to promote ZEV awareness funded by the Governor's Office of Business and Economic Development.

15. Small businesses and small fleets would benefit from increased support through TE ME&O activities.

16. The Staff Proposal accounts for party feedback on the Draft TEF, updated direction from the Legislature, recent Commission decisions and resolutions, and market developments.

17. The Staff Proposal's funding cycle approach moves beyond the current piecemeal application and approval processes and better account for the evolving TE policy and market landscape.

18. The passage of AB 841 and the resulting EV Infrastructure Rules clarified the scope and magnitude of the IOUs' TE role to support and enable the TE market by acting as utility-side infrastructure and fuel providers.

19. There is a significant need for more EV charging infrastructure in the near-term to meet California's TE and emissions goals.

20. FC1 program funding will help the state meet its TE goals by reducing the installation costs for EV charging infrastructure.

21. Additional analysis—provided in part through the FC1 evaluation and market assessments—is needed before the Commission considers authorizing BTM TE funding beyond FC1.

22. The five-year funding cycle timeline provides clarity, certainty, and a reasonable timeframe for the periodic evaluation of the need for IOU BTM TE investments.

23. D.21-07-028 adequately addresses near-term IOU funding opportunities for the remainder of FC0.

24. A two-year grace period for FC0 to overlap with FC1 allows the IOUs to accept customer applications and agreements within FC0 programs through December 31, 2026, if the Commission has not directed otherwise, and provides sufficient flexibility to allow for the effective completion of FC0 programs and allocation of the associated funding.

25. A single Mid-Cycle Assessment in 2027, the third year of FC1, is appropriate to ensure flexibility in program implementation, sufficient review of FC1, confirmation of whether investments are adequately serving the market and contributing to state goals.

26. The Mid-Cycle Assessment and the annual roundtables will provide sufficient flexibility for the FC1 program, while not overburdening stakeholders, the IOUs, and the Program Administrator.

27. An annual roundtable will provide program flexibility by creating a venue for stakeholder input and review of data/evaluation results to inform adjustments and updates to the Program Handbook, including modifications to rebate levels and changes to better reach underserved communities.

28. A single annual roundtable is more efficient than hosting separate data- and equity-focused roundtables.

29. It is premature to adopt guidance for FC2 due to the rapidly evolving TE market and policy landscape.

30. The FC1 program evaluation, market studies, and assessment of the continued role of IOUs in supporting BTM infrastructure will provide information needed to develop FC2 guidance.

31. The existing Commission application pathway per SB 350 provides the IOUs with an adequate process to propose supplemental and pilot programs during FC1.

32. Allowing the IOUs to only access up to 60 percent of FC1 funds within the first three-years of the FC1 program, with access to the remaining 40 percent of funding pending approval through the Mid-Cycle Assessment decision, provides flexibility to determine whether the full $1 billion budget is reasonable over FC1's five-year period and whether modifications to or termination of the program is warranted.

33. Applying all funding caps towards the total accessible FC1 program funds will help accommodate fluctuations in annual spending, such as higher administrative start-up costs in early years and the acceleration of rebate payment as the program progresses.

34. A funding allocation based on each IOU's percentage of electric sales for 2024 is the most equitable way to determine each IOUs' FC1 budget allocation.

35. Limiting disbursed funds to each IOU's funding contribution to the FC1 program and not allowing ratepayers of one IOU to fund another IOU's customers' participation in the FC1 program will prevent unjust and unreasonable rate increases without commensurate benefits.

36. The imposition of an annual funding cap impedes overall program effectiveness because it leads to program uncertainty; in contrast, continual access to authorized program funding will lead to better IOU customer experience, consistent infrastructure investment and deployment, and efficient program administration.

37. The Mid-Cycle Assessment will determine if annual caps are necessary for the second half of the FC1 program.

38. A cap of eight percent cap for both the IOUs' and the Program Administrator's administrative costs is reasonable based on their required program administration responsibilities.

39. An eight percent cap on administrative costs is consistent with the Self-Generation Incentive Program and the Solar on Multifamily Affordable Housing program.

40. The Mid-Cycle Assessment will determine if any adjustments to the eight percent administrative funding cap are warranted.

41. An audit or review will determine whether spent administrative funds exceed the cap.

42. A broader audit scope or additional audits may be necessary.

43. Increased budgets for ME&O and TA will help ensure adequate outreach and engagement with and participation from hard-to-reach and underserved communities and adequate levels of TA.

44. The Mid-Cycle Assessment will determine if any adjustments to the administrative, ME&O, and TA budgets are necessary.

45. Adopting an evaluation budget structure consisting of two separate budgets for the IOUs and ED staff will ensure adequate technical support is available for ED staff up to and throughout FC1.

46. The ED-managed evaluation budget will support contracting with a technical consultant to analyze and assess TE program progress.

47. Reasonable options beyond IOU ownership exist to support low-income, DAC, and small business customers for whom the rebate model may be challenging.

48. While expense treatment of the BTM rebate costs may result in somewhat higher upfront costs, capitalizing these costs will be significantly more expensive for ratepayers over time.

49. Allocating State Budget General Funds for the FC1 program budget is outside of the Commission's authority.

50. Securitization increases ratepayer costs more over time compared with expense treatment.

51. The rebate program provides a well-suited and flexible solution to accelerating TE infrastructure development.

52. The technology and market conditions that inspired declining incentives for the solar market do not translate to deployment of EV charging infrastructure at this time.

53. The Mid-Cycle Assessment will analyze any new information concerning a declining block rebate structure and propose program modifications, if warranted.

54. The ability to stack rebates—provided that total rebates do not exceed project costs—allows for the installation of a broader and larger amount of TE infrastructure.

55. Determination of the appropriate FC1 rebate level will benefit from Commission guidance and additional stakeholder input and analysis.

56. Allowing rebate levels to change annually provides program flexibility to respond to changing market conditions.

57. It is appropriate for the IOUs to maintain administration of TA—for all IOU customers, including FC0, FC1, and non-program participants, as well as bundled and unbundled customers—because TA is part of their core

responsibilities, and they are best positioned to administer the current scope of the program.

58. IOU administration of TA does not raise anti-competitive issues because TA functions involve helping customers with rates and D.12-12-036 includes an exception to marketing limitations for communications that are part of a Commission-authorized program.

59. D.12-12-036 includes an exception to IOU marketing limitations with respect to CCAs for communications that are part of a specific program that is authorized or approved by the Commission.

60. A split CCA- and IOU-administered TA structure would cause confusion for customers when determining with whom they should work.

61. CCAs may be best suited to speak to their customers about their own rate structures.

62. TA would benefit from the involvement of EVSPs and providers of ALM and DR based on their technical expertise.

63. The following TA services help provide comprehensive support and advisory services during the planning, installation, and post-deployment stages of customer projects: (1) basic technical assistance; (2) planning load management and other VGI considerations; (3) help with choosing rates; (4) support with walking through the IOU energization and interconnection process; (5) support and advisory services during planning, installation, and post-deployment; (6) operations post-deployment, like route optimization, load management, and future fleet electrification; and (7) available ALM and DER options to lower deployment costs.

64. Strict standards of technology and product neutrality for the IOUs' TA services avoids interference with competitive markets and ensures customer choice.

65. Additional development of TA and its scope is necessary prior to program launch.

66. Targeted outreach to the following groups will help ensure ME&O activities are effective: (1) underserved communities; (2) rural communities; (3) small businesses; (4) tribal communities; and (5) workforce development, job training and placement, and certification organizations.

67. Additional work is necessary to finalize the ME&O component's scope.

68. The annual roundtable process and associated Tier 2 Advice Letter can review and propose modifications to the ME&O component of the program.

69. Involvement of CBOs and CCAs in the design and implementation of the FC1 program's ME&O component will improve the effectiveness of ME&O due to CBOs' and CCAs' extensive experience working closely with various communities and knowledge of successful outreach practices.

70. The Program Handbook development process, associated workshops, and annual roundtables will benefit from engagement with: (1) the Disadvantaged Community Advisory Group; (2) CBOs that are already integrated into DACs and other underserved communities; (3) non-English speaking community groups; (4) youth groups; and (5) workforce development, job training and placement, and certification organizations.

71. Subcontracting with CBOs, CCAs, and other groups with relevant experience for local ME&O efforts will help the TE program reach targeted communities due to these groups' expertise working with customers and local communities.

72. Certain sites in DACs do not serve low-income residents, primarily or at all.

73. Adopting higher rebates for MUDs with a majority of low-income residents accounts for income variances across the state, better focuses on customers facing heightened barriers to EV adoption in underserved communities and does not contribute to potential displacement of low-income residents.

74. Higher rebates for MUDs and MUD-serving public locations situated in DACs are not needed because the additional incentives would not effectively target customers most in need.

75. Higher LD rebates for MUDs with a majority low-income residents target low-income customers who are more in need of rebates.

76. If the Program Administrator cannot reasonably determine whether a majority of a MUD's residents have incomes at or below 80 percent of the AMI, the Program Handbook can propose an alternative method of identifying MUDs with low-income residents where higher LD rebates are appropriate.

77. Higher MDHD rebates for customers in DACs are warranted because DACs suffer from poor air quality and the MDHD sectors have a disproportionate effect on air quality.

78. Higher MDHD rebates for tribal communities are warranted in light of the unique barriers to TE faced by these tribal communities.

79. Vehicles domiciled and operating in DACs produce higher level of emissions in DACs than vehicles only domiciled in DACs and therefore affect air quality more negatively.

80. Fortune 1,000 corporations do not require additional TE incentives funded by ratepayers.

81. Due to more limited resources, small businesses and fleets currently require more targeted support for TE investments, and higher rebates for these customers will promote compliance with the CARB Advanced Clean Fleets regulation.

82. Public Utilities Code Section 323.5(a)(2) provides a definition of small business.

83. Increasing the underserved communities' allocation to at least 65 percent of FC1 funding better serves the state's EV adoption goals, supports communities confronting greater barriers to EV adoption, and promotes equity.

84. Requiring a minimum FC1 investment of 65 percent in underserved communities advances the goals of the Commission's Environmental and Social Justice Action Plan more effectively than a 50 percent allocation requirement because this higher amount of funding will result in a higher impact on improving local air quality, public health, and opportunities for access.

85. Reserving a specific percentage of the minimum spending in underserved communities and considering the unique needs of tribal communities will ensure that these communities benefit from the program.

86. The FC1 program's equity goals will be advanced through ME&O initiatives focused on underserved communities, significant collaboration with CBOs, and engagement with tribal communities.

87. A major purpose of widespread TE, as set forth in Public Utilities Code Section 740.12(a)(1)(F), is the creation of high-quality jobs for Californians

88. Adoption of workforce training program goals, requirements, and implementation strategies will help ensure TE investments create high-quality jobs, facilitate access to these jobs for targeted populations, and address the need for a skilled, trained, and diverse workforce.

89. The Commission's Solar on Multifamily Affordable Housing program provides examples of workforce training requirements.

90. The LITE pilot program provides an opportunity to test new rebate design approaches that may fill gaps in the statewide rebate program in a creative way.

91. The Research and Evaluation Plan will provide an effective means of documenting the Commission's and the IOUs' research priorities.

92. The Commission has historically approved less funding for the MDHD sectors than for the LD sector.

93. Existing and forthcoming CARB regulations—including Advanced Clean Trucks, Advanced Clean Fleets, and Innovative Clean Transit—will accelerate adoption of MDHD EVs.

94. Electrifying the MDHD sectors will reduce air pollution disproportionately impacting DACs.

95. Updated data and analysis may justify modifying the MDHD/LD funding allocation during the Mid-Cycle Assessment.

96. The CEC's AB 2127 Charging Assessment identified the need to support charging at MUDs and MUD-serving public locations.

97. MUD residents face significant barriers to EV adoption in part due to a lack of access to charging infrastructure.

98. The market and regulatory landscape in 2025 and beyond may necessitate the prioritization of rebates for other LD-sector chargers.

99. The MDHD definition contained in D.20-09-025 includes all vehicle categories parties recommend in comments on the Staff Proposal but future circumstances may warrant modifying or updating the MDHD definition.

100. Certain MDHD use cases may require more assistance than others to electrify, for example small fleets often lack the resources needed to electrify as compared to larger fleets.

101. Future conditions may justify different FC1 use case prioritization for the MDHD sectors.

102. A MDHD EV purchase requirement would ensure FC1 rebates provide ratepayer benefits by increasing the purchase and use of EVs, and supporting shared MDHD charging infrastructure would ensure FC1 rebates provide ratepayer benefits by increasing the purchase and use of EVs by fleets that do not own or control their own fueling infrastructure.

103. Multiple MDHD EVs may use the same charger.

104. Implementing an MDHD EV purchase requirement in certain contexts, including for public/shared charging ports and small businesses, requires additional consideration and possibly an exemption.

105. A single third-party administrator for both LD and MDHD components of the rebate program enhances simplicity and accessibility for customers.

106. Allowing the Program Administrator to determine details of the program administration structure, including the Program Administrator's use of subcontractors, will provide for flexibility in implementation and technical expertise.

107. California mandates certain contracting requirements, including the Commission's "Conflict of Interest" policies.

108. A program name that is easily understandable and effectively communicates the program's purpose will promote the success of the program.

109. Rather than the current PACs, it is appropriate to utilize the annual roundtables to discuss any programmatic and market developments during FC1, as well as potential modifications to the program.

110. Allowing the Program Handbook development process to determine details of the program with stakeholder feedback will help create a well-designed and effective FC1 program.

111. The Commission has not yet established a clear VGI strategy or strategic focus areas to complement and inform FC1.

112. Establishing an annual VGI Forum and associated process will allow stakeholders to propose appropriate changes to the FC0 and FC1 programs.

113. If needed, the VGI Forum and associated process can propose appropriate changes to the FC0 and FC1 programs.

114. A flexible approach to VGI, rates, and DR is warranted because each customer has specific constraints and technology is rapidly advancing.

115. Defaulting customers onto applicable time-varying EV-specific rates promotes use of beneficial rates for EVs and is consistent with the requirements of the EV Infrastructure Rules.

116. Load management plans help ensure that EV charging load is flexible and responsive to price signals.

117. A study will help develop a broader understanding of the costs and benefits of ALM to support potential large-scale deployment of an incentive.

118. The ALM requirements in Ordering Paragraphs 5 and 6 of D.20-12-029 are overly broad and create unnecessary ambiguity given the new funding cycle structure and the potential impact on future EV rate design.

119. Modifying the ALM requirements in D.20-12-029 accounts for the ALM directives in this decision, reduces ambiguity, and emphasizes the importance of

ensuring that IOU-led education on ALM includes a thorough consideration of EV drivers' mobility needs.

120. Alignment of the Commission's qualification process for LD and MDHD EVSE with the CEC's process is warranted for administrative efficiency and to harmonize program requirements.

121. An approved product list, managed by the Program Administrator and accessible on the program website, will help ensure compliance with EVSE technical requirements.

122. Allowing review and modification of EVSE technical requirements through the annual roundtable process provides flexibility to the program.

123. Adoption of minimum EVSE requirements is necessary to ensure the effectiveness of the FC1 program.

124. Adopting program targets through the Program Handbook development process can improve program implementation and performance.

125. The Mid-Cycle Assessment can determine if any changes or adjustments to the targets are necessary.

126. A Commission decision is needed to adopt the Program Handbook due to the number of significant unresolved program details.

127. The following topics require additional discussion and feedback in workshops during the Program Handbook development process: (1) TA scope; (2) TA engagement with EVSPs and ALM/DR providers; (3) establishment of clear communication channels with CCAs for TA; (4) load management plans; (5) ME&O; (6) CBO engagement in ME&O; (7) rebate levels; (8) establishment of upfront rebate levels; (9) support for small fleets and small businesses; (10) effective support and outreach for underserved communities; (11) technical requirements; and (12) targets.

128. The Program Handbook development process will benefit from stakeholder discussions and feedback.

129. It is appropriate to adopt the minimum scope list contained in this decision for the Program Handbook.

130. Adopting a Data Assessment requirement will streamline existing reporting requirements, minimize unnecessary or duplicative reporting, and inform FC1 program reporting requirements.

131. Adoption of reporting requirements helps monitor progress towards program goals and provides transparency to the public.

Conclusions of Law

1. The Commission should not adopt the Draft TEF's TEP framework and the associated proposals.

2. The IOUs should continue to participate in and improve upon internal and interagency TE infrastructure planning efforts.

3. The Commission should adopt a $1 billion budget for FC1, which appropriately balances the benefits of increased access to TE, the costs of continued ratepayer investment in TE, and other sources of state and federal TE funding.

4. The Commission should establish the following sunset date for the near-term TE priorities pathways authorized in D.21-07-028: no later than May 31, 2023, for the IOUs to file any near-term TE priority applications or Advice Letters, and no later than December 31, 2026, for the IOUs to stop accepting customer applications or agreements within any approved near-term TE priority programs, unless the governing program decision directs another end date.

5. The IOUs and Program Administrator should continue to utilize and report on safety procedures throughout FC1 based on the TE Safety Checklists.

6. The Commission should clarify that the EVSE communication standards in D.22-08-024 apply to the FC1 rebate program.

7. The Commission should authorize SCE to implement the cybersecurity workplan approved in Advice Letter 4521-E and establish a memorandum account to track and record associated costs, with reasonableness review for recovery of the recorded expenditures within a GRC.

8. The Commission should authorize SCE to file an Advice Letter to establish a memorandum account to track and record costs associated with the cybersecurity workplan implementation, with reasonableness review and recovery to occur within SCE's GRC, limited by expected costs as filed confidentially in Advice Letter 4521-E.

9. The Commission should direct the FC1 Mid-Cycle Assessment to consider designating a portion of program funds for fuel cards for low-income customers.

10. The Commission should require the IOUs to record all BTM TE program costs in either one-way subaccounts within the IOUs' individual TE Balancing Accounts or through separate one-way balancing accounts and recover the costs through distribution rates.

11. The Commission should require the IOUs to allocate FC1 program costs and all BTM TE program costs on an equal cents per kWh basis.

12. The Commission should require the IOUs to conduct outreach to the Air Districts and Metropolitan Planning Organizations in their service territories to inform them of and request their participation in the development of the Program Handbook.

13. The Commission should phase out the authorization provided in D.21-07-028 because that decision served to provide the IOUs with guidance for any proposals for TE investments prior to adoption of the TEF, which this decision addresses.

14. The Commission should prevent ratepayer FC1 ME&O funds from duplicating broad EV awareness campaigns.

15. The Commission should require FC1 ME&O efforts to target small businesses and fleets.

16. The Commission should adopt the Staff Proposal's funding cycle framework, rather that the Draft TEF's proposed TEPs.

17. Given the significant need for more charging infrastructure in the near-term, the Commission should establish a role for ratepayers in supporting TE and EV charging infrastructure in the near-term.

18. The Commission should adopt the Staff Proposal's FC1 program, with modifications, to stimulate the TE market and foster private investment from 2025 through 2029.

19. The Commission should not extend the authorization provided in D.21-07-028 through FC1.

20. The Commission should initiate the Mid-Cycle Assessment in Quarter 1 of 2027 to assess and, if needed, modify the FC1 program.

21. The Commission should require the IOUs to annually review and, if needed, adjust the FC1 program through a Tier 2 Advice Letter process.

22. The Commission should require a single annual roundtable hosted by the IOUs and the Program Administrator to review program data and equity considerations.

23. The Commission should initiate the FC2 development process in early 2027 via ruling and subsequently issue FC2 program guidance, if needed, by the end of 2027, to allow FC2 to commence on January 1, 2030.

24. To promote technology and construction flexibility, while reducing the cost burden that capitalized IOU expenditures impose on ratepayers, the Commission should eliminate all IOU ownership of BTM TE infrastructure beginning with FC1.

25. Given the immensity and importance of the core IOU responsibilities, the role of IOU ratepayers in subsidizing BTM TE infrastructure requires careful and ongoing consideration; indefinite ratepayer support may not be warranted.

26. The Commission should decline to create additional application pathways for the IOUs to propose programs and pilots during FC1 beyond the process provided for in SB 350.

27. The Commission should approve a $1 billion budget for the FC1 program.

28. The Commission should allow the IOUs to only access up to 60 percent of FC1 funds within the first three-years of FC1, with access to the remaining 40 percent of funding pending approval through a future Commission decision following the Mid-Cycle Assessment.

29. The Commission should calculate funding caps over the first three years of FC1 based on the IOUs' respective percentage the $600 million in initial funding.

30. The Commission should allocate the FC1 budget based on each IOU's percentage of electric sales for 2024.

31. Each IOU should file a Tier 2 Advice Letter within 60 days of the issuance date of this decision to establish a one-way sub-account within their existing TE balancing account or separate one-way balancing account. Each sub-account

should be capped based on the approved FC1 budget and the percentage of electric sales for the IOU in 2024.

32. The Commission should limit disbursed funds to each IOU's funding contribution to the FC1 program.

33. The Commission should not adopt an annual cap on program funding.

34. The Commission should adopt an eight percent cap for program administrative costs.

35. The Commission should conduct an audit or review prior to the Mid-Cycle Assessment, to determine whether spent administrative funds exceed the cap.

36. The Commission should authorize ED staff, in consultation with the Commission's Utility Audit, Risk, and Compliance Division, to request additional audits or broaden the scope of the audit of administrative funds.

37. The Commission should adopt a budget for each ME&O and TA activities of up to six percent of the total program funding.

38. An IOU-managed evaluation budget of $3 million for the first three years of FC1 and up to $5 million for the full five years of FC1 is reasonable.

39. The Commission should approve an IOU-managed evaluation budget of $3 million for the first 3 years of the FC1 program and up to $5 million for the program's full five years.

40. An ED-managed evaluation budget of $3 million annually from 2023 through 2029 for technical consulting and support funding is reasonable.

41. The Commission should approve an ED-managed evaluation budget of $3 million annually from 2023 through 2029 for technical consulting and support funding, separate from the FC1 budget.

42. The Commission should eliminate all IOU ownership of BTM TE infrastructure beginning with FC1.

43. Private industry, not ratepayers, should cover any additional TE funding beyond the authorized FC1 program and the Commission's other approved TE spending.

44. The Commission should authorize the Program Handbook to propose up-front rebates and any other appropriate options—beyond IOU ownership—to support low-income, DAC, and small business customers for whom the FC1 rebate model may be challenging.

45. The Commission should authorize a stakeholder process led by the Program Administrator to set the FC1 rebate levels.

46. The Commission should not adopt a declining block rate structure at this time.

47. The Commission should allow rebate stacking, provided that the total received rebates do not exceed 100 percent of costs and any rebate amounts that exceed the limit are returned.

48. The Commission should authorize annual assessments of the appropriate rebate levels via the annual roundtable process.

49. The Commission should authorize the IOUs to administer TA.

50. The Commission should require the Program Handbook development process, and a corresponding workshop, to determine appropriate clear and defined channels of communication between the IOUs' TA efforts and the CCAs in their service territories.

51. The Commission should require the Program Handbook development process, and a corresponding workshop, to determine a clear method for IOU TA engagement with EVSPs and providers of ALM and DR.

52. The Commission should require the IOUs to host a workshop to develop and refine the final scope of TA for inclusion in the Program Handbook.

53. The Commission should require the Program Handbook development process to determine the scope and administration details of the program's ME&O component.

54. The Commission should require engagement with the following groups during the Program Handbook development process, associated workshops, annual roundtables, and the design and implementation of the FC1 program's ME&O component: (1) the Disadvantaged Community Advisory Group; (2) CBOs that are integrated into DACs and other underserved communities; (3) non-English speaking community groups; (4) youth groups; and (5) workforce development, job training and placement, and certification organizations

55. The Commission should allow the Program Administrator to subcontract with CCAs, CBOs, and other groups with experience working with local communities for local ME&O activities, including subcontracts to administer portions of the ME&O program on a local level.

56. The Commission should require the Program Handbook development process to determine: (1) any required percentage of budget allocated to local ME&O; (2) roles of subcontractors; (3) the geographic reach of subcontractors; and (4) how the subcontractors will ensure consistent implementation of the ME&O program.

57. The Commission should require engagement with CCAs during the Program Handbook development process, associated workshops, and annual roundtables.

58. The Commission should adopt higher LD rebates for MUDs with a majority low-income residents, defined as those customers with incomes at or below 80 percent of the AMI. If this requirement is not reasonably administrable,

the Program Handbook development process may explore and propose alternative criteria (e.g., California Alternative Rates for Energy/Family Electric Rate Assistance eligibility).

59. The Commission should not adopt higher LD rebates for MUDs and MUD-serving public locations in DACs.

60. The Commission should consider the unique needs of tribal communities to ensure charging infrastructure reaches these communities effectively, potentially including alternative use cases to provide rebates and higher rebate levels.

61. The Commission should require ME&O efforts to focus on reaching underserved communities and ensure collaboration with CBOs to respond to the unique needs and interests of local communities.

62. The Commission should authorize higher MDHD rebates for customers in DACs.

63. The Commission should require the Program Handbook development process to consider higher MDHD rebates for tribal communities.

64. The Commission should authorize higher MDHD rebates for customers whose vehicles are domiciled and operate for significant periods in DACs.

65. The record lacks evidence demonstrating why medium- and large-sized corporations located in DACs require additional MDHD subsidies.

66. The Commission should prohibit Fortune 1000 corporations—operating in DACs or elsewhere—from receiving FC1 rebates.

67. The Commission should require the FC1 rebate program to target small businesses and fleets, as defined in the Program Handbook, which should incorporate the definition provided in Public Utilities Code Section 323.5(a)(2).

68. The Commission should dedicate a minimum of 65 percent of FC1 rebate funds to underserved communities.

69. The Commission should dedicate a minimum of 65 percent of FC1 ME&O funds towards ME&O for underserved communities.

70. The Commission should require the Program Handbook to set aside a specific percentage of the required minimum spending in underserved communities for rebates in tribal communities.

71. To provide a venue to review and potentially modify the FC1 program, the Commission should require an annual roundtable, where the Program Administrator should present program metrics and data on rebate deployment, equity, usage, ME&O efforts, and TA activities.

72. The Commission should require the IOUs to jointly file a Tier 2 Advice Letter annually, containing a summary of the discussion at the roundtable and proposing any changes to the FC1 program (*e.g.*, rebate level, rebate design, ME&O strategies, customer targeting, or requirements to ensure participation of underserved communities); however, the Advice Letter should not propose modifications to the Program Administrator's contract or key terms of the program (*e.g.*, overall budget, allocation of FC1 rebates between the MDHD and LD sectors, prohibition on IOU ownership of BTM charging infrastructure, etc.).

73. The Commission should require the Program Handbook to: (1) propose ME&O initiatives specifically targeting underserved communities; (2) ensure collaboration with CBOs, and (3) incorporate principles from the Commission's Tribal Consultation Policy to advance efforts to engage with tribal communities.

74. The Commission should require the Program Handbook to: (1) develop contracting and procurement mechanisms that promote equity; (2) establish job

quality standards and job access requirements; (3) incorporate elements of the Commission's Environmental and Social Justice Action Plan related to high-quality workforce education and training; and (4) create targets related to workforce development.

75. A budget of up to $25 million of the total FC1 budget for the LITE pilot program is reasonable due to the potential to test new rebate design approaches that may fill gaps in the statewide rebate program in a creative way.

76. The Commission should require SDG&E to conduct an RFP and require the IOUs to execute contracts with selected entities administering LITE pilot projects according to the guidance and direction in this decision.

77. The Commission should authorize a budget of up to $25 million of the total FC1 budget for the LITE pilot program.

78. The Commission should retain the flexibility to extend, modify, or terminate the initial tranche of LITE pilot projects as a part of the Mid-Cycle Assessment.

79. The Commission should require the IOUs to assist ED staff in developing and maintaining the Research and Evaluation Plan.

80. The Commission should allocate 70 percent of FC1 rebates to the MDHD sectors and 30 percent of FC1 rebates to the LD sector.

81. The Commission should allow the Mid-Cycle Assessment to revisit and potentially modify the allocation of FC1 rebates between the MDHD and LD sectors.

82. The Commission should limit LD sector rebates to chargers sited at MUDs and MUD-serving public locations.

83. The Commission should require the Mid-Cycle Assessment to revisit and potentially modify FC1's eligibility requirements for LD-sector rebates.

84. The Commission should adopt the MDHD definition contained in D.20-09-025 for FC1.

85. The Commission should allow the IOUs to propose, following consultation with the Program Administrator and stakeholders, modifications to the MDHD definition through the post-roundtable Tier 2 Advice Letter filings or during the Mid-Cycle Assessment.

86. The Commission should require that the Program Handbook development process include a presentation of data and findings from current MDHD programs to determine whether and how the FC1 program should account for the needs of MDHD fleets.

87. The Commission should require the Program Handbook to include a process to prioritize small fleets, as well as a definition for small fleets that considers those in the CEC's EnergIIZE, CARB's Advanced Clean Fleets regulation, and other relevant MDHD regulations in California (*i.e.*, Drayage Trucks at Seaports and Railyards, Airport Shuttles, Transport Refrigeration Units, and Innovative Clean Transit).

88. The Commission should authorize the IOUs to propose, following consultation with the Program Administrator, modifications to prioritize or deprioritize MDHD use cases through the post-roundtable Tier 2 Advice Letter filings or during the Mid-Cycle Assessment.

89. The Commission should require a minimum of one EV purchase, lease, or retrofit per MDHD charging port rebate.

90. The Commission should require the Program Handbook to include details of the unique vehicle purchase requirement(s) for contexts such as MDHD public/shared-charging ports and small businesses, including a possible exemption.

91. The Commission should require the IOUs to contract with one Program Administrator for all components of FC1, other than the IOU-administered TA program.

92. The Commission should decline to impose restrictions on the program administration structure, including the Program Administrator's use of subcontractors.

93. The Commission should require the IOUs' contract with the selected Program Administrator, and any subcontracts with the Program Administrator, to comply with state contracting requirements, including the Commission's "Conflict of Interest" policies.

94. The Commission should require the Program Handbook to propose a name for the program.

95. The Commission should require the annual roundtables to address any programmatic and market developments, as well as potential modifications to the program, and allow the PAC meetings to end at the conclusion of the FC0 programs.

96. The Commission should require the IOUs to issue the RFP, contract with the selected Program Administrator, and manage the contract.

97. The Commission should authorize ED to select the Program Administrator.

98. The Commission should designate SCE as the lead IOU to execute the Program Administrator contract and to file a Tier 2 Advice Letter to request approval of the contract language prior to finalization.

99. The Commission should authorize a three-year contract period, with the potential but not the guarantee of a two-year extension, to be determined at the program's mid-cycle point.

100. The Commission should require that the Program Handbook development process determine details of the program for the Program Administrator to execute.

101. The IOUs' contract with the selected Program Administrator, and any Program Administrator subcontracts, must comply with state contracting requirements, including the Commission's "Conflict of Interest" policies.

102. The Commission should adopt a VGI strategy with strategic focus areas and require an annual VGI Forum.

103. The Commission should authorize the IOUs to propose changes to the FC0 and FC1 programs following the VGI Forums.

104. The Commission should require the IOUs to default all FC1 participants on to applicable time-varying EV-specific rates, with the ability to opt out for another time-varying rate, consistent with the EV Infrastructure Rules.

105. The Commission should direct the IOUs to work with each customer, and coordinate with relevant CCAs, to develop a load management plan including ALM options, if appropriate, with details of this process to be finalized through the Program Handbook development process.

106. The Commission should require a study to assess ALM opportunities and subsequently issue a report and recommendations on whether to pursue ALM rebates in the FC1 program.

107. The Commission should adopt the following definition of ALM for use throughout FC1: ALM refers to energy management systems that are deployed at a particular location to reduce aggregate EV charging load with the objective of reducing or eliminating the need for electrical capacity upgrades on the utility and/or customer side of the meter. Unless otherwise specified in other contexts (*e.g.*, rates, rules, etc.), this definition of ALM should apply.

108. If the Commission approves ALM rebates, the Commission should require the IOUs to implement and administer the rebates. The FC1 infrastructure rebate budget shall provide funding for any approved ALM rebates.

109. Requiring the IOUs to administer potential ALM rebates is reasonable due to the scope of the IOUs' TA programs and their role in educating customers under the EV Infrastructure Rules.

110. The Commission should modify the ALM requirements in Ordering Paragraphs 5 and 6 of D.20-12-029 to account for the ALM directives in this decision, reduce ambiguity, and emphasize the importance of ensuring that IOU-led education on ALM includes a thorough consideration of EV drivers' mobility needs.

111. The Commission should align its qualification process for LD and MDHD EVSE with the CEC's process.

112. The Commission should require the Program Handbook development process to adopt EVSE technical requirements that, at minimum, comply with the EVSE requirements adopted in D.22-08-024 and this decision.

113. The Commission should require an approved product list for the Program Administrator to manage and post on the program website.

114. The Commission should authorize review and modification of EVSE technical requirements through the annual roundtable process.

115. The Commission should adopt minimum EVSE technical and data sharing requirements.

116. The Commission should require a series of workshops to discuss and receive input on the requirements of the Program Handbook.

117. The Commission should require the Program Handbook development process, and associated workshop(s), to establish FC1 program targets, including

at minimum the following categories: (1) equity; (2) LD ports; and (3) MDHD vehicles electrified.

118. The Commission should require the Program Administrator in collaboration with the IOUs to host workshops on unresolved FC1 program issues.

119. The Commission should require the IOUs, in consultation with the Program Administrator, to file a workshop report within 60 days of the final workshop reflecting stakeholder feedback and conversations from the workshops.

120. The Commission should manage one or more contractors to perform tasks in support of the research priorities ordered in this decision. The costs of such tasks shall not exceed $3 million per year for seven years, or a total of $21 million, with costs eligible to be rolled over annually. These costs are separate from the $1 billion FC1 budget.

121. The Commission should require the Program Handbook to utilize the minimum scope list contained in this decision.

122. Once contracted, the Program Administrator should develop the Program Handbook in consultation with the IOUs, ED staff, and stakeholders.

123. The Commission should adopt, with any modifications, the Program Handbook in a subsequent decision following a ruling requesting comment on the draft Program Handbook and the workshop report.

124. The Commission should adopt the timeline, process, and deliverables for the Data Assessment described in Appendix B of this decision.

125. The IOUs should each file a Tier 2 Advice Letter to update the rate and bill impacts associated with the authorized investments for the FC1 program.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company (SCE) shall file a Tier 1 Advice Letter within 30 days of the issuance date of this decision to establish a memorandum account to track and record costs related to implementation of the cybersecurity workplan approved in SCE Advice Letter 4521-E. SCE shall implement the workplan according to the estimated budget specified confidentially in that Advice Letter. SCE shall seek reasonableness review for recovery of the recorded expenditures through a General Rate Case proceeding.

2. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities (CalPeco Electric) LLC, Bear Valley Electric Service Inc., and PacifiCorp d/b/a Pacific Power, collectively the investor-owned utilities (IOUs), shall not file any near-term priority applications or Advice Letters after May 31, 2023. By December 31, 2026, the IOUs shall stop accepting customer applications or agreements within all existing Commission-approved transportation electrification programs and any near-term priority programs the Commission approves pursuant to the direction in Decision 21-07-028, unless the governing program decision directs another end date.

3. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities (CalPeco Electric) LLC, Bear Valley Electric Service Inc., and PacifiCorp d/b/a Pacific Power, collectively the investor-owned utilities (IOUs), shall record all behind-the-meter transportation electrification (TE) program costs in either a one-way subaccount within each IOU's TE Balancing Account or through a separate one-way balancing account. The IOUs shall record such costs as expenses, rather than

capitalizing the costs. The IOUs shall recover such costs through distribution rates allocated on an equal cents per kilowatt hour basis applied equally to all customer classes.

4. Within 60 days of the issuance date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities (CalPeco Electric) LLC, Bear Valley Electric Service Inc., and PacifiCorp d/b/a Pacific Power, collectively the investor-owned utilities (IOUs), shall each file a Tier 2 Advice Letter to establish a one-way sub-account within their existing TE balancing account or separate one-way balancing account to track costs for the Funding Cycle 1 (FC1) program. This decision approves a $1 billion budget for the FC1 program. The IOUs may access up to 60 percent of FC1 funds within the first three-years of the FC1 program, which shall begin on January 1, 2025. Each sub-account or balancing account shall be capped at $600 million for the first three years and the percentage of electric sales for the IOU in 2024. Each IOU shall disburse appropriate funds to the Program Administrator. Total FC1 rebate funding in each IOU's service territory shall be capped based on each IOU's funding contribution, after deducting costs for program administration, technical support and evaluations, the Locally Invested Transportation Equity (LITE) pilot program, Technical Assistance (TA) programs, and marketing, education, and outreach (ME&O) programs. For the first three years, program administrative costs, including both IOU and Program Administrator administrative expenses, shall be capped at $48 million, or eight percent of the utilized portion of the approved FC1 program budget of $600 million, whichever is lower; TA program costs shall be capped at $36 million, or six percent of the utilized portion of the approved FC1 program budget of $600 million, whichever is lower; ME&O program costs shall be

capped at $36 million, or six percent of the utilized portion of the approved FC1 program budget of $600 million, whichever is lower; and costs for an IOU-managed program evaluation shall be capped at $3 million. Costs for a technical support and evaluation budget, managed by the Commission's Energy Division (ED) staff, shall be capped at $3 million annually from 2023 through 2029, or a total of $21 million. Costs for the ED-managed technical support and evaluation budget are not included in the $1 billion FC1 program budget. Costs for the LITE pilot program shall be capped at $25 million. Program Administrator costs shall be subject to audit or review by the Commission's Utility Audit, Risk, and Compliance Division. ED staff is authorized to request additional audits or broaden the scope of the audit.

5. Southern California Edison Company (SCE), on behalf of itself, Pacific Gas and Electric Company, San Diego Gas & Electric Company, Liberty Utilities (CalPeco Electric) LLC, Bear Valley Electric Service Inc., and PacifiCorp d/b/a Pacific Power, collectively the investor-owned utilities (IOUs), shall issue a request for proposals to contract with a Program Administrator to design and administer the Funding Cycle 1 program. Following selection of the Program Administrator by the Commission's Energy Division staff, the IOUs shall draft the contract with the Program Administrator. By May 1, 2023, before executing the contract, SCE shall submit the contract for approval to the Commission via a Tier 2 Advice Letter. The contract shall comply with all guidance and direction in this decision.

6. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities (CalPeco Electric) LLC, Bear Valley Electric Service Inc., and PacifiCorp d/b/a Pacific Power, in consultation with the Program Administrator, shall serve on the service list of this or any

successor proceeding, a draft Program Handbook and a workshop report covering all of the workshops held as part of the Program Handbook development process. The Program Handbook and the process to develop it shall comply with all guidance and direction provided in this decision. The workshop report shall reflect stakeholder feedback provided at the workshops.

7. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities (CalPeco Electric) LLC, Bear Valley Electric Service Inc., and PacifiCorp d/b/a Pacific Power, collectively the investor-owned utilities (IOUs), shall comply with this decision's guidance and direction in performing all required activities, including Funding Cycle 1 program administration and support, technical support and evaluations, the Locally Invested Transportation Equity pilot program, Technical Assistance programs, the Data Assessment, and marketing, education, and outreach programs. The IOUs shall complete all activities described in this decision by the deadlines provided in Appendices A and B. Energy Division staff is authorized to revise the deadlines related to Program Administrator selection and contracting, as needed.

8. By December 31, 2023, San Diego Gas & Electric Company (SDG&E), on behalf of itself, Pacific Gas and Electric Company, Southern California Edison Company, Liberty Utilities (CalPeco Electric) LLC, Bear Valley Electric Service Inc., and PacifiCorp d/b/a Pacific Power, collectively the investor-owned utilities (IOUs), shall issue a request for proposals for the Locally Invested Transportation Equity (LITE) pilot program. SDG&E shall submit the shortlisted pilots to the Commission via Tier 3 Advice Letter. The IOUs shall implement the LITE pilot program according to the guidance and direction in this decision. The LITE pilot program shall begin no later than Q1 2025.

9. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities (CalPeco Electric) LLC, Bear Valley Electric Service Inc., and PacifiCorp d/b/a Pacific Power, collectively the investor-owned utilities (IOUs), shall assist the Commission's Energy Division staff in developing and maintaining a Research and Evaluation Plan to document the Commission's and the IOUs' research priorities.

10. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, collectively referred to as the large investor-owned utilities (large IOUs), shall jointly host annual roundtables with the Program Administrator in July of each year of the Funding Cycle 1 program. The large IOUs and the Program Administrator shall seek input from the Commission's Energy Division staff on the roundtable agendas. During the roundtables, the large IOUs and Program Administrator shall gather stakeholder feedback on the program. By August 1 of each year of the Funding Cycle 1 program, the large IOUs shall, with input from the Program Administrator, jointly file a Tier 2 Advice Letter reporting on program evaluations and metrics, summarizing the roundtable discussion, and proposing any program modifications. Any approved program modifications shall take effect on January 1 of the following year, unless the Commission determines otherwise.

11. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, collectively the large investor-owned utilities (large IOUs), shall host annual vehicle-grid integration (VGI) Forums in conjunction with the Commission's Energy Division staff. Within 60 days of each VGI Forum, the large IOUs shall file a workshop report and serve it service lists for this proceeding, any successor proceeding, and any other relevant Commission proceedings. The large IOUs shall propose any changes to the

Funding Cycle 1 program based on the VGI Forum and the associated workshop report through the Tier 2 Advice Letter filed following the annual VGI Forum. The large IOUs may file separate Tier 2 Advice Letters, where appropriate, to propose any changes to other existing transportation electrification rebate programs.

12. Ordering Paragraphs 5 and 6 from Decision 20-12-029 are modified as follows:

> 5. Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company shall, each, in any future transportation electrification (TE) programs to support TE infrastructure installation identify how it will educate customers on how Automated Load Management technology may support TE installation at equal or lesser costs than hardware-based electrical capacity while meeting host site and electric vehicle drivers' charging and mobility needs.
> 6. Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company shall each evaluate customer acceptance once Automated Load Management is installed at a host site as part of a ratepayer-funded transportation electrification program.

13. Within 30 days of the date of issuance of this decision, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities (CalPeco Electric) LLC, Bear Valley Electric Service Inc., and PacifiCorp d/b/a Pacific Power shall each file a Tier 2 Advice Letter to update the rate and bill impacts associated with the authorized investments for the Funding Cycle 1 program, including the full revenue requirement associated with the approved program.

14. Rulemaking 18-12-006 remains open.

This order is effective today.

Dated November 17, 2022 at San Francisco, California

ALICE REYNOLDS
President
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
DARCIE L. HOUCK
Commissioners

Commissioner John Reynolds recused himself and did not participate in the discussion and vote of this item.

Appendix A

Timeline of Program Actions and Activities

Timing	Action/Activity
January 2023	• Each IOU files Tier 2 Advice Letter to establish new one-way balancing account or subaccount within 60 days of the adoption of this decision.
Q1 – Q2 2023	• SCE, in collaboration with other IOUs and ED staff, design and issue RFP for the Program Administrator; • By May 1, 2023, SCE files Tier 2 Advice Letter with proposed Program Administrator contract; • ED staff, in consultation with the CEC, approves the selection of Program Administrator; and • Deadline for submittal of near-term priority Advice Letter proposals pursuant to D.21-07-028 on May 31, 2023.
Q3 – Q4 2023	• Program Administrator holds workshops; • IOUs submit data assessment to ED staff, which the Commission would subsequently issue via ruling for party response; and • Annual VGI Forum and associated workshop report and Advice Letter.
Q1 2024	• IOUs and Program Administrator submit workshop report and proposed/draft Program Handbook by January 15, 2024; • Ruling with workshop report and draft Program Handbook; and • Ruling with ALM study results and recommendations.
Q2 2024	• Ruling with findings of the Data Assessment, along with recommendations for modifications to the current data reporting requirements, recommendations on the establishment of the TE Data Reporting Dictionary, and recommendations for additional data reporting requirements for FC1; • IOUs issue RFP for LITE equity pilot; and • CCAs, CBOs and other entities submit pilot proposals.
Q3 2024	• Decision adopting the Program Handbook;

	• First annual roundtable and associated Advice Letter, if needed; and • Program Handbook decision adopts modifications to TE reporting requirements—for FC0 and FC1—and process to update reporting requirements as needed.
Q4 2024	• Program Administrator finalizes pre-FC1 launch planning; and • Annual VGI Forum and associated workshop report and Advice Letter.
December 31, 2024	• FC0 ends; and • Grace period to wind down FC0 programs begins.
January 1, 2025	• FC1 begins, with rebate program, ME&O and TA programs launching.
Q1 2025	• CCAs, CBOs and other entities begin implementation of selected LITE equity pilots.
Q3 2025	• Annual roundtable and associated Advice Letter.
Q4 2025	• Annual VGI Forum and associated workshop report and Advice Letter.
Q3 2026	• Annual roundtable and associated Advice Letter.
Q4 2026	• Annual VGI Forum and associated workshop report and Advice Letter.
December 31, 2026	• FC0 grace period ends; and • FC0 program implementation concludes.
Q1 – Q2 2027	• Mid-Cycle Assessment decision; and • CCAs, CBOs and other entities to conclude implementation of selected LITE equity pilots.
Q3 2027	• FC2 guidance decision; and • Annual roundtable and associated Advice Letter.
Q4 2027	• Annual VGI Forum and associated workshop report and Advice Letter.
January 1, 2028	• Any changes to FC1 pursuant to the Mid-Cycle Assessment go into effect.
Q3 2028	• Annual roundtable and associated Advice Letter.
Q4 2028	• Annual VGI Forum and associated workshop report and Advice Letter.

Q3 2029	• Annual roundtable and associated Advice Letter.
Q4 2029	• Annual VGI Forum and associated workshop report and Advice Letter.
December 31, 2029	• End of FC1.
January 1, 2030	• Tentative beginning of FC2.

(END OF APPENDIX A)

Appendix B

Timeline, Process, and Deliverables for Data Assessment

Quarter 3, 2023

1. Deliverable: IOUs submit the Data Assessment by July 30, 2023.
2. Scope: IOUs should work together to identify all reporting requirements. This means identifying each required reporting period related to TE, each data field reported through that period, and the frequency and timing of each of these reports. The IOUs should then identify where there is any overlap or any missing reporting requirements, where any requirement is unnecessary along with a justification, and joint suggestions on how to streamline the timing, frequency, and process for these reporting requirements. IOUs should consult with ED staff during the data assessment process.
3. Process: After the IOUs jointly submit the Data Assessment, the Commission would ensure it is put on the record for this proceeding or a subsequent one. This will also allow parties to comment.

Quarter 1, 2024

1. Deliverable: Internal ED review of IOUs' Data Assessment.
2. Scope: ED and the contractor will review the Data Assessment the IOUs submit, evaluate the proposals from the IOUs on how best to streamline. Further, as this would be issued via ruling, ED will review suggestions submitted in comments to that ruling.
3. Process: ED and the supporting contractors should aim to complete the internal review of the Data Assessment by Q1 2024.

Quarter 2, 2024

1. Deliverable: Commission ruling with recommendations on reporting requirements based on the review of the Data Assessment.
2. Scope: based on the evaluation from ED and the contractor, a proposal for recommended modifications to TE reporting requirements would be issued. This would include modifications to existing reporting requirements and recommendations on reporting requirements for FC1.
3. Process: Commission should issue findings of the Data Assessment, recommendations for modifications to the current data reporting

requirements, the TE Reporting Dictionary and recommendations for additional data reporting requirements for FC1 via Ruling.

Quarter 3, 2024

1. Deliverable: adoption of modifications to TE reporting requirements via decision.
2. Scope: the decision would adopt modifications to existing reporting requirements (FC0 programs), as necessary and based on the record, and would adopt new reporting requirements for FC1. It would also establish a process to update the requirements as needed.
3. Process: Commission should adopt recommendations, as modified by party comments to the Ruling, along with the Program Handbook decision. Via that decision, we expect that a process would be established to enable ED staff to make periodic updates, as necessary, to the data requirements. That decision may allow ED staff to initiate updates via resolution, if necessary.

(END OF APPENDIX B)

Appendix C

Glossary

AB 841	Assembly Bill 841 (Ting, 2020)
AB 2127	Assembly Bill 2127 (Ting, 2018)
ACCII	Advanced Clean Cars II, a CARB regulation that would require all new passenger vehicles sold in California to be zero emission by 2035.
ACF	Advanced Clean Fleets, a proposed CARB regulation that would govern the transition of MDHD fleets towards zero emission.
ACT	Advanced Clean Trucks, a CARB regulation that provides a ZEV sales requirement for manufacturers.
ALJ	Administrative Law Judge
ALM	Automated Load Management, which this decision defines as energy management systems that are deployed at a particular location to reduce aggregate EV charging load with the objective of reducing or eliminating the need for electric system capacity upgrades on the utility-side of the meter.
AMI	Area Median Income
Balancing Account	Deferred debit accounts carried on the utility's books that are approved by the Commission and established by the IOUs to serve various ratemaking purposes. The primary purpose of a Balancing Account is to ensure that an IOU recovers its Commission-authorized revenue requirement from ratepayers for a given program or function.
BTM	Behind-the-Meter infrastructure and the associated costs on the customer-side of a utility-grade meter.
CALGreen	The California Green Building Standards Code, which includes a range of green building requirements, is developed in collaboration with various state agencies including the CEC and the Building Standards Commission and is updated every three years.
CARB	California Air Resources Board
CBO	Community-Based Organization

CCA	Community Choice Aggregators are organizations run by cities, counties, and other qualifying governmental entities who purchase and/or generate electricity for the residents and businesses in their region. The IOU continues to deliver the electricity through its transmission and distribution system and provide meter reading, billing, and maintenance services for CCA customers.
CEC	California Energy Commission
Charger, or Charging Port	Plug for EVSE to charge vehicles. Each port corresponds to its own parking space, but a single EVSE can serve multiple ports.
CPUC or Commission	California Public Utilities Commission
DAC	Disadvantaged Community, defined as census tracts in the top 25 percentile in CalEnviroScreen 4.0 on a statewide basis.
Data Assessment	IOU-led assessment of all TE-related data currently reported, aimed at streamlining future program reporting.
DCFC	Direct Current Fast Charger, which is a charging station with a minimum capacity of 50kW.
Distribution System Upgrade Plans	Ongoing efforts in various venues and proceedings (*e.g.*, R.20-05-003, R.21-06-017), and working groups such as the Joint Agency Steering Committee, which is comprised of the Commission, CARB, CAISO, and CEC, with direct IOU coordination.
DR	Demand Response is a way to encourage customers to help manage electricity demand by reducing, increasing, or shifting their electricity consumption in response to economic or reliability signals.
Drayage Trucks	Heavy-duty, Class 8, trucks that transport containers and bulk freight between a port and intermodal rail facilities, distribution centers, and other near-port locations.
Electrical Distribution Infrastructure	As defined by Public Utilities Code Section 740.19(b), includes poles, vaults, service drops, transformers, mounting pads, trenching, conduit, wire, cable, meters,

	other equipment as necessary, and associated engineering and civil construction work.
Electric Vehicle Charging Infrastructure Assessment	Pursuant to AB 2127 (Ting, 2018), the CEC is required to biennially assess the EV charging infrastructure needed to meet the state's goals of putting at least five million ZEVs on the road in California by 2030. The inaugural AB 2127 Electric Vehicle Charging Infrastructure Assessment was issued in July 2021.
EnergIIZE	Energy Infrastructure Incentives for Zero Emission, a CEC funded program that provides incentives for commercial fleets to cover costs associated with the infrastructure needed to support transition to ZEVs.
Energy Division or ED	The California Public Utilities Commission's Energy Division
Environmental and Social Justice Action Plan	The Environmental and Social Justice Action Plan, or ESJ Action Plan, is a Commission-adopted plan serving as both a commitment to furthering environmental and social justice principles, as well as an operating framework with which to integrate environmental and social justice considerations throughout the Commission's work.
EV	Electric Vehicle
EV Cost and Load Report	The EV Cost and Load Report is an annual joint IOU report that examines data on EV customer charging behavior, charging infrastructure costs, and service and distribution system upgrade costs related to EV load.
EV Infrastructure Rules	Electric Rules 24, 29, 45, established pursuant to AB 841 to "design and deploy all electrical distribution infrastructure on the utility side of the customer's meter for all customers installing separately metered infrastructure to support charging stations, other than those in single-family residences."
EVITP	Electric Vehicle Infrastructure Training Program
EVREV	Proposal included in the draft TEF envisioned as a plan the IOUs would submit outlining the evolution of electric rates, including a collaborative, stakeholder-guided strategy for improving the customer experience in paying for EV fueling and potentially receiving

	compensation for discharge of their EV batteries at times of grid congestion.
EVSE	Electric vehicle supply equipment, or the equipment used to charge electric vehicles.
EVSE Communications Protocols	Charging and data standards that the Commission adopted in D.21-08-024 to establish minimum qualification requirements for EVSE installed via ratepayer funded or IOU administered programs.
EVSE Service Energization	The full process to install utility-side and customer-side infrastructure needed to energize an EVSE.
EVSP	Electric Vehicle Service Provider
Executive Order N-79-20	Executive Order issued by Governor Newsom in 2020 calling for the elimination of sales of new internal combustion passenger vehicles by 2035, and MDHD vehicles by 2045.
FC0	Funding Cycle Zero, which represents the current array of IOU TE programs, pending applications and ALs, and forthcoming near-term priority proposals. Per this decision, FC0 will conclude at the end of 2024, with a two-year grace period concluding at the end of 2026.
FC1	Funding Cycle One begins in 2025 and runs through the end of 2029, consisting of a statewide rebate program for BTM make-readies and EVSE, as well as ME&O and TA programs.
FC2	Funding Cycle Two, as described in this decision would start in 2030, after FC1 completes at the end of 2029, and would be based on an assessment of FC1 and analysis of the policy and market needs.
Federal Infrastructure Investment and Jobs Act of 2021	The federal bipartisan infrastructure law signed by President Biden in 2021, and enacted as Public Law 117-58, that includes provisions to increase investments in EVSE and EVs.
Federal Inflation Reduction Act	Federal law signed by President Biden in August 2022, providing incentives for residential and commercial EVSE and the purchase of EVs.
Fortune 1000 Corporations	Fortune 1000 corporations is a ranking of the top largest companies annually.
GHG	Greenhouse Gas

GRC	General Rate Case
Innovative Clean Transit or ITC	Innovative Clean Transit is a CARB regulation that requires all public transit agencies to gradually transition to a 100-percent zero-emission bus fleet and encourages them to provide innovative first- and last-mile connectivity and improved mobility for transit riders.
IOU	Investor-Owned Utility
IRP	Integrated Resource Planning is an umbrella planning proceeding to consider all of the Commission's electric procurement policies and programs and ensure California has a safe, reliable, and cost-effective electricity supply. The proceeding is also the Commission's primary venue for implementation of SB 350 requirements related to integrated resource planning.
kWh	Kilowatt-hour
L2	Level 2 charging, which typically operates at 208-240 V and provides between 3 kW-19 kW of AC power.
LCFS	Low Carbon Fuel Standard, a CARB regulation designed to decrease the carbon intensity of California's transportation fuel pool and provide an increasing range of low-carbon and renewable alternatives, which reduce petroleum dependency and achieve air quality benefits.
LD	Light-Duty
Make-Ready or Make-Ready Infrastructure	Service connection and supply infrastructure installed on the utility-side and customer-side of the meter needed to support the installation of EVSE.
MDHD	Medium- and heavy-duty vehicles
ME&O	Marketing, Education, and Outreach
Memorandum Account	A Memorandum Account is an accounting device that, after approval by the Commission or upon statutory notice, may be used by a utility to record various expenses it incurs. The utility may later seek authorization from the Commission to recover the recorded amounts by passing them on to consumers in

	rates. The establishment of a memo account does not guarantee that the utility will recover tracked costs, but a utility is precluded from recovering amounts not booked to a Memorandum Account.
Mid-Cycle Assessment	The Mid-Cycle Assessment will occur once in 2027, the third year of FC1, to ensure flexibility in program implementation, sufficient review of FC1, and confirmation of whether investments are adequately serving the market and contributing to state goals.
MUD	Multi-unit dwelling
MUD-serving	Public charging designed and sited to strategically serve residents of MUDs, in particular for residents of MUDs for whom on site services are not feasible.
PAC	Program Advisory Council
PEV	Plug-in electric vehicle, which includes battery electric vehicles and plug-in hybrid electric vehicles
PEV Submetering Protocol	The PEV submetering protocol enables PEV customers to simultaneously enroll in an EV-specific rate and a time-of-use rate by allowing a submeter to measure and bill EV charging separately from a customer's primary utility meter.
Program Handbook	The Program Handbook will include requirements and program details to guide the implementation of the FC1 program. It will contain three main sections: (1) Rebate Program Rulebook, (2) Implementation Plan, and (3) Technical Assistance Rulebook.
PRP	Priority Review Project, as adopted via D.18-01-024.
Pub. Util. Code	Public Utilities Code
Public Safety Power Shutoffs or PSPS	Events that occur when an IOU de-energizes power lines as a last-resort measure to mitigate the risk of potential catastrophic wildfire caused by the IOU's infrastructure.
RFP	Request for Proposals
Roundtable	Annual stakeholder meetings to discuss program progress and modifications for the FC1 program, adopted in this decision.
Rule 15	The Electric Rule governing distribution line extensions.
Rule 16	The Electric Rule governing service line extensions.

SB 676	Senate Bill 676 (Bradford, 2019)
Staff Proposal	The Energy Division staff proposal issued via ACR in R.18-12-006 in February 2022.
TA	Technical Assistance programs established via this decision that the IOUs will administer and that are aimed at providing technical assistance to customers transitioning their vehicle operations to electric and installing charging infrastructure on their premises.
TE	Transportation Electrification, as defined in Public Utilities Code section 237.5, means the use of electricity from external sources of electrical power, including the electrical grid, for all or part of vehicles, vessels, trains, boats, or other equipment that are mobile sources of air pollution and GHGs and the related programs and infrastructure investments to enable and encourage this use of electricity.
TEF or Draft TEF	Transportation Electrification Framework, which refers to the staff proposal issued in R.18-12-006 in February 2020.
TEP	Transportation Electrification Plan, which was a proposal within the Draft TEF that would have required the IOUs to submit to the Commission ten-year TE plans for investment and infrastructure build out.
Time Varying Rate	A rate structure in which pricing varies by time period, like traditional TOU rates or dynamic rates.
TOU	Time-of-use rate structures
Underserved Communities	As defined in Public Utilities Code section 1601, "underserved community" means a community that meets one of the following criteria: (1) is a "disadvantaged community" as defined by subdivision (g) of Section 75005 of the Public Resources Code; (2) is included within the definition of "low-income communities" as defined by paragraph (2) of subdivision (d) of Section 39713 of Health and Safety Code; (3) is within an area identified as among the most disadvantaged 25 percent in the state according to the California Environmental Protection Agency and based on the most recent California Communities

	Environmental Health Screening Tool, also known as CalEnviroScreen; (4) is a community in which at least 75 percent of public school students in the project area are eligible to receive free or reduced-price meals under the National School Lunch Program; or (5) is a community located on lands belonging to a federally recognized California Indian tribe.
Uptime	Uptime reliability, pursuant to AB 2061 (Ting 2022), indicates the percentage of time chargers/EVSE are operational and functioning.
Utility-side	Infrastructure, and the costs associated with it, on the utility-side of a customer's utility-grade meter.
VGI	Vehicle-Grid Integration, per D.20-12-029, means any method of altering the time, charging level, or location at which grid-connected LD EVs, MDHD EVs, off-road EVs, or off-road electrical equipment charges or discharges, in a manner that optimizes PEV or equipment interaction with the electrical grid and provides net benefits to ratepayers by doing any of the following: (A) increasing electrical grid asset utilization and operational flexibility; (B) avoiding otherwise necessary distribution infrastructure upgrades and supporting resiliency; (C) integrating renewable energy resources; (D) reducing the cost of electricity supply; or (E) offering reliability services consistent with the resource adequacy requirements established by Section 380 or the California Independent System Operator's tariff.
ZEV	Zero-Emission Vehicles, which include battery electric vehicles, plug-in hybrid electric vehicles, and fuel cell electric vehicles.

(END OF APPENDIX C)

STATE OF CONNECTICUT

PUBLIC UTILITIES REGULATORY AUTHORITY
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 21-08-06 **ANNUAL REVIEW OF THE ELECTRIC VEHICLE CHARGING PROGRAM – YEAR 1**

December 15, 2021

By the following Commissioners:

Marissa P. Gillett
John W. Betkoski, III
Michael A. Caron

DECISION

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DECISION

I. INTRODUCTION

A. SUMMARY

In this Decision, the Public Utilities Regulatory Authority (Authority or PURA) approves, with modification, certain documents developed and proposed by The Connecticut Light and Power Company d/b/a Eversource Energy (Eversource) and The United Illuminating Company (UI; collectively, the electric distribution companies, EDCs, or Companies) to administer the statewide electric vehicle charging program (EV Charging Program, or Program) available to all customers and customer classes within the service territories of the EDCs.[1]

B. BACKGROUND OF THE PROCEEDING

On July 14, 2021, the Authority issued its Final Decision in Docket No. 17-12-03RE04, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Zero Emission Vehicles (EV Decision) establishing the EV Charging Program pursuant to §§ 16-11, 16-19, 16-19e, and 16-244i of the General Statutes of Connecticut (Conn. Gen. Stat.), and in accordance with the Interim Decision dated October 2, 2019, in Docket No. 17-12-03, PURA Investigation into Distribution System Planning of the Electric Distribution Companies (Equitable Modern Grid Decision). The Authority initiated the instant proceeding to review the Year 1 Program (i.e., 2022) design documents and other key compliance filings and to address other relevant topics as necessary regarding Program implementation.

C. CONDUCT OF THE PROCEEDING

On August 11, 2021, the Authority issued the Notice of Proceeding in the above-captioned proceeding.

On August 16, 2021, Eversource filed Motion No. 1 in Docket No. 21-08-06 requesting that the Authority approve its EV Rate Rider developed pursuant to Order No. 3 of the EV Decision. The Authority granted Motion No. 1 on September 13, 2021. On August 17, 2021, UI filed Motion No. 3 in Docket No. 21-08-06 requesting that the Authority approve its GS-EV and GST-EV tariffs developed pursuant to Order No. 3 of the EV Decision. On September 20, 2021, the Authority directed UI to make certain modifications and to refile its proposed tariffs. UI filed its modified GS-EV and GST-EV tariffs on September 27, 2021, and the Authority subsequently granted Motion No. 3 on October 5, 2021.

[1] This Decision specifically addresses the documents submitted in compliance with Order Nos. 5 through 7 of the EV Decision. Accordingly, the Decision contains the Authority's final ruling on Motion Nos. 10 through 13.

On August 16, 2021, UI filed Motion No. 2 in Docket No. 21-08-06 requesting that the Authority approve its proposed plan to develop a hosting capacity map specific to installing Level 2 and direct current fast chargers (DCFCs), developed pursuant to Order No. 2 of the EV Decision.[2] Similarly, on August 30, 2021, Eversource filed Motion No. 5 requesting that the Authority approve its compliance with Order No. 2 of the EV Decision.[3] On September 23, 2021, the Authority provisionally approved the EDCs' respective plans to develop hosting capacity maps, but directed the Companies to provide additional information. Each EDC filed their response on or before October 15, 2021.

On October 8, 2021, the Authority issued a Notice of Admitted Evidence pursuant to Conn. Gen. Stat. § 4-178, incorporating a Listening Session Summary Report and Draft Recommendations developed by RMI into the evidentiary record.

On October 18, 2021, the EDCs filed Motion No. 11 requesting Authority approval of a proposed request for proposals (RFP) to retain an evaluation, measurement, and verification consultant (EM&V Consultant) pursuant to Order No. 5 of the EV Decision. The EDCs also filed Motion No. 12 seeking Authority approval of a proposed electric vehicle supply equipment (EVSE) vendor RFP pursuant to Order No. 7 of the EV Decision.

On or before October 18, 2021, Eversource and UI filed Motion Nos. 10 and 13, respectively, requesting Authority approval of various proposed program design documents developed pursuant to Order No. 6 of the EV Decision.

On October 18, 2021, the Authority issued a Notice of Request for Written Comments on RMI's Draft Recommendations and the EDCs' Motion Nos. 2, 5, and 10 through 13. Contemporaneously, PURA issued a Notice of Technical Meeting to discuss all written comments received by the Authority. The Authority received nine sets of written comments on or before November 2, 2021, and held the publicly-noticed Technical Meeting on November 4, 2021. The Authority issued two sets of interrogatories on October 22, 2021 and on November 8, 2021.

The Authority issued a Proposed Final Decision on November 30, 2021, and provided an opportunity for Participants to file Written Exceptions and present Oral Argument.

D. PARTIES AND INTERVENORS OR PARTICIPANTS

A listing of all Participants to this proceeding is appended hereto as Appendix A.

[2] Motion No. 2 was also filed as Motion No. 19 in Docket No. 17-12-03RE04.
[3] Motion No. 5 was also filed on August 16, 2021 as compliance in Docket No. 17-12-03RE04.

II. LEGAL AUTHORITY

Electric distribution services are defined by statute as "the owning, leasing, maintaining, operating, managing or controlling of poles, wires, conduits or other fixtures along public highways or streets for the distribution of electricity, or electric distribution-related services[.]" Conn. Gen. Stat. § 16-1(a)(22). Thus, the EDCs are primarily engaged in the provision of distribution system infrastructure, and services collateral to providing that distribution system infrastructure. By the very nature of the EDCs' role in the electric grid, the EDCs are a necessary party to the successful deployment of ZEVs and their associated infrastructure of charging stations.

Pursuant to Conn. Gen. Stat. § 16-11, the Authority has broad statutory power and an obligation to order reasonable improvements, repairs or alterations to a public service company's plant or equipment (i.e., infrastructure), or such changes in the manner of operation, as may be reasonably necessary in the public interest. Further, pursuant to Conn. Gen. Stat. § 16-244i(a) and (b), the Authority regulates the EDCs in accordance with the provisions of section 16-19 and subsection (a) of section 16-19e, and each EDC is obliged to connect all customers to the company's distribution system, subject to the rates, terms and conditions as may be approved by the Authority in accordance with section 16-19 and the principles in subsection (a) of section 16-19e.

In the EV Decision, the Authority exercised its broad statutory powers and obligations under Conn. Gen. Stat. §§ 16-11 and 16-244i to establish the EV Charging Program. EV Decision, pp. 2-4. Moreover, the Authority found that a proactive programmatic approach to facilitating the deployment and integration of zero emission vehicles (ZEVs) and associated infrastructure is necessary and in the public interest, pursuant to its statutory authority and the State's overarching public policy objectives. Id. Herein, the Authority reviews the program design documents and other key compliance developed by the EDCs while incorporating the direction provided in the EV Decision.

III. EV CHARGING PROGRAM OBJECTIVES

In the EV Decision, the Authority adopted objectives (Program Objectives) to guide the EDCs in their administration of the EV Charging Program. In written comments, the Department of Energy and Environmental Protection (DEEP) proposed additional objectives to reflect the Authority's desire to achieve an equitable transition to EV deployment. DEEP Written Comments, Attachment A, p. 2. The Authority accordingly clarifies the following Objectives for the EV Charging Program:

1. Enable Connecticut's commitment to the ten state Memorandum of Understanding (MOU): to collectively deploy 3.3 million ZEVs among the participating states by 2025, and the deployment of approximately 125,000-150,000 EVs in Connecticut by 2025;
2. Facilitate the seamless integration of new and emerging ZEV-related technologies, to realize the potential electric system benefits of ZEVs, along with the economic, health, and environmental benefits they provide;

3. Deploy and integrate ZEVs into Connecticut's electric grid (i.e., the distribution system infrastructure) as a key component of meeting the objectives of the Authority's Framework for an Equitable Modern Grid, namely:
    a. Support (or remove barriers to) the growth of Connecticut's green economy;
    b. Enable a cost-effective economy-wide transition to a decarbonized future;
    c. Enhance customer access to a more resilient, reliable, and secure commodity; and
    d. Advance the ongoing energy affordability dialogue in the State, particularly in underserved communities; and
4. Achieve an equitable transition to wide-scale EV deployment across all communities in Connecticut.

The Authority reaffirms that the above listed Program Objectives shall guide the EDCs in their administration of the EV Charging Program, with the aim of fostering a self-sustaining ZEV market in Connecticut in order to meet the State's greenhouse gas emissions and ZEV MOU targets in a just and equitable manner. The Authority relied on these Program Objectives to guide its review of the EDCs' compliance with the EV Decision. The Authority focused its review on ensuring compliance with the EV Decision and providing clarity to the EDCs and other stakeholders regarding Program implementation.

IV. PROGRAM DESIGN

In the EV Decision, the Authority established a statewide, nine-year EV Charging Program to be administered by the EDCs in their respective service territories, with the same Program offerings made available to all EDC customers through a coordinated education and outreach campaign. The Program is structured around three-year Program review cycles whereby the Authority will re-evaluate whether the expected benefits are being delivered to Connecticut ratepayers, and further examine future deployment targets across five program areas (Program Areas) to optimize EVSE deployment and the associated distribution system infrastructure necessary to meet the State's transportation electrification goals; see Table 1.

Table 1
EVSE Program Deployment Targets

	NUMBER OF PORTS (STATEWIDE)			
PROGRAM AREA	2022-2024	2025-2027	2028-2030	TOTAL
Residential Single-Family (Level 2)	15,000	17,500	17,500	50,000
Residential Multi-Unit Dwellings (Level 2)	1,213	To be revisited	To be revisited	To be revisited
DCFC	137	172	172	550
Destination (Level 2)	789	1,654	1,654	4,868
Workplace & Light-Duty Fleets (Level 2)	2,314	2,521	2,521	7,356

EV Decision, p. 11.

To meet these deployment targets, the EV Decision established maximum per-site incentives that are inclusive of both EVSE incentives and make-ready costs covered by the Program, as summarized in Table 2.

Table 2
EV Charging Program EVSE and Make-Ready Incentives

	Residential Single-Family (Level 2)	**Multi-Unit Dwellings (Level 2)**	**Public Destination (Level 2)**	**Workplace & Light-Duty Fleets (Level 2)**	**DCFC**
Incentive Structure					
EVSE and Make-Ready Incentives	Up to $500 EVSE rebate + a portion of necessary electrical upgrades	Up to 50% of EVSE cost + Up to 100% make-ready installation (≥ 2 ports)		Up to 50% of EVSE cost + Up to 100% make-ready installation (≥ 4 ports)	Up to 50% of EVSE cost + Up to 100% make-ready installation (≥ 2 ports)
Maximum Incentive per Site (including make-ready costs covered by the Program)					
Baseline	-	$20,000			$150,000
Underserved Communities	-	$40,000			$250,000

EV Decision, p. 17.

V. PROGRAM IMPLEMENTATION

Pursuant to Order Nos. 5 through 7 of the EV Decision, the EDCs were required to develop program design documents and RFPs for EVSE vendors and a third-party EM&V Consultant. See, EV Decision, p. 47. Accordingly, on October 18, 2021, the EDCs jointly filed Motion No. 11 requesting that the Authority approve a proposed EM&V Consultant RFP pursuant to Order No. 5 of the EV Decision, and Motion No. 12 requesting that the Authority approve a proposed EVSE Vendor RFP pursuant to Order No. 7 of the EV Decision. Further, Eversource and UI filed Motion Nos. 10 and 13, respectively, requesting that the Authority approve proposed program documents developed pursuant to Order No. 6 of the EV Decision. Specifically, Order No. 6 directed the EDCs to include the following:

a. Proposed Program rules to implement a managed charging program for the Residential Single-Family and Workplace & Light-Duty Fleet Charging Program Areas;
b. A proposed level of the rebate and other program implementation details for residential EV drivers with an existing non-networked Level 2 charger;
c. A proposed definition of "site" and a process to determine on a site-by-site basis the level of make-ready infrastructure upgrades that would enable future charging infrastructure upgrades;
d. A proposed Program Budget for the first three-year Program Cycle (i.e., calendar years 2022 – 2024); and
e. A proposed joint Education and Outreach Plan, including, but not limited to, a coordinated messaging campaign, associated evaluation metrics, and an annual budget for each EDC.

Id.

The Authority directs the following modifications to the EDCs' compliance with Order Nos. 5 through 7 of the EV Decision, represented by Motion Nos. 10, 11, 12, and 13 in the instant docket. Further, the Authority directs the EDCs to submit various filings in support of Program launch on January 1, 2022.

A. MANAGED CHARGING PROGRAM REQUIREMENTS

Order No. 1 of the EV Decision directed the EDCs to initiate a working group to inform the development of managed charging programs for the Residential Single-Family and Workplace & Light-Duty Fleet Program Areas. EV Decision, p. 47. Order No. 6.a. directed the Companies to file proposed rules to implement the managed charging programs. Id. The EV Decision also directed the EDCs to establish participation targets and program parameters through the working group. Id., p. 15. Further, Order No. 6.b. directed the EDCs to propose rebate levels and other program implementation details for drivers with an existing non-networked Level 2 charger. Id.

Eversource and UI jointly proposed managed charging program requirements (Proposed Managed Charging Program Requirements) filed under Motion Nos. 10 and 13, respectively. The EDCs held three working group meetings between August 9 and October 7, 2021, and received written feedback and presentations from stakeholders.

Proposed Managed Charging Program Requirements, p. 4; Order 6ab, Attachment 2, Appendix 1. The Companies identified the following five objectives for the Managed Charging Working Group:

(1) Establish participation targets and program parameters for the two-tier managed charging program;
(2) Develop appropriate price signals;
(3) Develop other program parameters for managed charging of light-duty fleets;
(4) Determine program rules for potential EDC participation in the wholesale market; and
(5) Other key implementation matters.

Proposed Managed Charging Program Requirements, pp. 3-4.

1. Residential

The Authority directed the EDCs to administer a two-tier Managed Charging Program that allows residential customers to choose between a demand response program with up to daily weekday events (Baseline Managed Charging) or a direct load control program (Advanced Managed Charging) to optimize the distribution system and to maximize grid-level benefits of transportation electrification for all customers. EV Decision, pp. 15 and 19. As a condition of receiving a networked Level 2 rebate, customers are required to enroll in one of the managed charging levels and must also allow their EDC to access charger data. Id., p. 19. The EDCs proposed two objectives for the Residential Single-Family Managed Charging Program: (1) to promote off-peak charging; and (2) to promote managed charging. Proposed Managed Charging Program Requirements, p. 4.

The EDCs, however, proposed to offer only the Baseline Managed Charging tier for the Year 1 Program and indicated that the Advanced tier would be available "approximately one year from Baseline Program launch, i.e., early 2023." Id., p. 9. The Companies stated their reasoning was "to allow for technology development and learning by EDCs in infrastructure and the Baseline Tier Managed Charging Program." Id. Notably, neither Company expressed concerns with the two-tier managed charging approach and associated implementation timeline in their Written Exceptions filed in Docket No. 17-12-03RE04.[4] The current Proposed Managed Charging Program Requirements therefore fall short of meeting the adopted Program Objectives to integrate EVs into the distribution system and to realize electric system benefits. Nevertheless, the Authority is committed to working with the EDCs and docket Participants to continually refine and improve the Managed Charging Program Requirements to ensure ratepayer benefits associated with residential managed charging are realized. Inclusion of a robust Advanced Managed Charging tier offering in Year 2 of the Program is critical to this Program Objective.

[4] See, Eversource Written Exceptions dated June 25, 2021 in Docket No. 17-12-03RE04; UI Written Exceptions dated June 25, 2021 in Docket No. 17-12-03RE04.

a. Baseline Managed Charging Tier

The EDCs proposed to offer up to $200 annually – the maximum incentive amount authorized in the EV Decision – for residential customers who successfully participate in the Baseline Managed Charging tier and fall into one of the following categories: (1) customers receiving an incentive for a networked Level 2 charger; (2) customers participating through vehicle telematics; and (3) customers with an existing non-networked Level 2 charger installed prior to January 1, 2022, who install a device enabling managed charging participation. Proposed Managed Charging Program Requirements, p. 6; see also, EV Decision, p. 20. Specifically, the EDCs proposed to implement a program whereby each EDC would call demand response (DR) events to curtail EV charging in June, July, August, and September to align with the ISO New England critical peak periods. Id., p. 8. Typical events would be up to three hours in duration and occur between 3:00 pm and 9:00 pm, with up to 15 events per month during the summer season, as shown in Table 3. Id.; Eversource Response to CAE-2; UI Response to CAE-2.[5]

Table 3
Proposed EV Charging Program Managed Charging Parameters

	Summer
Season Dates	June 1 – September 30
Number of Events	Up to 60
Event Duration	Up to 3 hours
Time of Day	3:00 pm – 9:00 pm

Proposed Managed Charging Program Requirements, p. 6; Eversource Response to CAE-2; UI Response to CAE-2.

Pursuant to the EV Decision, the EDCs proposed to notify customers through a phone application, web portal, email, and/or text message typically one day prior to the event, except for emergency event notifications, which may be on the same day as the event. Proposed Managed Charging Program Requirements, p. 8. Further, customers would be required to enable the EDCs to access a minimum of hourly and up to 15-minute interval vehicle charging activity data. Id.

Under the EDCs' proposal, customers would be able to opt out of the DR events at any time, with no penalty. Id. Customers that opt out of no more than two events per month and charged at home at least once per month would receive $50 for each month, from June through September, for a total of $200 per year, provided as off-bill compensation following the summer season. Id. Participating customers would be required to remain in the program for 24 months, in an effort to "align the level of upfront incentive to the customer with an appropriate returned benefit [to] the program within reason." Id.; Eversource and UI Response to CAE-6. Customers with "extenuating circumstances" would be permitted to opt out of the program earlier, subject to EDC approval. Proposed Managed Charging Program Requirements, p. 8; Tr. 11/4/21, pp. 61-64.

[5] The EDCs state that they have typically not called more than 8-12 demand response events during summer months in other programs. See, Eversource Response to CAE-2; UI Response to CAE-2.

The Authority sought written comments from docket Participants on the EDCs' Proposed Managed Charging Program Requirements. ChargePoint and DEEP generally supported the EDCs' proposal. DEEP asserted that the requirements would encourage charging habits that are beneficial to the grid, incentivize off-peak charging, and encourage EV adoption among single-family residents. DEEP Written Comments dated 11/1/21, p. 5. ChargePoint similarly supported the requirements as proposed and stated that the managed charging working group process provided an open and collaborative process. ChargePoint Written Comments dated 11/1/21, pp. 4-5. Conversely, Sierra Club proffered that the Baseline tier should not be limited to the four summer months proposed by the EDCs and instead should target daily load-shifting to promote off-peak charging more broadly. Sierra Club Written Comments dated 11/1/21, p. 2. Additionally, OCC proposed that the requirements include specific criteria that must be met for customers to drop out of the Managed Charging Program prior to the end of the 24-month minimum participation term, and to also require such customers to return upfront incentives. OCC Written Comments dated 11/1/21, p. 4. DEEP similarly proposed that customers be subject to a minimum participation threshold with enforcement provisions to ensure ratepayer benefits are realized. DEEP Written Comments dated 11/1/21, p. 6.

Further, the written comments submitted by Managed Charging Working Group participants indicate stakeholder support for a more robust Baseline Managed Charging tier. Greenlots proposed that the EDCs implement a "consistent smart charging model," whereby customers receive incentives for charging at consistent, pre-determined times (i.e., off-peak). Order No. 6ab, Attachment 2, Appendix 1, p. 29. Greenlots stated that this design would "support more significant load-shaping" and could be modeled after Consolidated Edison's Electric Vehicle Charging Rewards program. Id. Additionally, WeaveGrid proposed that the Baseline Managed Charging tier shift charging to off-peak periods on weekdays rather than using traditional DR events and suggested that the EDCs stagger charging to avoid a coincident off-peak charging. Id., p. 52. WeaveGrid suggested this design would increase customer satisfaction and help the EDCs understand charging behavior. Id.

Eversource currently offers a similar EV demand response option through its ConnectedSolutions pilot program, with nearly 700 participating customers enrolled across the Massachusetts and Connecticut service territories. See, Eversource Response to CAE-35; Eversource Response to CAE-35, Exhibit 1. Eversource launched its ConnectedSolutions EV DR program in Connecticut as a pilot offering in 2020 through the Conservation and Load Management (C&LM) Plan. In its ConnectedSolutions EV pilot, Eversource can reduce participating customers' charging rates from Level 2 charging to Level 1 charging during events year-round, with up to 15 events per month.[6] Id. Customers with an existing networked EVSE receive a $150 enrollment incentive and are eligible for $50 annually for their first three years. Id. Customers purchasing an eligible EVSE receive a $300 enrollment incentive with a commitment to participate in the ConnectedSolutions program for three years. Id.

[6] Eversource describes its ConnectedSolutions EV pilot as events occurring for up to three hours between 6:00 p.m. and 6:00 a.m. See, Eversource Response to CAE-35, Exhibit 1. As detailed in Guidehouse's report, Eversource called five events that lasted two to three hours between 4:00 p.m. and 7:00 p.m. on non-holiday weekdays from June 2020 to September 2020, and four events that lasted two hours between 5:00 p.m. and 8:00 p.m. on non-holiday weekdays from October 2020 to March 2021. Id.

The Authority notes that the EDCs' proposed Baseline Managed Charging tier and Eversource's existing ConnectedSolutions EV pilot offered through the C&LM Plan are both designed to reduce EV demand, however, there are key differences in the DR program design. For example, the ConnectedSolutions program is designed as a year-round DR program, whereas the Baseline Managed Charging tier focuses on a four-month period over the summer to coincide with the ISO New England system peak. Given the importance of encouraging long-lasting customer behavior shifts to charging their EVs during off-peak times, the Authority finds that an all-year program may be more appropriate. The Authority is also concerned that there may be customer confusion, and ultimately, inefficiencies in program administration as Eversource intends to continue to offer its ConnectedSolutions DR EV Charging Program concurrently with the default Baseline Managed Charging tier, which have varying incentive and participation levels. Accordingly, no later than May 1, 2022, Eversource is directed to submit a proposed plan to transition customers participating in its ConnectedSolutions EV pilot to the Residential EV Managed Charging Program for Authority review and approval. The Authority further clarifies that customers shall not be eligible to receive incentives from both Eversource's ConnectedSolutions DR EV pilot implemented through the C&LM Plan and the two-tier managed charging program established in the EV Decision. [7]

The Authority recognizes a balance must be achieved between implementing a robust managed charging program and the EDCs engaging for the first time with customers regarding their at-home EV charging patterns. The Companies discussed these short-term and long-term considerations when designing the Baseline Managed Charging tier, stating that ultimately it is important to maximize customer engagement early on. Tr. 11/4/21, pp. 79-83. Eversource described the Baseline Managed Charging tier as "developing muscle memory" for customers and UI highlighted the shorter-term goals of "get[ting] people used to the idea of a demand response." Id., pp 77-78; 85.

Accordingly, the Authority accepts the Companies' proposed demand response program design for the Baseline Managed Charging tier as the initial, default offering for all residential customers receiving an incentive through the EV Charging Program beginning in January 2022. In the spirit of continuous improvement, the Authority directs the EDCs to establish comprehensive data collection mechanisms to track implementation and identify program improvements. As contemplated in the EDCs' response to CAE-3, the Companies, together with the EM&V Consultant, shall also develop methods to analyze data from the Baseline Managed Charging tier and create forecasts to calculate the expected reductions in peak demand in future Program years, and shall file the resulting analysis with the EM&V Consultant's 2022 annual report in the appropriate annual proceeding. The methodology shall enable the Companies to evaluate the savings associated with participants choosing to charge during off-peak hours as a result of their participation in the Program and evaluate the level of charging curtailment necessary to encourage participation in either Managed Charging tier while reducing grid impacts. In addition, the Authority expects the EDCs to leverage lessons learned in other jurisdictions, such as the September 2021 Guidehouse report to Eversource and the OptimizeEV pilot program in the New York State Electric and Gas Corporation's service territory, to accelerate the collective learning curve. See, Eversource Response to CAE-35, Exhibit 1; UI Response to CAE-35.

[7] As OCC proposed in its Written Exceptions dated 12/7/21, customers transitioning from ConnectedSolutions should not receive duplicative incentives. OCC Written Exceptions, p. 1.

Notwithstanding the foregoing authorization to move forward with the Baseline Managed Charging tier in its current form for Program Year 1, the Authority finds that the EDCs' Proposed Managed Charging Program Requirements do not fully meet the EV Charging Program Objective of realizing the electric system benefits of EVs, particularly since an Advanced Managed Charging tier will not be available for the Program's launch in January 2022. As a result, the Authority directs Eversource and UI to reconvene the Managed Charging Working Group to inform necessary improvements to the EDCs' Proposed Managed Charging Program Requirements for Authority review and approval no later than May 1, 2022, as discussed further herein. The revised Managing Charging Program Requirements must clearly identify the electric system benefits targeted for each managed charging level (i.e., reducing system peaks on the distribution system, avoiding local distribution system upgrades, renewables absorption, potential future EDC wholesale market participation, etc.).

In addition, the Authority directs the EDCs, through the Managed Charging Working Group, to reexamine the proposed DR program design and make a recommendation as to whether an alternative passive managed charging program design is more appropriate as the Baseline Managed Charging tier. As discussed in this proceeding and in Docket No. 17-12-03RE04, EV-only and whole-house time of use (TOU) rates, as well as incentive-based programs that reward participants for consistent off-peak charging, are alternatives to a DR model. The EDCs, with input from the Working Group, may propose a revised program design for the Baseline Managed Charging tier in their May 1, 2022 filing and provide justification for why such modification is warranted.

The Authority intends to initiate the 2022 annual review proceeding in April 2022 (2022 Annual Review) to review the EDCs' revised Managed Charging Program Proposals no later than May 1, 2022 to ensure the participation targets and expected benefits are being realized. Further, the Authority reiterates its intent to further examine an EV-only TOU rate offering as part of the 2022 Annual Review should it become evident that the current Baseline Managed Charging tier does not sufficiently optimize distribution system benefits through off-peak charging, and pending the outcome of Docket No. 17-12-03RE02, PURA Investigation into Distribution System Planning of the Electric Distribution Companies - Advanced Metering Infrastructure. See, EV Decision, p. 20. At a minimum, however, the Authority directs the EDCs to communicate the benefits to EV drivers of switching to a whole-house TOU rate through the Companies' education and outreach efforts beginning with the January 2022 EV Charging Program launch.

Alternatively, should the EDCs and Managed Charging Working Group participants determine a DR program design is the most appropriate offering for the Baseline Managed Charging tier beyond Year 1, the EDCs shall address the following, at a minimum, in their May 1, 2022 revised Managed Charging Program Requirements to be submitted for Authority review and approval:

- Program participation requirements – The current design does not account for the potential scenario whereby a program participant may not be at home charging their EV during a DR event, but nonetheless could be charging at work or at a public charging station during a DR event. Under the EDCs' proposal for Year 1, so long as the customer who was otherwise planning to charge their EV during a

DR event does not opt out of the event, the customer will receive $50 per month, up to $200 annually. The revised Managed Charging Program Requirements will therefore address potential mitigation strategies, such as assessing previous charging timelines, time of day restrictions, or modifying event participation measurement (i.e., whether or not the vehicle is plugged in at home during a DR event).[8]

- Baseline tier – The proposed Baseline Managed Charging tier only includes summer events, while ConnectedSolutions could have year-round events with a different window of time for calling potential events. The Managed Charging Program should at least require similar expectations for customer participation as Eversource's ConnectedSolutions EV DR pilot (i.e., a program design that encourages year-round, off-peak charging).

- Opt-out provision – The Proposed Managed Charging Program Requirements reference "extenuating circumstances" whereby participating customers would be permitted to opt-out of the Baseline tier prior to the conclusion of the 24-month period, but do not specify what qualifies as extenuating circumstances. In addition, the EDCs must clarify the practical implications of what it means to "opt out" of the Baseline Managed Charging tier, considering repeated inaction in response to DR events would only result in the customer not receiving the $50 monthly incentive. As a reminder, all residential customers receiving any kind of incentive through the EV Charging Program must allow their EDC to receive charging data.

Finally, as discussed further in Section V.F., the Authority directs the EDCs to develop a final Residential Managed Charging Program Participation Guide for the Residential Managed Charging Program effective January 2022, which contains the same or similar information as what will be included on the Companies' respective webpages regarding program participation. The Guide shall also include specific parameters for "emergency events" that shall align with any Electric Storage Program emergency event guidelines being developed pursuant to orders in Docket No. 21-08-05, Annual Review of the Electric Storage Program – Year 1.

b. Advanced Managed Charging Tier

As discussed above, although the EV Decision directed the EDCs to develop an Advanced Managed Charging tier for Program launch on January 1, 2022, the Companies proposed to instead offer the tier in "early 2023" to allow for "technology development and learning." Proposed Managed Charging Program Requirements, p. 9. The Companies further expressed that having more time to determine the appropriate incentive levels and technology options would allow for a better initial program design. Tr. 11/4/21, pp. 70-74.

Multiple stakeholders recommended that the EDCs make the Advanced tier available January 1, 2022. Sierra Club further stated that the direct load control contemplated in the EV Decision is important to manage EV load to enable increased EV adoption without new grid infrastructure, and that enabling technology is already

[8] The EDCs should also confirm through the application process that the participating customer is in possession of an EV (e.g., checkbox confirming ownership or a lease agreement, etc.).

available. Sierra Club Written Comments, p. 2. Sierra Club acknowledged that a delay of a few months may be necessary to implement administrative modifications but proposed the Companies be required to implement the Advanced tier in 2022. Id. Greenlots also noted that that EV Decision requires the Advanced tier to be available no later than January 1, 2022, but does not "preclude the EDCs from fine-tuning the program over the course of the first phase of implementation." Order 6ab Attachment 2, p. 30. WeaveGrid noted that launching both managed charging tiers at a similar time would help customers evaluate their options and the EDCs maximize grid-level benefits. Id., p. 54. WeaveGrid noted that other utilities launched both baseline and more sophisticated programs at similar times. Id.

As stated above, the Authority directs the EDCs, and the Working Group participants, to develop robust program rules for the Advanced Managing Charging tier. In the EV Decision, the Authority envisioned an Advanced Managed Charging tier whereby participants would actively engage with their EDC to optimize at-home charging to minimize distribution system infrastructure upgrades while adhering to minimum EV charging parameters set by the participant. EV Decision, p. 20. Further, the Authority stated that the EDCs should be able to curtail charging rates during predetermined time periods, including potentially daily direct control, in exchange for an incentive payment. Id. The Authority further indicated that the EDCs should have the ability to control both the rate and timing of charging, and that customers may opt out a limited number of times with incentives reduced accordingly thereafter. Id. Such design should complement the existing Baseline Managed Charging tier and whole-house TOU rate offerings from the EDCs. Id. Further, to the extent possible, the additional incentive amount should appropriately reflect the expected benefits over the Baseline Managed Charging tier. The Authority will review the EDCs' revised Managed Charging Program Proposals to be submitted no later than May 1, 2022, for implementation as soon as possible, but no later than January 1, 2023.

c. Other Incentives

i. Managed Charging Enrollment Incentives

Pursuant to Order No. 6.b. of the EV Decision, the EDCs proposed to offer a $200 managed charging enrollment incentive to customers that participate through eligible vehicle telematics without the need for a networked Level 2 charger. Proposed Managed Charging Program Requirements, p. 6. The Companies stated they plan to request changes to the incentive no more than annually according to program participation goals. Eversource and UI Response to CAE-1.

In written comments submitted by Managed Charging Working Group participants, stakeholders supported varying upfront enrollment incentive levels. Ev.energy proposed an enrollment incentive of $100 coupled with an ongoing performance incentive equal to $15 per month during peak summer months, while WeaveGrid referenced Xcel Energy Colorado's program that offers customers a $100 incremental incentive for customers to enroll in dynamic managed charging. Order 6ab Attachment 2, Appendix 1, pp. 26 and 52. OCC opposed enrollment incentives altogether. Id., p. 59.

The Authority finds that an upfront incentive is appropriate to encourage customers to enroll in the Managed Charging Program and share charging data with their EDC. However, the Authority finds there is insufficient evidence to support the EDCs' proposed upfront incentive level. Accordingly, the Authority approves a one-time $100 Program enrollment incentive for Year 1 for customers participating through eligible vehicle telematics, which shall be included in the Residential Managed Charging Participation Guide. The Companies shall include a list of vehicles that are eligible to participate through telematics in the Managed Charging Program Requirements to be updated at least annually.

For customers with an existing non-networked Level 2 charger installed before January 1, 2022, and a vehicle that does not have compatible telematics, the EDCs proposed to offer customers a $150 Managed Charging Program enrollment incentive and provide customers with an aftermarket device free of charge. Proposed Managed Charging Program Requirements, p. 6. Such device would be qualified through a request for quotation (RFQ) process. Eversource expects the device to cost less than $100 per device. Tr. 11/4/21, pp. 54-55. To participate, the EDCs proposed certain technical requirements, applicable to aftermarket devices as well as vehicle telematics and networked Level 2 chargers. Proposed Managed Charging Program Requirements, pp. 7-8. Specifically, the EDCs proposed to require (1) either Wi-Fi enabled internet of 25 Mbps or greater, or broadband with 4G capability; and (2) charging activity data collection at 15- to 60-minute intervals, with utility distributed energy resources management system (DERMS) integration through the original equipment manufacturer (OEM) or intermediary platform. Id. As a potential alternative to installing a separate device, UI expressed interest in determining whether the Company could use existing Advanced Metering Infrastructure (AMI) data to track customers' participation in DR events through the Baseline Managed Charging Program. Tr. 11/4/21, p. 56. DEEP proposed that at least one managed charging participation option should not require customers to have a Wi-Fi or cellular plan, referencing the SmartCharge NY program offered by Consolidated Edison in New York. DEEP Written Comments, p. 6.

The Authority finds the Companies' proposal to provide such device to customers will reduce barriers to managed charging participation for customers with an existing, non-networked Level 2 charger. To align with the telematics enrollment incentive, the Authority directs the EDCs to modify the one-time Program enrollment incentive for customers with an existing, non-networked Level 2 charger to be $100 for Year 1. The Authority agrees with DEEP that at least one managed charging option should not require the customer to have a Wi-Fi or cellular plan to participate. Accordingly, the EDCs shall jointly file the RFQ for such devices as compliance no later than January 7, 2022. In addition, no later than January 7, 2022, UI shall file as compliance its determination and supporting analysis of whether its existing AMI network could be utilized to enable customers with a non-networked Level 2 charger to participate in the Managed Charging Program.

As outlined in the EV Decision, Managed Charging Program participants must allow their EDC to access charger data. EV Decision, p. 19. The Authority further clarifies that all customers receiving any type of incentive through the EV Charging Program must allow their EDC to receive charging data from either a networked EVSE, vehicle telematics, or a device that enables participation in the Managed Charging Program, and

that customers are not able to opt out of data sharing, even if they are no longer actively participating in the Managed Charging Program. EV charging data shall be aggregated, anonymized, or otherwise encrypted if/when disclosed publicly. Accordingly, the EDCs shall update the Managed Charging Program Requirements to reflect this requirement and ensure that systems are implemented to collect and securely store EV charging data for all participants receiving an incentive through the EV Charging Program.

The Authority finds that the modified one-time Managed Charging Program enrollment incentives are acceptable for Year 1 (see Table 4, below), as receipt of the incentive enables each EDC to have visibility into participating customers' EV charging patterns in its service territory. However, the Authority intends to revisit whether the managed charging enrollment incentives authorized above are necessary in future Program Years, and if so, whether the current amount is appropriate.

Table 4
Residential Single-Family Program Area Incentives (2022)

Customer Scenario		Networked Level 2 Charger Rebate *(up to)*	Wiring Upgrade to 240v Rebate *(up to)*	Device Issuance	One-Time Enrollment Incentive	Baseline Managed Charging Program *(up to)*
Networked L2 Charger	Needs 240v	$500	$500	None	$0	$200/year
	Has 240v	$500	0	None	$0	$200/year
Telematics	Needs 240v	$0	$500	None	$100	$200/year
	Has 240v	$0	$0	None	$100	$200/year
Non-Networked L2 Charger	Has 240v	$0	$0	EDCs send device	$100	$200/year

ii. Electrical Upgrades

In addition to establishing managed charging program guidelines, the EV Decision directed the EDCs to submit data on typical electrical upgrade costs necessary for residential customers to support Level 2 charging and to propose a rebate level to cover a portion of such costs. EV Decision, p. 18. Further, Order No. 6.b. of the EV Decision directed the Companies to propose rebates and managed charging implementation details for EV drivers participating through onboard vehicle telematics or with an existing non-networked Level 2 charger installed prior to January 1, 2022. Id., pp. 20-21 and 47.

In its Managed Charging Program Requirements, the EDCs proposed to offer a rebate of up to $500 to cover any wiring upgrades necessary to support 240v EV charging, though the filing did not provide supporting data. Proposed Managed Charging Program Requirements, p. 6. UI stated that the Companies do not have experience collecting such data and instead referenced a study from the International Council on Clean

Transportation, which estimated the average cost for wiring upgrades at a single-family home to be approximately $680. Tr. 11/4/21, pp. 59-61; Eversource and UI Response to CAE-8. To implement the rebate, Eversource stated that customers would be able to indicate in the Program application that they need wiring upgrades to participate. Tr. 11/4/21, pp. 57-58. The customer would then have an electrician complete the required work and submit the invoice to the EDC, who would then disburse the rebate after the customer is enrolled in the Managed Charging Program. Id.

The Authority approves the proposed maximum $500 rebate for customers required to install wiring upgrades to accommodate Level 2 charging at home for the Year 1 Program. Such rebate will help ensure electrical upgrades are not a barrier to managed charging participation in support of the Program Objectives. The Authority clarifies that such rebate is only available to customers that agree to participate in the Managed Charging Program for at least 24 months, and customers that drop out early will be required to repay a prorated portion of the incentive. Further, the Authority directs the Companies to record and report through the annual reporting process the actual electrical upgrade costs submitted by customers. Based on participants' actual installation cost data collected by the EDCs, the Authority intends to examine whether the $500 maximum rebate for electrical upgrades should be adjusted in Program Year 2.

2. Light-Duty Fleets & Multi-Unit Dwellings (MUDs)

Order No. 6.a. also directed the EDCs' Managed Charging Working Group to develop a Managed Charging Program for light-duty fleets, including program rules and associated documents. EV Decision, p. 35. All non-public sites will be required to enroll in the managed charging offering to maximize the ratepayer benefits of light-duty fleet electrification. Id. The Companies' Proposed Managed Charging Program Requirements included parameters for light-duty fleets that are identical to the residential Baseline Managed Charging tier. Proposed Managed Charging Program Requirements, p. 10. Eligible site hosts, identified as those with four or more non-public chargers, would also be able to work with their EDC to develop a customized Alternate Managed Charging Plan with incentives not to exceed those of the Baseline tier. Id. While the Authority did not require the EDCs to establish a Managed Charging Program for MUDs in Year 1, the EDCs proposed to offer the Baseline tier or develop a customized Alternate Managed Charging Plan with eligible site hosts located in MUDs. Id., p. 11.

By requiring non-public light-duty fleet EVSE to participate in a managed charging program, the Authority's intent is to ensure that ratepayer funds used to support the electrification of private fleets provide sufficient benefits to ratepayers through increased electric sales. While the proposed light-duty fleet DR program would provide an incentive to avoid charging during certain system-wide peaks, the Authority finds the current proposal lacking necessary details and specifics to the charging use case.

Accordingly, the Authority directs the EDCs to reconvene its Managed Charging Working Group to inform a revised Managed Charging Program Requirements for light-duty fleets installing non-public EVSE under the EV Charging Program to be submitted for Authority review and approval no later than May 1, 2022, for implementation as soon as possible, but no later than January 1, 2023. The revised Managed Charging Program Requirements shall incorporate minimum parameters for customized managed charging

plans for participating light-duty fleets, including maximum annual incentives on a per unit basis that are designed to encourage consistent off-peak charging. Further, the incentives for light-duty fleet site hosts installing *non-public* EVSE shall not be the same as incentives for light-duty fleet site hosts installing *public* EVSE that decide to participate in managed charging.

Finally, as discussed further in Section V.F., the Authority directs the EDCs to develop a final Commercial Managed Charging Program Participation Guide for the Light-Duty Fleets and MUDs Managed Charging Programs, which contains the same or similar information as what will be included on the Companies' respective webpages regarding program participation.

B. NON-RESIDENTIAL CHARGING

a. Site Definition

Order No. 6.c. of the EV Decision directed the EDCs to propose a definition of "site" and a process to determine the appropriate make-ready infrastructure that would enable future charging infrastructure upgrades. EV Decision, p. 47. Further, the Decision stated that such future-proofing actions "must be driven by site host commitments and balanced against equitable allocation of limited Program funds." Id., p. 39. Accordingly, the EDCs proposed the following definitions:

> "Site: prewiring of electrical infrastructure at a set of parking spaces to facilitate cost-efficient installation of a bank of electric vehicle supply equipment (EVSE), either Level 2 or DCFC, on a property within the Company's electric service territory owned or controlled by the Site Host. A site may include a service panel, junction boxes, conduit, wiring and other components necessary to make a particular location able to accommodate a bank of EVSE. The maximum incentives shall apply to each site. A Site Host may have more than one Site at a single property to the extent that each site meets the specific electrical infrastructure criteria as defined.
>
> Site Host: the fee owner of Site or has a long-term (10 years or longer remaining term) lease or ground lease of the Site."
>
> Order 6c, Attachment 1, p. 1.

The EDCs further clarified that a Site could be easily differentiated by the distribution service panel to which the EVSE is connected. Eversource and UI Response to CAE-9. Eversource noted that while a Site Host could locate two banks of EVSE in close proximity to each other, technically located at separate "Sites," such an arrangement would not be cost effective and would not give Site Hosts a cost advantage. Tr. 11/4/21, pp. 101-102.

The Authority sought written comments on the EDCs' proposed Site definition. ChargePoint stated that the proposed definition "appropriately accounts for customer locations that may include multiple buildings and/or parking lots," such as a university or hospital campus. ChargePoint Written Comments dated 11/1/21, p. 5. DEEP noted it did

not object to the proposed Site and Site Host definitions. DEEP Written Comments dated 11/1/21, p. 7. Conversely, OCC stated that the proposed definition would permit multiple sites on a single property and therefore "undermines the intention of the Program to limit investment on individual properties" to equitably distribute Program resources. OCC Written Comments dated 11/1/21, p. 6.

In reviewing the proposed Site definition, the Authority relied on the Program Objectives to enable EV deployment to support the State's commitments and equitably deploy the required infrastructure. As described in the EV Decision, the established per-site maximum incentive levels will ensure the deployment targets are met in an efficient and equitable manner. See, EV Decision, p. 16. In the make-ready program structure authorized by the Authority, the EDCs will invest in the infrastructure up to the charging station, from the distribution system up to the EVSE and including, for example, a primary lateral service feed, transformer, utility meter, and conduit. See, EV Decision, p. 12. The Authority understands that locating multiple Sites on a single property creates the risk that a Site Host could cover more of their costs with incentives than they may have been able to otherwise, for example, by using common supply infrastructure to support additional charging stations that would not have otherwise been covered. However, such common equipment is included in the EDCs' proposed Site definition. As noted by Eversource, a Site Host building duplicate infrastructure in order to qualify as separate Sites would not make economic sense. Tr. 11/4/21, pp. 101-102. Accordingly, the Authority finds that the EDCs' proposed Site definition will appropriately distribute limited Program funds to distinct locations. However, the EDCs shall clearly indicate in their annual report submitted as part of each Annual Review when multiple Sites are located on the same property and identify any electrical infrastructure that is shared between the individual Sites.[9]

To ensure Site Hosts include the appropriate level of future proofing in site design, the EDCs proposed to require separate costs be provided for the additional associated make-ready work. Order No. 6c, Attachment 1, p. 1. The EDCs proposed that approved future-proofing costs would include the following: oversized or additional conduit; oversized panels; additional conduit, trenching, and connection points to additional parking spaces; service for the station; and larger or additional transformers and pads. Id. Site Hosts would be required to request such work in the Program application and explain their future expansion plans. Id. The EDCs would then evaluate the request and determine the feasibility and appropriateness of the plans. Id.

ChargePoint supported the EDCs' proposed future-proofing process but requested that the Companies clarify which specific costs can be included, potentially through examples that would or would not be covered under make-ready incentives. ChargePoint Written Comments dated 11/1/21, pp. 4-5. DEEP also supported the proposed process and stated that it aligns with the EV Decision, but DEEP views it as a "high-level starting point" and expects that further specificity will be included in Program documents, such as in the application. DEEP Written Comments dated 11/1/21, p. 7. The OCC recommended tracking future-proofing activity and that Site Hosts be required to return upfront incentives

[9] Pursuant to the EV Decision, the EDCs shall submit an annual report summarizing the Program results to date, and recommendations for any Program modifications, in the relevant Annual Review or Program Review proceeding. See, EV Decision, p. 44.

if EVSE infrastructure is not expanded or expanded in a way that does not meet Program requirements within two years of installation. OCC Written Comments dated 11/1/21, p. 6.

The Authority finds that additional details regarding the EDCs' proposed future-proofing process are needed to ensure future-proofing measures are appropriate and well understood by Program participants and other stakeholders. As discussed in Section V.F., the EDCs will be required to develop and submit a comprehensive Program Manual, inclusive of a Program application for Site Hosts. Therefore, the Authority directs the EDCs to include a detailed future-proofing process, including additional guidance for potential Site Hosts, in the applicable Program application and other documents. Specifically, the EDCs shall provide multiple examples of approved and unapproved future-proofing measures, including how to differentiate the costs associated with future proofing. While the EDCs do not expect many sites to be able to take advantage of future proofing measures due to the established maximum site incentive levels (See, Tr. 11/4/21, pp. 25-26), the Authority nonetheless directs the EDCs to clearly identify in their reporting the specific costs and types of work attributed to future proofing that are covered and not covered by Program incentives.

b. Capacity Maps

The EV Decision directed each EDC to file a proposed plan to develop a publicly available hosting capacity map specific to installing Level 2 and DCFC stations. EV Decision, pp. 46-47. UI filed Motion No. 2 on August 16, 2021, and Eversource filed Motion No. 5 on August 30, 2021, seeking Authority approval of the proposed plans.[10] On September 23, 2021, the Authority provisionally approved the Companies' plans but requested further details and deferred final approval of the associated costs until a later date. See, Motion No. 2 and 5 Rulings dated September 23, 2021. Each EDC subsequently filed the requested information by October 15, 2021.

The Authority reaffirms that any expenses related to the development of the Companies' hosting capacity maps for EV Charging will be deferred to a regulatory asset, and the Authority will review the prudency of such development costs in each Company's next rate case, as discussed further in Section V.E. Accordingly, each EDC shall maintain detailed, itemized records of all incremental costs incurred in the development and implementation of its EV Charging hosting capacity map.

c. EV Tariffs

In the EV Decision, the Authority found that separately metered EV charging stations under the EDCs' existing tariffs are subject to demand charges that can significantly impact the economics of DCFC installation, particularly when overall utilization is low but subject to short periods of high demand. EV Decision, p. 29. The Authority directed the Companies to propose longer-term, sustainable rate solutions (EV Tariffs) that incorporate appropriate cost allocation for EV chargers as utilization increases in the 2022 Annual Review. Id., p. 30. As a temporary, near-term demand

[10] Eversource originally submitted its response to Order No. 2 of the EV Decision on August 16, 2021, as a compliance filing in Docket No. 17-12-03RE04.

charge mitigation measure, the Authority directed Eversource to continue offering its existing EV Rate Rider for eligible charging stations, and to expand eligibility to light-duty fleets with separately metered Level 2 and/or DCFCs for non-public use.[11] Id., pp. 29-30 and 35. The Authority similarly directed UI to remove restrictions on its non-demand GS and GST rates for eligible separately metered EVSE. Id., p. 30. On August 16, 2021, Eversource and UI filed Motion Nos. 1 and 3, respectively, requesting Authority approval of the proposed EV Rate Riders, pursuant to Order Nos. 2 and 3 of the EV Decision. The Authority granted Eversource's Motion No. 1 on September 13, 2021, and directed certain changes to UI's EV Tariff prior to granting Motion No. 3 on October 5, 2021.

The Authority reiterates that each Company's EV Rate Rider shall be made available as soon as possible, but no later than January 1, 2022. Further, in the Decision dated March 6, 2019, in Docket No. 17-10-46RE01, Application of The Connecticut Light and Power Company d/b/a Eversource Energy to Amend its Rate Schedules – EV Rate Rider (EV Rate Rider Decision), the Authority directed Eversource to collect certain data from customers taking service under its EV Rate Rider. EV Rate Rider Decision, p. 8. The Authority expects a final report on Eversource's Expanded EV Rate Rider pilot program on April 1, 2022, pursuant to Order No. 6 of the EV Rate Rider Decision. Id., p. 10. The Authority hereby directs Eversource to also file its compliance with Order No. 6 of the EV Rate Rider Decision in the instant proceeding.

Finally, to inform the review process of the EDCs' proposed EV Tariffs in the 2022 Annual Review, the Authority directs the Companies to collect data on customers receiving service under the EV Rate Riders, including charger type, maximum capacity, location, and usage patterns, and to file such data in the 2022 Annual Review proceeding no later than August 1, 2022.

C. PROGRAM ADMINISTRATION

The Authority emphasizes that Eversource and UI individually bear the burden of proving the prudency of all administrative costs associated with the Program. To demonstrate prudency, the EDCs must provide sufficiently detailed and itemized records and evidence, including cost information, to support the finding that all efforts were taken to minimize costs, including, but not limited to, evidence that: (1) reasonable competitive procurement processes were held; (2) existing internal resources were leveraged to the extent possible; (3) investments in new resources were selected with current and future investments, programs, and public policies in mind; and (4) unnecessary costs were avoided. Out of an abundance of caution, the Authority is in no way pre-approving the estimated Program administrative costs provided to date; the approval of any Program administrative costs will be done through the examination of each Company's regulatory asset as part of the Company's next base rate case proceeding, as discussed further in Section V.E.

[11] Eversource's EV Rate Rider was first approved as a pilot in the Authority's March 6, 2019 Decision in Docket No. 17-10-46RE01, Application of The Connecticut Light and Power Company d/b/a Eversource Energy to Amend its Rate Schedules – EV Rate Rider.

1. EM&V RFP

Order No. 5 of the EV Decision directed the EDCs to file a proposed RFP to retain an EM&V Consultant for the first three-year Program Cycle and directed the Companies to notify the Authority of the Consultant's retention. EV Decision, p. 47. On October 18, 2021, the EDCs filed Motion No. 11 requesting the Authority approve the Companies' compliance with Order No. 5.

The EDCs' proposed EM&V RFP listed various Program Metrics to be collected, at a minimum, by the retained EM&V Consultant, pursuant to the EV Decision. Motion No. 11, Attachment 1, p. 3; see also, EV Decision, pp. 43-44. Notably, the EDCs estimated that the EM&V Consultant selection process would take nine weeks following the issuance of the RFP. Motion No. 11, Attachment 1, p. 5. Subsequently, the EDCs provided a general schedule of their procurement steps, which ranged from 20 weeks to 35 weeks. Eversource Response to CAE-12; UI Response to CAE-12. Order No. 8 of the Decision directed the EDCs, in consultation with their EM&V Consultant, to submit to the Authority for approval "[p]rogram metrics, associated calculation methodologies, and data requirements for verifying Program performance based on the established metrics, as discussed in Section VI.G" no later than December 15, 2021. Decision, p. 48 (Order No. 8 Compliance Filing).

The Authority emphasizes the importance of the EDCs establishing comprehensive data collection and other reporting requirements by January 1, 2022 to ensure program implementation data is tracked beginning at the Program's launch. While the Companies are unable to retain an EM&V Consultant prior to the December 15 deadline according to their filed timelines, the Authority nonetheless expects the EDCs to submit a comprehensive filing pursuant to Order No. 8 with detailed program metrics, associated calculation methodologies, and other data requirements by such date. Further, the Authority directs the EDCs to supplement their Order No. 8 filing with any additions or modifications once the EM&V Consultant is retained.

In an effort to inform the EDCs' forthcoming Order No. 8 Compliance Filing, the Authority sought additional input from docket Participants on necessary program data and corresponding metrics to be collected by the EDCs and analyzed by the EM&V Consultant. DEEP proposed that utilization data from participating networked chargers should align with the list provided by the Northeast States for Coordinated Air Use Management.[12] DEEP Response to CAE-32, pp. 2-3. Further, DEEP noted that the EM&V Consultant would need additional data to produce the metrics required in the EV Decision, including data from the site host application process. Id., p. 3. For the Managed Charging Program proposed by the EDCs pursuant to Order No. 6.a. of the EV Decision, DEEP proposed specific additional metrics and data collection. Id., pp. 4-5.

The Authority directs the following modifications to the EDCs' proposed EM&V RFP:

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[12] See, Collecting EV Charging Station Utilization Data: Model Language for State Grants and Procurement Contracts, https://www.nescaum.org/documents/evse-data-collection-model-contract-provision-for-public-evse-4-16-21.pdf/.

First, the EDCs shall update Section 1.1, Statement of Purpose, to reflect the clarified Program Objectives outlined in Section III of this Decision.

Second, the EDCs shall modify Section 2.1, Eligible Applicants, and Section 4, Services and Deliverables, to issue the EM&V Consultant RFP as an open solicitation and make the EM&V RFP publicly available. In addition, the EDCs shall develop a list of potential EM&V consultants to notify of the opportunity, incorporating DEEP's, Connecticut Green Bank's (CGB), and the Companies' own internal EM&V approved vendor lists in their outreach.

The EV Decision stated that the final cost of the EM&V Consultant shall not exceed five percent of the total EV Charging Program costs for any Program Cycle. EV Decision, p. 44. Eversource proposed a $500,000 annual budget for the E&MV Consultant for the 2022-2024 Program period (i.e., <5% of its proposed Program budget for 2022-2024). Motion No. 10, Order 6.d, Attachment 1. UI proposed $648,267 over the three-year Program period (i.e., 5% of its proposed Program budget for 2022-2024).

Upon further review of the scope of the proposed joint EM&V RFP, the Authority determines a total annual EM&V budget of approximately $500,000 is appropriate for the statewide program. As a result, the EDCs shall modify Section 2.4, Evaluation Process, Cost/Budget, to include the following language: "Applicants must submit a budget not to exceed $500,000 annually. Applicants may submit a second budget detailing all services and associated tasks that would exceed $500,000 annual budget, and provide a justification for why such services are integral to fulfilling the requirements of the RFP." The Authority further clarifies that the EDCs shall apportion the annual cost of the joint EM&V Consultant contract based on an 80/20 allocation between Eversource and UI, respectively. The Authority reiterates that the Companies shall notify the Authority of the Consultant selection, and the Companies shall further provide the final executed contract with the EM&V Consultant along with a justification for selection if the EM&V Consultant's total annual budget exceeds $500,000.

Fourth, the Authority directs the EDCs to incorporate, or otherwise account for, the program metrics and data fields and corresponding Program metrics proposed by DEEP and the CGB in the Companies' Order No. 8 Compliance Filing. In addition, the EDCs shall incorporate the edits proposed by DEEP in its written comments, with the exception of the Program Objectives, which shall reflect those described herein. See, DEEP Written Comments dated 11/1/21, Attachment A. The EM&V Consultant's Annual Report shall also include State EV sales and registration data reported by the Connecticut Department of Motor Vehicles.

Finally, in response to Interrogatory CAE-13, the EDCs requested clarification of two metrics included in the EV Decision regarding the MUD Program Area. Response to CAE-13, p. 1. The Authority clarifies that "external funds leveraged by MUDs" refers to funds used for EVSE and associated installation procured outside of EDC programs, and that "load profiles of Level 2 Lease Option participants and non-participants" refers to customers that choose to participate or not participate in the Lease Option. The EDCs shall update Section 1.2.1, Program Metrics, to reflect this clarification.

In conclusion, the EDCs shall incorporate the modifications described herein and submit the final EM&V RFP issued publicly as compliance in the above-captioned proceeding no later than December 22, 2021.[13] Further, in the Companies' motion for approval of compliance with Order No. 8 of the EV Decision, which requires the Companies to coordinate with the EM&V Consultant and submit Program metrics, associated calculation methodologies, and data requirements for verifying program performance, the EDCs shall incorporate, or otherwise account for, the Program metrics and data fields proposed by the CGB and DEEP. See, EV Decision, pp. 47-48. The EDCs shall provide an explanation for each metric proposed by the CGB or DEEP not included. Finally, as part of the Order No. 8 motion, the EDCs shall also submit the most current list of data fields to be collected from (1) participating EVSE and/or vehicle telematics and (2) site host applications.[14]

2. EVSE Vendor RFQ

Order No. 7 of the EV Decision directed the EDCs to submit a joint EVSE vendor open RFP to inform the development of a list of approved EVSE vendors, makes and models to be updated annually. EV Decision, pp. 36 and 47. The Authority subsequently held a series of stakeholder workshops, facilitated by a consultant, to investigate interoperability as it related to open access, payment methods, and communications in order to inform the EDCs' EVSE RFP standards. Id., p. 37. On October 18, 2021, the EDCs jointly filed Motion No. 12 requesting Authority approval of the proposed EVSE vendor request for qualification (EVSE Vendor RFQ).

Stakeholders provided comments proposing various revisions to the EDCs' Order No. 7 compliance. The OCC noted that the document submitted is based on an Eversource document used in Massachusetts. OCC Written Comments, p. 8. The OCC further noted that the vehicle capabilities listed in the document do not align with those in the Proposed Managed Charging Program Requirements. Id. DEEP was generally supportive of the requirements included in the proposed EVSE Vendor RFQ but filed redline edits to better align the requirements with the EV Decision. DEEP Written Comments, pp. 8-9. Specifically, DEEP proposed requirements to ensure equitable access, including through additional phone payment methods and multilingual phone assistance. Id. DEEP also proposed that vendors specify how the applicable warranty or maintenance plan covers contractor services after installation and identify all operational requirements. Finally, DEEP proposed that EVSE vendors pre-approved by the Connecticut Department of Administrative Services (DAS) for use by State agencies and municipalities be eligible for incentives through for the EV Charging Program, should a state agency or municipality select them. Id., p. 10; DEEP Written Exceptions, p. 2.

ChargePoint provided several redline edits and proposed modifications to the EDCs' proposed EVSE Vendor RFQ. First, ChargePoint proposed that any given product be eligible to qualify under multiple categories, rather than only one. ChargePoint Written

[13] For clarity, the EDCs may publicly issue the RFP as soon as possible with the modifications directed herein without further approval from the Authority; the EDCs shall file the final version in the instant proceeding as a compliance filing no later than December 22, 2021.

[14] The Authority recognizes that additional fields may be required based on the Final Decision in the above-captioned proceeding, and the list shall not be construed as final.

Comments, p. 9. ChargePoint also supported making hardware or networking pricing information available to the EDCs confidentially through the RFQ process, but not disclosed publicly. Id., pp. 9-10. Further, ChargePoint asserted that the RFQ should not require EVSE to use Open Charge Point Protocol (OCPP), noting that the standard has not been adopted by standards organizations and the communication pathway should remain open. Id., pp. 10-11.

The Authority agrees with stakeholder comments that the proposed EVSE Vendor RFQ has not been sufficiently tailored to the needs of the Connecticut EV Charging Program and therefore does not satisfy the requirements of Order No. 7. Accordingly, the Authority directs the EDCs to make the modifications described herein and resubmit the EVSE Vendor RFQ as a compliance filing no later than December 22, 2021.[15]

First, the EDCs shall ensure that the document references Connecticut and the EDCs collectively, rather than Massachusetts and Eversource, in all instances. Further, the EVSE RFQ requirements must align with the Proposed Managed Charging Program Requirements; the EDCs shall ensure that all EVSE that meets minimum requirements can participate in the Managed Charging Program, including details about the communications standards necessary to communicate with the EDCs' DERMS and enable EDCs access to all required Program data. The EDCs shall also ensure that data requirements and vehicle capabilities listed in the Appendices correspond with the most up-to-date Managed Charging Program Requirements.

Second, the Authority agrees that DEEP's revisions and redline edits better align the EVSE Vendor RFQ with the Program Objectives, specifically to achieve an equitable EV transition, and directs the EDCs to work with DEEP, as needed, to incorporate the edits as proposed. Further, regarding data collection Program requirements (pages 9, 17, and 28), the Companies shall develop and provide the final EVSE Equipment Agreement as an attachment to the RFQ. Additionally, the EDCs shall ensure the Appendix containing data requirements is as up to date as possible. The Authority also acknowledges DAS's forthcoming master contract to enable State agencies and municipalities to purchase from a list of pre-qualified EVSE vendors. However, if the DAS list of pre-qualified EVSE vendors includes EVSE that the EDCs deem incompatible with the managed charging or other EV Charging Program requirements, and therefore are not included on the EDCs' approved EVSE list, the EVSE will be ineligible for Program incentives. In an effort to minimize confusion among potential State and municipal agencies seeking to receive incentives through the EV Charging Program, the EDCs may indicate in the Program Manual and associated documents whether there are any EVSE included on DAS's master contract that are incompatible with the Program.

In addition, the Authority notes that the EDCs' proposed DCFC charging port requirements state that such charging stations "shall be dual port with both SAE J1772 Combined Connector System (CCS) and IEEE 2030.1.1 (CHAdeMO) charging ports. Support of simultaneous charging on both ports is not a requirement." Proposed EVSE Vendor RFQ, p. 26. Eversource stated that the proposed requirements are identical to

[15] For clarity, the EDCs may publicly issue the RFP with the modifications directed herein without further approval from the Authority, but the EDCs shall file the final version in the instant proceeding by December 22, 2021.

those in Massachusetts. Eversource Response to CAE-14. UI stated that the Company's affiliated programs in New York require charging sites to have at least two plugs, capable of simultaneously charging at 50 kW. UI Response to CAE-14. UI further states that in the Company's New York programs, proprietary plugs co-located with commonly accepted standardized plugs are allowed while those not co-located are eligible for a reduced incentive. Id.

To ensure efficient use of Program funds, DCFC stations shall support simultaneous charging of at least 50 kW in order to qualify as a two-plug charging site. In addition, the Authority directs the EDCs to clarify in the EVSE RFQ that vendors installing proprietary plugs are eligible for Program incentives as long as any EVSEs installed with proprietary plugs are co-located with standardized plugs (i.e., CCS and/or CHAdeMO) and meet all other Program requirements. The Authority further clarifies that EVSE incentives shall not be applied to offset EVSE costs for proprietary plugs, although make-ready incentives can be applied to sites with co-located standardized and proprietary plugs. The EDCs shall incorporate the above guidelines into the Program Manual (See, Section V.F.), along with rules governing the siting of DCFC stations using proprietary plugs (i.e., define co-location). Any incremental make-ready costs associated with the installation of proprietary plugs shall be tracked and included in the EM&V Consultant's annual reporting.

Finally, the Authority clarifies that individual pricing and other proprietary vendor information provided in response to the RFQ will not be shared publicly by the EDCs. However, the EDCs may aggregate and anonymize pricing and other data provided in response to the EVSE RFQ to be made publicly available. The Authority notes that this data will be critical to evaluating the appropriateness of incentive levels in future Annual Reviews.

3. Other Vendors

In addition to the EM&V Consultant, the EDCs each indicated they intend to contract with additional vendor(s) to fully implement the EV Charging Program. Specifically, Eversource identified the following needs:

(1) Program Tracking Software Vendor;
(2) Rebate Portal Vendor;
(3) Managed Charging Program Administration Vendors;
(4) Internal Engineer of Record;
(5) Data Aggregation and Analysis;
(6) EM&V Consultant; and
(7) Fleet Advisory Vendor.

Eversource Response to CAE-36.

Similarly, UI identified the following additional contract requirements:

(1) CRM Sales Support System;
(2) Data Collection Vendor;
(3) Fleet Assessment Services Vendor;

(4) Implementation Vendor;
(5) Managed Charging/DERMS Vendors; and
(6) Rebate Processing Vendor.

UI Responses to CAE-36 and 43.

UI stated it would jointly contract vendors with Eversource wherever possible and coordinate with the C&LM and Electric Storage Programs to achieve administrative efficiencies. UI Response to CAE-36.

The Authority reminds the EDCs that any external vendor costs deemed necessary by each Company shall be included in the EV Charging Program budget and will be subject to a future prudency review in each Company's next rate case, as discussed in Section V.E. Each EDC shall maintain detailed, itemized records of all costs incurred for external contracts in support of the EV Charging Program.

4. Education and Outreach Plan

Order No. 6.e. of the EV Decision directed the EDCs to propose a joint Education and Outreach Plan, including a coordinated messaging campaign, associated evaluation metrics, and an annual EDC-specific budget. EV Decision, p. 47. Specifically, the Authority directed the Education and Outreach Plan to focus on the statewide messaging campaign in order to raise awareness and solicit participation in the EV Charging Program, with tailored solutions for each program area and customers in underserved communities. Id., pp. 44-45.

In Motion Nos. 10 and 13, the EDCs filed their proposed Education and Outreach Plan, which identified tactical overviews, target audiences, and messaging themes for each Program Area, general Program-wide media tactics, and other education and outreach content. As the EV Charging Program is new to the market, the EDCs stated they would review the education and outreach metrics throughout the first Program Cycle to optimize marketing tactics. Eversource and UI Response to CAE-37. The Companies also proposed to call the Program the "CT EV Charging Program," but proposed to work with marketing vendors to determine if Program branding changes are needed and to consult PURA with re-branding options. Eversource and UI Response to CAE-38.

The Authority recognizes that the EV Charging Program launching in January 2022 represents a suite of new program offerings for customers, and the EDCs will play a key role in recruiting site hosts and educating customers on the benefits of EVSE installations. Further, the Authority acknowledges that all stakeholders have a vested interest in the success of the Program and successful execution of the Education and Outreach Plan. As discussed in later in Section V.D, this Decision must not be construed as a pre-approval of the Companies' proposed Education and Outreach budgets. The Authority reiterates that the EDCs must be prepared to demonstrate the prudency of expenses incurred to support implementation of the Education and Outreach Plan, as further discussed in Section V.E.

a. Fleet Engagement Advisory Services

The EV Decision directed the EDCs to provide a Fleet Engagement Advisory Service as part of their Education and Outreach Plan in order to assist potential site hosts to assess and implement transportation electrification opportunities for light-duty fleets. EV Decision, p. 33. Each EDC included such service in their respective Program Budgets developed pursuant to Order No. 6.d.

Eversource proposed a Fleet Engagement Advisory program that would (1) provide fleet electrification assessment studies for up to 80 private and 20 non-profit fleet customers; and (2) provide online tools for fleet planning and total cost of ownership. Eversource Response to CAE-42. Further, Eversource proposed to cover the fleet assessment costs for non-profit customers and share costs equally with private fleet customers, with a total cost of approximately $15,000 per customer. Id. Eversource expects the proposed tools to be available within one year of Program launch. Id. Finally, Eversource stated that the EDCs would collaborate to procure online fleet planning tools through a joint RFP and share development costs. Eversource Response to CAE-42.

Similarly, UI proposed Fleet Assessment Services that would include "a rate analysis and/or fuel cost comparison, a site feasibility analysis and charging infrastructure requirements, maintenance and other operating costs and total cost of ownership analysis," similar to the assessment provided by its New York affiliates. UI response to CAE-30; UI Response to CAE-44. UI stated it expects the average fleet assessment to cost $10,000. UI Response to CAE-44. Further, the Company stated that it is exploring a web-based fleet assessment tool that could reduce the labor required to provide fleet assessment services, but that it would not be available before 2023. Id.

The Authority reiterates that the Fleet Advisory Service is intended to support the EDCs' efforts to deploy EVSE to support the Workplace & Light-Duty Fleets Program Area and to ensure the cost-effective integration of EVs into Connecticut's electric grid. The Authority finds the EDCs' proposals appropriate to support light-duty fleet electrification and encourages the EDCs to collaborate to procure online fleet planning tools and share development costs as much as possible to ensure a consistent statewide customer experience. Pursuant to the EV Decision, any costs incurred to develop and maintain Fleet Advisory Services shall be included under the Education and Outreach budget and therefore subject to the maximum established in the EV Decision.[16]

b. Technical Assistance to Underserved Communities

Recognizing that low- to moderate-income (LMI) residents often face obstacles to EV ownership, and in support of the Program Objective to achieve an equitable transition to EVs across all communities in Connecticut, the Authority selected RMI, through an open solicitation, to conduct a study that examines potential electric mobility solutions for LMI residents that are best suited to meet their current and future needs (Study). See, EV Decision, p. 5. On October 8, 2021, the Authority issued a Notice of Admitted Evidence in the instant proceeding incorporating a Listening Session Summary Report

[16] Pursuant to the EV Decision, the total Education and Outreach budget shall not exceed 10 percent of each EDC's total program costs for the first Program Cycle.

developed by RMI, in partnership with Save the Sound, which discusses various electrified transportation modes that could meet the mobility needs of LMI communities in Connecticut and potentially benefit from EDC support. See, Notice of Admitted Evidence dated October 8, 2021, p. 1 (October 8 Notice). The October 8 Notice also incorporated into the record Draft Recommendations from RMI in advance of a final report expected in early 2022 (RMI Draft Recommendations). The final RMI Study will outline potential program structures for three modes of shared electric mobility – microtransit, carsharing, and micromobility – and recommend roles for the EDCs to provide greater support to implement electric mobility solutions in LMI communities.

RMI's Draft Recommendations noted that the EDCs have two primary levers to support LMI electric mobility program development and implementation: (1) program administrative support; and (2) capital expenditures. Draft Recommendations, p. 2. Within program administrative support, RMI identified five potential utility activities: (1) technical assistance for program design teams; (2) EVSE siting support; (3) interconnection application support; (4) facilitation of requests for information and/or bundled procurement; and (5) grant funding application support. Id., pp. 2-3. Regarding capital expenditures, RMI indicated that dedicating a portion of the EVSE deployment targets to locations that will enable LMI electric mobility programs will be included in RMI's forthcoming final report. Id., pp. 3-4.

In the Notice of Request for Written Comments dated October 18, 2021, the Authority asked respondents to "provide specific recommendations on how RMI's Draft Recommendations … should be incorporated into the EV Charging Program to provide greater support for the EDCs' LMI customers, particularly with respect to the education, outreach, and administration portions of the proposed program budgets." Notice of Request for Written Comments dated October 18, 2021, p. 3. The CGB proposed that a portion of the Education and Outreach budget be reserved for LMI-specific outreach and staff support, including co-marketing with the Connecticut Hydrogen and Electric Automobile Purchase Rebate (CHEAPR) program. CGB Written Comments dated 11/1/21, p. 2. DEEP expressed support for the Draft Recommendations but asserted that other entities should contribute to the EDCs' activities to ensure more robust program development. DEEP Written Comments dated 11/1/21, p. 10. In particular, DEEP stated that program administrative support for EVSE siting and interconnection would enable adequate siting in LMI communities. Id., p. 11. Additionally, DEEP proposed RMI's methodology for calibrating program scope based on demographic and transit data inform the definition of underserved community for purposes of the EV Charging Program. Id., p. 11. Finally, Save the Sound supported RMI's recommendation for the EDCs to provide grant funding and application support to help applicants identify additional available incentives. Save the Sound Written Comments dated 11/1/21, pp. 5-6. Save the Sound also recommended that community needs, such as identifying potential grid upgrades needed to support EVSE in underserved communities, should be the starting point for any EDC involvement. Id., p. 5.

While PURA looks forward to further integrating the findings from RMI's forthcoming Study into the EV Charging Program, the Authority finds that near-term implementation of tailored technical assistance in underserved communities is an appropriate first step. Accordingly, the EDCs shall leverage existing staff resources and utilize any incremental full-time employees (FTE) attributed to the EV Charging Program

to also provide technical assistance tailored to underserved communities. Such assistance will be further informed by RMI's forthcoming Study.

Finally, the Authority clarifies that, as defined in the EV Decision, underserved communities include environmental justice communities pursuant to Conn. Gen. Stat. § 22a-20a, distressed municipalities pursuant to Conn. Gen. Stat. § 32-9p, and public housing authorities as defined in the Connecticut General Statutes. EV Decision, p. 13. The Authority reiterates that it plans to monitor relevant discussions occurring in the state regarding definitions of low- and moderate-income residents and underserved communities, and will reevaluate through the annual review process the EV Charging Program definitions, as necessary, to appropriately meet the Program Objective to achieve an equitable transition to EVs across all communities in Connecticut. Id., p. 14. Such reevaluation may include establishing a methodology to identify communities that are not currently meeting their electric mobility needs, potentially in consultation with the EM&V Consultant, community representatives, and other interested stakeholders.

c. Data Collection and Reporting Requirements

DEEP noted that the EnergizeCT web portal is currently being redesigned and is expected to launch in early 2022, and proposed that the EDCs provide program information for the portal's EV webpages. DEEP Written Comments dated 11/1/21, p. 8. Consistent with the Energy Storage, Residential Renewable Energy Solutions, and Non-Residential Renewable Energy Solutions Programs, the Authority directs the EDCs to develop a landing page for all data relevant to the Program to provide interested stakeholders with the most up-to-date information possible, in an easily understood and digestible form.[17] The EDCs shall publish this data to their Program website and on the EnergizeCT website alongside data from other programs.[18]

5. Data Privacy and Security Plan

The EV Decision directed the EDCs to develop one comprehensive Data Privacy and Security Plan for the EV Charging Program, along with a list of data sharing and security requirements for devices participating in the EV Charging Program and accompanying data sharing agreements. EV Decision, p. 38. The EDCs' joint Data Privacy and Security Plan developed in compliance with Order No. 9 shall be filed for Authority review and approval no later than December 15, 2021. Pursuant to the Notice of Proceeding, stakeholders will be given two weeks to provide comments on the EDCs' motion prior to the Authority issuing a ruling.

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[17] See, Docket No. 17-12-03RE03, PURA Investigation into Distribution System Planning of the Electric Distribution Companies –Electric Storage, Final Decision dated July 28, 2021, p. 42. Docket No. 20-07-01, PURA Implementation of Section 3 of Public Act 19-35, Renewable Energy Tariffs and Procurement Plans, Final Decision dated June 30, 2021, p. 49.

[18] The Authority directed that similar webpages be developed for the Energy Storage, Residential, and Non-Residential Renewable Energy Solutions Programs authorized in Docket Nos. 17-12-03RE03 and 20-07-01. The Authority encourages the Program Administrators to develop one landing page for all data relevant to those programs and the EV Charging Program.

6. Labor

Each EDC included additional FTEs in their proposed Program Budgets. Eversource proposed to add six FTEs focused on the EV Charging Program: Manager, Implementation of EV Charging Program; Residential Program Manager; Commercial Program Manager; Equity, Workforce Development, and Fleet Advisory Program Manager; and two EV Account Executives. Eversource Response to CAE-18. UI, meanwhile, proposed to add 3 incremental FTEs, with two employees splitting time with the Company's New York affiliates. UI's proposed FTEs include the following: Program Manager; Energy Specialist; Program Manager, shared with NY; and Energy Specialist, shared with NY. UI Response to CAE-29.

As an initial matter, the Authority questions whether the EDCs' respective proposals to add a total of nine FTEs dedicated to the EV Charging Program is appropriately sized, or whether synergies with other programs, affiliates, etc. may exist. Regardless, the Authority notes that the EDCs will be required to justify the need for each additional FTE assigned to the EV Charging Program at the time of their next rate case prior to receiving cost recovery for such.

D. PROGRAM BUDGETS

Order No. 6.d. directed the EDCs to propose Program Budgets for the first three-year Program Cycle (i.e., calendar years 2022 through 2024). EV Decision, p. 47. Pursuant to the EV Decision, the maximum budget allocations for each Program Area will remain fixed for the duration of each Program Cycle to "ensure an even and equitable distribution of program funding across the different market sectors." Id., p. 41. In other words, funds allocated to one Program Area shall not be used to support deployments in another Program Area. Eversource and UI provided an estimated Program Budget for the first Program Cycle in Order 6d Attachment 1 to Motion Nos. 10 (Eversource Budget) and 13 (UI Budget), respectively.

1. Eversource

Eversource's proposed Program Budget dedicates approximately $59.5M to deploy EVSE throughout its service territory over the first Program Cycle. Eversource Budget. Approximately $21.5M would be allocated to the Residential Single-Family Program Area, split between Managed Charging Program incentives, upfront rebates and incentives, and administration costs inclusive of DERMS fees, telematics communication fees, rebate processing fees, and non-networked Level 2 device administration. Id.; Eversource Response to CAE-40, Exhibit 1. The remaining $38.0M would be allocated to DCFCs and Level 2 charging at MUDs, destinations, workplaces, and fleets. Eversource Budget. Eversource assumed 30 percent of installations would receive the incentive adder for underserved communities. Id. Eversource stated that 22 percent of its customers are located in distressed municipalities, and assumed an additional eight percent reside in Environmental Justice census blocks, though the Company did not conduct such analysis. Eversource Response to CAE-16. In addition, Eversource estimated approximately $14.2M in Program administration costs, with line items for Education and Outreach, EM&V, Fleet Engagement Advisory Services, information

technology (IT), labor, and "other administration." Eversource Budget. The total estimated Program Budget for the first Program Cycle is shown in Table 5.

Table 5
Eversource Proposed Program Budget (2022 – 2024)

Cost Category	Budget
Residential Single-Family (Level 2)	$21,520,934
MUDs (Level 2)	$9,700,000
Destination (Level 2)	$6,310,000
Workplace & Light-Duty Fleets (Level 2)	$12,031,500
DCFCs	$9,900,000
Subtotal	$59,462,434
Education & Outreach	$7,000,000
EM&V	$1,500,000
Fleet Engagement Advisory Service	$1,000,000
IT	$865,500
Labor	$3,600,000
Other Administration	$229,189
Program Administration Subtotal	$14,194,689
Total	$73,657,123

Eversource Budget.

2. UI

UI's proposed Program Budget dedicates approximately $13.0M to deploy EVSE throughout its service territory over the first Program Cycle. UI Budget. Approximately $4.5M would be allocated to the Residential Single-Family Program Area, split between upfront EVSE, wiring, and enrollment incentives, annual Managed Charging incentives, and device integration costs. Id. The remaining $8.5M would be allocated to DCFCs and Level 2 charging at MUDs, destinations, workplaces, and fleets. Id. UI assumed 60 percent of installations would receive the incentive adder for underserved communities. Id. UI stated that its allocation of EVSE to underserved communities was based on the portion of its customers that reside in such communities, as defined by the Program. Tr. 11/4/21, pp. 109-111. In addition, UI estimated approximately $5.1M in Program administration costs, with line items for Program administration, education and outreach, EM&V, and labor. UI Budget. UI allocated 15 percent of its proposed Budget to Program administration, an additional 10 percent to education and outreach, and an additional 5 percent to EM&V. Id. The total estimated Program Budget is shown in Table 6.

Table 6
UI Proposed Program Budget (2022 – 2024)

Cost Category	Budget
Residential Single-Family (Level 2)	$4,534,590
MUDs (Level 2)	$1,640,250
Destination (Level 2)	$1,264,000
Workplace & Light-Duty Fleets (Level 2)	$3,704,000
DCFCs	$1,822,500
Subtotal	$12,965,340
Program Administration	$1,944,801
Education & Outreach	$1,296,534
EM&V	$648,267
Incremental Internal Resources (i.e., 3 FTEs)	$1,223,996
Program Administration Subtotal	$5,113,598
Total	$18,078,938

UI Budget.

3. Summary

The launch of a new, nine-year, statewide EV Charging Program will undoubtedly necessitate improvements and other refinements based on lessons learned through implementation. The EDCs are directed to present detailed, itemized actual Program implementation costs to date as part of each Annual Review proceeding. As directed in the EV Decision, incentive levels will be calculated based on the net installed cost of the EVSE, after deducting any other applicable rebates, grants, or other incentives the site host may receive. EV Decision, pp. 18, 23, 28, 32, and 34. The EDCs are likewise expected to make a good faith effort to access available federal and state funding to support Program objectives and minimize Program costs.

As stated above, the Authority, and all stakeholders have a vested interest in the success of the Program executed at the least cost to ratepayers. The Authority reiterates that ultimately Eversource and UI bear the burden of proving the prudency of all capital and administrative costs associated with the Program. As a result, this Decision must not be interpreted as a pre-approval of the Companies' proposed Program Budget for the first Program Cycle. Further, the Authority notes that any increase of 10 percent or greater from the EDCs' refiled Program Budgets, reported on during each Annual Review, will invite additional scrutiny during the forthcoming prudency review.

No later than January 7, 2022, the Authority directs Eversource and UI to separately refile proposed Program Budgets as compliance to fully conform with the direction provided in the EV Decision and herein. Specifically, the EDCs shall modify their proposed Program administration budgets to incorporate Fleet Engagement Advisory Services as part of their Education and Outreach Plan and associated Budget. The EDCs shall also revise the EM&V RFP Budget to reflect a joint EM&V Consultant contract based on an 80/20 allocation between Eversource and UI, respectively, and to incorporate additional direction provided in Section V.C.1. In addition, the Companies, and UI in particular, shall provide greater detail under their respective Program administration budgets and be prepared to account for "other" Program administration costs as part of each Annual Review.

E. COST RECOVERY

The EV Decision states that the EDCs will recover the revenue requirement attributed to the implementation of the EV Charging Program through electric distribution rates following a normal base rate case proceeding, as expenditures related to the EV Charging Program shall be a core business function. EV Decision, pp. 45-46. The Companies' base distribution rates will therefore reflect Program costs and will also reflect the benefit of downward pressure on rates as increased kWh sales are realized due to the EV Charging Program. Id. The EV Decision further directs the EDCs to defer all EVSE program costs, including rebates, program administration, education and outreach to a regulatory asset to be reviewed as part of the Company's next rate case proceeding. Id. The EDCs shall not include capital or fixed assets in the regulatory asset; capital assets attributed to the EV Charging Program shall be treated as any other capital asset, i.e., included in rate base and depreciated over their useful lives. Id. The EV Decision directed the EDCs to assume a 15-year estimated useful life. Id.

The burden of demonstrating prudently incurred costs to implement the EV Charging Program rests with Eversource and UI, not the Authority, or any other docket Participant. In an effort to set expectations for the EDCs to provide sufficiently detailed cost information and evidence to support the finding that all efforts were taken to minimize costs, the EDCs shall be required to present evidence during their next rate case proceeding to demonstrate the following: (1) reasonable competitive procurement processes were held; (2) existing internal resources were leveraged to the extent possible; (3) investments in new resources were selected with current and future investments, programs, and public policies in mind; and (4) unnecessary costs were avoided.

F. PROGRAM MANUAL

In response to CAE-33, each EDC provided a list of internal and external resources being developed to establish the technical, administrative, and procedural requirements of the EV Charging Program. Specifically, Eversource listed the following resources:

(1) Frequently Asked Questions;
(2) EVSE Make-Ready Program Application;
(3) EVSE Make-Ready Customer Agreement;
(4) Residential Managed Charging Program Application;
(5) Residential Participation web content; and
(6) List of EVSE vendors.

Eversource Response to CAE-33.

Further, UI provided the following list of resources being developed:

(1) EVSE Make-Ready Program Participation Guide;
(2) EVSE Make-Ready Program Application;
(3) EVSE Make-Ready Customer Agreement;
(4) Residential Managed Charging Program Participation Guide;
(5) Residential Managed Charging Program Application; and
(6) Residential Managed Charging Customer Agreement.

UI Response to CAE-33.

The Authority appreciates the EDCs' efforts to develop comprehensive Program resources that will help ensure Program success. To ensure effective and consistent Program implementation and communication of the final Program design, the Authority directs the EDCs to compile a comprehensive EV Charging Program Manual (Program Manual) that incorporates all Program elements established herein and conforms to the EV Decision. The Program Manual shall include the following sections, at a minimum:

(1) EVSE Make-Ready Participation Guide;
(2) Residential Participation Guide;
(3) Residential Managed Charging Participation Guide, as directed in Section V.A.1;
(4) Commercial Managed Charging Participation Guide, as directed in Section V.A.2;
(5) List of approved EVSE vendors, makes, and models, and other pertinent information from the EVSE RFQ results;
(6) EVSE Make-Ready Program Application;
(7) Residential Managed Charging Program Application;
(8) EVSE Make-Ready Customer Agreement;
(9) Residential Managed Charging Customer Agreement; and
(10) Frequently Asked Questions (FAQ).[19]

The EDCs shall jointly file the Program Manual, and all associated guidelines and resources, no later than January 7, 2022. Further, the Program Manual shall be updated at least annually to reflect the most recent Program information and Authority orders and/or rulings.

Finally, to ensure a smooth Program launch for customers, the Authority directs the EDCs to provide the links and screenshots of their respective online customer portals that will be used to accept customer applications for incentives, and provide all relevant Program information, including an online FAQ section, no later than December 22, 2021. The EDCs shall also file with the Authority the dates, times, and locations of webinars listed in the Companies' response to CAE-39 no later than December 22, 2021.

G. OUTSTANDING PROGRAM MATTERS

In addition to the Year 1 Program Manual and associated resources discussed herein, there are two outstanding EV Decision compliance filings for 2021 that have not yet been addressed by the Authority; see Table 7. As stated in the Notice of Proceeding, **stakeholders will have two weeks to comment** on the remaining motions for Authority review and approval of **compliance filings associated with the EV Decision**. Accordingly, comments on compliance with Order Nos. 8 and 9 of the EV Decision are due no later than **4:00 pm on December 29, 2021**. The EDCs shall incorporate the outstanding compliance filings with both this Decision and the EV Decision in the Program Manual as appropriate.

[19] The EDCs shall submit an FAQ available online in accordance with Order No. 4; the Authority clarifies that the FAQ must also be included in the Program Manual material in accordance with Order No. 8.

Table 7
Outstanding Orders from the EV Decision

Order Number	Description	Due Date
2021		
8	Program metrics, associated calculation methodologies, and data requirements for verifying Program performance based on the established metrics	12/15/2021
9	Data Privacy and Security Plan for the EV Charging Program	12/15/2021
2022 and later (to be filed in Docket No. 22-08-06)		
11	Compliance filing that includes the number of interested site hosts and the number of customers that (1) moved forward with the EVSE project and (2) are no longer actively pursuing incentives through the Program	4/1/2022
13	Proposed Level 2 EVSE Lease Program at MUDs, including pricing	5/1/2022
12a	Proposed solution for offering an EV-only tariff within the Residential MUD Level 2 Charging Program for program implementation beginning January 1, 2023	8/1/2022
12b	Proposed key program parameters and a suggested timeline for implementation of a managed charging program at participating MUDs	8/1/2022
12c	Proposed tariff specifically for separately metered DCFCs and networked Level 2 EVSEs serving light-duty fleets	8/1/2022
14	Submit an annual report summarizing the Program results to date and recommendations for any Program modifications	8/1/2022
15	Propose MUD Level 2 EVSE deployment targets and a supporting calculation methodology for the second and third Program Cycles	8/1/2023
16	Submit the EM&V consultant's full report on the established Program metrics	6/1/2024

H. PURA PROGRAM REVIEW PROCESS

Pursuant to the EV Decision, the Authority will initiate an Annual Review proceeding during the first two years of every three-year Program Cycle to evaluate the EDCs' annual report and ensure: "(1) continued alignment with the Program Objectives; and (2) that the Program is on track to meet its Program Cycle deployment targets." EV Decision, pp. 42 and 45. During the last year of each Program Cycle, the Authority will conduct a full Program Review, including an evaluation of the existing program design

and the EM&V Consultant's report of the three-year Program Cycle. Id. As certain program design elements will not be implemented until after Program launch, such as the Advanced Managing Charging Program offerings, the 2022 Annual Review will necessarily be more substantive in nature.[20]

VI. CONCLUSION AND ORDERS

A. CONCLUSION

In this Decision, the Authority approves, with modification, certain documents developed and proposed by the EDCs to administer the statewide EV Charging Program available to all customers and customer classes within the service territories of the EDCs. Pursuant to the EV Decision, the Program will launch on January 1, 2022. The Authority also addresses the documents submitted in compliance with Order Nos. 5 through 7 of the EV Decision. Accordingly, this Decision contains the Authority's ruling on Motion Nos. 10 through 13.

B. ORDERS

For the following Orders, the Company shall file an electronic version through the Authority's website at www.ct.gov/pura. Submissions filed in compliance with the Authority's Orders must be identified by all three of the following: Docket Number, Title, and Order Number. Compliance with orders shall commence and continue as indicated in each specific Order or until the Company requests and the Authority approves that the Company's compliance is no longer required after a certain date. All Orders requiring Authority review and approval shall be submitted as a motion.

1. No later than December 22, 2021, the EDCs shall jointly file as compliance in Docket No. 21-08-06 the final EM&V RFP issued publicly, as discussed in Section V.C.1. The EDCs shall subsequently file as compliance the final executed contract with the EM&V Consultant along with a justification for selection if the EM&V Consultant's total annual budget exceeds $500,000.

2. No later than December 22, 2021, the EDCs shall jointly file as compliance in Docket No. 21-08-06 a final Residential Managed Charging Program Participation Guide for the Residential Managed Charging Program, as directed in Section V.A.1. The filing shall indicate that all EV charging data will be aggregated, anonymized, or otherwise encrypted if/when disclosed publicly.

3. No later than December 22, 2021, the EDCs shall jointly file as compliance in Docket No. 21-08-06 the final EVSE Vendor RFQ incorporating all direction included herein.

[20] The EV Decision indicated that the Authority would initiate the 2022 Annual Review in August 2022 and would endeavor to complete the proceeding in 90 days; however, the lack of an Advanced Managed Charging proposal submitted in this proceeding requires additional process for the 2022 Annual Review.

4. No later than December 22, 2021, the EDCs shall each file as compliance (1) the links and screenshots of their respective online customer portals that will be used to accept customer applications for incentives, including program details described in an online FAQ section; and (2) the dates, times, and locations of webinars to educate customers leading up to and after the launch of the EV Charging Program in Docket No. 21-08-06.

5. No later than January 7, 2022, the EDCs shall jointly file as compliance in Docket No. 21-08-06 an RFQ for devices that will enable customers with non-networked Level 2 chargers to participate in the Managed Charging Program, as outlined in Section V.A.1.c.

6. No later than January 7, 2022, UI shall file as compliance in Docket No. 21-08-06 its determination and supporting analysis of whether its existing AMI network could be utilized to enable customers with a non-networked Level 2 charger to participate in the Managed Charging Program, as discussed in Section V.A.1.c

7. No later than January 7, 2022, Eversource and UI shall separately refile as compliance in Docket No. 21-08-06 proposed Program Budgets to conform with the direction provided herein.

8. No later than January 7, 2022, the EDCs shall jointly file as compliance in Docket No. 21-08-06 a final Program Manual for Year 1 and all associated guidelines and resources as directed in Section V.F.

9. No later than January 15, 2022, the EDCs shall reconvene the Managed Charging Working Group to inform necessary improvements to the EDCs' Proposed Managed Charging Program Requirements, as directed in Section V.A.

10. No later than April 1, 2022, Eversource shall also file its compliance with Order No. 6 of the EV Rate Rider Decision in Docket No. 22-08-06.

11. No later than May 1, 2022, the EDCs shall file in Docket No. 22-08-06 for Authority review and approval revised Managed Charging Program Requirements, following recommendations provided by the Managed Charging Working Group and incorporating all direction included herein.

12. No later than May 1, 2022, as part of its revised Managed Charging Program Requirements, and with input from the Managed Charging Working Group participants, Eversource shall submit a proposed plan to transition customers participating in its ConnectedSolutions EV pilot to the Residential EV Managed Charging Program for Authority review and approval in Docket No. 22-08-06.

13. No later than August 1, 2022, Eversource and UI shall separately file a report on their respective EV Rate Riders in Docket No. 22-08-06 that, at a minimum, includes the following:
    a. The number of customers who filed a completed application for enrollment in the EV Rate Rider and either were not eligible or were not approved for service;

b. The charger type, maximum capacity, location, and date of installation of every EV charging station receiving service under the EV Rate Rider;
c. The monthly maximum demand, total usage, and load factor for every EV charging station receiving service under the EV Rate Rider; and
d. The monthly bill and per-kWh charge billed to every EV charging station receiving service under the EV Rate Rider, as well as the monthly bill and per-kWh charge in accordance with the Company's general service rate schedule that would otherwise apply to the charging station.

DOCKET NO. 21-08-06 **ANNUAL REVIEW OF THE ELECTRIC VEHICLE CHARGING PROGRAM – YEAR 1**

This Decision is adopted by the following Commissioners:

Marissa P. Gillett

John W. Betkoski, III

Michael A. Caron

CERTIFICATE OF SERVICE

The foregoing is a true and correct copy of the Decision issued by the Public Utilities Regulatory Authority, State of Connecticut, and was forwarded by Certified Mail to all parties of record in this proceeding on the date indicated.

December 15, 2021

Jeffrey R. Gaudiosi, Esq.
Executive Secretary
Public Utilities Regulatory Authority

Date

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FILED
DEC 30 2022
EXECUTIVE SECRETARY
G.P.S.C.

DOCKET# 44280
DOCUMENT# 192550

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Docket No. 44280

In Re: **Georgia Power Company's 2022 Rate Case**

ORDER ADOPTING SETTLEMENT AGREEMENT AS MODIFIED

Record Submitted: November 30, 2022 Decided: December 20, 2022

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BY THE COMMISSION:

I. GEORGIA POWER COMPANY'S 2022 RATE CASE STATEMENT OF PROCEEDINGS

Pursuant to the Rate Plan approved by the Georgia Public Service Commission ("Commission") in the February 6, 2020 Order Adopting Settlement Agreement as Modified, in Docket No. 42516, Georgia Power Company's 2019 Rate Case, the Commission ordered Georgia Power Company ("Georgia Power" or "Company") to file, by July 1, 2022, a general rate case to address any changes in revenue requirements which may have occurred during the three-year period of this Rate Plan as follows:

> *The Commission finds that a three-year term for the Settlement Agreement as Modified ending December 31, 2022 is reasonable. By July 1, 2022, the Company shall file testimony and exhibits required in a general rate case along with supporting schedules required by the Commission to support a "traditional" rate case. The test period utilized by the Company in its rate case filing shall be from August 1, 2022 to July 31, 2023. The Company may propose to continue, modify or discontinue this Alternate Rate Plan. The*

Company shall also file projected revenue requirements for calendar years 2023, 2024, and 2025.

To accommodate preferred hearing dates and provide Public Interest Advocacy Staff ("PIA Staff") adequate time to issue discovery prior to the Company's direct hearings, the Company agreed to move its planned filing date from July 1, 2022 to Friday, June 24, 2022.

Accordingly, the Company submitted its filing, including all direct testimony, on June 24, 2022, with proposed rate changes to become effective August 1, 2022. The Commission issued a Procedural and Scheduling Order which, due to the complexity of the matters to be addressed in this docket, suspended the use of the proposed rate changes as contemplated by O.C.G.A. § 46-2-25 for a five-month period ending January 1, 2023, and declared the proceeding to be a contested case pursuant to O.C.G.A. § 50-13-13. Additionally, the Order deemed the proceeding "complex litigation" as that phrase is used in O.C.G.A. § 9-11-33(a).

Georgia Power's 2022 Rate Case filing requested approval to continue the three-year Alternate Rate Plan ("ARP") structure and requested a levelized rate increase of $852 million in 2023, and additional step increases of $107 million and $45 million to be effective January 1, 2024 and 2025, respectively. Hearings on Georgia Power's direct case in support of its filing were held September 27-29, 2022.

In addition to the Commission's PIA Staff, which has a statutory right to participate in this proceeding, a number of interested parties filed interventions. These interested parties included Americans for Affordable Clean Energy ("AACE"); Chargepoint, Inc.; the Commercial Group; Concerned Ratepayers of Georgia; Cypress Creek Renewables; EVgo Services, LLC; Georgia Association of Manufacturers ("GAM"); Georgia Coalition of Local Governments ("the Coalition"); Georgia Conservation Voters[1]; Georgia Interfaith Power & Light, Inc. ("GIPL"); Georgia Solar Energy Association ("GA Solar"); Georgia Solar Energy Industries Association ("GSEIA"), Solar Energy Industries Association ("SEIA"), and Vote Solar; Georgia Watch; Interstate Gas Supply, Inc.; The Kroger Co. ("Kroger"); Lightstar Renewables, LLC[2]; Metropolitan Atlanta Rapid Transit Authority ("MARTA"); Resource Supply Management ("RSM"); Sierra Club; Southern Alliance for Clean Energy, Inc. ("SACE") and Southface Energy Institute ("Southface"); Southern Renewable Energy Association ("SREA"); the U.S. Department of Defense (on behalf of all Other Federal Executive Agencies) ("DOD/FEA"); and Utility Management Services ("UMS"). Thereafter, on October 20, 2022, PIA Staff and Intervenors filed testimony and exhibits presenting their respective direct cases. With the exception of Concerned

[1] The Commission consolidated several intervenors into a single group known in this case as Georgia Conservation Voters. Any intervenor in the group consolidated that did not want to be a part had the right to appear as a public witness.

[2] The Commission rejected Lightstar Renewables, LLC motion to intervene as the matters they addressed were unrelated to this proceeding.

Ratepayers of Georgia, Cypress Creek Renewables, LLC, Georgia Watch, Interstate Gas Supply, Inc., the Kroger Co., Resource Supply Management, Sierra Club, and Southern Renewable Energy Association, all other parties to this case filed direct testimony in this proceeding on October 20, 2022. Hearings on PIA Staff and Intervenors' direct cases were held November 8-10, 2022.

Consistent with the Commission's Final Order in Georgia Power's 2022 Integrated Resource Plan, Docket No. 44160, the Company filed its supplemental direct testimony, in accordance with the Second Amended Procedure and Scheduling Order, in relation to the Renewable/Non-Renewable-10 ("RNR") tariff on October 20, 2022. The Company filed errata to their supplemental testimony on November 21, 2022. PIA Staff, Georgia Coalition of Local Governments, GIPL, GA Solar, GSEIA, SEIA, Vote Solar, and Southface Energy Institute and Southern Renewable Energy Association filed their supplemental direct testimonies regarding the RNR tariff on November 18, 2022.

The Company filed its rebuttal testimony on November 18, 2022, in response to the positions advocated by PIA Staff and various intervenors. The Company filed its supplemental rebuttal testimony related to the RNR tariff on November 23, 2022. The Company presented its rebuttal case on November 29-30, 2022. Following the Company's rebuttal case, the Commission conducted hearings on PIA Staff and Intervenors' supplemental direct testimony. Following the hearings on PIA Staff and Intervenors supplemental direct testimony, the Commission conducted hearings on the Company's supplemental rebuttal testimony at which time the hearings were concluded. On December 8, 2022, parties in this matter filed proposed orders and briefs.

At each phase of the hearings of evidence in this case the Commission also heard from numerous public witnesses who expressed their views on the Company's application, either individually or on behalf of specific groups.

II. LEGAL AUTHORITY AND JURISDICTION

The Commission has general supervisory authority over electric utilities. O.C.G.A. § 46-2-20 and 21. The Commission has the exclusive power to determine just, and reasonable rates and charges made by Georgia Power Company. O.C.G.A. § 46-2-23(a). Unless the Commission has otherwise authorized the change, Georgia Power Company must provide thirty (30) days' notice to the Commission and to the public of any proposed change to any rate, charge, classification, or service subject to the jurisdiction of the Commission. O.C.G.A. § 46-2-25(a). The Commission is authorized to suspend the operation of any new schedule and defer the use of such rate, charge, classification, or service for a period not to exceed five months.

III. COMMISSION ACTION

Following its rebuttal testimony, PIA Staff filed a proposed Settlement Agreement with the Company intended to resolve the issues in the case except for three policy issues left to Commission discretion: 1) the earnings band to be applied for Annual Surveillance Report purposes; 2) the pricing for the Community Solar Program; and 3) the additional amount to be paid for export solar energy pursuant to the RNR tariff. In addition to PIA Staff and the Company, the following intervenors were also parties to the proposed Settlement Agreement: AACE, Chargepoint, Inc., EVgo Services, LLC, GAM, MARTA, DOD/FEA, UMS, the Commercial Group, and Kroger.

Among other provisions, the proposed Settlement provided for: approving twenty five percent (25%) of the Company's proposed Electric Vehicle Make Ready Program; approving sixty percent (60%) of the Company's proposed Grid Investment Plan ("GIP"); reducing Operation and Maintenance ("O&M") expenses by an additional $180 million dollars over three years; setting the Residential Service Tariff ("R rate") as the default rate for all residential premises; allowing for the 5,000 monthly net metering rooftop solar customers to be grandfathered in while providing that new RNR Tariff customers be reimbursed at a rate of avoided cost plus an additional amount to be set by the Commission; and increasing the Qualified Senior Citizen Discount by six dollars ($6.00) per month.

The Proposed Agreement provided for the continuation of the ECCR Tariff which would collect certain environmental costs that will be incurred by the Company including compliance with Coal Combustion Residual Asset Retirement Obligations ("CCR ARO").

At its regular Administrative Session held on December 20, 2022, the Commission voted to adopt a Commissioner Motion ("Motion") to accept the Settlement Agreement with certain modifications set forth in the Motion (referred to herein as the "Proposed Agreement or Settlement Agreement as Modified.").

IV. FINDINGS OF FACT

1.

The Commission finds that the resolution of the matters raised in this docket, as provided in the Settlement Agreement as Modified, (Attached as Exhibit I) is appropriate and in the best interest of the State of Georgia. It is supported by testimony and other evidence in the record and will result in just and reasonable rates. In discussing the individual components of the Settlement Agreement as Modified, the Commission remains mindful that the Proposed Agreement reflected a compromise among a number of parties with disparate interest, and that the Settlement Agreement as Modified must be considered as a whole. It is plain from reviewing the resolution that no party to the proceeding, including every party that signed on to the Proposed Agreement,

prevailed on every issue. However, the Settlement Agreement as Modified offers a fair resolution to the full range of issues presented in this docket.

2.

As set forth in the Motion, the Commission finds that rates shall be set using a 10.50% ROE, which appropriately balances the interests of the Company and its customers, and which the Commission finds to be just and reasonable. The difference between the respective ROE recommendations of Georgia Power and those of PIA Staff and other Intervenors represented the largest dollar amount of any single issue in the case. Georgia Power recommended a ROE of 11% based upon the analysis and recommendation of witness James Coyne. This ROE was within Mr. Coyne's range of 8.99% to 13.55% and intended to ensure the Company's continued access to capital markets.

Staff witness Mike Gorman recommended a return on common equity of 9.45%, within the range of 9.00% to 9.90%. Tr. 3515. Gorman recommended rate of return of 6.83% and 6.84% for the test year ending July 31, 2023, and calendar year 2023, respectively. *Id.* Based on a capital structure reflecting a 51% common equity ratio, Gorman recommended an overall rate of return of 6.57% and 6.61% for 2024 and 2025, respectively. *Id.*

GIPL supported Staff's recommendation stating that the ROE and capital structure strike the right balance between Company profits and reasonable rate. (GIPIL Brief, p.4).

The Commercial Group recommended that the Commission set an ROE for Georgia Power that would balance the interests of ratepayers and the utility and be low enough to help Georgia remain competitive in attracting and keeping businesses in the state; and that any earnings band should be directly tied to the ROE set in this proceeding. (Commercial Group Brief, p. 8).

Georgia Watch agreed with Staff and other intervenors that the Company's ROE should be lowered to an amount more consistent with the average of their peers. Georgia Watch suggested that a reduction from the current 10.5 percent profit to 10 or 9.5 percent ROE would allow the Company an opportunity to earn a fair return while reducing the impact of its proposed rate increase on their captive ratepayers. In addition, Georgia Watch agreed with Staff that any earnings above the band in 2023 should be applied to recovery of deferred costs and regulatory assets. (Direct Testimony Smith, Trokey, page 132, lines5-7) (Georgia Watch Brief p.2). GSEIA, SEIA, and Vote Solar recommended the Commission set the ROE band to +/- 50 basis points.

The GAM witness testified that a 9.83% ROE setpoint gives Georgia Power more than an adequate opportunity to earn a fair return. (LaConte Direct Testimony, p. 9).

DOD/FEA suggested an authorized ROE of 9.47% (DOD/FEA Brief p. 9). For the earnings band around the target ROE, DOD/FEA recommended it be established at 100 basis points, as originally designed when the ARP was first approved, and eliminate or reduce the 20% of earnings retained by the Company for amounts above the earnings ROE band. (*Id.* p.2).

The Commission finds and concludes that a continued ROE of 10.5% will allow the Company continued access to the capital markets at competitive rates and will allow the Company to construct the infrastructure necessary to serve customers and comply with environmental regulations. Accordingly, the Commission finds the Proposed Agreement's ROE for setting rates of 10.50% is reasonable and in the public interest.

3.

The Commission approves a capital structure of 56% equity and 44% long term debt for the test period as put forth in the Proposed Agreement. Georgia Power proposed that a capital structure containing approximately 44% debt and 56% common equity be used for ratemaking purposes in this proceeding. This is a continuation of the proposed capital structure approved in the 2019 Georgia Power Rate case.

Staff agreed with the request 56% common equity structure for 2023. However, Staff recommended that the Commission lower the Company's equity ratio to 51% common equity for 2024 and 2025 after Vogtle Units 3 and 4 are placed in-service, consistent with the ratio approved in the 2013 Rate Case.

GAM pointed out that the average common equity ratio for vertically integrated investor-owned utilities in 2022 is 51.58%. (LaConte Direct Testimony, p. 20).

GIPL recommended an increase in the Company's proposed common equity ratio to 61.7%, which was justified due to their much lower recommended ROE of 5.54%. (GIPL Brief, p. 2).

Based on the evidence presented and the totality of the Proposed Settlement Agreement, the Commission finds and concludes that a capital structure of 56% common equity level is just and reasonable and will help to mitigate the risk of a credit rating downgrade.

4.

Provision 3 of the Proposed Settlement Agreement approves the Company's filing with the following modifications to the revenue requirement. The agreed upon adjustments to the Company's request are set forth in the values in the table below and detailed on Exhibit A of Attachment 1 to this Order. The agreed upon adjustments by category and amount include the following:

a. The Company agrees to reduce the requested GIP spend by 40% over the term of this ARP, as shown in the table below and on Exhibit A of Attachment 1.

b. The Company agrees to reduce EV Make Ready spend by 65% over the term of this ARP, as shown in the table below and on Exhibit A of Attachment 1.[3]

c. The Company will not move forward with a full Distributed Energy Resource Management System ("DERMS") at this time. To prepare the electric system for higher levels of distributed energy resources ("DER"), the Company will be allowed to begin the following preliminary steps, which will include system modifications to allow for modeling and visibility of DER, integration of these modifications with the Company's real-time operations platforms such as EMS, DMS, and SCADA, and the establishment of DER remote configuration capabilities. The Company will report back to the Commission in the 2025 Integrated Resource Plan on the development of these systems and the need for any further system modifications to plan for DER integration. The investments made pursuant to this Paragraph will be amortized over 10 years.

d. In addition to the categories listed in the table below, Staff recommended several other adjustments to operations and maintenance ("O&M") expenses in this case. The Stipulating Parties agreed that the only specific adjustments being made are those identified in the table below. For purposes of settlement and compromise, the Company agreed to further reduce the revenue requirement associated with miscellaneous O&M expenses by $30 million each year, which is not allocated to any particular expense.

	Stock-Based Compensation	Ln 21
	Energy Direct Premium Packages	Ln 4
	Executive Financial Planning	Ln 7
	O&M Scrap Sales Proceeds	Ln 5
	Wireless Co-Location Revenues (80/20 sharing)	Ln 6
	Depreciation Expense and Accumulated Depreciation - New Depreciation Rates	Lns 10 - 14
	Depreciation Expense Reduction for Plant Scherer Units 1-3 and common, and Plant Bowen Units 1-2 (12 years)	Ln 9
	Reduce projected Storm Damage Accrual to $31M per year	Ln 20

[3] The Motions adopted by the Commission in this matter change the EV Make Ready reduction from 65% to 35%.

	CCR ARO recovery methodology to remain consistent with the 2019 base rate case Order except for a four, rather than three, year amortization period.	Ln 18
65%[4]	Electric Vehicle Make Ready Program	Ln 19
75%	O&M Expense - Electric Vehicle Make Ready Program	Ln 19
40%	Grid Investment Plan (Transmission and Distribution Plant Investment), and related Depreciation Expense and Accumulated Depreciation and ADIT	Ln 16
60%	Preliminary system modifications for Distributed Energy Resource Management System (DERMS) and related Amortization (10-years) and Accumulated Amortization and ADIT	Ln 17
	Depreciation Expense - Depreciation Rates Correction for Ft Benning and Ft Gordon	Ln 15
	Property Tax Expense	Ln 22
	Income Tax Credits Related to the Inflation Reduction Act, including Commission approval to opt out of normalization requirements for specified battery energy storage facilities	Ln 8

The Company had proposed to levelized its requested rate increase. The Company argued that customers are fairly compensated for the projected over-collection in the first two years of the levelization. For the projected advancement of revenues in 2023 and 2024, the Company would defer the amount as a regulatory liability, reducing retail rate base and giving customers credit on the advanced amount based on the Company's full weighted average cost of capital. This proposed deferral reduced the levelized revenue requirement requested by the Company and fully amortizes the advancement by the end of 2025.

PIA Staff recommended a step increase approach, which would increase customer rates by an increasing amount during each of the next three years and better align with the Company's demonstrated revenue deficiencies in 2024 and 2025.

Georgia Watch supported Staff's recommendation that the Commission disapprove the Company's requested ARP as filed in this case. Georgia Watch supported Staff's recommendation of no increase in base rates in 2023 and no levelized increases in 2024 and 2025. (Direct Testimony Smith, Trokey, page 133, lines 4-20). (Georgia Watch Brief p. 2).

[4] As noted in footnote 3, the Motions adopted by the Commission in this matter change the EV Make Ready reduction from 65% to 35%.

GAM disagreed with Georgia Power's levelized approach in the ARP. GAM further recommended that the Commission deny Georgia Power's accelerated recovery proposal and reaffirm that the Plant Scherer units will be recovered over their remaining useful lives as determined in the last rate case. (GAM Brief p.11).

Georgia Power's Grid Investment Plan as filed included a Distribution Investment Plan ("DIP") and a Transmission Investment Plan ("TIP"). Georgia Power proposed to continue its GIP in the amount of $2.3 billion from 2023 to 2025. Tr. 1563.

PIA Staff recommended that the Commission reject TIP in its entirety. PIA Staff recommended the Company should determine whether equipment should be replaced based on the objective, periodic, diagnostic testing the Company already employs. Staff also recommended that the Commission reject the circuit hardening and undergrounding packages, which make up approximately 85% of the DIP. In particular, PIA Staff argued that the Commission should reject DIP circuit hardening and undergrounding packages as cost-inefficient. For any components of DIP the Commission approves, Staff recommended that the Commission direct the Company to document SAIDI and SAIFI projections in 2032 and to hold the Company accountable for those projections. Tr. 1625. Staff recommended that the Company employ more aggressive vegetation management programs and more rigorous worst- performing circuit programs in place of their recommended DIP packages.

The Company argued that removing the circuit hardening and undergrounding packages would essentially forestall the purpose of the DIP, which focuses on ensuring lasting reliability improvements while mimimizing the total cost to customers. In addition, the Company argued that worsening reliability for a subset of feeders (also referred to as circuits) will be more pronounced without these investment packages, leading to significant negative impacts on customer experience due to more frequent and longer outages, as well as increases in the economic cost incurred by customers.

PIA Staff opined that the cornerstone of the TIP is replacing equipment based on the age of the equipment as opposed to replacing it based on the equipment failing a diagnostic test. PIA Staff did not agree with the Company's position that such projections or analyses are impossible to provide.

PIA Staff stated that the actual operating condition of transmission and distribution ("T&D") equipment as measured by periodic, objective testing and inspection programs should be the primary drivers of replacement.

Georgia Power argued that the TIP focuses on replacing aging assets that have or will exceed their Company expected life by the end of the Grid Investment Plan period. As the Company explained, much of its transmission equipment is now approaching 50, 60, and 70 year lives. Based on the Company's experience, the likelihood of failure for the transmission assets included in the TIP will exponentially increase as the assets age beyond their expected life, and

the reliability of the electric system could be negatively impacted as a result. According to the Company, replacing these aged assets will (1) reduce the number of emergency failures, (2) mitigate system operation reliability concerns, and (3) avoid higher maintenance and replacement costs while ensuring the safety of the general public and the Company's employees.

SREA urged the Commission to hire an independent transmission consultant to provide a report by July 1, 2024, that evaluates multiple scenarios of generation additions and retirements and measures multiple reliability, economic, and other quantifiable benefits associated with specific transmission project recommendations and order the Company to work with the Commission, Staff, stakeholders, and the hired consultant to provide the data and any other information necessary to complete the report. Additionally, SREA recommended the Commission open a new docket to evaluate the current transmission planning processes and evaluate recommendations for reform and improvements. (SREA Brief p. 1).

SACE and Southface suggested the Company work with Staff and stakeholders to develop a cost-benefit framework methodology for T&D investments. (SACE/Southface Brief p. 23).

With the exception of the costs associated with the EV Make Ready Program, the Commission finds the proposed revenue requirement modifications to be reasonable and appropriate and approves the adjustments in accordance with the Proposed Agreement. The Commission finds that a reduction in the Company's requested GIP spend by 40% over the term of this ARP is reasonable. With regards to the other modifications to O&M expenses and other costs made in Provision 3, the Commission finds that the modifications to the Company's findings are reasonable. The Commission authorizes Georgia Power to opt out of the IRS tax normalization requirements for the purposes of recognizing eligible Investment Tax Credits for specified battery energy storage facilities in accordance with the Inflation Reduction Act. The modification to the EV Make Ready Program will be further addressed below.

5.

The Proposed Agreement provides that, effective January 1, 2023, the Company shall increase its traditional base rate tariff to collect an additional $192 million, with additional adjustments in 2024 and 2025 of $273 million and $314 million respectively. (Proposed Agreement Provisions 4).

The Commission finds these base tariff changes to be reasonable based on the evidence presented, therefore, the changes are approved as provided for in the Proposed Agreement. Provided, however, that the increased approval amount for the EV Make Ready Program discussed in Paragraph 33 will increase these amounts slightly. When the Company makes its Compliance filing within thirty days of the date of this decision, the Company shall also file the updated amounts for the traditional base rate tariff adjustments.

6.

The Proposed Agreement provides that effective January 1, 2023, the Environmental Compliance Cost Recovery ("ECCR") tariff will be adjusted for traditional ECCR costs to reduce collections by $7 million and adjusted to reduce collections by an additional estimated $35 million effective January 1, 2024, and an additional estimated $9 million effective January 1, 2025. Additionally, effective January 1, 2023, the Coal Combustion Residual Asset Retirement Obligations ("CCR ARO") costs recovered in the ECCR tariff shall be adjusted to reduce collections by $13 million, and adjusted to collect an additional $101 million effective January 1, 2024, and an additional estimated $90 million effective January 1, 2025. The process for revising these estimates is described in Paragraph 8 (a) and (b) of the Proposed Agreement. As approved in the 2019 base rate case order in Docket No. 42516, ECCR shall continue to include the cost for compliance with CCR ARO. The projection of CCR ARO cost will be updated in 2023 and 2024 through compliance filings to set the actual ECCR tariff rates for 2024 and 2025. The Commission reserves the ability to make prudency determinations on the Company's coal ash related costs.

The Company and PIA Staff both agreed there should be a continuation of the CCR ARO cost recovery methodology approved in the 2019 Rate Case.

GAM Witness Pollock recommended the Company not be allowed to earn a return on the CCR ARO regulatory asset balance until securitization is authorized. GAM stated that fully embedded costs are recovered from the Customer Baseline Load ("CBL") portion of Real Time Pricing ("RTP") rates while RTP prices reflect marginal generation (capacity and energy) and transmission costs. GAM argued that to adopt the Watkins proposal would completely undermine RTP, which would no longer reflect marginal costs or real-time prices. (GAM Brief p. 9,13).

Sierra Club recommended that the Company be disallowed from recovering on any coal ash remediation that does not meet federal and state law requirements. They stated in their post hearing brief that the capping of coal ash which mixes with groundwater or mixed with water of any kind is violation of 40 C.F.R. § 257 Subpart D (the "CCR Rule") and Ga. Comp. R & Regs. 391-3-4-.10 ("Georgia CCR Regulations"). They asserted that the Company's current plan allows Coal Ash to remain saturated and in contact with groundwater and since this violates both federal and state regulations, the costs of such remediation should be deemed imprudent and disallowed for recovery. Sierra Club stated that despite the testimony of the Company's witness, the EPA's decision should not be interpreted as only applying to a specific instance in Ohio. They reiterated that if applied to the current coal ash remediation plan, the Company should not be allowed to recover on remediation plans that are not in compliance with federal or state regulations. They further recommended that the Commission should reserve a decision on the recovery of costs associated with the Hammond AP-3 until a final permit is issued. In accordance with the Proposed Agreement, the Commission is reserving the ability to make prudency determinations on the Company's coal ash related costs until after a determination of the lawfulness of the Company's Coal Ash remediation plan is made.

Resource Supply Management recommends that the Commission not allow the Company to recover on closed assets. (RSM Brief p. 2).

This Commission has carefully considered the evidence and testimony presented on these issues and finds that it is just and reasonable for Georgia Power to recover CCR ARO compliance costs as provided for in the Proposed Agreement. The Commission finds that it is appropriate to retain the ability to determine prudency on this spending until a later date, as contemplated by the Proposed Agreement.

7.

Provision 6 of the Proposed Agreement states that effective January 1, 2023, Georgia Power shall collect an additional $37 million through the Demand Side Management ("DSM") tariffs, and as adjusted during the term of this ARP based on the DSM true up process agreed to by the Company and Staff with a projected increase of $27 million effective January 1, 2024, and a projected decrease of $2 million effective January 1, 2025.

The Commission finds that Provision 6 is a reasonable and appropriate approach to the DSM tariff, as adjusted during the ARP.

8.

Provision 7 of the Proposed Agreement that effective January 1, 2023, the Municipal Franchise Fee ("MFF") tariff will be increased to collect an additional $5 million effective January 1, 2023, an additional estimated $9 million effective January 1, 2024, and an additional estimated $9 million effective January 1, 2025, which dollar amount will change as total revenue adjustments change as allowed by this ARP, as well as with any future Fuel Cost Recovery ("FCR") changes and future Nuclear Construction Cost Recovery ("NCCR") changes.

The Commission finds that this provision acceptable and adopts it as part of this Order. Provided, however, that the increased approval amount for the EV Make Ready Program discussed in Paragraph 33 may increase these amounts slightly. When the Company makes its Compliance filing within thirty days of the date of this decision, the Company shall also file any updated amounts for the MFF adjustments.

9.

Consistent with the 2019 base rate case order in Docket No. 42516, for purposes of the 2024 and 2025 rate adjustments, Provision 8 of the Proposed Agreement provides that the Company shall make compliance filings of the updated tariffs at least ninety (90) days prior to the effective date of the tariffs. The Company's compliance filings will include the following updates:

a) Effective January 1, 2024, (i) the traditional base tariffs shall be adjusted to collect an additional $273 million; (ii) the ECCR tariff shall be adjusted based upon the Compliance filing with updated CCR ARO costs as filed in the most recent semi-annual

report for calendar year 2023; (iii) the DSM tariffs shall be adjusted to reflect the DSM costs for calendar year 2024 as approved in Docket No. 44161 and as adjusted based on the DSM true up process agreed to by the Company and Staff; and (iv) the MFF tariff shall be adjusted to collect the MFF cost incurred by the Company. The 2024 increase to traditional base rate tariffs, ECCR tariff, and DSM tariffs will use the most current kWh sales forecast for the applicable year to set the rates.

b) Effective January 1, 2025, (i) the traditional base tariffs shall be adjusted to collect an additional $314 million; (ii) the ECCR tariff shall be adjusted based upon the Compliance filing with updated CCR ARO costs as filed in the most recent semi-annual report for calendar year 2024; (iii) the DSM tariffs shall be adjusted to reflect the DSM costs for calendar year 2025 as approved in Docket No. 44161 and as adjusted based on the DSM true up process agreed to by the Company and Staff; and (iv) the MFF tariff shall be adjusted to collect the MFF cost incurred by the Company. The 2025 increase to traditional base rate tariffs, ECCR tariff, and DSM tariffs will use the most current kWh sales forecast for the applicable year to set the rates.

The Commission finds that requirement that compliance filings of the updated tariffs which must be submitted at least ninety (90) days prior to the effective date of the tariffs as filed in the Proposed Agreement is reasonable and is hereby approved.

10.

The structure of the earnings band was set aside from the Proposed Agreement for Commission decision as a policy issue. Provision 9 provides for ASR purposes, beginning January 1, 2023, the earnings band shall be set at __% to __% ROE, to be decided by the Commission, and the Company shall report earnings based on the actual historic cost of debt and capital structure described in Paragraph 2. The Company will not file a general rate case unless its calendar year retail earnings are projected to be less than the bottom end of the band. (Agreement Provision 9)

At the December 20, 2022 Administrative session, Chair Pridemore offered a motion to set the earnings band from 9.5% to 11.9% ROE. The motion passed 4-1. The Commission finds this motion includes a just, reasonable and appropriate ROE earnings band that is in the public interest.

11.

The Stipulation stated that subsequent to finalization of Staff's review of the respective ASR, any excess retail revenues above the top end of the earnings band will be shared, with seventy percent (70%) being applied to regulatory assets in the following priority: Accumulated CCR ARO; Retired Generating Plant; and Obsolete Inventory, ten percent (10%) being directly refunded to customers, allocated on a percentage basis to all customer groups including the base revenue

contribution of RTP incremental usage, and the remaining twenty percent (20%) retained by the Company.

At the December 20, 2022 Administrative Session, Chair Pridemore offered a motion modifying the sharing mechanism offered by the Stipulation. The motion stated that forty percent (40%) of earnings above the band would be applied to regulatory assets, forty percent (40%) would be directly refunded to customers and twenty percent (20%) would be retained by the Company. The motion passed unanimously. The Commission finds that this motion represents a just, reasonable and appropriate allocation of any excess retail revenues.

12.

Pursuant to Provision 11, the Company will make its ASR filings for this ARP by March 15th of the following year. The Commission will consider the ASR filing and determine any direct refunds and reduction of regulatory assets by December 31st of that year.

The Commission finds that the ASR filing dates for review are appropriate and are hereby approved.

13.

The Company anticipates sharing revenues above the approved ROE band for 2022 with customers under the current ARP. For purposes of settlement, the Company will expedite sharing to provide the return of the estimated amount of customer sharing in the first quarter of 2023. Any revision, if needed, to the estimated amount of sharing will be adjusted once the Commission finalizes its review of the 2022 ASR. The customers' portion of sharing shall be applied in the manner ordered in the 2019 rate case in Docket No. 42516. (Provision 12 of the Settlement Agreement).

The Commission finds that Proposed Agreement Provision 12 is reasonable and is approved.

14.

The Commission finds that for book accounting and ASR purposes, the schedule for the Nuclear Decommissioning Trust - Tax Funding (reference the attached "Proposed Supplemental Order - Nuclear Decommissioning Costs") shall be approved. (Agreement Provision 13).

15.

Provision 14 of the Agreement provides that any additional tax benefits related to the Inflation Reduction Act, the Infrastructure and Investment Jobs Act, or any additional state or federal regulations shall accrue as a regulatory liability.

The Commission finds this to be the appropriate regulatory treatment of any state of federal regulation.

16.

The Proposed Agreement states that in the event that the Company determines that an asset is impaired or the Commission approves the retirement of a retail generation asset as a result of any environmental regulation or legislation, the Company may request that costs associated with such impairment or retirement be deferred as a regulatory asset. (Agreement Provision 15).

The Commission finds this provision of the Proposed Agreement to be reasonable and is hereby approved.

17.

Provision 16 of the Agreement provides that the Interim Cost Recovery ("ICR") mechanism as initially approved in the 2010 Rate Case in Docket No. 31958 is continued throughout the term of this ARP utilizing the earnings band set by the Commission in this case.

The Commission finds that the Provision is reasonable, and it is therefore, approved.

18.

Provision 17 of the Agreement provides beginning in 2023, with the adjustment to traditional base rate tariffs, except as otherwise provided in this Stipulation, the rate increase shall be applied to each traditional base rate on an equal percentage basis. The energy, demand, and basic service charge components of each base rate shall all be adjusted equally. Except as otherwise provided in this Stipulation, the Company will not apply any increase to the basic service charges for the tariffs that had this component adjusted to the full amount of the customer-related costs in the 2019 base rate case or apply an increase to the basic service charge for the domestic and small business rate groups.

GIPL urged the Commission to deny the Company's proposed basic service charge increase for residential customers because the current charge already recovers costs in excess of the Company's truly customer-related costs, and the Company's cost of service analysis shows a decrease rather than an increase in customer-related costs. (GIPL Witness Barnes Testimony at 54-61).

DOD/FEA encouraged the Commission to move toward cost-based rates rather that applying an across-the-board rate increase to all rate classes using guidance from GPC's filed Class Cost of Service Study ("CCOSS"), using the 4-Coincident Peak ("4-CP") allocation for production costs; (Exhibit GPC 31-LPE-5 and Exhibit GPC 32-LPE-6).

After careful consideration, the Commission finds that adjusting traditional rate base tariff as set forth in the Proposed Settlement Agreement is just and reasonable.

19.

The Commission finds it reasonable for tariffs within the Medium and Large Business rate groups to receive an equal adjustment to the energy, demand, and basic service charge components. (Agreement Provision 18).

20.

MARTA asked the Commission to grant its request to exempt the ET Tariff from any rate increase as part of Georgia Power's 2022 Rate Case stating that its investment in its infrastructure and public transportation services, particularly rail services, have a great multiplying effect on economic development in Georgia and the Atlanta region, increasing Georgia Power's electric sales to new customers and spreading the cost of service. (MARTA Brief p. 13).

The Commission finds it appropriate for Georgia Power to allocate the Electric Transportation ("ET") tariff on 50% of the base rate increase. The revenue deficiency for this adjustment will be accounted for within the Government/Institutional tariff group. (Agreement Provision 19).

21.

Provision 20 of the Agreement states that the Company will move the Medium Business and Large Business rate groups closer to parity, beginning in 2023, rates in the Medium Business and Large Business rate groups will receive 85% of the overall base rate increase with the resulting revenue deficiency being spread to other rate groups excluding the Small Business, Lighting, Agricultural, and Marginal Rate groups, which will receive the overall base rate increase.

The Commercial Group requested the Commission move class rates closer to parity noting that now, Medium Business and Large Business class rates are substantially above-cost. The Commercial Group stated that if the Commission expands TOU-FD eligibility to include unaffiliated restaurants, the Commission should contain any revenue erosion from such expansion to the TOU-FD rate itself. (Commercial Group Brief, p.1).

GAM supported the movement of the rate classes closer to parity consistent with principles of cost causation, fairness and gradualism. (GAM Brief, p.11).

RSM recommended the Company use their Cost-of-Service study in order to create their rate design proposals. It argued that commercial customers rates be set to the demand costs rather than collecting part of its fixed costs in a volumetric manner. It pointed that out that the Company is correctly setting the residential rates to collect demand costs after the old rates were being collected volumetrically.

The Commission finds the Company's move to bring Medium and Large Business rate groups closer to parity reasonable and approves Provision 20 of the Agreement.

22.

Pursuant to Provision 21 of the Settlement Agreement, the Company agrees to work with the Department of Defense to investigate a Backup rider for customers on the Real Time Pricing rate who install customer-owned generation that normally operates at least 6,000 hours per year. The Company will meet with the DOD within 90 days of the final Order in the case to begin that collaboration.

DOD/FEA recommended that to ensure that the customer capacity is reliable and to prevent cost-shifting onto other customers, it requested that RTP customers be given the option to subscribe to and pay for GPC Backup ("BU") services by changing the Applicability Section of the BU rate schedule to allow RTP customers to enroll, and to specify the rates that would apply to RTP BU customers. With BU service firming up the reliability and cost recovery from RTP customer generation, such a customer should qualify for a CBL reduction. (DOD/FEA Brief p. 5).

The Commission encourages this collaborative arrangement between the DOD/FEA and approves this Provision of the Settlement Agreement.

23.

In Provision 22, Georgia Power and Staff agreed that the Residential Service tariff ("R rate") will be the default rate for all residential premises.

Staff and numerous intervenors all proposed the same or similar recommendations. Staff, GIPL, and other intervenors all submitted extensive testimony demonstrating that Schedule TOU-RD has been significantly more expensive for customers than other available rates and that demand rates are inferior to volumetric time-of-use rates for providing efficient and actionable price signals to residential customers.

GIPL encouraged the Commission to order the Company to return to using the basic volumetric residential tariff, Schedule R, as the default rate and halt use of the complicated demand charge tariff, Schedule TOU-RD, as the default tariff for new residential premises. In the alternative, if the Commission prefers a time-varying rate as the default for new premises, it should set the time-of-use nights & weekends tariff, Schedule TOU-REO. (GIPL Brief p. 2-3).

Georgia Watch stated that the residential R-tariff should remain the default rate for all customers. Customers in newly constructed dwellings already defaulted onto the Company's TOU-RD rate should receive notification of the likelihood they have or will experience higher bills due to this rate.

The Coalition asserted that the standard R tariff should be maintained and become the default rate for both newly constructed and pre-existing premises. If the TOU-RD rate is maintained, the Coalition stated, it should not be the default for any customers, should be fully optional, and should be adjusted so that the demand charge will only apply to peak hours (i.e. between 2 pm and 7 pm on non-holiday weekdays between June and September). Additionally,

the Coalition supported PIA Staff's recommendation that the Company be ordered to create a rate comparison tool for all residential customers to better enable them to select the best rate for their usage and demand profile. (Coalition Brief p. 13)

The Commission finds that the evidence supports that the R rate should and shall be the default rate for all residential premises as laid out in Provision 22.

24.

Provision 23 of the Agreement states that the Company will maintain the R rate as a rate option available to all residential customers. In addition, there will be an elimination of the declining-block rates during the non-summer months to a flat rate for all kWh usage. The relationship between the summer and non-summer base rate energy charge revenues will be maintained.

The Commission supports the maintenance of the R rate as a rate option and the relationship between the summer and non-summer base rate energy charge revenues and approves this measure.

25.

The Proposed Agreement provides that the Stipulating Parties agree that within ninety (90) days of the Final Order in this docket, the Company and Staff will collaborate on a process to consider potential options for the expansion of income qualified discount opportunities to assist customers. (Provision 24). This process will allow for interested stakeholders to provide input on the options to be considered. Stipulating Parties further agree that within 270 days of the Final Order in this docket, the Company, after considering input from interested stakeholders, will report back to the Commission on their findings and may recommend additional action. Any potential program options must consider cost impacts to non-participating customers as well as the impacts of any revenue erosion.

The Commission finds that this provision is reasonable and is approved.

26.

Provision 25 of Proposed Agreement provides that the Company will agree to file quarterly reports regarding the location, peak demand, usage, and revenue of the Charge It Electric Vehicle rider.

The Commission finds this provision to be just and reasonable.

27.

The Proposed Agreement provided that the Company will withdraw proposed Section F.9 of the Company's Rules and Regulations for Electric Service and will work with the Georgia

Association of Manufacturers and Staff to identify alternative language, which will be filed with the Company's compliance filing in this case. (Agreement Provision 26).

The Commission finds this provision to be just and reasonable.

28.

The Proposed Agreement, No. 27, provided that the interconnection fee found in Section G of the Company's Rules and Regulations for Electric Service for customer generators smaller than 250 kW will be $100 for residential customers and $200 for commercial and industrial customers. The Company's proposed modification to the language in Section G.3 will limit the Company's communication with and control of the customer's generator to those capabilities provided in IEEE 1547-2018 (or as it is subsequently amended) and will only apply to new interconnecting customer generators at or above 250 kW and existing interconnected customer generators who expand or modify their generation facility.

Staff, SACE and Southface urged the Commission reduce the proposed interconnection fee for the RNR tariff to the $100 recommendation of PIA Staff and waive this fee for income-qualified customers. (SACE Brief p.5).

The Commission finds the interconnection fee structure included in Provision 27 of the Proposed Agreement to be just and reasonable.

29.

The Proposed Agreement provided that the pricing for the Community Solar program, the Stipulating parties agree that this is a policy issue for Commission determination. Depending on the Commission's intent for the program. The Company's proposed $27.99 per block for residential customers and $29.99 for commercial customers and Staff's proposed $20 per block for residential customers and $22 for commercial customers. (Provision 28).

The Coalition supported PIA staff's proposed price of $20 for residential customers and $22 for commercial customers, which it believes, strikes a more appropriate balance in terms of allocating costs and benefits and creates a more attractive program. The Company's argument that bill savings are not the purpose of the program should be rejected. The Coalition argued that the Commission has the authority and opportunity to revisit the purpose of the program in this rate case and create an offering that provides customers the opportunity to support the growth of renewable energy on Georgia Power's system and realize bill savings. (Coalition Brief p. 8).

At the December 20, 2022 Administrative Session, Commissioner Johnson made a motion to modify Paragraph 28 of the Stipulation. The motion set the pricing for the Community Solar program at $24 per block for residential customers and $25 per block for commercial customers. The motion was adopted unanimously. After weighing the arguments, the Commission finds that the motion is a just and reasonable resolution to this issue.

30.

The Proposed Agreement in Provision 29 stated that the Time of Use – Food and Drink ("TOU-FD") rate shall remain available to all food services and drinking places identified as 722 of the North American Industry Classification System ("NAICS") through December 31, 2025. During the term of the ARP, qualifying food services and drinking places will be accepted on TOU-FD on a first come, first allowed basis until the number of accounts on the rate equals 6,000. Any revenue erosion from the TOU-FD rate conversion during the term of the ARP will be captured in a regulatory asset account and recovered through rates in 2024 and 2025. All revenue loss resulting from the implementation of this provision shall be recovered by the Company from the TOU-FD rate.

UMS, representing the restaurant and food services industry, proposed that Georgia Power should modify the TOU-FD rate by extending the deadline for new qualifying customers to enroll in the TOU-FD rate by (3) three years, from December 31, 2022, until December 31, 2025, and to revise the current language in the TOU-FD-7 tariff such that the revised language reads: "Qualifying accounts will be accepted on TOU-FD on a first come, first allowed basis until the number of accounts equals 6,000 or until December 31, 2025, whichever occurs first." UMS recommended the Commission maintain its discretion to consider the Georgia Power's concerns over possible rate impacts associated with TOU-FD and will apply revenue erosion associated with TOU-FD back to TOU-FD in future rate case proceedings before the Commission. (UMS Proposed Order p. 1).

The Commission finds that the Proposed Agreement provides for a just and reasonable settlement of this issue.

31.

In the Proposed Agreement, the Company agreed to continue to make the Time of Use Residential Energy Only ("TOU-REO") rate available to customers. (Provision 30).

The Commission finds that this provision is just and reasonable.

32.

In the Proposed Agreement Provision 31, the Company agreed to rename the TOU-PEV tariff to clarify the broad availability of the tariff to Residential customers that do not own an electric vehicle.

The Commission finds that this clarification to the TOU-PEV tariff is just and reasonable.

33.

The Proposed Agreement stated that the Company's collective Electric Transportation program proposed in this case for investments in community electric vehicle ("EV") charging

facilities and electric transportation infrastructure upgrades to support customer EV charging (i.e., Make Ready, infrastructure maintenance, administrative costs, Community Charging, and rebates) is approved, provided however, that the EV Make Ready program would be approved at a reduced rate from the requested budget level, and the program shall be modified to prioritize electrification of public fleets and publicly available charging.

The Make Ready program will now allow EV charging providers to participate under the following conditions: (i) they have the permission of the site host customer to operate on the site host customer's premises; (ii) they will coordinate with the site host and Georgia Power for purposes of the Make Ready program; (iii) Georgia Power is able to obtain all required easements and any other rights required to implement the Make Ready program; and (iv) Georgia Power retains final approval of Make Ready project design. In addition, Make Ready criteria and terms and conditions will be available on Georgia Power's website. A Term Sheet detailing the operation of the Company's Electric Transportation program is attached to the Stipulation. The Company agrees to develop reporting requirements for the Electric Transportation program to keep the Commission informed of the program's progress. The Company also agreed that charger locations under the Community Charging component of the program will be subject to a right of first refusal for private EV charging providers and further agrees to establish publicly available criteria for the Company's Community Charging locations as detailed in the Term Sheet, hereto attached as Attachment 2. The Charge It Electric Vehicle rider is approved and will be available to all existing and new EV charging providers.

Additionally, the Company will work with Staff and the EV parties signing the Stipulation to review and design an alternate commercial EV rate in addition to the Charge It Electric Vehicle rider, which will enable the Company to collect the costs to provide electric service to EV charging providers through a transparent pricing structure and support the growth of EV commercial charging investments. The alternative design should primarily collect costs through a volumetric structure but may also allow for some collection of costs – such as distribution costs – through demand charges. In developing the rate, the parties will consider a variety of rate designs to ensure the best rate solution is developed. The Company will file an alternative EV charging rate within six months of the execution of the Final Order in this docket. The Company's Electric Transportation program and alternative charging rate(s) will be reviewed by the Commission in the next base rate case.

During the hearings, the Company clarified its recommendation to increase the dollar amount that ratepayers will have to pay for capital expenditures related to EV transportation. These expenditures include (1) investments in EV charging facilities and infrastructure upgrades, (2) administrative cost recovery, (3) infrastructure maintenance, and (4) rebates to accommodate the growth of EV transportation. Tr. 78. Specifically, the Company requested $30 million per year for EV capital infrastructure spending for plan years 2023 through 2025, nearly quintupling the $8 million approved for such expenditures in the 2019 rate case. Tr. 1315-17. The majority of that

request, $27 million per year, is for the Company's Make Ready program. *Id.* The remaining $3 million is for infrastructure upgrades for the Community Charging program. Tr. 1324.

Staff recommended that the Commission deny the Company their proposed increase to the Make Ready Program. (Staff Brief p. 19).

ChargePoint supported Georgia Power's proposal to invest in EV charging facilities and infrastructure upgrades, as long as site hosts that participate in the make ready and community charging infrastructure programs continue to be able to choose their preferred charging equipment. (ChargePoint Brief, p.1).

Sierra Club recommended that the Company's investment in EV charging infrastructure is reasonable and prudent and should be approved. They stated the Make Ready Program will benefit all ratepayers, is in the public interest, and the need will not be met by private investors. Sierra Club asserted that the Make Ready Program also supplies the infrastructure that the Clean School Bus Program does not cover. Sierra Club argued that Governments across the state are transitioning to electric vehicles and providing the public for access points to charge would be in the public interest. (Direct Testimony of C. Nicholas Deffley and David Nifong p. 4.)

Resource Supply Management recommended the Company not be allowed to compete with private investors who do not receive subsidization from other non-EV user and that the new EV rate should be available to both new and existing customers. (RSM p. 3).

At the December 20, 2022 Administrative Session, Commissioner Echols offered a motion modifying the Stipulation. The motion modified paragraph 32 of the Stipulation such that the EV Make Ready Program shall be approved at 65% of the Company's requested budget level. This increased the Proposed Agreement from 25% of the requested budget to 65% of the requested budget. The motion was approved unanimously. The Commission finds that Commissioner Echols' Motion offers a just and reasonable outcome to this issue.

Commissioner Echols' motion also amended the Electric Transportation program Term Sheet to include "franchise automobile dealers" in part one under Public Facing Projects. The Company shall file a revised Term Sheet to reflect this addition within 30 days of the date of this order.

34.

The Proposed Agreement includes a provision that the monthly netting pilot will remain capped at 5,000 customers. The Proposed Agreement further states that the 5,000 customers currently on monthly netting will be grandfathered for 15 years effective January 1, 2023.

To address the potential for continued behind the meter consumer complaints the Company and Staff agreed to collaborate with interested stakeholders to determine whether a more formal framework for the Commission's referral of consumer complaints to the Consumer Protection Division of the Georgia Attorney General's Office is needed. The Proposed Agreement states Staff

and the Company may make recommendations to the Commission as deemed appropriate for improvements in the process. Further, Staff and the Company shall also continue to review additional ways to improve consumer protection.

During the hearings, Staff recommended that the Commission remove the cap on Renewable and Non- Renewable ("RNR") Monthly-Netting.

GIPL recommended the Commission expand the monthly netting program for rooftop solar customer suggesting the Commission limit participation to 3% of the Company's 2021 peak load and revisit the program when participation approaches the limit. (GIPL Brief p. 13).

SACE and Southface urged the Commission to reinstate the RNR monthly netting uncapped for three years during which time the Company must: a) hold workshops with relevant stakeholders to: (i) consider alternative compensation rates for excess generation; (ii) monitor industry developments and local consumer protections; and (iii) engage with and educate Georgia Power's customers on the benefits of behind-the-meter solar and the recently restored 30% investment tax credit available to Georgia's taxpayers; b) conduct a cost-of-service study and provide it to Commissioners, PSC Staff, and interested stakeholders prior to the 2025 Rate Case; and c) reduce the proposed interconnection fee for the RNR tariff to the $100 recommendation of PIA Staff and waive this fee for income-qualified customers. (SACE Brief p.5).

GA Solar recommended that the Commission both continue and expand the Company's monthly netting program.

The Coalition urged the Commission to maintain monthly netting for three years and initiate a collaborative stakeholder process to determine a future successor tariff. (Coalition Brief p. 7)

The Commission finds that continuation of the cap on the number of participants on the monthly net metering program as set forth in the Proposed Agreement is just and reasonable.

35.

The Commission finds that increasing the Income Qualified Senior Citizen Discount by $6 per month, as included in the Proposed Agreement (Provision 34), is just and reasonable as there has not been an increase to the discount in several years.

36.

Provision 36 of the Proposed Agreement states that the Company's ASR filings Operating Income statement (Section 2 Page 2) will include a separate line item for fuel in Operating Revenues and Operating Expenses. The Company will modify future ASRs Average Rate Base (Section 2 Page 1) to include the following separate line items under Plant-in-Service: Steam – Coal, Steam – Gas, Combined Cycle, Combustion Turbine, Solar, and Other. In order to effectuate an efficient filing of the ASR, the Commission finds this reasonable.

37.

The Commission finds it appropriate that the Company be required to file semi-annual reports on the GIP starting with the period January 1 – June 30, 2023. Staff and the Company will collaborate on the formatting and content of these reports. Staff and the Company will agree to collaborate on what, if any, additional reporting is necessary to address transmission and distribution capital investment. (Provision 37).

38.

In conjunction with the ongoing level of review and analysis required by this Proposed Agreement (Provision 38), Georgia Power will agree to pay for any reasonably necessary specialized assistance to Staff in an amount not to exceed $400,000 annually. This amount paid by Georgia Power under this Paragraph shall be deemed as a necessary cost of providing service and the Company shall be entitled to recover the full amount of any costs charged to the utility. Due to the high costs associated with the ongoing review and analysis needed by the Proposed Agreement, the Commission finds this provision just and reasonable.

39.

GAM witness Pollock testified that the Commission should consider any and all innovative ways to reduce rate impacts for customers while still providing for the financial integrity of Georgia Power. GAM testified to the benefits of securitization financing that could help address some of the extraordinary costs like coal ash cleanup and early coal plant retirement when plants are no longer used and useful. Mr. Pollock described securitization thusly:

Securitization is a financing mechanism that provides timely recovery of certain regulatory assets by issuing a type of debt that would significantly lower the carrying costs of the assets relative to the costs that would be incurred using traditional ratemaking practices. Specifically, a special purpose entity would be created whose sole purpose is to issue transition bonds that are used solely for purposes of reducing the amount of recoverable regulatory assets and any other amounts as determined by the Commission through the refinancing or retirement of utility debt or equity. This special purpose entity would be entitled to the revenues collected by the utility through a separate cost recovery mechanism in an amount sufficient to timely recovery of the debt services associated with securitization bonds.

GAM noted that Securitization legislation was introduced in the 2022 Session of the General Assembly and is likely to be introduced again. In addition to providing up-front cash recovery of costs to Georgia Power, GAM contended, securitization can benefit ratepayers by significantly reducing rate impacts on both a nominal and net-present-value basis. (Pollock Direct Testimony, pp. 11-12).

Resource Supply Management recommended that the Commission cut revenues by disallowance rather than by allowing securitization. They state that most companies would be forced to write off obsolete and non-useful assets.

The Proposed Agreement does not include this adjustment and the Commission finds that the Settlement Agreement as Modified is reasonable as a whole. Additionally, the Commission notes that there is currently no securitization statute applicable. Therefore, GAM and Resource Supply Management's recommendations are denied.

40.

One of the issues that the Proposed Agreement left to Commission discretion was the amount the Company would agree to pay for excess generation for RNR customers.

Staff stated that if the Commission decides that it would prefer instantaneous net metering, that the rate the Company pays for excess generation be set at the retail rate less 3 cents per kWh beginning January 1, 2023. During the hearings, Staff stated that this issue is a policy decision for the Commission. (Staff Brief p. 24)

SACE/Southface recommended that the Commission pay for excess distributed generation to the grid to be paid at retail rate. (SACE/Southface Brief p. 7).

The Coalition recommended that if the Commission proposes a solution other than monthly netting, it should offer additional support to low- and moderate-income customers, such as a low-income adder or rebate.

In their Brief, GIPL raised an argument claiming that the Georgia Cogeneration and Distributed Generation Act of 2001 O.C.G.A. § 46-3-50 et seq. ("Cogen Act") required monthly netting. After thoroughly reviewing this argument, the Commission has determined that this is not the case. While the Cogen Act allows for monthly netting, it does not require it. O.C.G.A. § 46-3-55(1)(B) states that "[w]hen the electricity supplied by the electric service provider exceeds the electricity generated by the customer's distributed generation, the electricity shall be billed by the electric service provider, *in accordance with tariffs filed with the commission.*" (emphasis added). The idea that if instantaneous netting were contemplated the bill would be written to make separate calculations between imports and exports of electricity is simply unfounded. The General Assembly made clear that these calculations can be made in accordance with tariffs filed with the Commission. *(Id.)*

O.C.G.A. § 46-3-55(1)(B), states that "the electricity" is billed in accordance with the tariffs. It does not restrict that to only "the *net* electricity." If the Commission were to determine, for instance, that over the course of each month the value of the electricity being placed on the system was the same as the cost of the electricity being provided by the system, monthly netting might be a reasonable way to design the tariff. But, that is not the case here. In this case, the Commission finds that monthly netting would overvalue the electricity that the customer is placing

on the Company's system just as paying only avoided cost would undervalue it. Simply put, monthly netting is a possible way to structure the tariff; but, it is not the only way to structure the tariff.

GIPL also states that by using the term "billing period" in O.C.G.A. § 46-3-55 (1)(A), the General Assembly also meant that monthly netting is the only choice. However, this section does not address how the charge for the electricity that is measured during the billing period is actually calculated. O.C.G.A. § 46-3-55(1)(B) lays out the method for billing that amount of electricity which is measured, in accordance with tariffs filed with the Commission.

At the December 20, 2022 Administrative Session, Commissioner Shaw made a motion that for current and new customers on instantaneous net metering, the Company shall pay avoided cost plus an additional amount of 4 cents per kWh for excess generation beginning January 1, 2023. The additional amount shall be in place for three years and will be reviewed in the Company's 2025 base rate case. Prior to the next rate case, Staff and the Company shall collaborate to determine whether a monthly minimum bill for customers on the RNR tariff is appropriate. The motion was approved unanimously. After a thorough review of the arguments, the Commission finds that this motion represented a just and reasonable resolution to this issue.

41.

Georgia Power's basic service charge was moved to cost in the last rate case for PLM, customer-related costs for PLM have also increased since that time. The Kroger Co. claimed if the basic service charge for PLM is not increased in this proceeding it will no longer recover one hundred percent (100%) of customer-related costs and the PLM basic service charge will be too low relative to the PLM other rate elements, from a cost-of-service perspective. Therefore, Kroger contended that it is appropriate to apply a modest increase to the basic service charge along with the hours use energy/demand charges in this case in order to set the basic service charge for PLM at, or close to, cost. (Kroger Brief p.2).

The Proposed Agreement does not include this adjustment and the Commission finds that the Settlement Agreement as Modified is reasonable as a whole. Therefore, the Kroger Co.'s recommendation is denied.

42~~3~~.

With respect to Schedule Time of Use – Residential Demand ("TOU-RD") Staff and numerous intervenors all proposed the same or similar recommendations. Staff, GIPL, and other intervenors all submitted extensive testimony demonstrating that TOU-RD has been significantly more expensive for customers than other available rates and that demand rates are inferior to volumetric time-of-use rates for providing efficient and actionable price signals to residential customers. For example, GIPL Expert Witness Barnes demonstrated that Georgia Power's TOU-RD customers paid on average about $16/month more than they would have on the Schedule R tariff. Mr. Barnes's analysis showed that on an annual basis, the TOU-RD rate is roughly 4.8

cents/kWh higher than the average of other rates – a significant deviation considering that Georgia Power's average residential rate is about 13.9 cents/kWh. (GIPIL Brief, pp, 8-9).

GIPIL encouraged the Commission to order the Company to return to using the basic volumetric residential tariff, Schedule R, as the default rate and halt use of the complicated demand charge tariff, TOU-RD, as the default tariff for new residential premises. In the alternative, if the Commission prefers a time-varying rate as the default for new premises, it should set the time-of-use nights & weekends tariff, Schedule TOU-REO. (GIPIL Brief p. 2-3).

Georgia Watch stated that the residential R-tariff should remain the default rate for all customers. Customers in newly constructed dwellings already defaulted onto the Company's TOU-RD rate should receive notification of the likelihood they have or will experience higher bills due to the flawed design of this rate. (Georgia Watch Brief p. 2).

The Coalition asserted that if the TOU-RD rate is maintained, it should not be the default for any customers, should be fully optional, and should be adjusted so that the demand charge will only apply to peak hours (i.e. between 2 pm and 7 pm on non-holiday weekdays between June and September). Additionally, the Coalition supported PIA Staff's recommendation that the Company be ordered to create a rate comparison tool for all residential customers to better enable them to select the best rate for their usage and demand profile. (Coalition Brief p. 13)

The Proposed Agreement does not include the adjustment to the Schedule TOU-RD and the Commission finds that the Settlement Agreement as Modified is reasonable as a whole. Therefore, the intervenors' recommendations to adjust the rate are denied. However, the Commission is setting the R rate as the default rate.

43.

SACE recommended the Commission order Georgia power to identify, track, secure federal funding to lower costs to ratepayers across the proposed three-year ARP, during which time, the Company must:

a. Provide annual reviews of revenue requirements that identify cost savings available from federal funding in 2024 and 2025, within the three-year ARP.
b. Adopt an annual step increase with annual review and adjustment for savings from federally available funds instead of locking into the proposed levelized increase.
c. Develop federal funding tracking processes – agreed upon by the Commission and in collaboration with PIA Staff – which include anticipated funding as well as actual and estimated costs and benefits to customers and the Company.
d. Provide tax and other savings to benefit customers, including to offset anticipated rate and bill increases during the 2023-2025 period. (SACE Brief p. 6)

SACE recommend the Commission exempt low-income residential customers – at or below 200% of the Federal poverty level – from any rate increase associated with Plant Vogtle. SACE maintains that the Commission should consider the historic, disproportionate allocation of the Nuclear Construction Cost Recovery ("NCCR") rider when deciding the allocation of the rate increase it considers most equitable. (SACE Brief p. 6-7).

The Proposed Agreement does not include these adjustments and the Commission finds that the Settlement Agreement as Modified is reasonable as a whole. Therefore, SACE's recommendations are denied. While the Commission has not made a low-income adjustment specific to Plant Vogtle in this order, the Commission has increased the senior low income assistance.

44.

The Coalition recommended that the Commission direct the Company to replace or reprogram residential and commercial meters as needed to collect Hourly Usage Data with all reasonable haste and at the Company's cost. The Coalition stated it is not opposed to the limited exceptions defined by the Company in its rebuttal testimony. The Coalition also recommended that the My Power Usage platform be modified to make it easier for customers to export data in bulk (i.e. 8760 format as a .csv file). (Coalition Brief p. 9).

During the December 20, 2022 Administrative Session, Commissioner Johnson made a motion that the Company shall open a docket in calendar year 2023 to provide all residential and commercial customers with access to hourly usage data. This new docket should provide the cost to access data and an implementation timeline. The motion further ordered to the Company to replace or reprogram meters as necessary to ensure hourly interval data is easily accessible to all customer classes with Advanced Metering Infrastructure ("AMI") meters. This data would need to be exportable in bulk in a usable format, such as a .csv file. The motion states that this order will not apply to customers that have opted out of an AMI meter, unmetered accounts, Special Service accounts, or RTP customers. The Commission voted to approve this motion unanimously. The Commission finds that this requirement would be in the public interest and reasonable.

45.

The Commission finds that a three-year term for the Settlement Agreement as Modified ending December 31, 2025 is reasonable. By July 1, 2025, the Company shall file testimony and exhibits required in a general rate case along with supporting schedules required by the Commission to support a "traditional" rate case. The test period utilized by the Company in its rate case filing shall be from August I, 2025 to July 31, 2026. The Company may propose to continue, modify or discontinue this Alternate Rate Plan. The Company shall also file projected revenue requirements for calendar years 2026, 2027, and 2028. (Proposed Agreement, Provision 35).

V. CONCLUSIONS OF LAW

1.

The Georgia Public Service Commission has general ratemaking jurisdiction over Georgia Power Company under O.C.G.A. Ch. 2, T. 46. The Georgia Public Service Commission has general supervision over electric light and power companies. O.C.G.A. §§ 46-2-20(a) and 46-2-21. The Commission has "exclusive power to determine what are just and reasonable rates and charges to be made by any person, firm, or corporation subject to its jurisdiction." O.C.G.A. § 26-2-23; see also O.C.G.A. §§ 46-1-1(5), 46-2-24, 46-2-25, 46-2-26.1, and 46-2-26.2.

2.

The Settlement Agreement as Modified complies with the test year statute for electric utilities which provides in relevant part:

> *In any proceeding to determine the rates to be charged by an electric utility, the electric utility shall file jurisdictionally allocated cost of service data on the basis of a test period, and the commission shall utilize a test period, consisting of actual data for the most recent12- month period for which data are available, fully adjusted separately to reflect estimated operations during the 12 months following the utility's proposed effective date of the rates. After the initial filing and until new rates go into effect, the utility shall file actual cost of service data as they become available for each month following the actual data which were filed. The utility shall have the burden of explaining and supporting the reasonableness of all estimates and adjustments contained in its cost of service data.*

(O.C.G.A. § 46-2-26.1(b))

Georgia Power filed the requisite data on the basis of a test period, and the Settlement Agreement as Modified uses the test period as a starting point and then makes necessary and appropriate adjustments to reflect operations during the 12 months following the utility's proposed effective date of the rate. The test period data serves as the benchmark from which adjustments are made for each year of the Alternative Rate Plan. This methodology is consistent both with the statute and with Commission precedent in rate case proceedings dating back to 1998.

3.

The rates resulting from the Settlement Agreement as Modified are fair, just and reasonable. By adopting the Settlement Agreement as Modified, the Commission retains its jurisdiction to ensure that the Company's rates are fair, just and reasonable.

4.

The remaining terms and conditions of the Settlement Agreement as Modified are reasonable and appropriate. By adopting the Settlement Agreement as Modified, the Commission adopts a reasonable resolution of the remaining issues in this docket.

5.

The Georgia Cogeneration and Distributed Generation Act of 2001 O.C.G.A. § 46-3-50 et seq. ("Cogen Act") allows for monthly netting; however, it does not require it.

6.

The Commission retains its jurisdiction to ensure that the Company abides by and implements the rates, terms and conditions set forth in the Settlement Agreement as Modified adopted herein, and to issue such further order or orders as this Commission may deem proper.

VI. ORDERING PARAGRAPHS

WHEREFORE, IT IS ORDERED, that the Settlement Agreement as Modified shall be and the same hereby is adopted, that its terms and conditions are fully incorporated herein, and that Georgia Power Company shall comply with said terms and conditions.

ORDERED FURTHER, that the terms and conditions set forth in the Settlement Agreement as modified are just and reasonable and shall take effect for service rendered from and after January 1, 2023.

ORDERED FURTHER, that the tariffs implemented by Georgia Power to implement the aforesaid annual rate increase in the years 2023, the adjustments contemplated in 2024 and 2025, as well as the terms and conditions of the Settlement Agreement as Modified shall be subject to review by the Commission to ensure that such tariffs, as implemented, are proper and just.

ORDERED FURTHER, that for purposes of the rate increase in the year 2023, Georgia Power shall file compliance tariffs within 30 days of the issuance of this Order, reflecting rates to implement the rate increases ordered herein. These tariffs shall reflect the rate allocations adopted in this Order and shall be subject to the Commission's review for final approval. Contemporaneous with the filing of the compliance tariffs, the Company shall file any updates to the traditional base rate tariff adjustments or MFF adjustments as a result of the change in the EV Make Ready approval amount as provided in Paragraphs 5 and 8 of this order.

ORDERED FURTHER, that for purposes of the rate adjustments specified in the Settlement Agreement as Modified, the Company shall make compliance filings of the updated

tariffs at least 90 days prior to the effective date of the tariffs. Compliance filings shall be served upon all parties of record to this proceeding. Upon receipt of such compliance filing, parties may offer input relative to the filing to the Commission.

ORDERED FURTHER, that all findings, conclusions and decisions contained within the preceding sections of this Order are adopted as findings of fact, conclusions of law, and decisions of regulatory policy of this Commission.

ORDERED FURTHER, that jurisdiction over this proceeding is expressly retained for the purpose of entering such further order or orders as this Commission may deem proper.

ORDERED FURTHER, any motion for reconsideration, rehearing, or oral argument shall not stay the effectiveness of this order unless expressly ordered by the Commission.

The above by action of the Commission in Administrative Session on the 20th of December 2022.

Sallie Tanner
Executive Secretary

12-30-22
Date

Tricia Pridemore
Chairman

12-30-22
Date

Attachment 1

SETTLEMENT AGREEMENT

Georgia Power Company's 2022 Rate Case

Docket No. 44280

Georgia Power Company ("Georgia Power" or the "Company") and the Public Interest Advocacy Staff ("Staff"), along with the undersigned Stipulating Parties, agree to the following Alternate Rate Plan ("ARP"), which shall commence January 1, 2023, and shall continue through December 31, 2025. This Stipulation is intended to resolve all issues in this case except (1) the earnings band to be applied for Annual Surveillance Report ("ASR") purposes, (2) pricing for the Community Solar program, as described in Paragraph 28, and (3) the additional amount to be paid for export energy pursuant to the RNR tariff, as described in Paragraph 33. The Stipulating Parties leave these three issues for the Commission to decide. Other than these issues, the Company's filing is accepted as filed with the following modifications:

1. Increases to base rate tariffs shall not be levelized but adjusted each year of the ARP.

2. The Company's retail revenue requirement shall be calculated using a total return on investment of 7.43% in 2023, 7.46% in 2024, and 7.49% in 2025, which incorporates an equity ratio of 56% and a return on equity ("ROE") of 10.50%.

3. For the purposes of settlement and compromise, the Company's filing is approved with the following modifications to the revenue requirement. No ratemaking policy or precedent is being set as it pertains to the issues on which the Stipulating Parties disagreed, and the resolution of this case does not suggest that a specific position, policy, or precedent is being adopted by the Stipulating Parties or the Commission on such issues. The agreed upon adjustments to the Company's request are set forth in the values in the table below and detailed on Exhibit A. The agreed upon adjustments by category and amount include the following:

    a. The Company agrees to reduce the requested Grid Investment Plan ("GIP") spend by 40% over the term of this ARP, as shown in the table below and on Exhibit A.

    b. The Company agrees to reduce EV Make Ready spend by 75% over the term of this ARP, as shown in the table below and on Exhibit A.

    c. The Company will not move forward with a full Distributed Energy Resource Management System ("DERMS") at this time. To prepare the electric system for higher levels of distributed energy resources ("DER"), the Company will be allowed to begin the following

preliminary steps, which will include system modifications to allow for modeling and visibility of DER, integration of these modifications with the Company's real-time operations platforms such as EMS, DMS, and SCADA, and the establishment of DER remote configuration capabilities. The Company will report back to the Commission in the 2025 Integrated Resource Plan on the development of these systems and the need for any further system modifications to plan for DER integration. The investments made pursuant to this Paragraph will be amortized over 10 years.

d. In addition to the categories listed in the table below, Staff recommended several other adjustments to operations and maintenance ("O&M") expenses in this case. The Stipulating Parties agree that the only specific adjustments being made are those identified in the table below. For purposes of settlement and compromise, the Company agrees to further reduce the revenue requirement associated with miscellaneous O&M expenses by $30 million each year, which is not allocated to any particular expense.

Exhibit A

	Stock-Based Compensation	Ln 21
	Energy Direct Premium Packages	Ln 4
	Executive Financial Planning	Ln 7
	O&M Scrap Sales Proceeds	Ln S
	Wireless Co-Location Revenues (80/20 sharing)	Ln 6
	Depreciation Expense and Accumulated Depreciation - New Depreciation Rates	Lns 10 - 14
	Depreciation Expense Reduction for Plant Scherer Units 1-3 and common, and Plant Bowen Units 1-2 (12 years)	Ln 9
	Reduce projected Storm Damage Accrual to $31M per year	Ln 20
	CCR ARO recovery methodology to remain consistent with the 2019 base rate case Order except for a four, rather than three, year amortization period.	Ln 18
75%	Electric Vehicle Make Ready Program	Ln 19
75%	O&M Expense - Electric Vehicle Make Ready Program	Ln 19
40%	Grid Investment Plan (Transmission and Distribution Plant Investment), and related Depreciation Expense and Accumulated Depreciation and ADIT	Ln 16

60%	Preliminary system modifications for Distributed Energy Resource Management System (DERMS) and related Amortization (10-years) and Accumulated Amortization and ADIT	Ln 17
	Depreciation Expense - Depreciation Rates Correction for Ft Benning and Ft Gordon	Ln 15
	Property Tax Expense	Ln 22
	Income Tax Credits Related to the Inflation Reduction Act, including Commission approval to opt out of normalization requirements for specified battery energy storage facilities	Ln 8

4. Effective January 1, 2023, traditional base tariffs shall be adjusted to collect $192 million, with additional adjustments in 2024 and 2025 of $273 million and $314 million, respectively.

5. Effective January 1, 2023, it is estimated that the Environmental Compliance Cost Recovery ("ECCR") tariff will be adjusted for traditional ECCR costs to reduce collections by $7 million, and adjusted to reduce collections by an additional estimated $35 million effective January 1, 2024, and an additional estimated $9 million effective January 1, 2025. Additionally, effective January 1, 2023, it is estimated that the Coal Combustion Residual Asset Retirement Obligations ("CCR ARO") costs recovered in the ECCR tariff shall be adjusted to reduce collections by $13 million, and adjusted to collect an additional $101 million effective January 1, 2024, and an additional estimated $90 million effective January 1, 2025. The process for revising these estimates is described in Paragraph 8 (a) and (b). As approved in the 2019 base rate case order in Docket No. 42516, ECCR shall continue to include the cost for compliance with CCR ARO. The projection of CCR ARO cost will be updated in 2023 and 2024 through compliance filings to set the actual ECCR tariff rates for 2024 and 2025. The Commission reserves the ability to make prudency determinations on the Company's coal ash related costs.

6. Effective January 1, 2023, Georgia Power shall collect an additional $37 million through the Demand Side Management ("DSM") tariffs, and as adjusted during the term of this ARP based on the DSM true up process agreed to by the Company and Staff with a projected increase of $27 million effective January 1, 2024, and a projected decrease of $2 million effective January 1, 2025.

7. Effective January 1, 2023, the Municipal Franchise Fee ("MFF") tariff will be increased to collect an additional $5 million effective January 1, 2023, an additional estimated $9 million effective January 1, 2024, and an additional estimated $9 million effective January 1, 2025, which dollar amount will change as total revenue adjustments change as allowed by this ARP, as well as with any future Fuel Cost Recovery ("FCR") changes and future Nuclear Construction Cost Recovery ("NCCR") changes.

8. Consistent with the 2019 base rate case order in Docket No. 42516, for purposes of the 2024 and 2025 rate adjustments, the Company shall make compliance filings of the updated tariffs at least

ninety (90) days prior to the effective date of the tariffs. The Company's compliance filings will include the following updates:

a) Effective January 1, 2024, (i) the traditional base tariffs shall be adjusted to collect an additional $273 million; (ii) the ECCR tariff shall be adjusted based upon the Compliance filing with updated CCR ARO costs as filed in the most recent semi-annual report for calendar year 2023; (iii) the DSM tariffs shall be adjusted to reflect the DSM costs for calendar year 2024 as approved in Docket No. 44161 and as adjusted based on the DSM true up process agreed to by the Company and Staff; and (iv) the MFF tariff shall be adjusted to collect the MFF cost incurred by the Company. The 2024 increase to traditional base rate tariffs, ECCR tariff, and DSM tariffs will use the most current kWh sales forecast for the applicable year to set the rates.

b) Effective January 1, 2025, (i) the traditional base tariffs shall be adjusted to collect an additional $314 million; (ii) the ECCR tariff shall be adjusted based upon the Compliance filing with updated CCR ARO costs as filed in the most recent semi-annual report for calendar year 2024; (iii) the DSM tariffs shall be adjusted to reflect the DSM costs for calendar year 2025 as approved in Docket No. 44161 and as adjusted based on the DSM true up process agreed to by the Company and Staff; and (iv) the MFF tariff shall be adjusted to collect the MFF cost incurred by the Company. The 2025 increase to traditional base rate tariffs, ECCR tariff, and DSM tariffs will use the most current kWh sales forecast for the applicable year to set the rates.

9. For Annual Surveillance Reporting ("ASR") purposes, beginning January 1, 2023, the earnings band shall be set at __% to __% ROE and the Company shall report earnings based on the actual historic cost of debt and capital structure described in Paragraph 2. The Company will not file a general rate case unless its calendar year retail earnings are projected to be less than the bottom end of the band.

10. Subsequent to finalization of Staff's review of the respective ASR, any excess retail revenues above the top end of the earnings band will be shared, with seventy percent (70%) being applied to regulatory assets in the following priority: Accumulated CCR ARO; Retired Generating Plant; and Obsolete Inventory, ten percent (10%) being directly refunded to customers, allocated on a percentage basis to all customer groups including the base revenue contribution of RTP incremental usage, and the remaining twenty percent (20%) retained by the Company.

11. The Company will make its ASR filings for this ARP by March 15th of the following year. The Commission will consider the ASR filing and determine any direct refunds and reduction of regulatory assets by December 31st of that year.

12. The Company anticipates sharing revenues above the approved ROE band for 2022 with customers under the current ARP. For purposes of settlement, the Company will expedite sharing to provide the return of the estimated amount of customer sharing in the first quarter of 2023. Any revision, if needed, to the estimated amount of sharing will be adjusted once the Commission

finalizes its review of the 2022 ASR. The customers' portion of sharing shall be applied in the manner ordered in the 2019 rate case in Docket No. 42516.

13. For book accounting and ASR purposes, the schedule for the Nuclear Decommissioning Trust - Tax Funding (reference the attached "Proposed Supplemental Order - Nuclear Decommissioning Costs") shall be approved.

14. Any additional tax benefits related to the Inflation Reduction Act, the Infrastructure and Investment Jobs Act, or any additional state or federal regulations shall accrue as a regulatory liability.

15. In the event that the Company determines that an asset is impaired or the Commission approves the retirement of a retail generation asset as a result of any environmental regulation or legislation, the Company may request that costs associated with such impairment or retirement be deferred as a regulatory asset.

16. The Interim Cost Recovery ("ICR") mechanism as initially approved in the 2010 Rate Case in Docket No. 31958 is continued throughout the term of this ARP utilizing the earnings band set by the Commission in this case.

17. Beginning in 2023, with the adjustment to traditional base rate tariffs, except as otherwise provided in this Stipulation, the rate increase shall be applied to each traditional base rate on an equal percentage basis. The energy, demand, and basic service charge components of each base rate shall all be adjusted equally. Except as otherwise provided in this Stipulation, the Company will not apply any increase to the basic service charges for the tariffs that had this component adjusted to the full amount of the customer-related costs in the 2019 base rate case or apply an increase to the basic service charge for the domestic and small business rate groups.

18. Tariffs within the Medium and Large Business rate groups will receive an equal adjustment to the energy, demand, and basic service charge components.

19. The Electric Transportation ("ET") tariff will be allocated 50% of the base rate increase. The revenue deficiency for this adjustment will be accounted for within the Government/Institutional tariff group.

20. To move the Medium Business and Large Business rate groups closer to parity, beginning in 2023, rates in the Medium Business and Large Business rate groups will receive 85% of the overall base rate increase with the resulting revenue deficiency being spread to other rate groups excluding the Small Business, Lighting, Agricultural, and Marginal Rate groups, which will receive the overall base rate increase.

21. The Company agrees to work with the Department of Defense to investigate a Backup rider for customers on the Real Time Pricing rate who install customer-owned generation that normally

operates at least 6,000 hours per year. The Company will meet with the DOD within 90 days of the final Order in the case to begin that collaboration

22. The Residential Service tariff ("R rate") will be the default rate for all residential premises.

23. The Company will maintain the R rate as a rate option available to all residential customers. In addition, there will be an elimination of the declining-block rates during the non-summer months to a flat rate for all kWh usage. The relationship between the summer and non-summer base rate energy charge revenues will be maintained.

24. The Stipulating Parties agree that within ninety (90) days of the Final Order in this docket, the Company and Staff will collaborate on a process to consider potential options for the expansion of income qualified discount opportunities to assist customers. This process will allow for interested stakeholders to provide input on the options to be considered. Stipulating Parties further agree that within 270 days of the Final Order in this docket, the Company, after considering input from interested stakeholders, will report back to the Commission on their findings and may recommend additional action. Any potential program options must consider cost impacts to non-participating customers as well as the impacts of any revenue erosion.

25. The Company will agree to file quarterly reports regarding the location, peak demand, usage, and revenue of the Charge It Electric Vehicle rider.

26. The Company will withdraw proposed Section F.9 of the Company's Rules and Regulations for Electric Service and will work with the Georgia Association of Manufacturers and Staff to identify alternative language, which will be filed with the Company's compliance filing in this case.

27. The interconnection fee found in Section G of the Company's Rules and Regulations for Electric Service for customer generators smaller than 250 kW will be $100 for residential customers and $200 for commercial and industrial customers. The Company's proposed modification to the language in Section G.3 will limit the Company's communication with and control of the customer's generator to those capabilities provided in IEEE 1547-2018 (or as it is subsequently amended) and will only apply to new interconnecting customer generators at or above 250 kW and existing interconnected customer generators who expand or modify their generation facility.

28. Regarding the pricing for the Community Solar program, the Stipulating parties agree that this is a policy issue for Commission determination. Depending on the Commission's intent for the program, it can adopt either the Company's proposed $27.99 per block for residential customers and $29.99 for commercial customers or Staff's proposed $20 per block for residential customers and $22 for commercial customers.

29. The Time of Use – Food and Drink ("TOU-FD") rate shall remain available to all food services and drinking places identified as 722 of the North American Industry Classification System ("NAICS") through December 31, 2025. During the term of the ARP, qualifying food services and drinking

places will be accepted on TOU-FD on a first come, first allowed basis until the number of accounts on the rate equals 6,000. Any revenue erosion from the TOU-FD rate conversion during the term of the ARP will be captured in a regulatory asset account and recovered through rates in 2024 and 2025. All revenue loss resulting from the implementation of this provision shall be recovered by the Company from the TOU-FD rate.

30. The Company will continue to make the Time of Use Residential Energy Only ("TOU-REO") rate available to customers.

31. The Company agrees to rename the TOU-PEV tariff to clarify the broad availability of the tariff to Residential customers that do not own an electric vehicle.

32. The Company's collective Electric Transportation program proposed in this case for investments in community electric vehicle ("EV") charging facilities and electric transportation infrastructure upgrades to support customer EV charging (i.e., Make Ready, infrastructure maintenance, administrative costs, Community Charging, and rebates) is approved, provided however, that the EV Make Ready program shall be approved at 25% of the requested budget level, and the program shall be modified to prioritize electrification of public fleets and publicly available charging. The Make Ready program will now allow EV charging providers to participate under the following conditions: (i) they have the permission of the site host customer to operate on the site host customer's premises; (ii) they will coordinate with the site host and Georgia Power for purposes of the Make Ready program; (iii) Georgia Power is able to obtain all required easements and any other rights required to implement the Make Ready program; and (iv) Georgia Power retains final approval of Make Ready project design. In addition, Make Ready criteria and terms and conditions will be available on Georgia Power's website. A Term Sheet detailing the operation of the Company's Electric Transportation program is attached to this Stipulation. The Company agrees to develop reporting requirements for the Electric Transportation program to keep the Commission informed of the program's progress. The Company also agrees that charger locations under the Community Charging component of the program will be subject to a right of first refusal for private EV charging providers and further agrees to establish publicly available criteria for the Company's Community Charging locations as detailed in the Term Sheet. The Charge It Electric Vehicle rider is approved and will be available to all existing and new EV charging providers. Additionally, the Company will work with Staff and the EV parties signing the Stipulation to review and design an alternate commercial EV rate in addition to the Charge It Electric Vehicle rider, which will enable the Company to collect the costs to provide electric service to EV charging providers through a transparent pricing structure and support the growth of EV commercial charging investments. The alternative design should primarily collect costs through a volumetric structure, but may also allow for some collection of costs – such as distribution costs – through demand charges. In developing the rate, the parties will consider a variety of rate designs to ensure the best rate solution is developed. The Company will file an alternative EV charging rate within six months of the execution of the Final Order in this docket. The Company's Electric Transportation program and alternative charging rate(s) will be reviewed by the Commission in the next base rate case.

33. The monthly netting pilot will remain capped at 5,000 customers. The 5,000 customers currently on monthly netting will be grandfathered for 15 years effective January 1, 2023. For current and new customers on instantaneous net metering, the Company agrees that it shall pay avoided cost plus an additional amount of __ cents per kWh for excess generation beginning January 1, 2023. The additional amount shall be in place for three years and will be reviewed in the Company's 2025 base rate case. Prior to the next rate case, Staff and the Company shall collaborate to determine whether a monthly minimum bill for customers on the RNR tariff is appropriate.

    To address the potential for continued behind the meter consumer complaints the Company and Staff agree to collaborate with interested stakeholders to determine whether a more formal framework for the Commission's referral of consumer complaints to the Consumer Protection Division of the Georgia Attorney General's Office is needed. Staff and the Company may make recommendations to the Commission as deemed appropriate for improvements in the process. Staff and the Company shall also continue to review additional ways to improve consumer protection.

34. The Income Qualified Senior Citizen Discount will be increased by $6 per month.

35. By July 1, 2025, the Company shall file testimony and exhibits required in a general rate case along with supporting schedules required by the Commission to support a "traditional" rate case. The Company will collaborate with Staff to determine what additional supporting materials for revenue estimates will be provided at the time of filing. The test period utilized by the Company in its rate case filing shall be from August 1, 2025, to July 31, 2026. The Company may propose to continue, modify, or discontinue this ARP. The Company shall also file projected revenue requirements for calendar years 2026, 2027, and 2028.

36. The Company's Annual Surveillance Review ("ASR") filings Operating Income statement (Section 2 Page 2) will include a separate line item for fuel in Operating Revenues and Operating Expenses. The Company will modify future ASRs Average Rate Base (Section 2 Page 1) to include the following separate line items under Plant-in-Service: Steam – Coal, Steam – Gas, Combined Cycle, Combustion Turbine, Solar, and Other.

37. The Company will be required to file semi-annual reports on the GIP starting with the period January 1 – June 30, 2023. Staff and the Company will collaborate on the formatting and content of these reports. Staff and the Company will agree to collaborate on what, if any, additional reporting is necessary to address transmission and distribution capital investment.

38. In conjunction with the ongoing level of review and analysis required by this agreement, Georgia Power will agree to pay for any reasonably necessary specialized assistance to Staff in an amount not to exceed $400,000 annually. This amount paid by Georgia Power under this Paragraph shall be deemed as a necessary cost of providing service and the Company shall be entitled to recover the full amount of any costs charged to the utility.

Attachment 2

Electric Transportation Programs Term Sheet

12/20/2022

Make Ready

- For purposes of prioritizing Make Ready funding, the Company will place Make Ready projects into two groups – (1) Public Facing Projects and (2) Other EV Projects – and provide Make Ready funding to each group as described below:

1. **Public Facing Projects**
    - Public Facing Projects are projects that involve infrastructure to support (i) EV charging in public locations (e.g., grocery store parking lots, malls, gas stations and convenience stores) and (ii) the electrification of public fleets (e.g., MARTA, public school buses).
    - Consistent with how the Make Ready Program works today, Public Facing Projects would be funded at 100% of the Make Ready costs, which would include funding for the charging panel.
    - The customer would then be responsible for funding the chargers.

2. **Other EV Projects**
    - Funding shall be first made available to Public Facing Projects prior to funding Other EV Projects.
    - Other EV Projects represent projects that are *not* associated with public chargers or electrification of public fleets; rather, these are projects where an entity (for example, Amazon or UPS) installs chargers on their *private* property to assist with the electrification of their *private* EV fleet.
    - In contrast to how the Make Ready Program works today, going forward, Other EV Projects would receive less funding as compared to Public Facing Projects.
    - Specifically, for Other EV Projects, Georgia Power would *only* fund the infrastructure up to, but not including the electrical panel.

The Other EV Project customer would have to fund the rest of the infrastructure costs themselves; this would include the panel, the charger and beyond.

- The Company will continue to maintain any infrastructure funded through the Make Ready program for the shorter of the life of the asset or ten years, and all Make Ready customers will be required to agree to the Company's terms and conditions of participation. Maintenance schedules of the infrastructure will be reviewed in the Company's next base rate case.

Community Charging

- Each year, GPC would file a Community Charging Plan (the Plan) with the Georgia PSC
  - The Plan would identify the location of up to (but not more than) eleven (11) Community Chargers GPC plans to install in the forthcoming year based on the budget in the original rate case filing.
  - The Plan will focus on underserved areas -- both rural and income qualified, but which are not located within one (1) mile of a designated Alternative Fuel Corridor or any other location for which funding is provided through the Georgia Electric Vehicle Infrastructure Deployment Plan.
  - Rural areas and Income Qualified areas will be defined as "counties identified as Tier 1 and 2 by the Georgia Department of Community Affairs (DCA)." *See*: https://www.dca.ga.gov/sites/default/files/jtc2022.pdf [dca.ga.gov]

- Once the annual Plan is filed, private EV charging service providers (Private Providers) would have a one-time, 60-day right of first refusal (ROFR) to claim a location within 15 miles of a Company-proposed location in the Plan.

  - Specifically, the Private Providers would have the ability to make a filing with the Georgia PSC asserting their intent to serve one or more of the eleven (11) locations identified in the Company's annual Community Charging Plan. Should the Private Providers fail to break ground at the community charging location within 1.5 years (18 months), they would waive their ROFR and the right to install chargers at that particular location would revert to GPC.

- Interested parties will have the opportunity to provide comments on the Plan within 30 days of the filing of the Plan.

- The Company's actual costs incurred to own, operate and maintain approved community charging equipment may be recovered in its rates for retail electric service.

- The need for a Community Charging program will be reviewed in the Company's next base rate case.

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Commonwealth Edison Company	:	
	:	**22-0432**
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.	:	**(Cons.)**
Illinois Commerce Commission On Its Own Motion -vs- Commonwealth Edison Company	:	**22-0442**
Investigation into Commonwealth Edison Company Beneficial Electrification Plan Filing pursuant to 20 ILCS 627/45.	:	

ORDER

March 23, 2023

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ORDER

By the Commission:

I. INTRODUCTION

Pursuant to Section 45(c) of the Electric Vehicle ("EV") Act ("EVA"), the Illinois Commerce Commission ("Commission") initiated a workshop for the purpose of soliciting stakeholder input on beneficial electrification ("BE") program design. 20 ILCS 627/45(c). The Commission, under the facilitation of a coordinator hired as a consultant, initiated the workshop process on November 3, 2021, to solicit input from stakeholders on BE program design. Ten workshops, including two equity-focused sessions, were held between the initiation of the process and February 28, 2022.

Following the conclusion of the BE workshop process, the EVA required Staff of the Commission ("Staff") to prepare a report of recommendations for investment or incentives in areas specified in the statute ("Staff Report"). 20 ILCS 627/45(c)(i)-(v). The Staff Report, released March 30, 2022, summarized feedback and ideas received from workshop participants, incorporated appendices consisting of participants' actual contributions, and provided Staff recommendations for utilities to consider "where practicable while also focusing on ensuring a seamless customer experience, attempting to minimize confusion in the market, and reducing barriers to electric vehicle adoption." Staff Report at 34.

II. PROCEDURAL HISTORY

On July 1, 2022, Commonwealth Edison Company ("ComEd" or "Company") filed a Petition with the Commission under the EVA to approve ComEd's proposed BE Plan. Additionally, ComEd seeks a waiver of 83 Ill. Adm. Code 452.280 to facilitate the use of hourly pricing by customers receiving rebates for the installation of EV infrastructure. The Commission assigned the proceeding Docket No. 22-0432.

On July 7, 2022, as required by Section 45(d) of the EVA, the Commission issued an Order Initiating Proceeding, for the purpose of considering whether ComEd's BE Plan serves the public interest and is cost beneficial and including whether the BE Plan meets the objectives and contains the information required by EVA Section 45(d). The Commission assigned the proceeding Docket No. 22-0442, and it was consolidated with Docket No. 22-0432.

The following parties (collectively, the "Intervenors") filed Petitions to Intervene, all of which were granted: Citizens Utility Board ("CUB"); Natural Resources Defense Council ("NRDC"); ChargePoint Inc. ("ChargePoint"); Building Owners and Managers Association of Chicago ("BOMA/Chicago"); Environmental Defense Fund ("EDF"); Illinois Competitive Energy Association ("ICEA"); Environmental Law and Policy Center ("ELPC"); Chicago Transit Authority ("CTA"); Weave Grid, Inc. ("WeaveGrid"); EVgo Services LLC ("EVgo"); Walmart Inc. ("Walmart"); Advanced Energy Economy ("AEE"); Little Village Environmental Justice Organization ("LVEJO"); Respiratory Health Association ("RHA"); Electrify America, LLC ("Electrify America"); FreeWire Technologies, Inc. ("FreeWire"); Tesla, Inc. ("Tesla"); Sierra Club; Illinois Industrial Energy Consumers ("IIEC"); FLO Services USA, Inc. ("FLO"); and the Illinois Environmental Protection Agency ("IEPA"). The Attorney General of the State of Illinois ("AG") and the City of Chicago ("City") filed appearances and each participated in the case as a party of right.

A prehearing conference was held on August 2, 2022 via videoconference before a duly authorized Administrative Law Judge ("ALJ") of the Commission. On September 2, 2022, Staff filed a Combined Motion to Dismiss and Motion for Interim Order ("Combined Motion"), which was fully briefed.

On September 22, 2022, Staff and Intervenors filed direct testimony. On October 18, 2022, the ALJ issued a Proposed Interim Order addressing Staff's Combined Motion. On October 20, 2022, ComEd filed rebuttal testimony.

On November 10, 2022, the Commission issued an Interim Order.

On November 16, 2022, Staff and Intervenors filed rebuttal testimony.

On November 21, 2022, ComEd sought rehearing regarding the Commission's Interim Order, which dismissed ComEd's proposals to provide certain rebates incentivizing the purchase of passenger EVs by residential customers, and the purchase of charging stations by commercial and industrial ("C&I") customers.

On November 29, 2022, ComEd filed surrebuttal testimony.

On December 1, 2022, the Commission denied ComEd's Application for Rehearing. ComEd later filed an appeal of the Interim Order in the Second Judicial District and submitted to the Commission a related Notice of Appeal.

An evidentiary hearing was held on December 7, 2022, and the pre-filed testimony and exhibits were admitted into the record.

On December 9, 2022, the AG sought rehearing regarding portions of the Commission's Interim Order, related to the determination to not dismiss the non-transportation components of the BE Plan and the failure to find that the entire BE Plan is subject to the statutory cap on the retail rate impact of the BE Plan. On December 15, 2022, the Commission denied the AG's Application for Rehearing. The AG later filed an appeal of the Interim Order in the Second Judicial District and submitted to the Commission a related Notice of Appeal.

On January 4, 2023, the following parties filed Initial Briefs ("IB"): ComEd; Staff; the AG; CUB; ChargePoint; Walmart; FLO; BOMA/Chicago; CTA and the City (collectively, "CTA/City"); EVgo; WeaveGrid; IIEC; Electrify America; AEE; Tesla; ICEA; LVEJO; and NRDC, EDF, Sierra Club, RHA, and LVEJO (collectively, the "Clean Jobs Coalition Parties" or "CJCP"). On January 18, 2023, the following parties filed Reply Briefs ("RB"): ComEd; Staff; the AG; ChargePoint; Walmart; FLO; BOMA/Chicago; CTA/City; EVgo; WeaveGrid; IIEC; Electrify America; AEE; Tesla; ICEA; LVEJO; and CJCP. On January 20, 2023, the following parties filed draft orders or position statements: ComEd; Staff; the AG; ChargePoint; Walmart; FLO; BOMA/Chicago; CTA/City; EVgo; WeaveGrid; IIEC; Electrify America; AEE; Tesla; ICEA; and CJCP.

On February 16, 2023, EDF filed a Motion for Administrative Notice of Federal Highway Administration and United States Department of Transportation Final Rule ("Motion for Administrative Notice").

A Proposed Order was served on February 21, 2023. No party objected to EDF's Motion for Administrative Notice, and it was granted on March 2, 2023.

On March 3, 2023, the following parties filed Briefs on Exceptions: ComEd; Staff; the AG; CJCP; CTA/City; ICEA; WeaveGrid; ChargePoint; BOMA/Chicago; Electrify America; and LVEJO. On March 9, 2023, the following parties filed Reply Briefs on Exceptions: ComEd; Staff; the AG; CJCP; ICEA; ChargePoint; BOMA/Chicago; Electrify America; LVEJO; AEE; Walmart; IIEC; and EVgo. On March 16, 2023, the Commission heard oral argument.

III. LEGAL STANDARDS

Section 45 of the EVA defines beneficial electrification programs as follows:

> programs that lower carbon dioxide emissions, replace fossil fuel use, create cost savings, improve electric grid operations, reduce increases to peak demand, improve electric usage load shape, and align electric usage with times of renewable generation. All beneficial electrification programs shall provide for incentives such that customers are induced to use electricity at times of low overall system usage or at times when generation from renewable energy sources is high.

"Beneficial electrification programs" include a portfolio of the following:

(1) time-of-use electric rates;

(2) hourly pricing electric rates;

(3) optimized charging programs or programs that encourage charging at times beneficial to the electric grid;

(4) optional demand-response programs specifically related to electrification efforts;

(5) incentives for electrification and associated infrastructure tied to using electricity at off-peak times;

(6) incentives for electrification and associated infrastructure targeted to medium-duty and heavy-duty vehicles used by transit agencies;

(7) incentives for electrification and associated infrastructure targeted to school buses;

(8) incentives for electrification and associated infrastructure for medium-duty and heavy-duty government and private fleet vehicles;

(9) low-income programs that provide access to electric vehicles for communities where car ownership or new car ownership is not common;

(10) incentives for electrification in eligible communities;

(11) incentives or programs to enable quicker adoption of electric vehicles by developing public charging stations in dense areas, workplaces, and low-income communities;

(12) incentives or programs to develop electric vehicle infrastructure that minimizes range anxiety, filling the gaps in deployment, particularly in rural areas and along highway corridors;

(13) incentives to encourage the development of electrification and renewable energy generation in close proximity in order to reduce grid congestion;

(14) offer support to low-income communities who are experiencing financial and accessibility barriers such that electric vehicle ownership is not an option; and

(15) other such programs as defined by the Commission.

20 ILCS 627/45(b).

The EVA requires the Commission to "determine if the proposed [BE] plan is cost-beneficial and in the public interest." 20 ILCS 627/45(d). The EVA enumerates eight objectives that the BE Plan should achieve and provides that:

> When considering if the plan is in the public interest and determining appropriate levels of cost recovery for investments and expenditures related to programs proposed by an electric utility, the Commission shall consider whether the investments and other expenditures are designed and reasonably expected to:
>
> (1) maximize total energy cost savings and rate reductions so that nonparticipants can benefit;
>
> (2) address environmental justice interests by ensuring there are significant opportunities for residents and businesses in eligible communities to directly participate in and benefit from beneficial electrification programs;
>
> (3) support at least a 40% investment of make-ready infrastructure incentives to facilitate the rapid deployment of charging equipment in or serving environmental justice, low-income, and eligible communities; however, nothing in this subsection is intended to require a specific amount of spending in a particular geographic area;
>
> (4) support at least a 5% investment target in electrifying medium-duty and heavy-duty school bus and diesel public transportation vehicles located in or serving environmental justice, low-income, and eligible communities in order to provide those communities and businesses with greater economic investment, transportation opportunities, and a cleaner environment so they can directly benefit from transportation electrification efforts; however, nothing in this subsection is intended to require a specific amount of spending in a particular geographic area;
>
> (5) stimulate innovation, competition, private investment, and increased consumer choices in electric vehicle charging equipment and networks;
>
> (6) contribute to the reduction of carbon emissions and meeting air quality standards, including improving air quality in eligible communities who disproportionately suffer from emissions from the medium-duty and heavy-duty transportation sector;
>
> (7) support the efficient and cost-effective use of the electric grid in a manner that supports electric vehicle charging operations; and

> (8) provide resources to support private investment in charging equipment for uses in public and private charging applications, including residential, multi-family, fleet, transit, community, and corridor applications.
>
> The plan shall be determined to be cost-beneficial if the total cost of beneficial electrification expenditures is less than the net present value of increased electricity costs (defined as marginal avoided energy, avoided capacity, and avoided transmission and distribution system costs) avoided by programs under the plan, the net present value of reductions in other customer energy costs, net revenue from all electric charging in the service territory, and the societal value of reduced carbon emissions and surface-level pollutants, particularly in environmental justice communities. The calculation of costs and benefits should be based on net impacts, including the impact on customer rates.

20 ILCS 627/45(d). The EVA also lists minimum information requirements that the BE Plan must address. 20 ILCS 627/45(d)(i)-(x).

IV. POLICY CONSIDERATIONS

A. ComEd's Position

ComEd states that the EVA delegates to the Commission an important role in transitioning Illinois to a cleaner and more equitable energy future through the adoption of BE technology and sets aggressive goals to realize the General Assembly's vision in the EVA. ComEd argues its BE Plan sets out such impactful action, in a range of programs and incentives that directly address the goals set out in the EVA.

ComEd argues its BE Plan meets the EVA's requirements, incorporates stakeholder feedback, and outlines concrete action it will take to support BE. ComEd demonstrates that its BE Plan includes the following five programs: (1) a Residential Program; (2) a C&I and Public Sector program; (3) a Customer Education and Awareness Program; (4) a BE Pilot Program; and (5) a Portfolio of cross-cutting activities that support the BE Plan. To support these programs and improve access to BE technology, promote equity and environmental justice ("EJ"), and reduce carbon dioxide and criteria air surface-level pollution throughout northern Illinois, ComEd states it will expend approximately $100 million dollars per year in each of the next three years.

Under the BE Plan, ComEd states it will offer customers incentives that support investment in EVs and charging infrastructure, as well as the electrification of non-transportation end-uses of energy, including heat pumps and other building electrification measures. ComEd argues that the comprehensive nature of its BE Plan – the fact that it encompasses transportation and non-transportation end uses – is critical because reduced reliance on fossil fuels and lowered carbon dioxide emissions are among the objectives explicitly outlined in the EVA. *See* 20 ILCS 627/45(a) ("It is the intent of the General Assembly to decrease reliance on fossil fuels …"); 20 ILCS 627/45(b) (defining

BE programs to include "programs that lower carbon dioxide emissions, [and] replace fossil fuel use").

ComEd points out that while 33% of carbon emissions in Illinois come from the transportation sector, an even greater portion of carbon emissions in Illinois – 38% – come from the residential, commercial, and industrial sectors. ComEd argues that to effectively achieve the statutory goals related to reduced use of fossil fuels and carbon dioxide emissions, non-transportation sources must be addressed.

ComEd argues its BE Plan is designed to meaningfully reduce barriers to the adoption of BE technologies in order to accelerate the benefits of electrification for those customers that need, and could benefit the most from, those technologies – namely, low-income customers, and customers located in EJ and Restore, Reinvest, Renew ("R3") communities. ComEd notes that while increasing access to the benefits of electrification is important for all consumers, it is a priority for low-income customers and customers in EJ and R3 communities because air pollution burdens tend to be higher in these areas. To this end, ComEd notes that it elected in its BE Plan to offer higher incentives to customers in these areas and targets distributing over 50% of the Residential Program funding and 40% of the C&I and Public Sector Program funding to low-income, EJ, or R3 applicants.

Within the BE Plan, and pursuant to pre-existing authority under Public Utilities Act ("Act") (220 ILCS 5/1-101 *et seq*.), ComEd also proposes two new EV Charging Delivery Classes, which will enable participating customers to have their EV charging billed on a kilowatt-hour ("kWh") (volumetric) or kilowatt ("kW") (demand) basis. ComEd states that the goal of these new rate classes is to encourage the development of public charging stations and to provide rate options other than the traditional demand-based structure. As an alternative to the establishment of the EV Charging Delivery Classes, ComEd proposes that EV charging customers be permitted to join ComEd's pre-existing Watt-Hour Delivery Class, which ComEd claims will enable them "to elect to take delivery service under a class that recovers distribution facilities costs based upon a volumetric $/kWh charge." ComEd Ex. 15.0 at 8.

ComEd argues the BE Plan will deliver significant benefits to northern Illinois. ComEd states that its BE Plan is projected to reduce carbon dioxide emissions by nearly 900,000 metric tons, avoid consumption of 175 million gallons of gasoline or diesel fuel, and substantially reduce local levels of air pollution. ComEd states that the total net benefit of its BE Plan is $197 million on a net present value basis. ComEd Ex. 13.0 at 5.

ComEd states that its BE Plan represents the bold, aggressive action towards electrification that is envisioned in the EVA. ComEd notes its BE Plan incorporates all of the various considerations detailed in the EVA, and the feedback of a wide variety of stakeholders received both prior to filing and over the course of this proceeding. The BE Plan, ComEd asserts, will deliver enormous benefits – estimated at nearly $200 million more than the cost of the BE Plan – to its customers and all residents of Illinois, primarily in the form of reduced carbon dioxide emissions and air pollution mitigation. ComEd argues that its BE Plan is in the public interest, supports the goals detailed by the General Assembly, and should be approved. Furthermore, ComEd indicates that it is committed

to achieving the ambitious policy goals of the EVA, while ensuring that the cost of doing so is not overly burdensome to customers.

ComEd argues that each of the major open issues in this docket is committed to the Commission's discretion and should be resolved in light of the policy objectives set forth by the General Assembly in the EVA. First, ComEd contends that the Commission has discretion to set the budget for incentives and rebates offered pursuant to the BE Plan. ComEd notes that AG and Staff argue that the overall size of the BE Plan budget should be reduced from the annual $100 million amount ComEd proposed to Staff's $44.4 million, or the AG's $26 million, although both the AG and Staff recognize that the reductions they propose are discretionary, rather than required by law. ComEd argues that the size of its proposed budget recognizes the legislative direction to move aggressively to implement BE within a very short timeframe. The General Assembly expressly designed Section 45 of the EVA with the intention that there should be one million EVs on the road in Illinois by 2030, 20 ILCS 627/45(a), and with the knowledge there were fewer than 50,000 EVs on the road at the time it was enacted. Accomplishing that goal requires a seismic shift in the implementation of BE technology. ComEd argues that Staff and the AG's reduced budgets simply will not support the seismic shift necessary to accomplish the General Assembly's goals. ComEd argues that the Commission has clear direction from the General Assembly concerning the guiding principles for this proceeding and should exercise its discretion on this issue to adopt ComEd's BE Plan, which is in line with the ambitious goals of the EVA.

Second, ComEd contends that the Commission has discretion regarding the types of programs and incentives included in the BE Plan. In particular, ComEd argues that its BE Plan would provide support for the adoption of non-transportation electrification measures, in addition to measures intended to spur adoption of EVs. As the Commission found in the Interim Order, "the plain language of Section 45 of the EVA is broad and does not contain a limitation that programs may only apply to transportation-related electrification." Interim Order at 15. The Interim Order notes the EVA's "wide-ranging" definition of BE, which "is followed by a non-exhaustive list of programs that may be included, not all of which are specifically related to transportation," and finds that this "broadly worded plain language of the statute is determinative" of the issue whether these kinds of programs may be approved as part of a BE Plan. *Id*. In response to Staff and the AG's arguments, ComEd argues that Interim Order should not be reversed; it correctly interpreted the plain language of the EVA. ComEd also contends that, to the extent that Staff and AG are instead arguing that the Commission should, in its discretion, decide not to adopt non-transportation measures as part of a BE Plan, they are also misguided. The General Assembly's goals, set forth in the EVA, include increasing electrification and reducing emissions of carbon dioxide and other pollutants. 20 ILCS 627/45(a). Buildings account for a significant portion of carbon dioxide emissions – in fact, buildings account for more carbon dioxide emissions than transportation. ComEd Ex. 2.0 at 17-18. Therefore, ComEd concludes, accomplishing the goal of reducing carbon dioxide emissions will require significantly more programming than simply making EVs more affordable or readily available in ComEd's service territory.

Third, ComEd argues that the Commission has discretion to address the manner in which the costs of the BE Plan will be recovered – the EVA provides no guidance on

this question. ComEd has proposed that the costs of the BE Plan be treated as a regulatory asset, meaning that they are amortized over time, and recovered via a rider, Rider BE. Staff and the AG contend that both the regulatory asset and the rider should be rejected, and that the costs should be recovered in base delivery rates as operating expense. ComEd contends that the Commission should approve ComEd's proposed cost recovery mechanisms, including the regulatory asset and Rider BE, because they enable ComEd to make investments at the scale necessary to make significant progress towards the ambitious policy goals of the EVA while ensuring the cost of doing so is not overly burdensome to customers. They also function to align the costs that customers bear with the benefits they receive from the BE measures they adopt.

In addition to the items committed to the Commission's discretion, ComEd contends that two additional issues merit discussion from a policy perspective. First, ComEd points out that Staff and the AG accuse ComEd of using the BE Plan, and its associated rate recovery mechanisms, to increase its own profits. *See* AG IB at 45; Staff IB at 12. ComEd replies that these accusations ignore the reality that, as an electric utility serving more than 500,000 customers in Illinois, ComEd is required by the EVA to file a BE Plan. What's more, ComEd argues the EVA is extremely and explicitly ambitious in describing the goals of a BE plan. It is ComEd's position that its BE Plan aligns with those goals. ComEd says that, in making these accusations, Staff and the AG also ignore the significant benefits the BE Plan will provide to customers – benefits that exceed its costs by nearly $200 million. According to ComEd, cost recovery is a necessary part of providing programs as a public utility, and ComEd's proposals to that end are not self-serving, as suggested by the AG and Staff. ComEd explains that it has worked hard throughout this entire process to design programs that would address both the goals of increased electrification and increased equity in pursuing BE adoption, while ensuring that the costs borne by customers are reasonable. ComEd argues that it is inappropriate to characterize ComEd's efforts to design a plan that balances costs with the drive to achieve the statutory goals as intended "solely" to enrich ComEd's shareholders.

Second, ComEd points out that Staff and AG each offer arguments, on different topics, that suggest the Commission should consider whether ComEd's proposed BE Plan is consistent with the BE plan proposed by Ameren Illinois Company d/b/a Ameren Illinois ("Ameren"). ComEd argues that these suggestions are inappropriate and must be disregarded. The Commission's decisions in any proceeding must be based exclusively on the relevant law and the facts in the evidentiary record. 220 ILCS 5/10-201(e)(iv). ComEd contends that there is no evidence whatsoever in the record of this proceeding concerning Ameren's proposed BE plan. ComEd further observes there is no evidence as to why Ameren chose to structure its plan in any particular way, or the relative merits or disadvantages of the Ameren proposals in comparison to ComEd's. There is also no statutory requirement that ComEd's BE Plan be consistent with the plan offered by Ameren. In addressing a similar argument in a different recent proceeding, the Commission concluded that the "fact that a different [result] is being adopted in the Ameren proceeding is immaterial to the appropriate [result] in this proceeding." *Commonwealth Edison Co*., Docket No. 22-0067, Order at 35 (Sept. 27, 2022). ComEd argues that the Commission therefore may not, and should not, evaluate ComEd's BE Plan against that of Ameren.

B. Staff's Position

Staff explains that in this proceeding the Commission considers for the first time a BE Plan proposed by ComEd, in furtherance of the ambitious energy policy objectives set forth in Public Act 102-0662 ("P.A. 102-0662"); as such, this proceeding presents many new challenges and considerations. It is not enough that the Commission *can* approve the BE Plan, it must also conclude that it *should.* In other words, Staff states, the Commission must consider the BE Plan not in a vacuum but instead as one piece of ComEd's overall plan to implement P.A. 102-0662 policy goals. Accordingly, Staff urges the Commission to be mindful of several critical policy considerations, in addition to the legal and statutory considerations discussed in detail below, when reviewing ComEd's BE Plan:

- the plan should focus exclusively on increasing EV adoption and improving EV infrastructure to avoid overlap with other programs;
- the amount spent on the BE Plan should be below the statutory retail rate cap to ensure ComEd is able to spend enough to advance the objectives of the EVA but not so much as to cause an undue burden on ratepayers;
- because ratepayers bear the financial costs of implementing the BE Plan, programs approved under the plan should have a demonstrable nexus to ComEd's electric delivery service. Staff raises objections to several programs because they do not require the beneficiary of the program to have an ongoing relationship with ComEd;
- the BE Plan should not seek solely to enrich shareholders at the expense of ratepayers. Because ComEd's proposal to create a series of regulatory assets would do just that, Staff strongly opposes the proposal;
- the BE Plan should enable effective and ongoing Commission oversight. Because recouping BE Plan costs through a rider would require the Commission to consider components of ComEd's BE Plan costs in separate proceedings, rather than aggregate all its costs in a single proceeding, Staff strongly opposes creation of a rider; and
- the BE Plan should not create barriers to retail competition.

The Commission should reject ComEd's proposal to spend $12 million per year on non-transportation electrification sub-programs in its BE Plan. Staff Ex. 1.0 at 17. ComEd's proposal to spend BE funds on energy efficiency ("EE") electrification measures disrupts the long standing, performance incentive construct established for EE through Section 8-103B of the Act. ComEd seeks to leverage ratepayer funds from its BE Plan which are in excess of the amount allowed by the EE statutory spending cap in order to increase spending on EE measures and then count the resulting savings toward its EE goals, which will make it easier for ComEd to achieve its energy savings goals and earn higher performance incentives (i.e., profits) from ratepayers through its EE formula rate. Notably, ComEd does not dispute this fact. Section 8-103B(b-5) establishes cumulative persisting annual EE savings goals for ComEd and imposes a spending cap on EE programs, set forth in Section 8-103B(m). If ComEd exceeds its applicable annual incremental goal without exceeding the spending cap, it earns financial performance

incentives from ratepayers through increases to the return on equity ("ROE") component of its EE formula rate. 220 ILCS 5/8-103B(g)(7). Simply put, if ComEd exceeds its EE goals, the Company earns additional profit for shareholders.

ComEd's BE Plan would drive participation in its EE electrification programs, which makes it easier for ComEd to earn financial performance incentives funded by ratepayers under its EE formula rate because it will spend money to supplement its EE program without regard to the EE spending cap. Moreover, ComEd's proposal circumvents EE policies related to electrification, which are developed through stakeholder collaboration on updates to the IL EE Policy Manual. ComEd's proposal flies in the face of the plain statutory language in the EE statute. Specifically, ComEd's proposal results in increased costs for its ratepayers because ratepayers would fund EE electrification measures that exceed the EE spending cap set forth in Section 8-103B(m) of the Act, as well as increased shareholder profits if those additional funds allow the Company to achieve its EE goals.

ComEd's BE proposal is intended to drive participation in its EE electrification programs (Staff. Ex. 1.0 at 19) without regard to the EE spending cap. ComEd proposes to provide customers with two sets of incentives for the same electrification measure (i.e., stacking incentives and bundled offers), with one incentive funded through the BE Plan and the other funded through the EE Plan. ComEd Ex. 2.0 at 18. As ComEd acknowledges, "[t]he ability to stack incentives is critical to address the barrier of high upfront costs." Staff Ex. 1.1 at 9. In other words, higher incentive levels may induce additional customers to purchase an electrification measure who otherwise could not afford to do so. Staff Ex. 1.0 at 19.

ComEd's proposal will result in increased costs for ratepayers while needlessly conflating the BE Plan with the EE plan. Staff Ex. 1.0 at 20. ComEd proposes to spend money on EE electrification measures exceeding the EE statutory spending cap set by Section 8-103B(m). That proposal alone will increase costs for ComEd ratepayers. In addition, ComEd designed its EE plan to achieve its energy savings goals within the Section 8-103B(m) statutory spending cap. If ComEd is now allowed to leverage ratepayer funds in excess of the amount allowed by the EE statutory spending cap and count the resulting savings toward its EE goals, it will be easier for ComEd to achieve its energy savings goals and earn higher performance incentives from ratepayers through its EE formula rate. Staff asserts that the Commission should decline to allow ComEd to budget funds in its BE Plan to supplement spending on EE measures, which will result in spending in excess of the EE cap on EE programs.

Staff's concern that ComEd will use BE Plan funds to improve its EE performance is not mere speculation. ComEd readily admits that it "intend[s] to claim 100% of energy savings for co-funded measures towards its [Section 8-103B energy savings] goals." It justifies this approach by referencing how ComEd "braids" EE funds with the Illinois Home Weatherization Assistance Program ("IHWAP") program funds and counts all of the savings toward its EE goals. ComEd Ex. 7.0 at 5. Both Staff and the AG explain that the IHWAP agreement is not analogous. Staff Ex. 12.0 at 9-10; AG Ex. 1.0 at 34-35. The braiding done with the IHWAP program is funded by the federal government, not ratepayers. Within its EE plan, ComEd leverages federal funding, a totally unique and distinct source of funds, for weatherization to supplement its ratepayer-funded low-

income IHWAP EE programs. The IHWAP program contemplates leveraging federal funds to help meet statutory energy savings goals cost-effectively, while reducing the amount of funding required from ComEd ratepayers. Staff Ex. 12.0 at 9-10; AG Ex. 1.0 at 34-35. This stands in stark contrast to what ComEd proposes in this proceeding, which is to use additional ratepayer funds to supplement the existing ratepayer-funded electrification EE programs within its EE Plan. For these reasons, the Commission should not conclude that ComEd's proposal is analogous to the IHWAP agreement.

Additionally, ComEd's proposal circumvents EE policies related to electrification, as those will be developed through stakeholder collaboration on updates to the IL EE Policy Manual. Specifically, ComEd indicates that it "does not support wholesale Commission approval of 'program approaches' applicable to non-EV measures included in ComEd's BE Plan consistent with the 'program approaches' that the Commission has adopted under [Section] 8-103B of the [Act.]" Staff Ex. 1.1 at 1 (citation omitted). This is problematic because ComEd's EE programs are formulated through a robust stakeholder process, and electrification has been a topic of particular interest to numerous stakeholders, including the gas utilities. Non-transportation programs such as building electrification work to the disadvantage of gas utilities, as electrification inherently displaces gas service as an energy source.

Further, not only does the ComEd EE Plan Stipulation have an entire section devoted to electrification, but numerous policies related to electrification have been proposed as part of the collaborative IL EE Policy Manual Update process. *See Commonwealth Edison Co*., Docket No. 21-0155, ComEd Ex. 1.02R, Revised Settlement Stipulation ("EE Plan Stipulation") (filed April 27, 2022) (see Section F, Energy Efficiency Electrification under Section 8-103B). Staff is concerned that ComEd may be able to circumvent those EE electrification policies by obtaining approval from the Commission to support electrification through its BE Plan. Staff Ex. 1.0 at 21. Accordingly, the Commission should reject ComEd's proposal.

Staff notes that one of ComEd's arguments for including the electrification measures in its BE Plan is that the electrification savings cap set by Section 8-103B(b-27) of the Act "necessarily limits the amount of EE funding that can go toward electrification to an amount insufficient to support electrification at scale or to meet the State's decarbonization goals[.]" ComEd Ex. 2.0 at 9. However, the Commission should reject ComEd's argument. First, this "limit[ation on] the amount of EE funding that can go toward electrification" is a limitation that the General Assembly intended and imposed. Second, ComEd's approved EE plan demonstrates that ComEd is not remotely close to hitting the electrification savings cap, although it has maxed out on the overall Section 8-103B(m) spending cap for the entire EE plan. Staff Ex. 1.0 at 23. Specifically, ComEd is between 59 gigawatt-hours ("GWh") and 68 GWh below the electrification savings cap in any year, 2022-2025, meaning it has flexibility to shift EE spending within its EE plan budget to achieve additional electrification savings. Staff Ex. 1.2 at 1.

For all the above reasons, the Commission should reject ComEd's proposal to spend $12 million per year of ratepayer funds on non-transportation electrification subprograms in its BE Plan. Staff Ex. 1.0 at 17. The AG agrees with Staff that the Company's non-transportation programs should be removed from the BE Plan for policy reasons. AG IB at 42-46.

C. CJCP's Position

CJCP state the BE Plan proposed by ComEd at issue here could play a fundamental role in ensuring a transition to zero-emission vehicles; if it provided structural support for EVs, ComEd could help provide market certainty and ensure that there is a strong basis from which to see continued uptake of EVs and corresponding reductions in air emissions. However, CJCP state that if ComEd is to obtain desired results in an equitable fashion while making optimal use of ratepayer funds, its proposed BE Plan must be improved and incorporate lessons learned from electrification efforts that are well underway in other regions. CJCP listed out key learnings, which include, *inter alia*:

- A focus on medium- and heavy-duty vehicles ("MHDVs") offers the greatest pollution reduction benefits and has some of the most powerful potential to remedy environmental injustices. EDF Ex. 1.0 REV at 5-6. Indeed, CJCP posit that the fact that the medium- and heavy-duty EV sector is less mature than the passenger vehicle EV sector makes utility support all the more critical. EDF Ex. 1.0 REV at 8. In addition, CJCP state that because many MHDVs do not use public charging, they will not be able to take advantage of IEPA rebates for charging stations, making an emphasis on these vehicles in utility programs all the more important. Finally, CJCP note that one of the most important means of ensuring equitable benefit in EJ and R3 communities is to electrify MHDVs - because many lower-income individuals do not have access to personal vehicles, ensuring that they have a sustainable method of transit is critical; as well, electrifying the trucks and buses that ride through pollution-burdened communities is an imperative part of what utilities should be seeking to accomplish.
- Customers who will be using the electric grid to fuel vehicles can be distinguished from other customers by the speed with which their new load can materialize and, in the case of commercial fleets, their relative inexperience with the complexities of being large commercial electricity customers. EDF Ex. 1.0 REV at 8-10. Also, as a specific example, low-income, "unbanked" customers require public charger payment equipment and methods to make it practical for that customer segment to help boost EV adaptation. NRDC Ex. 2.0 REV at 13. Unless utilities devote resources to understanding their actual needs, utility programs are unlikely to meet those needs efficiently and effectively.
- Many customers who are likely candidates for electrification may know a lot less about electrification than utilities do. Utilities, in collaboration with various local organizations and businesses, should develop targeted educational materials to help disseminate information to potential EV purchasers, including private truck fleets. EDF Ex. 1.0 REV at 10-11. Outreach must be designed with and facilitated by impacted communities and their representatives to ensure that key information is disseminated in a way that furthers equitable deployment of infrastructure, and ultimately vehicles.

- While the number of EVs on the road in the ComEd service territory is currently small, state and federal policies suggest that it will grow rapidly; indeed, this is borne out by experience – utility policies and programs aimed at spurring market development in states like California have resulted in significant growth in EV deployments. Without effective load management, the resulting impact of new load will be higher than necessary, and ComEd ratepayers will pay for the resulting overbuild. Rather than wait for EV adoption to cause negative grid impacts to the grid before taking action, ComEd should undertake market potential analyses now to determine proactively when and how much anticipated demand growth will be coming onto the grid to ensure that the grid will be able to accommodate the increased charging load reliably and cost-effectively (EDF Ex. 1.0 REV at 21; NRDC Ex. 1.0 REV at 27), as well as develop a comprehensive EV rate design and load management plan (NRDC Ex. 1.0 REV at 27-28). These analyses should then feed directly into pilots and programs that incentivize the use of software and hardware solutions referred to as automated load management ("ALM") and EV energy management systems ("EMS"). NRDC Ex. 1.0 REV at 28-31; EDF Ex. 1.0 REV at 16. Experience in other jurisdictions teaches that grid impact can be mitigated through proactive collection of data relevant to load growth and integration, and programs and rate designs that incentivize efficient grid use by charging customers.
- For the best results, vehicle electrification should be co-optimized with other changes that are coming to the electric system. Vehicle electrification need not compete against storage and renewable energy resources for funding. Rather, at a given customer location, other resources such as storage can be combined with vehicle charging to improve vehicle-grid integration ("VGI"), and at the scale of the grid itself, flexible charging needs can be leveraged as a virtual energy storage resource at very low cost. Managed charging programs designed to affect customer EV charging behavior can further unlock the flexibility of EV load. NRDC Ex. 1.0 REV at 8-10. Optimal vehicle electrification programs and rate designs must support customers leveraging these opportunities. EDF Ex. 1.0 REV at 6-7.
- To ensure that ComEd's efforts do not fall out of step with vehicle electrification trends in its territory, ComEd should be collecting data on such items as the rate of deployment of EV infrastructure associated with programs, the extent to which charging load is being optimized to coincide with periods of low-cost times and high renewable energy availability, the use and effectiveness of incentives to facilitate VGI capabilities, and the potential and realized cost savings associated with these programs. EDF Ex. 1.2 at 12-18. As well, data should be reported in a publicly available format such that stakeholders can have access to provide feedback on this collected data. EDF Ex. 1.0 REV at 36.

D. ICEA's Position

According to ICEA, ComEd's initial proposal would have caused customers to choose between receiving a rebate for EV charging infrastructure and selecting an

alternative retail electric supplier ("ARES") supply product or service. ICEA argues that ComEd's proposal forced this choice because ComEd would have required customers to take service under the Company's Rate BESH - Basic Electric Service Hourly Pricing ("Rate BESH") program, a supply rate that competes with (and is mutually exclusive to) ARES supply service. ICEA and Staff strongly opposed ComEd's initial proposal. ICEA concedes that ComEd evolved its proposal to allow customers on time-variant ARES supply products and services to participate in the residential EV charging infrastructure subprogram, although ICEA further posits that ComEd continued to propose that the Residential Optimized Charging pilot exclusively allow ComEd supply customers.

In addition to restrictions on customer choice, ICEA contends that ARES-offered time-variant supply products and services are not widely available for residential customers currently. *See* ICEA Ex. 1.0 at 4. ICEA avers that the reason that there are few ARES-offered time-variant products and services is that there are barriers, particularly regulatory hurdles to obtaining the necessary interval meter data to initially price products and "real-time" data to administer certain products and services. *See id*. at 4-5; ICEA Ex. 2.0 at 6-7. ICEA argues that those barriers are far lower for residential customers with EVs, meaning residential customers with EVs are a desirable market for ARES seeking to offer time-variant supply products and services. *See* ICEA Ex. 1.0 at 5-6; ICEA Ex. 2.0 at 7-8.

According to ICEA, it has prioritized removing barriers to ARES accessing necessary data to serve residential customers with time-variant products and services. *See* ICEA Ex. 1.0 at 4-5. ICEA postulates that the Commission should be removing barriers to ARES providing time-variant products and services. Instead, ICEA continues, forcing customers to choose between taking any ARES product (even a time-variant product) and BE Plan subprograms or pilots erects yet another barrier for residential customers with EVs that would otherwise be ideal for ARES to serve with time-variant products and services.

ICEA contends that no party appears to have presented evidence or argument disputing that ARES are currently challenged to offer residential time-of-use ("TOU") supply products due to lack of access to data but that residential customers with EVs do not have the same challenges. ICEA highlights that Staff emphasized the importance of the Commission supporting the competitive retail market. *See, e.g.,* Staff IB at 13, 27-28, 31-32, 111-113. ICEA states that it both wholeheartedly agrees and notes that allowing customers participating in BE Plan programs to take ARES supply is a double benefit: it both allows customers more choices (the primary benefit of competition) but also allows ARES to begin developing and deploying TOU supply products even as barriers to serve non-EV customers persist. In other words, ICEA concludes, allowing all customers to choose ARES supply helps customers participating today have more options and also allow ARES to develop new products that will provide options in the future. ICEA recommends that the Commission consider these benefits of allowing ARES to serve participating customers — specifically in the Residential EV Charging Infrastructure Sub-program and the Residential Optimized Charging pilot—in ComEd BE Plan programs.

E. CTA/City's Position

CTA witnesses presented testimony demonstrating that mass transit agencies including the CTA offer both direct and indirect environmental and societal benefits. The CTA witnesses noted that reduction in energy consumption occurs by aggregating riders in a single, shared vehicle, be it a bus or rapid transit railcar, rather than in numerous personal vehicles. Reduced energy consumption—electricity, diesel, or gasoline—means less primary fuel is used, resulting in lower levels of "criteria" air pollutants (carbon monoxide, lead, ground-level ozone, particulate matter, nitrogen dioxide, and sulfur dioxide). No party contested the CTA's testimony as to the environmental and societal benefits it provides. The National Academies of Sciences, Engineering, and Medicine have graphically illustrated greenhouse gas emission rates per passenger mile across various modes of transportation. The CTA evidence shows that the CTA operates both a rapid transit system and a bus system that allow residents and visitors to access jobs, education, healthcare, airports, and other needs and amenities. Both the rapid transit system and the bus system contribute to energy efficiency, reduce pollution, and provide benefits to residents of EJ and R3 communities in Chicago.

The CTA observed that for decades in numerous ComEd rate cases, the Commission has recognized the important public interest served by the CTA in providing public mass transit in the Chicago area via its rapid transit system. The Commission articulated this public interest in its orders acknowledging the Commission's desire "to encourage the efficient use of energy and conservation of scarce resources" by the CTA. *Commonwealth Edison Co*., Docket No. 05-0597, Order at 190 (July 26, 2006). The Commission affirmed that its "commitment to a policy of encouraging conservation, efficient energy use and the environmental benefits of affordable public transportation has not lessened since the . . . Order in Docket [No.] 05-0597." *Commonwealth Edison Co*., Docket No. 07-0566, Order at 223 (Sept. 10, 2008). Providing mass transit via buses — especially electric buses — is vital to the public interest in promoting energy conservation and meeting the intent of the EVA.

The CTA asserts that its request for ComEd's BE Plan to include support for purchasing electric buses and providing make-ready infrastructure not only complies with the General Assembly's intent as provided in the EVA, but also would continue the Commission's commitment to encouraging efficient use of energy, conservation of scarce resources, and promoting environmental benefits of affordable public transportation.

The CTA witnesses explained that CTA riders use the bus system, which operates more than 1,800 buses over 128 routes with 10,700 stops. The CTA ensures equitable service for EJ and R3 communities in its planning processes and has prioritized EJ and R3 communities in its bus fleet electrification implementation. CTA buses serve the entire city of Chicago on a systemwide basis and connect to suburban public transit. A particular bus route may originate, pass through, or terminate in EJ and R3 communities. The CTA explained that the majority of Chicago is either in a low-income census tract or minority census tract which means that the CTA's bus network serves all of the city's EJ and R3 communities.

CTA witnesses explained, that beginning in 2014, the CTA began replacing its diesel-powered fleet with electric-powered buses — the first step toward its commitment

to full electrification of the entire bus fleet by 2040, a goal formally established in 2019. A February 2022 report submitted as evidence by the CTA, "Charging Forward: CTA Bus Electrification Planning Report" and "Appendix to Charging Forward," details the CTA bus electrification plan and its environmental and societal benefits.

The CTA asserts that electrification of the bus fleet must include the upgrading of the CTA garages to provide charging of the electric buses because the electric buses cannot function unless they are recharged, and extensive analysis by the CTA determined that the CTA garages are the most operationally efficient and cost-effective locations for bus charging. Currently, the CTA garages' electric needs are limited to the support of diesel fueling, maintenance, and related activities. As part of the conversion of the bus fleet to electric, the CTA plans to charge about 300 buses at each garage, increasing the demand to up to 20 megawatts ("MW") per garage. The current demand at each garage today is about 1 MW. The CTA explained that the CTA garages' existing electric rooms are too small and must be expanded or new adjunct facilities must be built. Having viable charging equipment requires not only the overhead pantograph chargers but also upgrading the lines and installing switchgear, controls, communications systems, and other related equipment from the CTA side of ComEd's meters to the chargers. The CTA testified that the total cost for the CTA for these electric system changes (excluding the chargers themselves) is estimated at $20 million to $30 million at each garage. Moreover, the CTA asserts that because the CTA garages and charging facilities are critical infrastructure, the two independent lines currently feeding each garage also must be upgraded to meet the increased electric load. ComEd estimated the costs it would impose on the CTA for upgrading the lines could be as high as $3 million to $7 million per garage.

Bus purchases and upgrading the CTA garages for charging must be coordinated because an electric bus cannot operate without being charged. The CTA provided evidence that it incorporated equity factors, including the locations of EJ communities, in determining the sequencing of garages and routes slated for electrification. CTA witness Connelly testified that the "first garages and routes slated for electrification are those located within communities that bear a disproportionate burden of pollution, experience greater vulnerability to pollution-related health impacts, and are in areas with relatively high proportions of minority and low-income residents." CTA Ex. 1.00 at 10.

While reducing air pollution in these areas is a primary benefit, the CTA states that upgrading the CTA garages also allows the CTA to lead by example for other fleet operators in the Chicago area. As noted in the CTA's Charging Forward plan, "Electrification of our garages in these areas could also help push forward the grid infrastructure upgrades required to support charging, and the improved power infrastructure investment will benefit nearby residents and employers." CTA Ex. 1.02 at 22.

The CTA asserts that ComEd's BE Plan can play a critical role in the CTA's electrification plan by providing funding for the purchase of electric buses and the upgrading/modification of CTA garages to provide the necessary charging for these buses. Because bus purchases and garage modifications must be coordinated, the CTA has embarked on a multi-year program with emphasis on first upgrading garages and providing electric buses that provide the greatest amount of service to the EJ and R3 communities. The CTA requests that ComEd's BE Plan include funding assistance to

purchase CTA buses and to enable the charging of these buses. In addition, the CTA requests that ComEd Riders NS and DE be modified to clarify that ComEd must pay for the make-ready infrastructure, including the feeder lines and all electrical and construction work necessary to connect distribution equipment to the chargers. The CTA opined that these modifications reflect the importance that the Legislature placed on transit system electrification.

F. Walmart's Position

Walmart states that, while the EVA clearly articulates the public policy of the State of Illinois to facilitate EV growth in the State, there are a number of issues within ComEd's BE Plan for which the EVA is silent. For example, nothing in the EVA specifies the method by which costs should be recovered from customers. This includes not only ComEd's proposal for rider recovery through Rider BE, but also its initial proposal to recover costs from customers on an energy, or ¢/kWh, basis.

Walmart explains that the Commission should only authorize ComEd to recover BE Plan costs if the evidence establishes that BE Plan costs are volatile and unpredictable, outside the Company's ability to control, and the costs are sufficiently material to justify rider recovery. In the absence of proof that ComEd's BE Plan satisfies all three elements, public policy advocates against single-issue ratemaking. *See People ex. Rel. Madigan v. Ill. Commerce Comm.*, 354 Ill. Dec. 662, 672. In that case, ComEd should be required to recover BE Plan costs through a traditional base rate case or a Multi-Year Rate Plan ("MYRP").

According to Walmart, regardless of whether rider recovery is authorized for BE Plan costs, the Commission must reject the Company's original proposal to recover costs on an energy, or ¢/kWh, basis. While the Legislature has seen fit to dictate the appropriate cost recovery method in other contexts, it did not do so here. In determining the appropriate method of cost recovery for BE Plan costs, the Commission must be guided by the general obligation set forth in Section 9-241 of the Act, which states that "[n]o public utility shall, as to rates or other charges, services, facilities or in other respect, make or grant any preference or advantage to any corporation or person or subject any corporation or person to any prejudice or disadvantage." 220 ILCS 5/9-241. Because there is no dispute that BE Plan costs are fixed in nature, it would violate Section 9-241 to recover costs on an energy basis, as ComEd originally proposed because it would result in high load factor customers subsidizing BE Plan costs for low load factor customers.

G. ChargePoint's Position

ChargePoint submits that the most important policy consideration before the Commission in this proceeding is ensuring that ComEd's BE Plan invests sufficiently in EV charging infrastructure to support the General Assembly's goal of supporting one million EVs on Illinois' roads by 2030. The EVA limits the retail rate impact resulting from the development of EV infrastructure. To do so, ChargePoint argues, that the Commission should increase the budgets of both the Make-Ready Infrastructure Rebate and the Residential EV Charging Infrastructure Sub-programs so that the sum of the budgets for these two sub-programs equals the retail rate impact limit (which ComEd estimates is $44 million).

ChargePoint explains that the Commission addressed the meaning of this phrase in its Interim Order in this proceeding, finding: "The plain language of the statute clearly states that the retail rate cap applies to development of EV infrastructure." Interim Order at 38. Accordingly, the only BE Plan spending that counts against the retail rate cap is spending on EV charging infrastructure, specifically, the EJ/R3 EV Charging Make-Ready Infrastructure Rebate (Make-Ready Rebate) Sub-program and the Residential EV Charging Infrastructure Sub-program. Pursuant to the Interim Order, none of ComEd's other proposed programs count against the retail rate impact limit.

ChargePoint further asserts that, recognizing that the retail rate impact limit is a ceiling and not a floor, the fact that the EVA establishes a budget for utility spending on EV charging infrastructure is a clear indication that the General Assembly intended that the focus of ComEd's BE Plan would be on EV charging infrastructure and that the utilities would make sizeable investments in EV charging infrastructure. According to ChargePoint, the $16 million total budget that ComEd has proposed for the two programs ($6 million for the residential program and $10 million for the nonresidential program) falls short of the General Assembly's vision. As a matter of policy, ChargePoint urges the Commission to direct ComEd, in its inaugural BE Plan, to make an investment in EV charging infrastructure on the scale envisioned by the General Assembly, which is approximately $44 million annually. Specifically, ChargePoint recommends a budget of $14 million for the Residential EV Charging Infrastructure Sub-program and $30 million for the Make-Ready Rebate Sub-program. ChargePoint also recommends that the Commission find that as a matter of policy all nonresidential customers willing to host EV charging stations should be able to participate in the Make-Ready Rebate Sub-program, with lower incentives for customers that are not public sector entities or located in eligible communities. If needed, ComEd should reserve sufficient funds for eligible communities for both of these sub-programs to meet the 40% investment target for make-ready infrastructure in eligible communities.

ChargePoint responds to Staff's statement that "none of the Intervenors in this proceeding explicitly disagrees with Staff's 97% uptime requirement recommendation," (Staff IB at 23) arguing that while ChargePoint supports requirements to ensure that charging stations supported by utility programs are reliable, Staff's uptime requirement is based on the draft federal National Electric Vehicle Infrastructure ("NEVI") requirements, which applies only to the specific use case of DCFCs along Alternative Fuel Corridors in specific configurations. ChargePoint further explains that the NEVI requirements, which have not yet been finalized, may not be appropriate for all use cases and may discourage prospective site hosts from participating in the BE Plan programs. Rather than adopt an uptime requirement that applies to all BE Plan programs now as Staff recommends, ChargePoint recommends that the Commission direct Staff to convene a stakeholder workshop process at the conclusion of this proceeding with the goal of developing an evidence-based uptime requirement.

H. IIEC's Position

IIEC believes that while ComEd's proposed BE Plan has the potential to facilitate the development of the EV market in Northern Illinois, it goes far beyond this and addresses issues that have nothing to do with EVs. In addition to its tangential spending, IIEC believes the BE Plan ultimately would become a profit center for ComEd. IIEC

argues that the regulatory asset which ComEd proposes to create in this case, which would provide additional profit to ComEd, will induce it to spend as much as possible under the auspices of the EVA. IIEC points out that this excessive spending comes at a time when customers are facing major electric rate increases due to increases in commodity costs, along with the continued climb of ComEd's delivery rates, including new and increased charges due to the enactment of P.A. 102-0662. IIEC argues that in order to protect consumers, the Commission should adopt the proposals of Staff and the AG that seek to restrain ComEd's spending and the associated impacts on customers' rates.

IIEC observes that in addition to its request for a regulatory asset and associated returns thereon, ComEd proposes to establish yet another rider, to guarantee it recovery of its costs and return, and thus further eliminate the discipline that regulatory lag provides utilities to control costs. IIEC asserts that riders generally should be avoided and should be allowed only when either mandated by law, which is not the case here, or when warranted by meeting the three prong criteria for rider justification: (1) volatile and unpredictable costs; (2) costs outside the utility's control; and (3) costs that are of sufficient magnitude to cause a rate case absent the rider mechanism. IIEC argues ComEd's proposed rider meets none of these, let alone all three.

Finally, IIEC argues that whether or not Rider BE is approved, costs should be assigned separately and there should be separate charges for each of the rate classes or as many groups as possible. Further, the Commission should reject ComEd's proposed equal cent per kWh recovery charge for all customers in each of the very broad categories of residential and nonresidential.

I. FLO's Position

In response to Staff's proposal that ComEd should require all EV charging station owner/operators to install EVSE that are certified by ENERGY STAR®, FLO notes that Staff continues to support such requirements despite the Commission's Interim Order. The motivating factor behind Staff's proposal appears to be EE and any potential savings that may result from the use of more energy efficient infrastructure. The purpose of BE plans such as ComEd's is much broader than simply achieving potential charger-level EE savings. Notably, one of P.A. 102-0662's goals states, "[w]idespread adoption of [EVs] requires increasing public access to charging equipment throughout Illinois, especially in low-income and [EJ] communities, where levels of air pollution burden tend to be higher." 20 ILCS 627/45(a)(7). Accordingly, as explained in FLO's filings, if ComEd launches a curbside charging pilot program, as proposed, technology-specific limitations like requiring an ENERGY STAR® rating should not apply because the purpose of the pilot is to test certain aspects like consumer receptivity, charger reliability, use cases, and how to more equitably deploy chargers in historically underserved communities, not to deploy specific technology at scale, or see how much energy an EV charger consumes when not in use.

As previously explained by FLO, charging station designs currently available for curbside charging, such as FLO's non-residential curbside L2 charging station models (SmartTwo and SmartTwo-BSR), are unique and are designed to meet high reliability standards despite the challenges of the surrounding environment. To meet such high reliability standards, these charging station models use certain mechanisms to prevent

issues like equipment freezing and vandalism — features which currently result in the use of slightly higher levels of energy while in standby mode than would be allowable for the ENERGY STAR® certification threshold.

The success rate in deploying a significant number of curbside charging stations using FLO's current technology, coupled with the proven and consistent reliability of these stations, makes them valuable options for customers, despite currently falling slightly below the ENERGY STAR® certification threshold. Indeed, the benefits of understanding how EV charging infrastructure can be developed and deployed at large scale in the public right-of-way, while achieving almost 100% uptime for the benefit of customers, outweighs the temporary need to deviate from requiring ENERGY STAR® certification for pilot programs.

J. BOMA/Chicago's Position

BOMA/Chicago suggests that, at its core, the EVA's primary purpose is to increase the adoption of EVs in the State of Illinois to one million EV's by 2030. By so doing, the benefits would satisfy the majority, if not all of the General Assembly's intent codified in 20 ILCS 627/45, particularly to decrease reliance on fossil fuels, reduce pollution, increase access to electrification for all consumers, and create benefits for Illinois residents, including the EJ communities, and create high quality jobs in Illinois.

BOMA/Chicago notes that there are currently about 50,000 electric vehicles across the state, including over 32,000 in the Chicagoland area. To reach the goal of one million EVs on the road by 2030 requires an increase of approximately 950,000 vehicles in less than seven years. Clearly, a 20-fold increase in this period of time requires a significant change in consumer behavior as well as strategic investments. BOMA/Chicago submits that its proposed infrastructure plan to develop a central hub for all communities within the city and metropolitan region, incorporating convenience, safety, and economy of scale, goes a long way to helping ComEd, the Commission, and the State of Illinois into realizing this lofty goal. Staff recognized the value of building a network of EV charging stations in downtown Chicago to support the EVA's ambitious goal of increasing EV adoption to one million by 2030.

K. Commission Analysis and Conclusion

The Commission notes that parties discuss policy considerations and recommendations that do not require a finding by the Commission or are otherwise addressed in other sections of this Order, for instance: non-transportation programs are addressed in Section V.C.5.a.; budget issues are generally addressed in Sections V.C.1 and 2; specifics of ComEd's BE Plan Programs are addressed in Section V.A.; recovery of BE Plan costs is addressed in VI.A.; rate options are addressed in V.A.1 and 4; and rate classes are addressed in Section VII.A.

V. COMED'S BE PLAN

A. BE Plan Programs

1. Residential Programs

a. ComEd's Position

ComEd states that its Residential Program includes four sub-programs that, together, fully address the range of issues involved in introducing BE technologies to residential communities. Annually, the Residential Program will distribute approximately $12 million across these sub-programs to incentivize the purchase and use of BE technology, including the adoption of EVs, and to improve EV charging infrastructure, according to ComEd. ComEd Ex. 12.0 REV at 5. ComEd states that it committed to target 50% of the funding for the Residential Program for low-income customers and customers in EJ or R3 communities. *Id*. at 6. According to ComEd, this program will help place these innovative technologies directly in the hands of consumers and allow customers to capture the benefits associated with BE. Far from benefiting shareholders at the expense of customers, this program will ensure that there is increased access to BE technology in residential areas for those who wish to participate. The Residential Program is comprised of several sub-programs.

(i) Residential EV Purchase Sub-program

ComEd's originally-filed BE Plan included a proposed Residential EV Purchase Sub-program which would have offered a $4,000 rebate per EV purchased for passenger use, a $6,000 rebate for a new EV purchase by a low-income customer or a customer in an EJ or R3 community, and a $3,000 rebate for the purchase of a used EV by a low-income customer or a customer in an EJ or R3 community. However, the Interim Order directed that this sub-program should be removed from the BE Plan. Interim Order at 24. Although ComEd is pursuing an appeal on this issue, ComEd did not continue to advocate for the adoption of the Residential EV Purchase Sub-program as part of its BE Plan.

In reallocating funds originally budgeted for this program, ComEd states that it took efforts to shift funds from this program, which is targeted to end-uses (rather than infrastructure), to other programs that support end-uses, to ensure that the overall BE Plan continues to support investment of at least 40% in make-ready infrastructure incentives in EJ, R3, and low-income communities, and to target 50% of residential program funding for low-income customers and those in EJ and R3 communities. ComEd notes that while Staff suggests that the funding originally allocated to this sub-program should have been removed from the budget completely, rather than reallocated to other programs, LVEJO supports ComEd's proposal to reallocate the funds to other programs. ComEd argues that while LVEJO suggests that the reallocation should be different, ComEd's proposed reallocation of funds is appropriate.

(ii) Residential EV Charging Infrastructure Sub-program

ComEd states that one of the primary barriers to the widespread adoption of EVs is the lack of adequate and accessible charging equipment. ComEd claims its Residential EV Charging Infrastructure Sub-program seeks to address that burden by offering rebates that lower the up-front costs associated with installing EV charging stations. In order to

address the historical financial and environmental inequities in this space, ComEd proposes to provide higher incentives to low-income customers and those residing in EJ or R3 communities. Moreover, ComEd states that small multi-family properties will be eligible to receive rebates offered under this sub-program.

ComEd notes that the sub-program also incentivizes rebate recipients to charge their EVs during periods when energy prices – and demand on the grid – are relatively low by requiring recipients to enroll in either an hourly pricing program, an ARES supplied TOU supply, or the Residential Optimized Charging pilot. According to ComEd, this requirement will mitigate increases in peak demand, and avoid adding costs to the grid during hours of high prices or limited resource availability.

ComEd states that the BE Plan budgets approximately $6 million per year for this sub-program. These funds will enable rebates for residential customers of up to $2,500 per EV charging unit, and for low-income customers and those located in EJ or R3 communities, rebates of up to $3,750 per unit. ComEd Ex. 2 at 17.

ComEd observes that Staff and the AG suggest that the Commission should significantly modify the sub-program. ComEd argues that these proposals should not be adopted, because they would negatively impact the Residential Program and the BE Plan as a whole. ComEd argues that the Commission should reject as unnecessary Staff's proposal to divide this Sub-program into two separate Sub-programs. ComEd disagrees, because this division would create additional administrative burden with little benefit. ComEd notes that it has already committed to target 50% of the funding for the overall Residential EV Charging sub-program to low-income/EJ/R3 communities, and argues that, as a result, Staff's proposed sub-division is unnecessary. ComEd also argues that the Commission should reject Staff's recommended changes to the manner in which receipt of incentives under this Sub-program is tied to participation in rate structures or programs that encourage EV charging at off-peak times.

Similarly, ComEd opposes the AG's modifications to the program. The AG argues that ComEd's proposed incentive amounts under this sub-program are too high, because they are calibrated to the cost of L2 chargers, which the AG contends are not necessary for residential customers. ComEd points out that, although most EVs come with a Level 1 ("L1") charger that can be plugged into a standard 120 volt alternating current outlet, those chargers are unable to optimize EV charging load. Therefore, ComEd has chosen to focus on L2 chargers that are "smart" and ENERGY STAR® certified. Given the focus in the EVA on incentivizing EV charging activity at off-peak times, ComEd argues that its proposal to incentivize L2 charging is appropriate and should be adopted. ComEd also argues that it is unnecessary to exempt low-income customers from the requirement to participate in a time-variant rate as many low-income customers already save on time-variant rates and ComEd has tools to help them make a decision if such a rate structure is a good fit for them.

(iii) Residential BE Technology Adoption Sub-program

ComEd argues that the Residential BE Technology Adoption Sub-program addresses the complementary need for adoption of BE technology other than EVs, including high efficiency electric heat pumps, electric lawn equipment, induction cooking equipment, and electric clothes dryers. Non-EV beneficial electrification technology is an

important component of an effective BE Plan, ComEd claims, because non-electric emissions from the residential, commercial, and industrial sectors combined in the State of Illinois are greater than the non-electric emissions for transportation in the State. ComEd Ex. 2.0 at 17.

ComEd explains that its Residential BE Technology Adoption Sub-program is comprised of two components designed to reduce barriers to adoption and promote the use of residential building electrification technologies. First, ComEd will offer rebates for high efficiency electric heat pumps, primarily as a supplemental incentive to enhance Energy Efficiency Electrification ("EEE") efforts within low-income customer segments facing exceptionally high barriers to adoption. According to ComEd, barriers are expected to be highest within the multifamily sector serving low-income residents. ComEd contends that those particularly high barriers will be addressed under this sub-program because it would allow ComEd customers to receive multiple related rebates for the same measure (under the BE Plan and other EEE efforts). Second, ComEd will offer incentives for electrification technologies including lawn equipment, induction electric cooking appliances, and electric or heat pump clothes drying appliances. Together, ComEd argues that these rebates will present customers with a holistic opportunity to receive a financial incentive on the conversion of nearly every fossil fuel end-use in their home. *Id*. at 18.

ComEd notes it budgeted approximately $5 million for this sub-program per year. Within this sub-program, $4 million will be devoted to support high efficiency heat pumps and $1 million will be devoted to supporting rebates for other BE technology, according to ComEd. ComEd Ex. 12.0 REV at 5. ComEd anticipates providing rebates of up to $3,000 for high efficiency electric heat pumps, and $25-50 per electric lawn equipment unit, $100-$500 per induction cooktop, and $50-$200 per electric or heat pump clothes dryer units. ComEd Ex. 2.0 at 23.

ComEd notes that ChargePoint and LVEJO support this sub-program, with small modifications, while Staff and AG contend that non-transportation electrification measures should be excluded from ComEd's BE Plan. Staff argues that ComEd should not be permitted to fund rebates through its BE Plan for any measure for which rebates are offered under ComEd's Energy Efficiency and Demand Response Plan ("EE Plan"). The AG advanced similar concerns, arguing that this sub-program should be removed from the BE Plan entirely because non-transportation measures should be excluded from the scope of BE as a matter of law. ComEd disagrees, arguing it is not impermissible under the EVA to include this sub-program. Non-transportation electrification is within the scope of BE as defined in the EVA. ComEd points out that the purposes set forth in the EVA include "decreas[ing] reliance on fossil fuels" and "increas[ing] access to electrification for all consumers." 20 ILCS 627/45(a). By building on other programs, not just filling gaps, ComEd argues its proposals merely enable ComEd to reach more customers through different approaches, accelerating the adoption of electrification in accordance with statutory guidance.

ComEd points out that it is not required to demonstrate energy savings in the context of the BE Plan, so there is no risk that such savings would be "double counted." ComEd 12.0 REV at 14. To the extent the savings arising from measures funded in part via the BE Plan need to be addressed for purposes of EE Plan compliance, that issue

that would be better suited for resolution through the existing Illinois Energy Efficiency Stakeholder Advisory Group process. Moreover, ComEd states, Section 8-103B establishes energy efficiency and demand response planning requirements and progress – its principal focus is not electrification. When Section 8-103B was enacted in 2017, the term "electrification" did not appear. P.A. 102-0662 added a new electrification provision to Section 8-103B as part of the broad decarbonization and electrification objectives. That Section now permits a utility to offer, via its EE Plan, "measures that electrify space heating, water heating, cooling, drying, cooking, industrial processes, and other building and industrial end uses," but it also limits the role of electrification measures in EE plans. 220 ILCS 5/8-103B(b-27). Thus, ComEd contends, the General Assembly incorporated a degree of electrification in EE plans, but there is nothing to suggest that EE plans are the sole or exclusive platform for offering non-transportation electrification incentives.

ComEd argues that a review of P.A. 102-0662 in its entirety reveals a "both/and" approach that incorporates electrification in a variety of contexts. For example, in addition to EE and BE plans, P.A. 102-0662 incorporates a Public Schools Carbon Free Assessment, intended to move schools to become carbon free energy users through electrification of their space heating, water heating, and transportation needs. 220 ILCS 5/8-402.2(b)(3)(C)-(D). But this program is limited to assessments – ComEd states this makes it critical that the measures, programs, and incentives are realized elsewhere.

According to ComEd, the purpose of a BE Plan is to drive the adoption of electrification measures in Illinois, and deliver the benefits of those measures, including reduced emissions and more efficient use of electricity. ComEd argues that it would be unreasonable for the Commission to conclude that an incentive must be excluded from the BE Plan because it would be effective at achieving those ends.

(iv) Residential BE Infrastructure Readiness Sub-program

ComEd explains that the Residential BE Infrastructure Readiness Sub-program offers rebates to residential customers in an effort to reduce costs associated with electrical infrastructure upgrades for non-transportation BE technology such as heat pumps, electric water heaters, and induction cooktops. ComEd notes that the infrastructure upgrades necessary to use residential BE technology can be a high barrier to the widespread adoption of such devices. ComEd contends that this sub-program addresses those barriers by offering financial incentives to make the requisite infrastructure upgrades.

ComEd explains that it budgeted approximately $1 million per year for this sub-program. ComEd notes that these funds will provide incentives of up to $750 per infrastructure upgrade per residential unit, with a $5,000 cap for a multi-family residence. ComEd Ex. 2.0 at 23.

ComEd notes that Staff and the AG offer the same arguments against the inclusion of non-transportation electrification measures as were offered in opposition to the Residential BE Technology Adoption Sub-program. As discussed above, ComEd maintains that non-transportation efforts benefit the public and are appropriate and should be approved as part of the BE Plan.

b. Staff's Position

Staff proposes significant modifications to ComEd's programs including but not limited to recommending separating out sub-programs to focus on EJ and R3 communities and low-income customers as well as changes to the amount budgeted for programs and sub-programs.

(i) Residential EV Purchase Sub-program

Pursuant to the Interim Order, ComEd modified its BE Plan to remove this program. The Commission found that it lacked authority to authorize rebates to residential customers for the purchase of EVs because that authority was vested in the IEPA.

(ii) Residential EV Charging Infrastructure Sub-Program

Staff recommends the Commission approve this sub-program with modifications. However, the Commission should approve the following budget amounts consistent with Staff's budget proposal set forth in Staff Exhibit 17.1. Specifically, Staff recommends the Commission split this sub-program out into the following two subprograms, each with a $2.5 million annual budget: (1) Residential EV Charging Infrastructure Sub-program EJ/R3 and income-qualified ("IQ") and (2) Residential EV Charging Infrastructure Sub-program (non-EJ/R3/IQ). This is the same budget amount of $5 million originally proposed by ComEd in its original BE Plan filing but is split out between EJ/R3/IQ and non-EJ/R3/IQ for budget flexibility and tracking purposes to make it easier to ascertain whether the statutory requirements related to EJ/R3/IQ are being met.

Staff states the Commission should modify ComEd's BE Plan to provide customers with different options that incentivize customers to charge their EVs during off-peak times as a condition for customers receiving the Residential EV Charging Infrastructure Sub-program rebate. Specifically, Staff recommends the following options:

(1) Customers should be given the option to enroll in a time variant rate of the customer's choosing, whether it be (a) a distribution TOU rate offered by the Company (as recommended in Staff's direct testimony (Staff Exhibit 6.0)), (b) ComEd's Rate BESH, or (c) a time variant supply rate offered by an ARES;

(2) Customers should be given the option to install a smart charger and enroll in an active managed charging program; or

(3) Customers should be allowed to participate in ComEd's optimization pilot.

Staff Ex. 20.0 at 3.

ComEd originally proposed that "[a]s a condition of receiving a Residential EV Charging Infrastructure Sub-program rebate, ComEd requires that the customer enrolls in ComEd's [Rate BESH] for at least three years." ComEd Ex. 1.01 at 31. Staff raised concerns that ComEd's proposal "creates a barrier to competition [prohibited by the Act] because it makes ComEd's Rate BESH the sole option for residential rebate recipients, to the exclusion of all ARES who might serve these customers." Staff Ex. 9.0 at 6.

Furthermore, Staff expressed concern that ComEd's proposal would prevent "customers enrolled with an ARES for electric supply, such as those who participate in municipal aggregation programs, from qualifying for the rebate." *Id*. at 7.

In its rebuttal testimony, ComEd modified its proposal to provide customers receiving the rebate the option to "choose to remain on Rate BESH, or choose to take service pursuant to either: (i) an approved ARES TOU rate…or (ii) a potential future ComEd TOU rate, that is not offered on a limited, pilot basis, if and when one is approved by the Commission." ComEd Ex. 10.0 at 24. In its surrebuttal testimony, ComEd further modifies its proposal to provide a third option, so "[customers receiving the rebate] may elect to participate in ComEd's proposed Rate Optimization Pilot." ComEd Ex. 15.0, 17.

While Staff supports ComEd's proposed modifications, Staff has concerns with ComEd's proposal to place customers receiving a rebate onto "Rate BESH, as a default, in circumstances when no other eligible option has been elected by the customer." ComEd Ex. 15.0 at 17. Staff testified that "[e]nrolling customers onto ComEd's Rate BESH as the default rate and then having customers switch to an incentive program of their choosing will complicate an already novel experience for most customers which could disincentivize customers and lead to low program participation." Staff Ex. 20.0 at 15. Switching customers onto Rate BESH, when the customer did not elect to enroll in that program, creates a risk that the customer will not understand the intricacies of the hourly pricing rate they are being enrolled in or how they will be charged for their electricity usage and the effect that will have on their electric bill. ComEd fails to justify the need to enroll some customers onto Rate BESH without their affirmative consent instead of allowing customers to choose between one of the eligible options when applying for the Residential EV Charging Infrastructure Sub-program rebate.

Placing customers onto Rate BESH, or any of the other incentive programs available, as a condition of the rebate and without the customer's affirmative consent could be detrimental to the customer. All customers should knowingly consent to the rate structure pursuant to which they will be charged. Therefore, the Commission should direct ComEd not to place any customer onto Rate BESH, or any other incentive program, without the customer's affirmative consent. Staff Ex. 20.0 at 16.

Staff recommends the Commission reject both CJCP's recommendation that ComEd offer a TOU rate that includes distribution, transmission, and supply costs as part of the Company's BE Plan and the AG's recommendation that ComEd develop a TOU rate for generation and distribution charges. Staff Ex. 20.0 at 12.

Both of those proposals are in direct conflict with the Commission's mandate to promote retail electric competition in Illinois, because the rate would include supply / generation charges. Staff explains that Illinois is a restructured state in which customers have the right to choose whether they obtain their electric supply from the public utility or an ARES. These proposals "would result in the utility encroaching into the competitive retail electric market, which is not expressly allowed by P.A. 102-0662 and would go against the Commission's mandate to promote retail competition in Illinois." Staff Ex. 20.0 at 11. Therefore, the Commission should reject CJCP's recommendation for ComEd to offer a TOU rate that includes distribution, transmission, and supply costs as part of the

Company's BE Plan and the AG's recommendation for ComEd to develop a TOU rate for generation and distribution charges. Staff Ex. 20.0 at 12.

WeaveGrid recommends ComEd "tie Residential EV Purchase and Residential EV Charging Infrastructure subprogram incentives to participating in either Rate BESH or the optimization pilot." WG Ex. 1.0 at 16-17. In surrebuttal testimony, ComEd agreed to allow customers receiving the rebate to participate in the Company's proposed Rate Optimization Charging Pilot. ComEd Ex. 15.0 at 17. Therefore, Staff recommends the Commission approve the proposal that allows residential customers to participate in ComEd's optimization pilot as one of the options available to customers receiving the EV Charging Infrastructure Sub-program rebate. Staff Ex. 20.0 at 13.

Staff notes that ChargePoint recommends increasing the budget of ComEd's proposed Residential EV Charging Infrastructure Sub-program from $6 million to $14 million. As Staff has made clear, it would be inappropriate to expand the sub-program's proposed budget, especially given issues with the overall size of ComEd's proposed BE Plan relative to its retail rate cap and effect on ratepayers. Staff Ex. 14.0 at 8. ChargePoint urges allocation of additional funds to specific areas of ComEd's BE Plan from which ChargePoint stands to financially benefit, while failing to recognize, or perhaps simply ignoring, the reality that this expansion – more than doubling ComEd's proposed spending - would have a direct and adverse effect on the ratepayers who would pay for this increase. Under Staff's budget flexibility conditions, which are supported by ComEd, the Company has additional flexibility to shift funding to this sub-program after approval if demand is stronger than anticipated provided the flexibility conditions are met. ChargePoint's recommendation is unnecessary and should be rejected.

(iii) Residential BE Technology Adoption Sub-program

Staff asserts that the Commission should reject this sub-program for the reasons set forth in Section IV.B.

(iv) Residential BE Infrastructure Readiness Sub-program

Staff asserts the Commission should reject this sub-program for the reasons set forth in Section IV.B.

c. AG's Position

(i) Residential EV Purchase Sub-program

The AG agrees with the Interim Order's conclusion on this point and supports the removal of this program from ComEd's BE Plan.

(ii) Residential EV Charging Infrastructure Sub-program

ComEd proposed to spend $6 million annually on its Residential EV Charging Infrastructure Sub-program. This sub-program provides rebates to offset the costs of installing EV charging stations for residential customers who enroll in TOU rates. ComEd Ex. 1.01 at 36; ComEd Ex. 15.0 at 16. Staff argued that the budget for this sub-program should be $5 million. The AG does not oppose incentives for the installation of EV charging stations but maintains that the incentive amount established by ComEd is too

high. The AG also requests that the Commission exempt low-income ratepayers from the proposed requirement to enroll in a TOU rate. *See* infra Section VII.C.1.

(iii) Residential BE Technology Adoption Sub-program

ComEd proposed to spend $5 million on its Residential BE Technology Adoption Sub-program, which consists of "supplemental" rebates for high efficiency heat pumps and rebates for other residential non-transportation electrification technologies. Staff argued the Commission should remove this sub-program. The AG also recommends that the Commission remove this sub-program from the BE Plan because non-transportation electrification programs should not be permitted under the EVA as a matter of law. In addition, the AG maintains that non-transportation electrification programs are properly administered through ComEd's EE Plan, and thus, as a matter of policy, it is inappropriate to include non-transportation electrification programs in the BE Plan.

(iv) Residential BE Infrastructure Readiness Sub-program

ComEd proposed to spend $1 million on its Residential BE Infrastructure Readiness Sub-program. This program would provide rebates for residential customers to lower the cost of electrical infrastructure upgrades associated with the adoption of non-transportation electrification technologies such as heat pumps, water heaters, and induction cooktops. ComEd Ex. 1.01 at 37. These rebates would be delivered "alongside EEE program efforts." *Id*. As with the Residential BE Technology Adoption Sub-program, Staff argued the Commission should remove this sub-program. The AG also recommends that the Commission remove this sub-program from the BE Plan.

d. ICEA's Position

(i) Residential EV Charging Infrastructure Sub-Program

ICEA notes that over the course of the BE Plan litigation, ComEd has evolved its position on the Residential EV Charging Infrastructure Sub-program in a way that — if accepted by the Commission — would take what was originally a highly anticompetitive approach to (if all modifications are adopted) a far fairer and customer-beneficial approach. ICEA argues that the Commission should adopt the approach proposed in ComEd's surrebuttal testimony, subject to an additional modification to which ComEd confirmed it would not object and an additional change to prevent the need for an Integrated Distribution Company ("IDC") waiver.

ICEA notes that ComEd requested a waiver of Section 452.280(e) to allow ComEd to require every single residential customer participating in the residential EV charging infrastructure subprogram to take service under Rate BESH for three years. *See* Pet. at ¶ 12. ICEA raises that it and Staff strongly opposed this approach and separately sponsored testimony that urged the Commission to direct ComEd to allow customers to participate in the Residential EV Charging Infrastructure Sub-program while on an ARES time-variant supply product or service. *See, e.g*., ICEA Ex. 1.0 at *passim*; ICEA Ex. 2.0 at 9-11; Staff Ex. 9.0 at 5.

However, continues ICEA, ComEd eventually agreed that for participants in the Residential EV Charging Infrastructure Sub-program:

> each residential customer may choose to remain on Rate BESH or choose to take service pursuant to either: (i) an approved ARES TOU rate (subject to ARES affirmation that the TOU provides an adequate price signal); or (ii) a potential future ComEd TOU rate, that is not offered on a limited, pilot basis, if and when one is approved by the Commission.

ComEd Ex. 15.0 at 16. In other words, ICEA concludes, ComEd agreed that for the three-year period following the Residential EV Charging Infrastructure Sub-program rebate, ComEd no longer intended to restrict all residential customers to Rate BESH and instead allows ARES participation. ICEA argues that allowing customers to choose time-variant products and services will increase customer choices and benefit the nascent residential time-variant ARES product market. *See, e.g.*, ICEA Ex. 1.0 at 9-10; ICEA Ex. 2.0 at 10. ICEA further argues that residential EV customers are uniquely better positioned than other residential customers to allow ARES to offer time-variant products and services. *See* ICEA Ex. 1.0 at 5-6; ICEA Ex. 2.0 at 7-8.)

ICEA notes that in terms of the mechanics of supporting participation of customers on ARES time-variant products and services, ComEd further agreed with a proposal from ICEA witness Wright to work with stakeholders to create a warrant process that allowed ARES to communicate the affirmation to ComEd that the time-variant supply product or service would, in fact, qualify. *See* ComEd Ex. 15.0 at 17-18; *see also* ICEA Ex. 3.0 at 3-5.

ICEA further notes that in addition to requesting ComEd's cooperation, ICEA witness Wright also asked the Commission to clarify that in order to meet the "adequate price signal" standard:

> the ARES supply rate must change during each month (as opposed to a fixed-rate product with demand response) and the rate must be either: (1) indexed to a time-variant index (such as real-time locational marginal prices), or (2) split into regularly occurring intervals that are intended to differentiate between peak/super-peak and off-peak

ICEA Ex. 3.0 at 5. ICEA highlights that ComEd witness Fruehe did not indicate an objection to Mr. Wright's proposal. Taken together, ICEA concludes, these mechanical changes will present clear structures and rules under which ARES time-variant products and services can operate within the BE Plan structure for the Residential EV Charging Infrastructure Sub-program.

ICEA notes that ComEd further agreed in surrebuttal testimony to not switch residential customers who are on an ARES time-variant product or service to Rate BESH upon participation in the residential EV charging infrastructure subprogram. *See, e.g.*, ComEd Ex. 15.0 at 16-17. ICEA posits that while ComEd in its surrebuttal only committed to "considering" not automatically switching customers to Rate BESH from other ComEd rates or ARES products (other than time-variant products), ComEd clarified later in

discovery that it would not object to a Commission directive that ComEd not switch any customer to Rate BESH without affirmative customer action. *See* ComEd Ex. 15.0 at 18 (noting ComEd "consideration"); ICEA Cross Ex. 1 (indicating ComEd non-objection). ICEA argues that, taken together, ComEd: (i) agreed not to switch customers on ARES time-variant products and services to Rate BESH without affirmative customer consent and (ii) does not object to a Commission order prohibiting ComEd from switching a customer from all other supply options to Rate BESH without affirmative customer consent. ICEA advocates that these improvements will greatly improve the customer experience and reduce the likelihood of bad customer experiences with unexpected and unwelcome changes in supply rates.

ICEA notes that in surrebuttal, ComEd for the first time provided that participation in the Residential Optimized Charging pilot would be a third option (in addition to ComEd time-variant rates and ARES time-variant supply products and services) for residential customers participating in the Residential EV Charging Infrastructure Sub-program. *See, e.g.*, ComEd Ex. 15.0 at 17. ICEA submits that it does not object to the Residential Optimized Charging pilot as an option per se, but that ICEA does have substantial concerns with ComEd restricting customer supply options to Rate Basic Electric Service ("Rate BES") and Rate BESH. ICEA clarifies that some of its concerns are related to ComEd's proposed IDC waiver. ICEA expresses that it is also concerned that ComEd seeks to restrict access to the Residential Optimized Charging pilot to ComEd rates without any justification for doing so. ICEA concludes that it has no objection to the Residential Optimized Charging pilot serving as a third option for Residential EV Charging Infrastructure Sub-program participants, but the Commission should direct ComEd to allow ARES customers to participate.

ICEA notes that, according to ComEd's BE Plan, the Residential Optimized Charging pilot ramps charging based on wholesale energy prices:

> Optimized charging allows customers to modify the level of charge they receive passively within a charging session to optimize the savings available through an hourly pricing rate. This would also improve the overall grid efficiency by shifting EV charging to hours in which lower cost resources are available to meet their needs. Implementing passive optimized charging requires a third-party platform to schedule and modify customer charging levels in response to real-time PJM Locational Marginal Prices ("LMPs") subject to customer-defined constraints such as the desired charge level and duration of a charging session

ComEd Ex. 1.01 at 41. ICEA argues that Rate BESH does include a passthrough of PJM day-ahead LMPs, but neither the BE Plan nor subsequent testimony from ComEd witness Borggren describing the Residential Optimized Charging pilot explains why only Rate BESH — and not an ARES time-variant supply product or service—should qualify.

ICEA juxtaposes ComEd's arguments with the testimony of ComEd witness Newhouse, who explained in his surrebuttal testimony that customers participating in the Residential Optimized Charging pilot could choose not only ComEd Rate BESH but also

ComEd Rate BES. *See* ComEd Ex. 14.0 at 24. ICEA argues that if ComEd Rate BES — which has the same supply rate for every hour during a billing cycle — is an allowable supply rate for participation, there appears to be no reason that any ARES supply product (not just time-variant) should be eligible. ICEA continues that to the extent that ComEd has a reason in mind to restrict participation to ComEd customers when the pilot program is responsive to wholesale (i.e. the same market applicable to all) and not retail (i.e. customer specific rate) signals, it is not in the record.

ICEA deduces that because ComEd has not justified the restriction on taking ComEd supply service — as opposed to ARES supply service — for the Residential Optimized Charging pilot, the Commission should direct ComEd to allow residential customers on ARES supply to participate as well.

e. AEE's Position

(i) Residential EV Charging Infrastructure Sub-program

AEE strongly supports ComEd's proposed make-ready programs, including its Residential EV Charging Infrastructure Sub-Program. AEE states that the cost of make-ready infrastructure is typically one of the largest costs associated with installing EV charging facilities. AEE Ex. 1.0 Corr. at 7, 13-14. Make-ready costs can therefore end up being a major barrier to charger installation and hinder EV adoption. *Id*. AEE argues that ComEd's make-ready programs will meaningfully reduce that upfront cost barrier, allowing more of the Company's customers to adopt EVs and charge those EVs at home (including at multifamily buildings). *See* ComEd Ex. 12.0 at 16.

AEE states that make-ready programs are both a fundamental and common component of utility electrification plans. As AG witnesses Borden and Lane note, utility EV programs in other states have focused heavily on make-ready spending. AG Ex. 1.0 at 13-15. This is because, as the operators of the electrical infrastructure to which an EV charger must connect in order to receive service, utilities are well-situated to implement make-ready programs that defray the cost of that infrastructure and thereby facilitate broad and equitable access to EV charging. IEPA Ex. 1.0 at 10. As such, while utilities can and must play several roles in supporting the electrification of transportation in Illinois, AEE asserts that one of the most important roles that utilities can play is to offer robust, widely accessible make-ready infrastructure development incentives. AEE Ex. 1.0 Corr. at 15.

AEE notes that ComEd's BE Plan, however, dedicates only $6 million to its residential make-ready program, and $16 million to its make-ready programs in total out of an overall budget of $100 million. Several parties, including AEE, urge ComEd to reconfigure its electrification strategy to prioritize support for charging infrastructure installation. AEE Ex. 2.0 at 3-4. AEE specifically recommends that ComEd expand its proposed make-ready sub-program budgets such that, collectively, the Company's annual budget for make-ready incentives is closer to the $44 million retail rate impact cap (which limits ComEd's overall spending on charging infrastructure). As AEE witness Gallentine explains, "Illinois will require a substantial buildout of charging infrastructure, distributed throughout the state, in order to support its policy goals of one million EVs on the road by 2030. The most effective way to spur the installation of EV charging

infrastructure is through accessible charging infrastructure incentive programs." AEE Ex. 1.0 Corr. at 16.

AEE does not object to Staff's proposed modifications to ComEd's Residential EV Charging Infrastructure Sub-program, including the proposal to divide the Sub-program's budget between EJ/R3/IQ and non-EJ/R3/IQ customers. However, as discussed above, AEE recommends a substantially larger budget for ComEd's make-ready infrastructure incentive sub-programs. To the extent that the Commission does not adopt AEE's recommendation, AEE recommends that the Commission approve ComEd's proposed $6 million budget for the Residential EV Charging Infrastructure Sub-program (revised upwards from ComEd's originally-proposed $5 million budget), and decline to adopt Staff's proposed total $5 million budget for the sub-program. While AEE believes that ComEd's surrebuttal budget proposal does not adequately reflect the parties' broad support for the Residential EV Charging Infrastructure Sub-program, it represents an incremental improvement over ComEd's original proposal.

f. ChargePoint's Position

(i) Residential EV Charging Infrastructure Sub-program

ChargePoint supports utility programs that provide incentives to residential customers for the purchase and installation of residential L2 charging stations. ChargePoint witness Deal, explained that support of residential charging is vital for EV drivers, utilities, and ratepayers; with over 80% of EV charging occurring at home, implementing programs that reduce barriers to the deployment of residential charging stations and effectively manage residential charging will be critically important to achieving Illinois' goal of having one million EVs on the road by 2030. Additionally, ChargePoint states that most personal vehicles are stationary for 22 or more hours daily, meaning there is a massive potential to manage EV charging and encourage off-peak charging, providing benefits to the grid and all utility customers. The Residential EV Charging Infrastructure Sub-program will help customers overcome a key barrier to EV adoption: the cost of installing a L2 charger at their home.

According to ChargePoint, the Residential EV Charging Infrastructure Sub-program is critical for encouraging EV adoption and encouraging customers to charge their vehicles during off-peak periods. Further, the sub-program appropriately provides enhanced rebates to low-income customers and customers in eligible communities. ChargePoint asserts that the program's primary shortcoming is that ComEd has proposed a budget of only $6 million, which will likely be insufficient to meet customer demand and falls short of the General Assembly's vision for a sizeable utility investment in EV charging infrastructure. ChargePoint urges the Commission to ensure that the total budget for ComEd's EV charging infrastructure programs – namely, the Residential EV Charging Infrastructure Sub-program and the Make-Ready Rebate program – is equal to the retail rate impact limit of approximately $44 million. Specifically, ChargePoint recommends the Commission should direct ComEd to budget $14 million annually for the Residential EV Charging Infrastructure Sub-program. ChargePoint notes that if customer demand is lower than expected, then ComEd's actual spending and the amount ComEd collects from ratepayers to fund the program will be lower.

ChargePoint supports ComEd's proposal to target 50% of funding for this program for low-income customers and customers in EJ or R3 communities, and would also support actually reserving 40% of funds for these customers (rather than just target spending for these customers). ChargePoint does not oppose Staff's proposal to split this sub-program into two separate sub-programs, one for EJ/R3/IQ customers and one for non-EJ/R3/IQ customers, if doing so would improve flexibility and tracking. Finally, ChargePoint also supports ComEd's proposal to allow small multi-family properties to receive rebates through this sub-program, which will allow more residential customers to participate.

ChargePoint appreciates that ComEd has proposed to cover the entire cost of installing L2 chargers for residential customers (up to $2,500 standard and up to $3,750 for EJ/R3/IQ customers) because these costs can be substantial, especially in older houses, and pose a significant obstacle to EV adoption in the absence of a source of funding support. However, ChargePoint also notes that it is important to remember that the actual installation costs and thus the actual rebate awarded will be less than the maximum amounts for many if not most residential customers. According to ChargePoint, this fact alone mitigates many of the concerns expressed by the AG that ComEd's proposed residential rebates are too high because most customers will not receive the maximum rebate amount. ChargePoint further explains that, while the AG recommends reducing the rebate amounts for this sub-program, the AG does not recommend a specific dollar amount. ChargePoint requests that the Commission reject the AG's recommendation on the rebate levels for the Residential EV Charging Infrastructure Sub-program as unnecessary and unsupported.

ChargePoint appreciates that ComEd, along with other parties, agrees with ChargePoint's recommendation that the Residential EV Charging Infrastructure Sub-program should require customers to install L2 chargers "which are 'smart,' i.e., wi-fi enabled, ENERGY STAR[®] Certified, and UL listed at a minimum." ChargePoint notes that this recommendation appears to be uncontested for the Residential EV Charging Infrastructure subprogram and should be approved.

According to ChargePoint, requiring chargers to be smart ensures that all chargers funded through the program have the ability to connect to the internet and actively manage the charging of the electric vehicle. As EV adoption increases, the Company may seek to offer additional programs or incentives (e.g., demand response or active managed charging programs) to customers that leverage the capabilities of networked chargers. ChargePoint asserts that this requirement would ensure that any customers receiving utility support for the installation of residential charging stations would be capable of participating in existing time varying rates (including Rate BESH) or future managed charging programs without the need for additional investment to upgrade the charging stations.

ChargePoint explains that the U.S. EPA awards ENERGY STAR® certification to EV charging equipment that meets specific efficiency standards in standby mode, meaning that a charger conserves energy when not actively charging. ENERGY STAR® certified chargers can use up to 40% less energy than standard chargers while not in active use. To fully achieve the benefits of electrifying the transportation sector,

ChargePoint recommends that the Commission require that all residential L2 charging equipment supported through utility incentives be ENERGY STAR® certified.

ChargePoint further asserts that ensuring that charging equipment is certified by a third-party Nationally Recognized Testing Laboratory ("NRTL") for safety, such as Underwriters Laboratory ("UL"), gives customers, utilities, and regulators confidence that they are purchasing or incentivizing products that have been rigorously tested to ensure safety and reliability. ChargePoint clarifies that it recommends that the Commission require chargers to be certified for safety by any NRTL, including UL, rather than specifically requiring safety certification by UL.

ChargePoint also appreciates that ComEd modified its original proposal to require residential customers that receive BE Plan incentives to take service on Rider BESH for a period of three years. Specifically, ComEd now proposes that Residential EV Charging Infrastructure Rebate recipients can choose to take service on Rider BESH, an approved ARES TOU rate, a potential future ComEd TOU non-pilot rate if and when one is approved by the Commission, or participate in the proposed Residential Optimized Charging pilot. Providing customers with flexibility and options is key to encouraging program participation. Accordingly, ChargePoint supports ComEd's modified proposed requirements for customers that participate in the Residential EV Charging Infrastructure Rebate Sub-program. Finally, ChargePoint notes that ICEA largely supports these modified proposed requirements and does not oppose ICEA's other proposed modifications.

With these modifications, ChargePoint recommends that the Commission approve the Residential EV Charging Infrastructure subprogram with a budget of $14 million.

(ii) Residential BE Technology Adoption Sub-program

ChargePoint does not oppose ComEd's proposed Residential BE Technology Adoption Sub-program because, consistent with the Commission's Interim Order, spending on these types of sub-programs that are unrelated to EV charging infrastructure does not count against the retail rate impact limit. However, ChargePoint recommends that if the Commission seeks to reduce the overall BE Plan budget or to mitigate the impact of increasing the budgets for the Make-Ready Rebate and Residential EV Charging Infrastructure Sub-programs consistent with ChargePoint's recommendation, it should reduce or eliminate the budgets for ComEd's non-transportation programs, including the Residential BE Technology Adoption Sub-program, before reducing the budgets for any of the transportation programs. ChargePoint notes that it does not ask the Commission to reverse its determination in the Interim Order that ComEd may propose non-transportation programs as a matter of law, but the Commission may reduce or eliminate the budget for these programs as a matter of sound policy.

(iii) Residential BE Infrastructure Readiness Sub-program

Consistent with the preceding discussion of the Residential BE Technology Adoption Sub-program, ChargePoint does not oppose the Residential BE Infrastructure Readiness Sub-program. If the Commission finds that any budget reductions are necessary, ChargePoint recommends that it should reduce or eliminate the budgets for

ComEd's proposed non-transportation programs, including the Residential BE Infrastructure Readiness Sub-program, before reducing the budgets for any of the transportation programs.

g. WeaveGrid's Position

(i) Residential EV Charging Infrastructure Sub-program

WeaveGrid supports the Residential EV Charging Infrastructure Sub-Program but proposed limited modifications. First, WeaveGrid recommends that the program should allow for customers who enroll in BESH, a time-varying rate product for ARES suppliers, a potential future TOU rate, or the Residential Optimization pilot, to participate. WeaveGrid explains that some customers may not initially want their whole home to be on the BESH rate, but they could be willing to have their EV's charging respond to the pricing signals in the BESH rate along with other signals.

Second, WeaveGrid recommends that the Commission should include a requirement that residential L2 charging stations incentivized by the sub-program meet ENERGY STAR® and NRTL/UL requirements. WeaveGrid supports adoption of only these standards, noting the disagreement in the record. WeaveGrid further states that ENERGY STAR® is a federal program that has been supported for decades and can save participants money by reducing energy being used during standby mode. WeaveGrid indicated that UL-listing provides additional assurance to customers that the charging equipment will work safely and effectively. WeaveGrid explained that no other party opposed these two standards for the residential programs.

Finally, WeaveGrid recommends that residential L2 chargers should not be required to be networked for customers to receive an incentive. WeaveGrid explains that while there is merit for customers investing in networked chargers if they desire the features, EV charging can be controlled by the networked capabilities in either vehicles (via telematics) or chargers. WeaveGrid notes ComEd's recognition of the potential for networked and/or smart capabilities in vehicles and chargers. WeaveGrid states that providing customers with choices for residential charging is well aligned with the directives of the EVA regarding stimulating innovation, competition and increased choices in electric vehicle charging equipment and networks.

h. LVEJO's Position

(i) Residential EV Purchase Sub-Program

LVEJO notes that ComEd initially included a Residential EV Purchase Sub-Program, which was dropped in response to the Interim Order, and those funds were reallocated to other sub-programs. The proposal includes moving $3M to C&I and Public Sector Light Duty, Medium Duty, and Transit EV Rebates, $2M to the Supplemental Rebates for High Efficiency Heat Pumps, and $1M to the Residential Charging Infrastructure Rebate. ComEd Ex. 12.0 REV at 3.

LVEJO generally supports the proposed replacements for the Residential EV Purchase Sub-program. However, the proposal still needs more detail about these reallocations. None of ComEd's testimony mentions whether any amount of this reallocation will still be reserved exclusively for EJ/R3 customers. The proposed changes

should keep the extra emphasis on helping EJ/R3 communities by carrying over the commitment that at least 50% of the moved funding will go to customers or businesses in those communities, even for the affected C&I and Public Sector Programs. This is also in-line with ComEd's commitment to rolling over unspent funds marked for EJ/R3 communities, rather than spending them on non-EJ/R3 customers/communities.

(ii) Residential EV Charging Infrastructure Sub-Program

LVEJO states that the Residential EV Charging Infrastructure Sub-program seeks to address the issue of lack of accessible charging equipment by offering rebates that lower the up-front costs associated with installing EV charging stations. While accessibility of chargers to residential customers is major barrier to widespread adoption of EV's generally, this is especially true for residents of multifamily housing, who disproportionately live in EJ/R3/low-income areas. LVEJO continues to emphasize the importance for the explicit inclusion of rebates and resources for these types of households within the plan. Support for these forms of households will be essential for meeting the charging needs of EJ/R3/low-income communities. LVEJO supports ComEd's proposal for including resources for them in this sub-program, as well as the in the C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program.

i. Commission Analysis and Conclusion

(i) Residential EV Purchase Sub-program

This program was removed by ComEd due to the findings in the Interim Order.

(ii) Residential EV Charging Infrastructure Sub-program

Staff recommends that this program be divided into two separate sub-programs – EJ/R3/IQ and non-EJ/R3/IQ. Staff's bifurcation proposal splits the funding for this program 50/50, with half of the funding going towards EJ/R3/IQ communities and half toward non-EJ/R3/IQ communities. ComEd committed to "target 50% of the funding for the overall Residential EV Charging Sub-program for EJ/R3/[low-income] communities." ComEd RB at 12, citing ComEd Ex. 2.0 at 6. The Commission agrees that ComEd should have budget flexibility, but for the purposes of this program the Commission finds that ComEd shall ensure that at least 50% of this program's funding goes towards EJ/R3/low-income communities. The Commission does not find Staff's bifurcation proposal necessary.

ComEd agrees to require customers receiving incentives under this program to participate in (1) Rate BESH, (2) a time-variant supply rate offered by an ARES, or (3) the Residential Optimization pilot for a three-year period. This appears to be supported by Staff and Intervenors and the Commission hereby adopts it. The Commission also adopts the standard proposed by ICEA for determining whether an ARES time-variant supply rate provides an "adequate price signal" as proposed by ComEd. Staff also requests that customers be allowed to enroll in an "active managed charging program." It is not clear what this "active managed charging program" is or would be and therefore this recommendation is denied.

The Commission agrees with Staff that rebate recipients should be required to make a selection among the available rate options when they apply for the rebate. Customers should be aware of the options and make an informed decision when applying for any rebates. The Commission does not accept ComEd's proposal to use Rate BESH as a default in the event a customer does not make an election. ComEd's concern that customers will not receive rebates in a timely manner if there is no default is not persuasive. The Commission does not fully understand the distinction between Staff's recommendation and ICEA's further modification to "allow the customer to receive the rebate upon making a choice at the customer's pace." Per Staff's recommendation, the customer also only gets the rebate upon making a choice of rate options, and it is entirely up to the customer when that happens.

The Commission finds that ComEd's proposal to focus on L2 chargers that are "smart" and ENERGY STAR® and NRTL certified is reasonable and it is adopted.

The AG's recommendation to exempt low-income customers from the requirement to participate in a time-variant rate is denied. *See* Section VII.C.1.

The Commission notes that ComEd already addressed and agreed to some of ICEA's recommendations regarding the Residential Program. Issues regarding the Residential Optimization pilot are addressed in Section V.A.4.

Some Intervenors recommend increasing the budget for this program and urge ComEd to reconfigure its BE Plan to prioritize support for charging infrastructure installation. The Commission agrees that support for charging infrastructure is important. However, the Commission finds merit in ComEd's other proposed programs and will not cut funding from other programs to add to this program in this BE Plan. The Commission is also not inclined to increase ComEd's budget to add more funding for this program. The budget is further addressed in Section V.C.1.

(iii) Residential BE Technology Adoption Sub-program

ComEd argues that the Residential BE Technology Adoption Sub-program addresses the complementary need for adoption of BE technology other than EVs, including high efficiency electric heat pumps. The Commission agrees with the Company in part. The Commission approves a limited scope of the Company's proposed non-transportation programs, specifically $2 million for residential heat pumps (Residential BE Technology Adoption Subprogram-Supplemental Rebate for High Efficiency Heat Pumps). ComEd specified that "[t]his sub-program is geared towards residential customers in ComEd's service territory and has a focus on customers residing in multi-family buildings who are either low-income or located in EJ or R3 communities." ComEd Ex. 1.01 at 33. ComEd notes that these customers will be eligible for this sub-program regardless of their choice of supplier. *Id*. For this BE Plan, however, cautious of the overall Plan budget and its prioritization, the Commission directs ComEd to reserve funding under these non-transportation programs only to the low-income customers and customers located in the EJ/R3 communities, including customers residing in multi-family buildings who are either low-income or located in EJ or R3 communities. This will also ensure a more transparent tracking of the success of the programs and ComEd's related customer outreach activities.

Parties have raised concerns regarding interactions between BE and EE portfolios. The General Assembly incorporated a degree of electrification in EE plans, but nothing suggests that EE plans are the sole or exclusive platform for offering non-transportation electrification incentives. ComEd points out that it is not required to demonstrate energy savings in the context of the BE Plan, so there is no risk that such savings would be "double counted." To ensure no double counting, ComEd shall not count any benefits, savings and costs under the BE Plan related to residential heat pumps and make-ready infrastructure programs towards the Company's 220 ILCS 5/8-103B obligations. The Company must ensure the residential heat pump and related make-ready components of the Company's BE Plan do not undermine the Company's efforts pursuant to Section 8-103B and the Commission-approved EE savings goals that were negotiated by the Company and stakeholders in Docket No. 21-0155. *See* Section V.C.5.a.

(iv) Residential BE Infrastructure Readiness Sub-program

Consistent with the findings in Section V.A.1.i(iii) above, the Commission approves a limited scope of the Company's proposed Infrastructure Readiness Sub-program. Specifically, $1 million is approved to only fund make-ready investments tied directly to heat pump installations under the Residential BE Technology Adoption Subprogram-Supplemental Rebate for High Efficiency Heat Pumps. *See* Section V.C.5.a.

2. C&I and Public Sector Program

a. ComEd's Position

ComEd states that its C&I and Public Sector Program seeks to promote the electrification of fleet vehicles, public transit buses, and school buses, install new public charging stations, and implement other non-transportation BE measures for C&I customers. ComEd budgeted approximately $66 million for this program, more than 40% of which will be targeted for applicants located in or primarily serving EJ or R3 communities. ComEd has proposed that the C&I and Public Sector Program be divided into four sub-programs to allow customers in these sectors to fully capture the benefits of BE technology.

(i) C&I and Public Sector EV Purchase Sub-Program

ComEd notes that the C&I and Public Sector EV Purchase Sub-program offers financial incentives for the purchase of electric fleet vehicles, including school and transit buses, to C&I customers. ComEd explains that higher incentives will be provided to customers that are either located in, or primarily serve, EJ and R3 communities.

ComEd proposed a budget of approximately $50 million for this sub-program per year. ComEd notes that different rebates will be awarded to five different classes of eligible vehicles. Specifically, a $5,000 rebate will be available for the purchase of light-duty vehicles, a $20,000 rebate for the purchase of medium-duty vehicles, a $50,000 rebate for the purchase of heavy-duty vehicles, a $120,000 rebate for the purchase of school buses, and a $80,000 rebate for the purchase of transit buses. ComEd Ex. 2.0 at 26. For C&I customers located in or primarily serving EJ/R3 communities, the rebate values would be higher – specifically, a rebate of $7,500 for the purchase of a light-duty vehicle, $30,000 for the purchase of a medium-duty vehicle, $75,000 for the purchase of

a heavy-duty vehicle, $180,000 for the purchase of a school bus, and $120,000 for the purchase of a transit bus. *Id*.

In response to LVEJO's recommendation that ComEd commit a higher portion of this sub-program's funding to low-income and EJ/R3 communities, ComEd notes that it agrees that funding for these communities is a priority. However, because this is the first BE Plan, and the rate at which customers in general, or any subset of customers, will claim incentives is not yet known, ComEd argues that its proposal to commit at least 40% of the funding for the overall C&I and Public Sector Program to low-income and EJ/R3 communities is reasonable. ComEd committed that, if any funds targeted to low-income and EJ/R3 communities are unspent in any given year, those unused funds will be rolled-forward for use in programs targeted to low-income and EJ/R3 communities in a future year. ComEd states that, if the portion of the budget targeted to those communities is increased above 40%, the likelihood that some targeted funds will go unused over the course of the BE Plan increases.

ComEd also argues that Staff's budgetary recommendations for this program should be disregarded. Staff first argues that the light duty, medium duty, and heavy-duty fleet sub-programs should be broken out between EJ/R3 and non-EJ/R3 categories for statutory tracking purposes. ComEd argues that this is unnecessary, because ComEd has already committed 40% of the C&I and Public Sector Program funding to the EJ/R3/low-income communities, and has committed that funding, if unspent in any given year, will be rolled over to a future year for use to benefit EJ/R3/low-income communities. ComEd notes that it will report this information in its annual reports; as a result, it is not necessary to sub-divide the budget.

Staff also states that the school bus and transit sub-categories should be "expanded" to low-income or IQ communities. But ComEd points out that its proposal already includes incentives for school buses ($120,000 per bus) and transit buses ($80,000 per bus) that would be available to any qualifying C&I customer, including customers located in low-income or IQ communities. Thus, ComEd states that it is not clear how Staff's proposal differs from ComEd's on this point. ComEd contends that its proposed budget is reasonable, and is divided into reasonably manageable sub-categories, as follows: light duty vehicle ($13 million), medium duty vehicle ($13 million), heavy duty vehicle ($10 million), school bus ($6 million), and transit ($8 million). ComEd argues that its budget should be adopted.

In response to the AG's argument that the rebates proposed by ComEd are duplicative of incentives offered by the federal government, ComEd notes that the AG does not identify the particular federal rebates to which it refers, but the rebates ComEd proposes to offer under this sub-program are not duplicative of federal incentives. ComEd argues that, given the uncertainty as to whether customers will actually be able to claim federal incentives, the incentives offered under ComEd's BE Plan are not duplicative.

ComEd also notes that it recognizes the CTA's concerns that the transit bus rebate sub-category in this sub-program should allow for payments to be made over several years, and ComEd has agreed to reserve funding across years in this program as CTA recommended.

(ii) C&I Public Sector EJ/R3 Charging Infrastructure Sub-program

ComEd explains that the C&I Public Sector EJ/R3 EV Charging Infrastructure Sub-program was initially designed to provide incentives for the installation of EV charging stations for public sector entities and public charging stations located in or primarily serving EJ or RJ communities. However, testimony from many of the parties reflected that there is a funding gap for C&I and Public Sector make-ready work. ComEd Ex. 12.0 REV at 3-4; *see also* AEE Ex. 2.0 at 3; CTA Ex. 4.00 at 1-2; EDF Ex. 2.0 at 7; ChargePoint Ex. 2.0 at 9; EVgo Ex. 2.0 at 11-13; Tesla Ex. 2.0 at 4. According to ComEd, the consensus among these opinions is that make-ready funding is particularly well-suited for a utility program. In response to this feedback and in accordance with the Interim Order, ComEd modified the C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program to focus on rebates for make-ready work.

Under the new design of this sub-program, ComEd says, incentives would go toward make-ready work, whether located on the customer side or ComEd side of the meter. If ComEd's Charging Delivery Classes are approved, ComEd explains that customers participating in those classes would not have to pay any upfront costs for ComEd-supplied make-ready infrastructure, and so would not be eligible for an incentive. ComEd has also proposed an alternative design, under which customers will have the option to make an upfront payment, and such a payment would be eligible for a rebate. ComEd states that it also commits to offer EJ/R3 customers technical assistance and information regarding other sources of funding or existing financing options. ComEd proposed a budget of approximately $10 million for the make-ready infrastructure sub-program per year.

LVEJO recommends there be some level of public participation regarding the entities that receive incentives under this program, since the infrastructure will be supporting public chargers. LVEJO suggested that public input should be incorporated into the application process to reflect that applicants have performed some sort of public outreach before the application can be approved. ComEd is open to including a criterion for applicants to demonstrate public participation in siting and expects to address this issue in detailed program design.

ComEd notes that Staff offers a series of recommendations concerning the budget and scope of this sub-program, which generally are not cohesive. In place of ComEd's budget proposal, Staff recommends that this sub-program should be bifurcated between EJ/R3/IQ recipients and non-EJ/R3/IQ recipients, with the former receiving $4.4 million and the latter receiving $1.5 million annually. Finally, Staff contends that incentives in this sub-program should be sized to offset only a portion of make-ready infrastructure costs. In response, ComEd argues that expanding the program while significantly reducing the budget, as Staff suggests, is not feasible, and Staff's proposal should therefore be rejected.

ComEd also argues that the package of incentives CTA has proposed (under which the BE Plan, rather than the CTA, would cover the full cost of make-ready infrastructure on CTA's side of the meter) is excessive, unreasonably preferential to the CTA, and should be rejected. ComEd observes that the bulk of the CTA's proposals

would require amendments to ComEd's existing Rider DE – Distribution System Extensions ("Rider DE") that would create special carve-outs for the CTA as a recipient of BE Plan incentives. ComEd argues this is an unreasonable outcome, and alone is sufficient to reject CTA's proposals.

In response to CJCP's argument that private fleets should also receive funding, ComEd notes that there is limited funding available within the BE Plan, and it is not feasible that this sub-program be expanded to address every possible C&I and Public Sector fleet at this time. CJCP also argue that the mechanism for determining whether an applicant is primarily serving EJ/R3 communities — by demonstrating that over 50% of the driving done by the vehicles will be in EJ/R3 communities — is arbitrary and overly burdensome, particularly for smaller fleets. CJCP IB at 18. But ComEd's approach to this determination is reasonable. It was endorsed by Staff, and it appears to be the most reasonable method on record to ensure that the entities involved are primarily serving the EJ/R3 communities. Targeting this sub-program to recipients located in, or primarily serving EJ/R3/low-income communities will ensure that the development of charging infrastructure occurs in the communities that need it most.

ComEd also disagrees with the CJCP assertion that ComEd's BE Plan does not address the methods that EV drivers may use to pay for charging at public charging stations. Specifically, CJCP recommend that the BE Plan should require incentive recipients to have credit card capability that at a minimum includes a card reader device physically located on the EVSE or at a kiosk that accepts the Europay, Mastercard and Visa ("EMV") chip and contactless payment from major debit and credit cards. ComEd notes that there is no evidence in this docket as to whether this standard would have an impact on the competitive marketplace for EVSE, or how the benefits compare to any such impact. *See* ComEd Ex. 6.0 at 18-19. ComEd does not recommend that this type of standard be required and the Commission should not require its adoption on a utility-specific basis.

ChargePoint, EVGo, and AEE also advance various arguments for expanding the program, but ComEd points out that expanding the program would increase competition for funds and would be detrimental to EJ/R3 communities. ComEd argues that its approach is a feasible and reasonable way to ensure that the benefits of BE accrue to EJ and R3 communities.

(iii) C&I and Public Sector BE Technology Adoption Sub-program

ComEd asserts that the carbon reduction and air pollution mitigation goals of the EVA make clear that it is important to encourage the adoption of BE technology in all sectors, not merely transportation settings. While C&I building operations present an important opportunity to reduce carbon emissions, ComEd states, there are substantial barriers for C&I and public sector customers to make efficient BE upgrades.

ComEd explains that it designed the C&I BE Technology Adoption Sub-program to provide monetary incentives to business and public sector customers who adopt qualifying non-transportation BE measures. ComEd points out that the value of each incentive will be determined based on the calculated emissions benefit of BE upgrades to applications, equipment types, or systems – otherwise known as a "Custom" measure.

Custom measures are site-specific, according to ComEd, which will offer technical assistance in the evaluation and implementation of custom BE projects in certain circumstances. ComEd states that the C&I BE Technology Adoption Sub-program is designed to complement other ComEd programs and is specifically aimed at helping customers with electrification projects that may not be eligible for a rebate, or would receive only a small rebate, through ComEd's EE Custom Incentive program. ComEd proposed a budget of approximately $2 million per year for this program.

The AG and Staff oppose this program because it is related to non-transportation measures. ComEd addresses these arguments in Section IV of this Order.

ChargePoint does not oppose this sub-program but argues that the budget of this sub-program and any other sub-program that supports non-transportation measures should be reduced before the budget of any sub-program dealing with transportation measures. ComEd believes the budget should be approved as is, with no reductions for any sub-programs. ComEd has also committed to not shifting funds from transportation initiatives to non-transportation initiatives for the first two years of the BE Plan.

(iv) C&I BE Infrastructure Readiness Sub-program

ComEd's proposed C&I BE Infrastructure Readiness Sub-program offers financial incentives for two non-EV categories of infrastructure upgrades. The first category, ComEd states, is for small business customers located in EJ or R3 communities to help cover the costs of upgrading infrastructure to support non-transportation BE technology, such as heat pumps, electric water heaters, or commercial food service equipment (the Small Business BE Infrastructure Rebate). The second category of rebates is for C&I customers to upgrade fossil-fueled forklifts to high efficiency electric forklift equipment (BE Forklift Infrastructure Rebate).

ComEd points out that there are steep upfront costs associated with both adopting new BE technology and upgrading infrastructure to accommodate such equipment, and these costs can present a barrier for customers to take advantage of BE technology. ComEd states that this is particularly true for the costs associated with upgrading infrastructure to support electric forklift equipment, which represents a large opportunity for the C&I sector to benefit from BE technology. By providing these rebates to C&I customers, ComEd contends that it will be able to help customers capture dramatic energy and emissions savings as well as savings on the overall maintenance of their equipment. ComEd proposed a budget of approximately $4 million per year for this sub-program. Under ComEd's proposal, the Small Business Infrastructure Rebate would be up to $10,000 per customer facility, and the High Efficiency Forklift Infrastructure Rebate would be up to $5,000 per unit, capped at $50,000 per customer facility. ComEd Ex. 2.0 at 34.

ChargePoint asks the Commission to reduce the budget for non-transportation sub-programs before reducing the budget of any of the transportation-related programs should the overall budget be reduced. ComEd does not believe that the budget for any of these programs should be further reduced after the extensive work it has done to create a balanced budget that will allow for the success of the BE Plan. ComEd has committed to not shifting funds from transportation initiatives to non-transportation initiatives for the

first two years of the BE Plan, with plans to reevaluate and ensure that EJ/R3/low-income customers are fully benefiting from the BE Plan after that period is complete.

b. Staff's Position

(i) C&I and Public Sector EV Purchase Sub-program

CTA requests that the Commission approve this sub-program and "include a finding that all CTA buses are eligible for the $120,000 per bus rebate because the CTA fleet serves EJ and R3 communities." CTA IB at 22. In Staff's opinion, it would be inappropriate for the Commission to make findings about the specific eligibility of any particular entity at this stage in the development of ComEd's plan, and the Commission should reject CTA's request. ComEd's BE Plan specifies that the $120,000 rebate amount is for "customers that are located in or primarily serve EJ or R3 communities." ComEd Ex. 1.01 at 40. The Commission should approve the broad parameters of the BE Plan sub-programs in this proceeding, pursuant to which ComEd will develop and implement program details and specifics, including eligibility requirements. While the CTA argues that its network serves all EJ and R3 communities since "the majority of Chicago is either in a low-income census tract or minority census tract," (CTA IB at 9) this conclusion is premature. The CTA should be required to demonstrate eligibility through the same process ComEd will develop for demonstration of eligibility that any other customer will be required to utilize. This will ensure that any funding CTA receives through this sub-program is primarily targeted at eligible communities whose prioritization the EVA contemplates and that no recipient receives the preferential treatment CTA seeks here.

(ii) C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program

Staff states that the Commission should direct that ComEd create a new sub-program that provides C&I customers with incentives for make-ready infrastructure for non-EJ/R3/IQ. Multiple parties support inclusion of a less geographically restrictive sub-program for make-ready infrastructure incentives. *See* CJCP IB at 18; Tesla IB at 10; ChargePoint IB at 8; AEE IB at 5-6. In fact, ComEd seems to be the only party to this proceeding that opposes such a sub-program. The Commission should also direct that incentives should only be provided to offset a portion of make-ready infrastructure costs, and not cover the costs for the charging station as the IEPA is granted with that statutory authority. Staff maintains the percent of overall budget for the C&I EV Infrastructure (EJ/R3) as that contained in ComEd's original filing. Staff recommends expanding the sub-program to IQ communities as well. Accordingly, the Commission should adopt the following sub-programs and annual budgeted amounts: C&I EV Infrastructure (EJ/R3/IQ) $4.4 million and C&I EV Infrastructure (non-EJ/R3/IQ) $1.5 million.

The Commission should also reject the AEE proposal to broaden eligibility to all C&I and Public Sector customers (AEE Ex. 1.0 at 5) and instead adopt Staff's recommendations which would broaden eligibility for C&I and Public Sector customers by establishing separate "buckets" of funds for EJ/R3/IQ customers versus non-EJ/R3/IQ customers.

Section 45(d)(2) requires the BE Plan to, in relevant part: "[a]ddress [EJ] interests by ensuring that are significant opportunities for residents and businesses in eligible communities to directly participate in and benefit from [BE] programs." 20 ILCS 627/45(d)(2).

AEE proposes to substantially increase the size of ComEd's C&I and Public Sector EV Charging Infrastructure sub-program and broaden the program's eligibility beyond public sector entities and public charging facilities located in EJ or R3 communities. ComEd states that the AEE proposal would fail to spur development of charging infrastructure in those communities that need it the most – namely, low-income/EJ/R3 communities – and thus contravenes the aims of P.A. 102-0662. ComEd Ex. 7.0 at 26.

Given that the BE Plan is not yet finalized, the AEE proposal may have the unintended consequence of negatively impacting programs designed to provide EV charging infrastructure for eligible communities. If the AEE proposal to expand eligibility to include all applicable customers is adopted, it may create significant competition for available funds, which may further diminish the opportunities for customers in eligible communities. Therefore, this proposal should not be adopted and instead Staff's proposal should be adopted, as Staff's proposal helps to ensure that Company targets for eligible community recipients will be met. Staff Ex. 15.0 at 28-30.

Staff asserts that the Commission should reject the ChargePoint proposal to increase the C&I and Public Sector EV Charging Infrastructure Sub-program budget. Instead, the Commission should adopt the budgets as recommended by Staff. The Commission should also reject the ChargePoint proposal to broaden eligibility to all nonresidential customers, with higher incentives for customers in EJ/R3 communities, and instead adopt Staff's recommendations to broaden eligibility to all C&I and Public Sector customers as discussed earlier in this section that clearly set aside separate buckets of funds for EJ/R3/IQ versus non-EJ/R3/IQ. ChargePoint Ex. 1.0 at 5.

Section 45(d)(2) requires ComEd to, in relevant part: "address [EJ] interests by ensuring that are significant opportunities for residents and businesses in eligible communities to directly participate in and benefit from [BE] programs." 20 ILCS 627/45(d)(2). ComEd states that the ChargePoint proposal would fail to spur the development of charging infrastructure in those communities that need it the most-namely, low-income/EJ/R3 communities and contravene the aims of P.A. 102-0662. ComEd Ex. 7.0 at 26. Given that the final design of the BE Plan is not yet finalized, the ChargePoint proposal to increase the C&I and Public Sector EV Charging Infrastructure Sub-program budget may have the unintended consequence of negatively impacting programs designed to provide EV charging infrastructure for eligible communities. In Staff's opinion, if the ChargePoint proposal to expand eligibility to include all applicable customers is adopted, it may introduce significant competition for those funds which further diminish the opportunities to serve eligible communities. Staff Ex. 15.0 at 30-32.

For these reasons, Staff concludes that the Commission should reject ChargePoint's proposal because BE plan implementation is necessary to protect against unintended negative consequences to the eligible communities. Instead, the Commission should adopt Staff's proposal as a reasonable compromise. ChargePoint objects to the standard proposed by ComEd and supported by Staff to be used to determine when

charging equipment is "located in or primarily serving EJ or R3 communities" which would require that the "applicant demonstrates that over 50% of the driving done by vehicles to be served by the charging infrastructure will be in EJ/R3 communities." ComEd 12.0 REV at 19. ChargePoint claims this method would require speculation on the part of site hosts which would lead to attempts at gaming and proposes instead that the Company provides enhanced rebates for charging infrastructure in eligible communities while still providing smaller rebates for nonresidential customers locating chargers outside of eligible communities. ChargePoint IB at 11-12.

Staff states that the alternative method that ChargePoint proposes is problematic for a number of reasons. First, it makes no distinction between charging equipment near eligible communities and charging equipment located miles away from such communities when considering methods to reduce emissions that affect the residents of those communities. This does not appear to comport with the objectives set forth both in Sections 45(d)(3) and 45(d)(4), which refer to charging equipment or vehicles in or serving EJ, low-income, and eligible communities. 20 ILCS 627/45(d). Additionally, the problems that ChargePoint describes relate more to passenger vehicle charging stations than to charging equipment used at C&I facilities by companies that know the routes on which vehicles drive or that possess data on past routes. Having to estimate or project driving locations of vehicles that charge using rebated equipment is less of an issue for such fleet vehicles, which are likely to regularly use certain routes or serve certain facilities or customers. Notably, eligible communities face large levels of pollution from industrial and multimodal facilities that may employ fleets and install private chargers for use by those fleets. ComEd Ex. 1.01 at 22; LVEJO Ex. 1.0 at 7. Commercial charging stations for passenger vehicles available for public use also receive payment for charging regardless of whether utilities provide rebates. For these reasons ComEd's proposed method is preferable to the one proposed by ChargePoint despite the difficulty of determining the location of driving done by charged vehicles for public stations.

(iii) C&I and Public Sector BE Technology Adoption Sub-program

Staff states that the Commission should reject this sub-program for the reasons set forth in Section IV.B.

(iv) C&I BE Infrastructure Readiness Sub-program

Staff states that the Commission should reject this sub-program for the reasons set forth in Section IV.B.

c. AG's Position

(i) C&I and Public Sector EV Purchase Sub-program

The AG does not categorically oppose this sub-program, but notes that the rebates proposed are duplicative of existing incentives offered by the federal government and agrees with Staff that the amount should be reduced to ensure that the overall budget for the BE Plan remains below the retail rate cap.

(ii) C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program

ComEd proposes to spend $10 million on rebates for make-ready infrastructure for EV charging facilities. Staff argues that the Commission should reduce the budgeted amounts to $5.9 million in total. Staff Ex. 17.1. The AG agrees with Staff's reduction and argues that further reductions are needed to ensure the overall budget does not exceed the retail rate cap.

(iii) C&I and Public Sector BE Technology Adoption Sub-program

ComEd proposes to spend $2 million on this sub-program. The AG recommends that the Commission remove this sub-program from the BE Plan because non-transportation electrification programs are not permitted under the EVA, those programs are not properly coordinated with and conflict with ComEd's EE plan and including such programs would be imprudent policy.

(iv) C&I BE Infrastructure Readiness Sub-program

ComEd proposes to spend $4 million on this sub-program. The AG recommends that the Commission remove this sub-program from the BE Plan because it is not a transportation related program.

d. CJCP's Position

(i) C&I and Public Sector EV Purchase Sub-program

CJCP point out that ComEd's rebates for purchase of C&I and Public Sector EVs have the potential to reduce the total cost of ownership of new EVs as well as help overcome the upfront cost barrier resulting from the purchase price of EVs, which remain high compared to their gas- and diesel-powered equivalents. CJCP go on to state that this funding for vehicles, however, far outpaces what ComEd is proposing to support the deployment of make-ready infrastructure for these vehicles – another upfront cost of electrification. CJCP state that utility support in providing make-ready infrastructure similarly overcomes an upfront cost barrier and improves the total cost of ownership of commercial EVs. Indeed, CJCP aver, the relative paucity of make-ready support to ensure successful deployment of charging infrastructure in the C&I sector risks undermining the intended impact of the vehicle rebates sub-program, since EVs without adequate access to charging are of no use anyway.

Clean Jobs Coalition Parties point out that CTA/City argue that because CTA serves the entire Chicago region including "all of the city's EJ and R3 communities," and is a critical source of transportation for residents of those communities, its entire bus fleet should be eligible for the enhanced EJ/R3 transit bus rebate, which would increase the available per-bus incentive from $80,000 to $120,000. CJCP agree that transitioning transit fleets such as CTA is of critical importance for providing the benefits of transportation electrification to all people in Illinois, including those "for whom car ownership is not an option," 20 ILCS 627/45(d)(iv), and that the Commission should therefore direct ComEd to make CTA and other similarly situated transit agencies in their service territory eligible for the EJ/R3 enhanced vehicle purchase rebate. As such, CJCP agree with CTA/City's request that these vehicle purchase rebates be payable beyond

the year in which they are awarded, given the fact that the procurement process and the associated government bidding requirements can extend the process beyond a single calendar year. Because this change will lower the barriers for transit agencies seeking these rebates, thereby facilitating greater bus electrification, Clean Jobs Coalition Parties support this change to the BE Plan.

(ii) C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program

CJCP state that make-ready infrastructure is a necessary component of EV charging infrastructure and can make up a significant portion of infrastructure costs for a commercial charging customer. EDF Ex. 1.0 REV at 13. Given this, Clean Jobs Coalition Parties point out the proposed rebates for make-ready infrastructure would be a valuable tool for those eligible customer segments. Despite this importance, CJCP state, the proposal includes several flaws that may significantly limit the impact of the sub-program, namely the exclusion of private fleets, the limitation of only supporting customers located or operating in EJ and R3 communities, and the failure to ensure MHDV fleets will benefit from the program. EDF Ex. 1.0 REV at 11-12. According to CJCP, a certain amount of focus on private medium- and heavy-duty fleets is made all the more important by the fact that the IEPA rebate for vehicles and charging stations is designed to accommodate light-duty vehicles and public chargers, respectively, if the IEPA charger rebate currently being finalized does not change. As CJCP state, this means that many MHDVs, including public transit and school buses that charge at private sites will not be eligible for IEPA rebates and will not have an alternative through this proposal. EDF Ex. 2.0 at 5.

CJCP highlight several flaws in the current iteration of the Company's program. First, CJCP state ComEd's failure to make private fleets relying on depot charging eligible for any of the funding in this sub-program is a serious omission; because MHDVs have distinct charging needs as compared to light-duty vehicles—including both higher power needs and diverse operational profiles—this means most electric trucks and buses will rely primarily or exclusively on charging infrastructure at non-publicly accessible depots for their charging needs. EDF Ex. 1.0 REV at 8-9. CJCP state this is particularly true in the near term, as the earliest electrifying fleets are more likely to be fleets with local or regional operational profiles that involve returning to depots to charge overnight, rather than long-haul operators that rely on enroute charging. However, Clean Jobs Coalition Parties are concerned that despite this, the only depot charging supported by this sub-program is for public-sector entities such as schools, transit agencies, and other government fleets. ComEd Ex. 2.0 at 28. CJCP's rationale is that, given the significant pollution and climate burden caused by these vehicles, EDF Ex. 1.0 REV at 5-6, the failure to include private MHDVs in this program fails to adequately account for the deep reductions that will be needed in order to protect the health of the environment and Illinoisans disproportionately impacted by freight emissions.

Second, CJCP state, by limiting access to this sub-program to those public-sector entities and publicly accessible charging stations "located in or primarily serving EJ or R3 communities," ComEd Ex. 2.0 at 28, ComEd's proposal fails to recognize the value of emissions reductions outside of these communities, and the indifference that vehicle emissions (particularly greenhouse gas emissions) have with respect to geographic boundaries. Clean Jobs Coalition Parties fully support prioritizing deployment in these

communities – however, they state this prioritization should take the form of higher incentives and a dedicated budget set-aside for charging stations in or serving these communities, rather than a wholesale exclusion of those charging customers not falling into those categories. EDF Ex. 2.0 at 7. CJCP state ComEd's proposal also risks creating incentive cliffs, where a small change in a charging station's usage could create large changes in incentive eligibility. Per ComEd witness Borggren, who states that a charging station would be deemed to be primarily serving an EJ/R3 community "if the applicant demonstrates that over 50% of the driving done by the vehicles to be served by the charging infrastructure will be in EJ/R3 communities," ComEd Ex. 12.0 REV at 18, CJCP posit this may mean that a public-sector fleet with 50% of its driving in EJ/R3 communities, or that uses a particular charging station in an EJ/R3 community, could be eligible for up to $500,000 per year for make-ready, while a similar fleet with 49% of its driving in those communities is completely ineligible for that support. In addition, CJCP state this creates a significant administrative burden, particularly for smaller fleets. In sum, CJCP posit that having to prove in advance and with a high degree of certainty where vehicles are traveling and charging might result in a barrier to EV adoption without a clear benefit. ComEd's requirement, assuming Clean Jobs Coalition Parties have interpreted it correctly, would be both arbitrary and administratively burdensome.

Third, CJCP state the sub-program as proposed does not guarantee that any funding would actually be dedicated to MHDVs. CJCP state this is because the program is open to "[a]ll such customers taking delivery service from ComEd," ComEd Ex. 2.0 at 28, such that the $10 million budget could be entirely used up by public charging stations serving light-duty vehicles, with no money available for MHDVs. In this way, CJCP aver, this outcome would not be consistent with addressing "make-ready investments" to "facilitate the electrification of public transit and other vehicle fleets in the light-duty, medium-duty, and heavy-duty sectors" as directed by the EVA. 20 ILCS 627/45(d)(i).

Even if the Commission were to approve ComEd's proposed EV charging delivery classes or its alternative proposal, Clean Jobs Coalition Parties state, the BE Plan itself would still need to be strengthened to provide adequate support for make-ready investments – given that the delivery classes are outside the confines of what is at issue within ComEd's BE Plan – and address the serious limitations of this sub-program. Per CJCP, the EVA requires the BE Plan itself to address such make-ready investments, 20 ILCS 627/45(d)(i), and the Company has stated that the charging class proposals "are independent of the BE Plan" and "must be adopted as rates, not as part of the BE Plan." ComEd Ex. 10.0 at 6. To that end, state CJCP, approval of those proposed delivery classes cannot be used to satisfy the requirements of Section 45(d) of the EVA. CJCP aver that ComEd could address these shortcomings of the C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program by expanding eligibility criteria to include private fleets and fleets located and operating outside of EJ/R3 communities, while guaranteeing a portion of the sub-program budget for MHDVs, and a set portion of the budget and higher incentives for fleets located or operating in EJ/R3 communities.

Clean Jobs Coalition Parties state another concern with this sub-program has to do with EV driver payment methods that can be accepted at public charging stations; more specifically, the fact that the permissible payment methods that EV drivers can use to charge at public charging stations were not addressed. Clean Jobs Coalition Parties

witness Baumhefner noted that, in its proposed BE Plan, ComEd states that it supports accessibility and ease of payment for all charging infrastructure its customers will use, but that this is its first BE Plan situated in a "developing ecosystem." ComEd should be able to rely on real-world experience over the last twelve years in the U.S EV market. As Mr. Baumhefner put it, "[d]rivers should be able to pay for charging as easily as they can buy gasoline." NRDC Ex. 2.0 REV at 44. As evidence, CJCP cite an extensive public process in California, after which the California Air Resources Board put in place standards in 2019 that require EMV chip card readers at all public charging stations that can accept credit, debit, and cash cards. CJCP aver that EMV chip is the most secure and dominant payment technology upon which consumers rely; contactless card payments constitute a small percentage of in-person payments. NRDC Ex. 2.0 REV at 45-47. Under ComEd's plan, CJCP state, many individuals who live in EJ/R3 communities, where ComEd has targeted publicly-accessible charging stations, will not be able to use those charging stations without payment standards that will accommodate their payment methods. Many such individuals are low-income, unbanked, or underbanked. As Mr. Baumhefner stated, unbanked individuals pay for gas, or charging, with either cash or prepaid cash cards. NRDC Ex. 2.0 REV at 48. As such, CJCP state, ComEd's plan will not require a payment option that comports with the preferred payment method of nearly one-quarter of all drivers, and a much larger portion of unbanked drivers. As such, state CJCP, given the obvious difficulty of using cash to pay for EV charging, prepaid cash cards are the remaining viable alternative to meet the needs of most unbanked drivers; such cards require EMV chip readers because most prepaid debit cards lack contactless capability and are not compatible with Apple Pay or Google Pay mobile wallets. NRDC Ex. 2.0 REV at 48-49. CJCP recommend ComEd should be required to adopt minimum payment standards for public charging stations that will serve the needs of unbanked individuals, which will align with P.A. 102-0662's equity goals and with current standards for public charging stations in half the U.S. market. NRDC Ex. 2.0 REV at 49. Specifically, CJCP state, ComEd should adopt payment requirement language that requires qualifying installations to have credit card capability that at a minimum includes a card reader device physically located on either the EVSE or kiosk that accepts the EMV chip and contactless payment from major debit and credit cards. NRDC Ex. 2.0 REV at 50.

CJCP point out that various parties make several arguments with respect to this sub-program: both Staff and the AG recommend significant cuts to ComEd's proposed budget that would decrease the sub-program budget to $5.9 million under Staff's proposal, or approximately $3.7 million under the AG's Office's proposal. As CJCP point out, several parties disagree, arguing that the budget for this sub-program should be increased. Clean Jobs Coalition Parties agree with the latter group that ComEd should do more to support the installation of make-ready infrastructure to serve both public and private commercial EV charging. As a preliminary matter, CJCP posit, the recommended budget cuts from Staff and the AG's office are not the result of those parties' opposition towards ComEd providing such incentives for make-ready infrastructure, but rather are based on these parties' objection to how the retail rate cap is calculated. Clean Jobs Coalition Parties believe the Commission correctly interpreted the EVA's statutory provisions regarding the retail rate cap; the BE Plan's budget, as proposed, falls short of, rather than exceeds, that cap. CJCP also point out that Staff and the AG's office also fail to grapple with the importance, and potential cost, of make-ready infrastructure. This is

because, CJCP state, make-ready is a necessary part of installing EV chargers and can make up a significant fraction of customer's total infrastructure costs. It is crucial that ComEd's BE Plan maximize the potential benefits through supporting make-ready installation. In order to do this, CJCP state, the Commission should direct ComEd to increase, rather than slash, the budget for this sub-program.

CJCP support the several parties who recommend that the sub-program be expanded to offer incentives for nonresidential charging infrastructure in both EJ/R3 communities and non-EJ/R3 communities, rather than limiting incentives to only those sites located in or primarily serving EJ/R3 communities.

Clean Jobs Coalition Parties do, however, continue to support a dedicated budget allocation for make-ready support in EJ/R3 communities, something which is supported by several other parties. CJCP state that customers located in or serving these EJ/R3 communities should be eligible for higher rebates, to reflect the greater need for a transition to EVs in those areas.

BOMA/Chicago proposes a modification to this sub-program that would provide $10 million per year for make-ready infrastructure in BOMA/Chicago buildings in the Chicago Central Business District. Staff recommends approving this proposal with modifications, specifically by modifying the proposal to allow BOMA/Chicago members and other organizations to apply for make-ready incentives in the existing C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program "collectively rather than individually." Staff IB at 35. Clean Jobs Coalition Parties support Staff's recommendation to allow interested parties to apply for charging infrastructure sub-program funding in groups, as this allows for flexibility for innovative deployment scenarios, such as joint landlord/tenant-funded projects and charging hubs with ownership shared among several parties. BOMA/Chicago's proposal, CJCP avers, however, would not do enough to turn the Chicago Central Business District into an "all-electric vehicle transportation hub" as Staff envisions. Staff IB at 34. As stated by CJCP, this is because BOMA/Chicago's proposal focuses on the "residents, visitors and tourists" most likely to park their vehicles in BOMA/Chicago's members' garages and buildings, and neglects to include any meaningful consideration of the MHDVs that do not fall neatly into these categories. According to CJCP, this is a troubling omission, as Staff's qualified support for BOMA/Chicago's proposal is based in large part on its supposed potential to "reduce the level of pollution due to medium-duty and heavy-duty vehicles in a major transportation hub." Staff IB at 34-35. As such, CJCP state, in reality it is unclear how—if at all—these vehicles would be served by BOMA/Chicago's proposal. For that reason, CJCP urge the Commission should instead focus its attention on increasing the budget and accessibility of the C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program proposed by ComEd, rather than carving out narrowly applicable sub-programs as proposed by BOMA/Chicago.

CJCP point out that multiple parties recommended modifications to the $500,000 per customer, per year limitation on make-ready incentives through this sub-program. CTA proposed, and ComEd agreed, that this limit be applied per-garage for CTA. ComEd Ex. 12.0 REV at 20-21. In order to recognize the need to prioritize the electrification of transit buses, Clean Jobs Coalition Parties support this modification.

In addition, CJCP point out, EVSPs argue for further modifications to this per-customer limitation. As an example, CJCP point out that Electrify America proposes that this incentive cap be applied per site host rather than per customer. Electrify America IB at 10. Additionally, CJCP state, EVgo argues that, as clarified by ComEd, the per customer limitation would in fact apply to individual charging stations at separate sites rather than a single operator of stations at multiple sites. EVgo IB at 8. Finally, CJCP point to the Staff argument that the BE Plan should retain the per customer limitation to ensure incentives are going to ratepayers, rather than third-party agents or contractors, and that making the limitation applicable to site hosts "runs contrary to enabling diverse and equitable distribution of BE Plan benefits" and would result in "favoring certain EVSP business models over others." Staff IB at 37. Clean Jobs Coalition Parties agree that BE Plan incentives should be designed to benefit ratepayers, but caution against creating restrictions that would unnecessarily restrict EVSP business models. Where an EVSP is a ratepayer and operates charging stations at multiple sites, CJCP state that EVSP should be able to access incentives in this subprogram on a per-site basis – since such a program design is consistent with the EVA's recognition that "[w]idespread adoption of electric vehicles requires increasing public access to charging equipment throughout Illinois…" 20 ILCS 627/45(a)(7). CJCP also posit that this design would also support fleet electrification through supporting alternative business models such as charging-as-a-service, where an EVSP — which may serve multiple fleets — may be responsible for both infrastructure installation and charging operations, passing costs through to the customer. As with public charging use cases, CJCP state that customer limitations that ignore the use case of a large customer with multiple sites would be restrictive and contrary to the EVA goals that contemplate encouraging medium- and heavy-duty vehicle electrification. 20 ILCS 627/45(d).

CJCP point to an EVgo proposal that "ComEd rely on a 'one-mile buffer' around EJ/R3 communities to create a clear parameter that can be implemented without added ambiguity or determining whether a proposed site 'primarily serves' an EJ/R3 community." EVgo IB at 6. CJCP also cites EVgo's contention that "as explained in EVgo's direct testimony, other jurisdictions have adopted this requirement with success." EVgo IB at 6. However, as CJCP points out, the explanation to which EVgo refers is one sentence of a Public Service Enterprise Group ("PSEG") program; they state simply that "PSEG has adopted this framework for their make-ready infrastructure program." EVgo Ex. 1.00 at 8. CJCP also point out that both Staff and ComEd oppose this recommendation; ComEd states that "the suggested one-mile buffer is not appropriate, as it is too far a distance in certain areas, where there is an EJ community that is one block," ComEd Ex. 7.0 at 26, and Staff states "as employed by PSEGLI [PSEG Long Island], such a buffer zone is only considered for DCFC installations" and "as [ComEd witness] Borggren points out, such a definition would grant undue additional benefits to entities locating chargers in Downtown Chicago and other areas where users are unlikely to primarily drive in or serve EJ and R3 communities." Staff Ex. 14.0 at 23. Clean Jobs Coalition Parties agree that this buffer is inappropriate. CJCP admits that an overly prescriptive definition of whether a fleet "primarily serves" EJ or R3 communities is difficult to implement and may lead to unintended consequences. That is, they state, fleets that do operate inside those communities and would offer significant air quality benefits in EJ and R3 communities, but whose exact degree of operation in those communities may be hard to predict in

advance and may fluctuate over time, might be arbitrarily shut out. However, CJCP draw a distinction between that and EVgo's proposed solution, which they state is so blunt as to risk eliminating all benefit to those communities. As such, CJCP state, instituting a "buffer" around these 12 communities would inappropriately and unnecessarily dilute the ability of these programs to prioritize benefits in EJ and R3 communities; per Clean Jobs Coalition Parties, the Commission should not accept EVgo's suggestion.

(iii) C&I and Public Sector BE Technology Adoption Sub-program

CJCP is troubled by the fact that Staff continues to advocate against non-transportation sub-programs in the BE Plan; they state that "the Commission should reject ComEd's proposal to spend $10 million per year on non-transportation electrification sub-programs in its BE Plan" since "ComEd's proposal flies in the face of the plain statutory language in the [EE] statute." Staff IB at 13. Per Clean Jobs Coalition Parties, Staff's continued adherence to this notion is inappropriate for several reasons. First, CJCP state, the rationale provided in the Interim Order is sound—the plain language of the statutory phrase BE programs as defined in the EVA is the best evidence, and when unambiguous — as it is here — is determinative of legislative intent. Interim Order at 15. "If a statutory provision is unambiguous, we must apply it straightforwardly, without reading in exceptions, limitations, or qualifications." *Save Our Ill. Land v. Ill. Commerce Comm'n*, 2022 IL App (4th) 210008, as modified upon denial of rehearing (2022), ¶ 49, (quoting *People ex rel. Webb v. Wortham*, 2018 IL App (2d) 170445, ¶ 31). CJCP state the Illinois Supreme Court recently reiterated the well-settled central tenets of how statutory construction is to be approached when faced with clear and unambiguous statutory language, stating "[t]he primary objective of statutory interpretation is to ascertain and give effect to the intent of our legislature." *People v. Leib*, 2022 IL 126645, ¶ 28. "[T]he plain and ordinary meaning of the statutory language … is the surest and most reliable indicator of legislative intent." *Id*. "Where that language is clear and unambiguous, we must apply the statute without further aids of statutory construction." *Id*. In this case, the language is clear. As stated by CJCP, Section 45 of the EVA states, the intent of the General Assembly is "to decrease reliance on fossil fuels, reduce pollution from the transportation sector, increase access to electrification for all consumers, and ensure that electric vehicle adoption and increased electricity usage and demand do not place significant additional burdens on the electric system and create benefits for Illinois residents." 20 ILCS 627/45(a). As discussed in Clean Jobs Coalition Parties' response to Staff's Combined Motion that resulted in the Interim Order, "it would be unreasonable to interpret Section 45 to apply only to Evs and transportation and thereby give 'decrease reliance on fossil fuels,' 'increase access to electrification for all consumers,' and 'create benefits for all consumers.' Either no meaning or unduly restrictive meanings." CJCP Response to Staff's Combined Motion at 3 (Sept. 16, 2022). Reading a qualification into the language that does not exist — namely that only transportation is contemplated—is contrary to principles of statutory interpretation; as such, the Interim Order holding is appropriate.

Moreover, CJCP point out that Staff's use of an inapposite piece of legislation – the EE statute – provides another reason for finding their argument unpersuasive. This is because, per CJCP, this BE Plan process and resulting utility programs are a direct

product of the EVA and are thus governed by that statute; as such, requirements in the EE statute have no bearing in this instance and should not be regarded by the Commission as dispositive. Finally, state CJCP, it is inappropriate for Staff to continue to try and win on an issue that has been settled in this proceeding; because there is a case related to the Interim Order pending in appellate court, this is no longer the appropriate forum to raise such a concern. In sum, CJCP posit that the Interim Order was decided correctly and no further discussion of this issue is needed or appropriate.

e. Electrify America's Position

Electrify America supports proposals by other Intervenors to expand the C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program to all nonresidential EV charging customers in order to further incentivize and support the expansion of publicly available EV charging infrastructure in ComEd territory. It also supports the expansion of the sub-program in a way that prioritizes EJ/R3, stating that doing so will support the public interest goal of the EVA, while supporting EV infrastructure development throughout the state. *See* 20 ILCS 628/45(d)(3).

f. CTA/City's Position

(i) C&I and Public Sector EV Purchase Sub-program

ComEd's BE Plan includes two segments under the C&I and Public Sector Plan that directly affect the CTA's goal to complete the electrification of its diesel bus fleet by 2040. The first is the C&I EV Purchase Sub-program and the second is the C&I EV Charging Infrastructure Sub-program. Because electric buses cannot operate without being properly charged, funding for both sub-programs is vital.

CTA/City argue that ComEd's BE Plan should include funding to assist in the purchase of electric buses to help the CTA convert all of its over 1,800 diesel buses to electric. CTA/City support the inclusion of a bus purchase rebate in ComEd's BE Plan because the C&I and Public Sector EV Purchase Sub-program meets both the requirements of the EVA and assists the CTA in funding the acquisition of buses as part of its bus electrification plan. In addition, the CTA point out that a cash grant for bus purchases not only provides a reduction in the amount the CTA would need to fund but also a ComEd award could serve as a local cash match for federal funds, thus leveraging the amount of the award. For these reasons, it also is important to allow the ComEd grants to extend for more than one year.

CTA testimony shows the base cost of a new diesel transit bus for the CTA is $600,000 and an electric transit bus is $1.1 million. In other words, the incremental cost of an electric bus over a diesel bus is $500,000 per bus and rising. No party disputed these costs. Under ComEd's revised proposal, the annual per bus rebate to the CTA should be $120,000, which is the amount ComEd designated for transit agencies located in or primarily serving EJ/R3 communities. Staff suggests that a decision on the amount of rebate to the CTA is "premature." On the other hand, CTA/City argue that $120,000 is the correct amount it should receive because the CTA serves the City, the majority of which is comprised of EJ/R3 communities, a fact not disputed by any party. In its Reply Brief, ComEd raises for the first time that there must be a bus-by-bus analysis and only buses that serve primarily EJ/R3 communities should receive the $120,000 rebate. As

the CTA showed, a transit bus route may originate, pass through, or terminate in an EJ or R3 community. In addition, a particular bus may be assigned to different routes over its lifetime. Rather than conduct a street-by-street analysis of each bus route and constrain any given bus to operating only on a specific segment of a single route, the CTA argues that it is appropriate to designate the CTA as qualifying for the $120,000 per bus rebate because the majority of its service is provided to EJ/R3 communities, any given route passes through such communities, and an individual bus covers an entire route and may operate on different routes over its lifetime.

ComEd's revised transit bus rebate sub-program would create an annual $8 million pool for the annual awards in a grant year. However, CTA notes that annual awards need to allow for payment over several years because electric transit buses are not an off-the-shelf purchase that can be completed in one year. Rather, buses are designed according to the detailed specifications of the transit agency purchasing the buses. The procurement process also must adhere to rigorous federal, state, and local requirements, which ensure that the contract award is competitive. The bidding requirements and delivery of the bus may extend beyond a particular calendar year. As a result, CTA states it is important that any grant for bus purchases awarded in a particular year be payable beyond the particular year of award. ComEd agreed through the rebuttal testimony of Ms. Borggren to modify the language to allow grants to carry forward into future years. Staff also agreed that a carry forward provision would be appropriate.

(ii) C&I Public Sector EJ/R3 EV Charging Infrastructure Sub-program

CTA testified that in order for the CTA to electrify its bus fleet, the CTA not only must purchase the electric buses but also must have the ability to charge the buses. An electric bus obviously cannot function without charging infrastructure. CTA presented evidence supporting inclusion in ComEd's BE Plan of a sub-program that awards rebates or incentives to help pay for the CTA's make-ready infrastructure needed for charging stations.

CTA's bus electrification plan provides for bus charging stations at the CTA garages. CTA's electric buses are charged using a gantry and pantograph. The CTA explained that, because existing diesel transit buses have a 14-year life, the CTA's fleet of more than 1,800 diesel buses will be replaced over an approximately 18-year period. The CTA outlined its plan to update the CTA garages incrementally, so they are ready as new electric buses are acquired and placed in service. Following studies and analysis of where and how the new electric buses will be phased in, as well as accounting for equity-related issues of air quality, health, and proximity to minority and low-income populations, the first two garages in the electrification sequencing are garages that service bus routes that received an overall "very high" rating for proximity to minority and low-income populations. In addition, the CTA contends that electrification of these garages "could also help push forward the grid infrastructure upgrades required to support charging, and the improved power infrastructure investment will benefit nearby residents and employers." CTA Ex. 1.02 at 2.

ComEd modified its C&I and Public Sector Charging Infrastructure Sub-program in its surrebuttal testimony by removing the actual chargers from the eligible equipment

per the Interim Order. Instead, the rebate program would apply to "make-ready work" on either side of the ComEd meter. ComEd defines "make-ready" to include the secondary line from the transformer to the charging station's stub. The CTA observes that ComEd's definition of "make-ready" is not as broad as the statutory definition of "make-ready infrastructure." Make-ready infrastructure should include all lines and equipment necessary for service to a charging station as contemplated by the EVA.

CTA/City argue the Commission should use the "make-ready infrastructure" definition in the EVA rather than the narrower ComEd definition and make clear that make-ready infrastructure is considered standard service for bus charging facilities. The necessary tariff modifications are discussed in Sections VII. B. 1 and 2 of this Order. In the workshops prior to ComEd's filing, CTA proposed that ComEd provide an incentive to cover the full cost of extending utility distribution infrastructure to the CTA's charging facilities. CTA/City argue that the full costs for the utility side make-ready infrastructure should include:

- Analysis and assessment of capacity requirements to meet all electric bus charging anticipated to occur at a facility;
- Design and engineering of a primary line and a secondary line to the facility to provide redundancy in the event of an outage; and
- Construction of the primary and secondary lines, including all required transformers, trenching, conduit, cabling, and other labor and materials to complete the new service to the CTA's meter.

In addition, CTA asserts the BE Plan should include incentives to cover a significant portion of the cost for make-ready infrastructure on the CTA side of the meter. This cost includes the design, engineering, electrical equipment (switchgear, controls, communications, etc.), housing, and HVAC for electrical equipment, materials, and labor to install the electric bus charging system from CTA's meter up to (but, per the Interim Order, not including) the actual charger that connects with the electric bus.

The total cost for changes to the electric system on the CTA side of the meter at each garage is estimated to be $20 to $30 million. In addition, the costs on the ComEd side of the meter could be as high as $3 to $7 million per garage. The costs on both sides of the meter should be included in the rebates or incentives under the Make-ready Infrastructure Sub-program.

In its surrebuttal testimony, ComEd removed the $500,000 per customer per year limitation for the CTA, instead applying this limitation on a per facility per year basis for the CTA. In addition to removing the limitations on the amount per year that could be awarded to the CTA, the CTA and the City argue that ComEd should not require the CTA to pay any deposits, letters of credit, design/engineering fees, or other ancillary costs that ComEd currently requires from the CTA where there are distribution line extensions. The CTA reasons that make-ready infrastructure costs should be considered standard service for which no deposit is required.

The CTA testified that, to the extent the Commission adopts ComEd's C&I and Public Sector EJ/R3 Charging Make Ready Infrastructure Sub-program and ComEd provides awards or incentives to the CTA to help pay for the CTA's make-ready

infrastructure, the CTA should retain full ownership, including operation and maintenance, of the installed make-ready infrastructure on the CTA side of the meter.

The CTA testified that the make-ready infrastructure would be installed in a 24/7 active bus garage with all its inherent safety and security considerations. In addition, because the facilities charge transit buses, the charging stations and the related equipment are critical infrastructure. The CTA asserts it cannot grant third parties unrestricted access to these facilities.

Unlike other ComEd customers, the CTA has the personnel and experience to maintain the electric facilities on its property. The CTA operates an electric rapid transit system, powered by a third rail that delivers current to the rapid transit trains. This means that all electrical equipment in the CTA substations, including transformers and conversion equipment, is maintained and operated by CTA personnel. Operation and maintenance of the electric charging facilities at the bus garages requires similar expertise as the operation and maintenance of the traction power substations, which the CTA has been doing for 75 years. Therefore, CTA/City assert the BE Plan should provide for ComEd to assist in funding "make-ready" infrastructure but not provide the option for ComEd to own, maintain, or operate the equipment at the CTA garages.

g. AEE's Position

(i) C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program

AEE strongly supports ComEd's proposed make-ready programs, including its C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-Program. AEE explains that the cost of make-ready infrastructure is typically one of the largest costs associated with installing EV charging facilities. AEE Ex. 1.0 Corr. at 7, 13-14. Make-ready costs can therefore end up being a major barrier to charger installation and hinder EV adoption. AEE Ex. 1.0 Corr. at 7, 13-14. AEE asserts that ComEd's make-ready programs will meaningfully reduce that upfront cost barrier, allowing more of the Company's customers to adopt Evs and charge those Evs in public locations.

AEE states that make-ready programs are both a fundamental and common component of utility electrification plans. As AG witnesses Borden and Lane note, utility EV programs in other states have focused heavily on make-ready spending. AG Ex. 1.0 at 13-15. This is because, as the operators of the electrical infrastructure to which an EV charger must connect in order to receive service, utilities are well-situated to implement make-ready programs that defray the cost of that infrastructure and thereby facilitate broad and equitable access to EV charging. IEPA Ex. 1.0 at 10. As such, while utilities can and must play several roles in supporting the electrification of transportation in Illinois, AEE observes that one of the most important roles that utilities can play is to offer robust, widely accessible make-ready infrastructure development incentives. AEE Ex. 1.0 Corr. at 15.

AEE notes that ComEd's BE Plan, however, dedicates only $10 million to its C&I and Public Sector Make-ready Program, and $16 million to its make-ready programs in total out of an overall budget of $100 million. Several parties, including AEE, urge ComEd to reconfigure its electrification strategy to prioritize support for charging infrastructure

installation. AEE Ex. 2.0 at 3-4. AEE specifically recommends that ComEd expand its proposed make-ready sub-program budgets such that, collectively, the Company's annual budget for make-ready incentives is closer to the $44 million retail rate impact cap (which limits ComEd's overall spending on charging infrastructure). As AEE witness Gallentine explains, "Illinois will require a substantial buildout of charging infrastructure, distributed throughout the state, in order to support its policy goals of one million EVs on the road by 2030. The most effective way to spur the installation of EV charging infrastructure is through accessible charging infrastructure incentive programs." AEE Ex. 1.0 Corr. at 16.

AEE also joins several parties in recommending that ComEd expand eligibility for its C&I and Public Sector Sub-program — beyond locations in or primarily serving EJ or R3 communities — to catalyze the deployment of public and fleet charging throughout its service territory. AEE Ex. 1.0 Corr. at 17-18; EDF Ex. 2.0 at 4-6; ChargePoint Ex. 2.0 at 9-12; Electrify America Ex. 2.0 at 14-16; Tesla Ex. 2.0 at 3. Expanding eligibility to that sub-program need not compromise benefits to EJ and R3 communities, and in fact, can increase benefits to these communities. As AEE witness Gallentine explains, the deployment of a robust public and fleet charging infrastructure throughout ComEd's service territory can benefit EJ and R3 communities because: (1) members of EJ and R3 communities using EVs will need to charge those EVs wherever they drive, and not just within their own communities, and (2) diesel and other transportation emissions do not respect geographic boundaries, and thus EJ and R3 communities in ComEd's service territory disproportionately impacted by transportation-related emissions stand to benefit directly from the rapid deployment of EVs throughout the territory. AEE Ex. 1.0 Corr. at 17. A robust public and fleet charging network is an important catalyst for that deployment.

AEE therefore argues that ComEd should expand eligibility for its C&I and Public Sector infrastructure incentive. It can do so while continuing to prioritize support for investments in EJ and R3 communities by implementing a tiered incentive structure. While ComEd does not support expanded eligibility for its C&I and Public Sector Infrastructure incentive, it supports a tiered incentive structure in the event that the Commission directs the Company to expand eligibility for its C&I and Public Sector Infrastructure incentive. ComEd Ex. 7.0 at 28. Consistent with ComEd's approach to its Residential Charging Infrastructure Sub-program, AEE states that the Commission should establish a relatively higher rebate value for C&I and public sector customers located in or primarily serving EJ/R3 communities. AEE Ex. 1.0 Corr. at 17-18.

AEE does not object to Staff's proposal that the Commission approve two separate C&I and Public Sector Charging Infrastructure Incentive Sub-programs. While a single "bucket" of funding with tiered incentives can more effectively ensure that funding is not stranded in any narrow category within ComEd's broader BE Plan, AEE agrees that the establishment of separate C&I and Public Sector Sub-programs strikes a balance between making make-ready incentives more widely accessible, consistent with the legislature's intent, (*see* 20 ILCS 627/45(a)(7)) while avoiding competition between EJ/R3/IQ and non-EJ/R3/IQ customers. AEE objects, however, to Staff's proposed budgets for each C&I and Public Sector Charging Infrastructure Incentive Sub-program.

h. ChargePoint's Position

(i) C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program

ChargePoint explains that its most serious concerns in this proceeding are that ComEd has only proposed to provide make-ready incentives to a limited subset of commercial customers through the C&I and Public Sector EJ/R3 EV Charging Make-Ready Infrastructure Rebate Sub-program and that ComEd has proposed a rather limited budget for the sub-program. To remedy these shortcomings, ChargePoint recommends that the Commission: (1) approve the incentives ComEd has proposed for this program for public sector customers and customers in eligible communities ($8,000 per port for L2 and $1,000 per kW for DCFCs) and direct ComEd to offer $6,000 per port for L2 and $800 per kW for DCFCs for all other nonresidential customers (up to 100% of the total installed cost after accounting for any other incentives the customer receives); and (2) increase the annual budget for the Make-Ready Infrastructure Rebate Sub-program to $30 million.

ChargePoint explains that in the EVA's list of ten items that the BE Plan must address, the first item is "make-ready investments to facilitate the rapid deployment of charging equipment throughout the State, facilitate the electrification of public transit and other vehicle fleets in the light-duty, medium-duty, and heavy-duty sectors, and align with Agency-issued rebates for charging equipment." 20 ILCS 627/45(d)(i). Conversely, ChargePoint notes, under ComEd's proposed BE Plan the vast majority of ComEd's nonresidential customers will not qualify for make-ready incentives. ChargePoint asserts that as a result, most nonresidential customers will be required to pay the full cost of the wiring, conduit, and panels needed to supply power to EV charging stations, either upfront or over time through ComEd's proposed EV Charging Delivery Service Classes or its alternative proposal (if approved). Given that the term "infrastructure" appears in five of the fourteen types of BE programs described in the EVA, ChargePoint claims that it is unfortunate that ComEd's primary make-ready infrastructure proposal – the EV Charging Delivery Service Classes – falls outside of the BE Plan entirely.

ChargePoint also argues that ComEd's BE Plan falls short by failing to provide any incentives for public charging outside of EJ or R3 communities. ChargePoint strongly supports providing enhanced incentives for deploying charging infrastructure in eligible communities and reserving funds for eligible communities to ensure they can participate. However, ChargePoint explains that the EVA defines BE plans as including (among other elements): "incentives or programs to enable quicker adoption of electric vehicles by developing public charging stations in dense areas, workplaces, and low-income communities," and "incentives or programs to develop electric vehicle infrastructure that minimizes range anxiety, filling the gaps in deployment, particularly in rural areas and along highway corridors." 20 ILCS 627/45(b)(11), (12).

ChargePoint argues that despite this statutory guidance, under ComEd's proposal, incentives for public charging stations are limited to public sector entities and public chargers located in or serving EJ or R3 communities. Any prospective site host interested in providing public chargers in dense areas, workplaces, rural areas, or along highway corridors in areas that do not qualify as EJ or R3 communities would not be eligible for any incentives under the BE Plan. As an example, ChargePoint states that a downtown

supermarket, an employer in a business park, or a fueling center in a rural area would not qualify for any incentives under ComEd's proposal unless they were located in an EJ or R3 community.

According to ChargePoint, ComEd's proposal to restrict eligibility for the Make-Ready Infrastructure Rebate Sub-program exclusively to public sector customers and customers in eligible communities finds no support in the EVA. To the contrary, ChargePoint argues that the EVA directs the Commission to consider whether ComEd's BE Plan investments and expenditures are reasonably expected to (among other considerations) "support at least a 40% investment of make-ready infrastructure incentives to facilitate the rapid deployment of charging equipment in or serving environmental justice, low-income, and eligible communities … ." 20 ILCS 627/45(d)(3). If the General Assembly intended ComEd to reserve 100% of its nonresidential make-ready incentives for eligible communities, ChargePoint asserts that it would have specified a 100% investment target and not a 40% investment target for these communities.

ChargePoint further argues that it is neither just nor reasonable to require all nonresidential customers to pay for the cost of the Make-Ready Infrastructure Rebate Sub-program but restrict program eligibility to a small subset of nonresidential customers. ChargePoint also asserts that it is discriminatory and simply unfair to allow all single-family residential customers to participate in the Residential EV Charging Infrastructure Sub-program but exclude multifamily customers not located in an eligible community from the Make-Ready Infrastructure Rebate program, as ComEd has proposed. ChargePoint again expresses support for providing enhanced incentives to public sector customers and customers in eligible communities and reserving at least 40% of the program budget for such customers but argues that restricting the Make-Ready Infrastructure Rebate Sub-program to these customers will hamstring the program's ability to support EV charger deployment and EV adoption. According to ChargePoint, any site host that is willing to invest its own capital and dedicate space on its property for public EV chargers should be encouraged to do so and should be eligible to receive incentives through the Make-Ready Infrastructure Rebate Sub-program. ChargePoint urges the Commission to direct ComEd to reserve sufficient funds for and provide higher incentives to customers in eligible communities, which "will ensure the development of charging infrastructure in those communities that need it the most… ." ComEd Ex. 12.0 REV at 19.

ChargePoint also agrees with EVgo that ComEd's proposal to allow customers that deploy public chargers in locations that are "located in or primarily serving" EJ or R3 communities to participate in the Make-Ready Infrastructure Rebate Sub-program "would be nearly impossible to implement." EVgo Ex. 2.0 at 18. ChargePoint explains that ComEd witness Borggren attempts to allay these concerns in her surrebuttal testimony, explaining that "ComEd will deem the charging station(s) to be primarily serving an EJ/R3 community if the applicant demonstrates that over 50% percent of the driving done by the vehicles to be served by the charging infrastructure will be in EJ/R3 communities." ComEd Ex. 12.0 REV at 18. However, ChargePoint further explains that site hosts can neither track nor predict where privately owned vehicles that use their public charging stations are driven. Accordingly, any information an applicant provides purporting to demonstrate that at least 50% of the driving done by the vehicles that will use their

charging stations will be entirely speculative, with the result that this requirement will likely be subject to gaming. ChargePoint states that it would be far simpler and more effective for ComEd to require chargers to be physically located in eligible communities to receive incentives at the levels ComEd has proposed ($8,000 per port for L2 and $1,000 per kW for DCFCs) and for the Commission to direct ComEd to offer lower incentives to all other nonresidential customers ($6,000 per port for L2 and $800 per kW for DCFCs, up to 100% of the total make-ready costs after accounting for any other incentives the customer receives).

ChargePoint explains that Staff, AEE, Electrify America, Tesla, and CJCP all agree that the Commission should direct ComEd to expand eligibility for the Make-Ready Infrastructure Rebate Sub-program to all nonresidential customers. ChargePoint notes that although Staff states that it opposes ChargePoint's proposal to expand the eligibility of the sub-program and urges the Commission instead to approve Staff's proposal to create two sub-programs – one for EJ/R3/IQ customers and one for non-EJ/R3/IQ customers – ChargePoint fails to see any meaningful distinction between the proposals. If the Commission finds that it is preferable to have two separate subprograms rather than simply reserving 40% of sub-program funding for EJ/R3/IQ customers, ChargePoint would not oppose that approach. If the Commission adopts Staff's proposal for two separate subprograms, ChargePoint recommends that it allocate $12 million to the EJ/R3/IQ subprogram and $18 million to the non-EJ/R3/IQ subprogram, for a total budget of $30 million across the two subprograms.

ChargePoint further explains that no party expressed support for restricting this critical sub-program only to public sector customers and customers in eligible communities, including ComEd, which simply stated the proposed eligibility restriction without providing any justification for it. Further, while ChargePoint does not support reserving funding for specific groups of customers (other than public sector customers and customer in eligible communities), it argues that expanding eligibility for the Make-Ready Infrastructure Rebate Sub-program to all customers would allow BOMA/Chicago's members to qualify for incentives to deploy chargers in their buildings in the Chicago Central Business District, consistent with the goal of BOMA/Chicago's dedicated funding proposal. ChargePoint recommends that the Commission should find that the evidence in this proceeding and the requirements of the EVA weigh heavily in favor of requiring ComEd to allow all nonresidential customers to participate in the Make-Ready Infrastructure Rebate Sub-program, again noting its support for reserving 40% of the budget of this subprogram for public sector and customers in eligible communities and providing such customers with higher incentives.

Finally, to ensure that the Make-Ready Infrastructure Rebate Sub-program has sufficient funding to meet expected demand from all nonresidential customers, ChargePoint recommends that the Commission direct ComEd to increase the budget for the Make-Ready Infrastructure Rebate Sub-program to $30 million. ChargePoint also recommends that the Commission approve a BE Plan budget that includes $44 million of spending on EV charging infrastructure, consistent with the EVA's directive that the retail rate impact from developing EV infrastructure not exceed one percent of ComEd's total annual revenue requirements. By directing ComEd to budget $30 million for the Make-Ready Infrastructure Rebate Sub-program and $14 million for the Residential EV

Charging Infrastructure subprogram, ChargePoint argues that the Commission will ensure that ComEd's investments in EV charging infrastructure are commensurate with the General Assembly's vision.

ChargePoint notes the assertions made by CJCP witness Baumhefner that the Commission require Ameren to implement the payment technology regulations developed by the California Air Resources Board. ChargePoint argues that Mr. Baumhefner presented no compelling evidence or arguments that ComEd's proposal to allow site hosts to determine what payment technologies to offer at their charging stations will somehow undermine the goal of ensuring that EVs and EV charging are accessible to everyone. To the contrary, ChargePoint asserts that requiring all EV charging stations supported by ComEd's BE Plan to have credit card chip readers as Mr. Baumhefner recommends is more likely to undermine the goal of ensuring equitable access to EV charging stations than support it. ChargePoint further argues that contrary to CJCP's suggestion that the Commission should adopt California's payment technology requirements to "align with P.A. 102-0662 equity goals," the EVA contains no mention of payment technology.

ChargePoint witness Deal explained that Mr. Baumhefner misses the mark in arguing that EV drivers at public charging stations cannot pay for charging as easily as they can pay for gasoline. According to ChargePoint, drivers' payment experience at gas stations is far from a "gold standard" of convenience or accessibility that the EV charging industry or the Commission should strive to achieve. ChargePoint states that it, as well as many of our industry peers, strives to make the experience of using and paying for EV charging stations better than the typical experience of refueling at a gas station. Just as a driver's experience of owning and operating an EV will be different from and (hopefully) superior to the experience of owning and operating a gasoline-powered vehicle, ChargePoint argues that a driver's experience of charging their EV will be somewhat different from – and hopefully superior to – their experience of using gas stations.

ChargePoint states that it does not typically offer chip card readers on its charging stations because ChargePoint seeks both to offer a superior, more seamless fueling experience than the experience provided by traditional gasoline and diesel fueling stations and to future-proof our charging stations. According to ChargePoint, payment terminals that require a card to be physically inserted into a reader are a legacy technology that is quickly being replaced by contactless payment technologies, which includes contactless cards and App-based payments. EV charging stations are long lived assets that are designed to be in operation for ten years or longer and during most of that time, contactless payments will be the dominant form of payment methods for in-person transactions.

ChargePoint further explains that physical chip readers are more vulnerable to environmental conditions (e.g., rain, snow, ice, sand, etc.), which poses concerns for EV charging stations that are often more exposed to the elements and can be located in remote areas. Physical chip readers are also vulnerable to "shimming" devices that can steal a customer's credit card information. By contrast, ChargePoint asserts that contactless credit cards and smartphone/app payments use the same Near-Field Communication reader that is internal to the charging station, making it secure, reliable, and durable.

ChargePoint argues that charging station networks such as ChargePoint, as well as site hosts, have every motivation to make it as easy and convenient as possible for EV drivers to use their stations. If the absence of chip readers actually prevented EV drivers from using charging stations as Mr. Baumhefner alleges, ChargePoint would have every motivation to address the problem. In reality, ChargePoint, as an industry leader, has seen no evidence that EV drivers are unable to initiate charging sessions through the multiple payment methods ChargePoint offers and that are in widespread use today.

ChargePoint asserts that CJCP is simply incorrect that ComEd's proposal not to impose payment technology requirements on site hosts ignores the needs of unbanked drivers. To the contrary, argues ChargePoint, offering mobile payment capabilities such as App-based payments, mobile payments, and contactless cards provides more options to unbanked individuals than chip card readers alone.

By contrast, asserts ChargePoint, if an EV charging station were to only offer a chip card reader as CJCP recommends, an unbanked individual's only way to pay for charging would be to purchase one of the handful of prepaid cash cards that have chips.

ChargePoint also states that a chip card reader increases the cost of installing and hosting an EV charging station by approximately $3,000. ChargePoint alleges that this incremental cost would likely lead to fewer site hosts installing charging stations and to site hosts installing fewer charging stations than they otherwise would than if chip card readers were not required. Reducing the total number of charging stations runs directly contrary to the goal of accessibility and would disproportionately impact those EV drivers who do not have the ability to charge at home or work.

ChargePoint argues that it is simply not appropriate for the Commission to favor or require any particular credit card payment technology over others in ComEd's BE Plan. ChargePoint explains that the Commission regulates utilities, not EV charging stations or EV charging station site hosts, which are utility customers. In fact, ChargePoint states, Illinois statute specifically states that a site host that provides EV charging services "is not and shall not be deemed a public utility notwithstanding the basis on which the service is provided or billed." In other words, according to ChargePoint, the manner in which site hosts charge EV drivers for EV charging is not within the Commission's purview. ChargePoint further asserts that the Commission has the authority to approve reasonable equipment standards such as ChargePoint has recommended for ComEd's BE Plan, but it should not be in the business of regulating the transaction between site hosts and EV drivers. ChargePoint also notes that both the California Air Resources Board and the Washington State Department of Agriculture are very different agencies with much broader jurisdictions and different statutory mandates in their respective states than the Commission.

ChargePoint explains that the EVA directs the Commission to consider whether ComEd's BE Plan investments and expenditures are reasonably designed to: "stimulate innovation, competition, private investment, and increased consumer choices in electric vehicle charging equipment and networks." 20 ILCS 627/45(d)(8). ChargePoint further explains that site hosts are in the best position to choose what type of EV charging equipment to install on their property and what features and capabilities that equipment has, including which payment technologies it offers. If a site host wants to offer charging

stations with chip card readers, it should be free to do so. ChargePoint therefore asserts that if a site host prefers to offer a seamless payment experience for drivers with contactless technology and avoid the increased costs and increased security risks that accompany chip card readers, it should be free to install charging equipment that does not include a chip card reader. ChargePoint urges the Commission to support site hosts' ability to choose the payment technology that works best for their unique needs and not make this choice for them.

ChargePoint's primary recommendation is that the Commission approve ComEd's proposal not to impose any requirements regarding the payment technologies available at EV charging stations. However, ChargePoint asserts, if the Commission has any concerns about this issue, ChargePoint would not object to ComEd requiring EV charging stations to accept credit cards, without specifying any particular card reader technology. As another alternative, ChargePoint would not object to requiring qualifying EV charging equipment to offer at least two payment methods.

Ultimately, ChargePoint recommends that the Commission should reject CJCP's recommendation to adopt California's payment technology standards.

(ii) C&I and Public Sector BE Technology Adoption Sub-program

ChargePoint does not oppose the C&I and Public Sector BE Technology Adoption Sub-program. ChargePoint recommends that, if the Commission finds that any budget reductions are necessary, it should reduce or eliminate the budgets for ComEd's proposed non-transportation programs, including the C&I and Public Sector BE Technology Adoption Sub-program, before reducing the budgets for any of the transportation programs.

(iii) C&I BE Infrastructure Readiness Sub-program

ChargePoint does not oppose the C&I BE Infrastructure Readiness Sub-program. ChargePoint recommends that, if the Commission finds that any budget reductions are necessary, it should reduce or eliminate the budgets for ComEd's proposed non-transportation programs, including the C&I BE Infrastructure Readiness Sub-program, before reducing the budgets for any of the transportation programs.

i. Tesla's Position

(i) C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-Program

Tesla testified that it, along with other stakeholders, continues to support an expanded budget for ComEd's C&I and Public Sector EJ/R3 Charging Infrastructure Sub-program. Tesla Ex. 2.0 at 3-5. Tesla recommends reintroducing an increased budget of $30 million in conformance with the Interim Order, which clarified, *inter alia*, that the statutory retail rate impact cap, by its plain language, clearly applies to the development of EV infrastructure. Interim Order at 38. Tesla explains that, as stated in ComEd's BE Plan, 1% of its total annual revenue requirement is $47 million. ComEd Ex. 1.01 at 54-55. Accordingly, Tesla avers that its recommendation would be within the retail rate impact limitation, and would also align with the broader BE Plan, which proposes similar funding for rebates for fleet electrification across light-, medium-, and heavy-duty fleet

vehicles included the in the C&I and Public Sector EV Purchase Sub-program ($35 million). *See* ComEd Ex. 2.0 at 26.

Tesla further states that it agrees with ChargePoint's proposal to increase the Make-Ready Rebate Sub-program budget to $30 million, inclusive of both EJ/R3 communities and nonresidential customers outside of those geographies, which is a substantially higher budget level than Staff's proposed $4.4 million for C&I EV infrastructure (EJ/R3/IQ) and $1.5 million for C&I EV infrastructure (non-EJ/R3/IQ). Tesla notes that while it appreciates ComEd's acknowledgment that "testimony from many of the parties reflected that there is a funding gap for C&I and Public Sector make-ready work" and that there is consensus "that make-ready funding is particularly well-suited for a utility program," Tesla finds ComEd's proposed annual budget of $10 million to be inadequate. ComEd IB at 14-15.

Tesla also explains that other parties appear to agree with Tesla that an expanded budget is warranted. Indeed, AEE stated that "ComEd's proposed budget for those incentives is grossly insufficient to meet the state's electrification goals." AEE IB at 2. In a similar vein, Tesla states that CJCP appropriately highlight the imbalance inherent in ComEd's proposal between the funding provided for vehicle rebates and that for make-ready investments, noting that the funding for vehicles far outpaces what ComEd is proposing to support the deployment of make-ready infrastructure for those vehicles. CJCP IB at 15. Tesla agrees that "the relative paucity of make-ready support to ensure successful deployment of charging infrastructure in the C&I sector risks undermining the intended impact of the vehicle rebates sub-program, since EVs without adequate access to charging are of no use anyway." *Id*. at 15-16. Tesla states that it further agrees with CJCP that ComEd's current proposal fails to recognize the value of emissions reductions outside of EJ/R3 communities and the indifference that vehicle emissions (particularly greenhouse gas emissions) have with respect to geographic boundaries. *Id*. at 18.

In an addition to an expanded budget, Tesla testified that it recommends a make-ready program that is less geographically restrictive. Tesla Ex. 2.0 at 3-4. Tesla states that Section 45(d)(3) of the EVA provides that, when considering if ComEd's BE Plan is in the public interest and determining appropriate levels of cost recovery for investments and expenditures related to ComEd's proposed programs, the Commission should consider, *inter alia*, whether the investments and other expenditures comply with Section 45(d)(3) of the EVA. *See* 20 ILCS 627/45(d)(3). Tesla explained that while it supports ComEd's emphasis on EJ/R3 communities in its make-ready proposal, Tesla recommends that the EJ/R3 priority be communicated through higher incentive levels and a dedicated budget set-aside rather than through a geographic restriction. Tesla acknowledges that Section 45(d)(3) states that at least 40% of make-ready infrastructure investments need to be made in EJ/R3 communities but underscores that it also states that "nothing in this subsection is intended to require a specific amount of spending in a particular geographic area." Tesla argues that if the legislature intended for 100% of make-ready infrastructure investments to be made in EJ/R3 communities, it would have expressly stated so.

Lastly, Tesla states that it supports Staff's proposal that the "Commission should also direct that ComEd create a new subprogram that provides C&I customers with incentives for make-ready infrastructure for non-EJ/R3/[Income Eligible ("IQ")]." Staff IB

at 34. Indeed, Tesla explains that Staff's proposal aligns with its position that there should be an expanded make-ready program that includes customers outside of EJ/R3 communities while maintaining increased incentives for those customers who qualify under the EJ/R3 criteria. Tesla underscored that such an expansion is important given all drivers will need access to public EV charging infrastructure as they travel throughout ComEd's service territory, and that it is not merely access to local charging options that encourages EV adoption, but confidence in a robust and reliable charging network.

j. EVgo's Position

(i) C&I and Public Section EJ/R3 EV Charging Infrastructure Sub-program

EVgo supports Commission approval of the C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program. EVgo's concerns with certain aspects of the sub-program have been resolved through discussions with ComEd and through ComEd's commitment to continue to solicit stakeholder input through the implementation phase of its BE Plan. EVgo appreciates this invitation and looks forward to working with ComEd and other stakeholders during the implementation stage of the sub-program, if approved. EVgo urges the Commission to memorialize this commitment to work with stakeholders and to ensure that ComEd's implementation of the BE Plan reflects stakeholder considerations and incorporates best practices where possible.

k. LVEJO's Position

(i) C&I and Public Sector EV Purchase Sub-program

While LVEJO generally supports the reallocation of funds from the discarded Residential EV Purchase Subprogram, there remains issues with the level of funding in this sub-program that is reserved for low-income and EJ/R3 communities. ComEd committed that at least 40% of the funding for the entire C&I and Public Sector Program would be reserved for these vulnerable communities. However, LVEJO states, ComEd provided no assurances as to the level of funding reserved for those communities within this program specifically. In LVEJO's opinion, this is especially an issue for this sub-program, since it is receiving extra funding from another sub-program where ComEd initially committed to allotting a higher percentage of the program funding towards low-income and EJ/R3 communities (50% rather than 40%). Even though these new funds only represent a fraction of the total funding for the sub-program, it is concerning for ComEd to move large amounts of funding to a sub-program with a lower allotment towards EJ/R3 communities. Instead, LVEJO asserts that ComEd should commit that at least 50% of the funding for this sub-program will go towards low-income or EJ/R3 communities. This would ensure that the shuffled funding is still benefiting the vulnerable communities that need it, and it would help reaffirm the BE Plan's overall EJ commitments.

LVEJO notes that Staff endorses LVEJO's proposal that 60% of this sub-program's funding be directed to customers in EJ/R3/IQ areas, as opposed to ComEd's proposed 40%. LVEJO also supports Staff's recommendation to expand both School Bus and Transit Sub-programs beyond EJ/R3 communities to low Income and IQ areas as well.

(ii) C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program

In ComEd's revised BE Plan, this sub-program is changed to provide rebates for make-ready infrastructure rather than chargers, but the funding level ($10 million) and application requirements are the same. ComEd also committed to providing more explicit support for multi-family housing utilizing the sub-program. ComEd Ex. 12.0 REV at 16. LVEJO supports the addition of extra support for infrastructure multi-family housing, which is a need LVEJO has stressed in previous witness testimony. However, there still remain some issues with the sub-program. Even though the subprogram is shifting from supporting chargers to supporting make-ready infrastructure, LVEJO emphasizes that there should still be some element of public participation regarding siting, since the infrastructure will be supporting public chargers. LVEJO states that providing some requirement for public outreach or public participation in picking locations for public chargers will help ensure that they are at locations that are most helpful for their community. LVEJO acknowledges that there are challenges to implementing this suggestion since ComEd itself would merely be proving rebates rather than choosing charger sites itself. However, this requirement could be integrated into the application process for the make-ready rebates, by requiring that applicants have performed at least some form of public outreach before their application is approved. LVEJO concludes that the Commission should require that ComEd integrate some form of public outreach requirement for applicants of rebates for make-ready infrastructure for public chargers.

I. Commission Analysis and Conclusion

(i) C&I and Public Sector EV Purchase Sub-program

The Commission approves CTA/City's request that all CTA buses should be eligible for the $120,000 per bus rebate. CTA/City demonstrated that the CTA serves the City, the majority of which is comprised of EJ/R3/low-income communities. Moreover, an entire bus route is likely to pass through such communities, and a bus is likely to operate on different routes over its lifetime.

The Commission also approves CTA/City's request that the transit bus rebate sub-category be payable beyond the year in which they were awarded. The Commission notes ComEd agrees to this recommendation.

The AG states it does not oppose this sub-program but indicates that the rebates in this sub-program are duplicative of incentives offered by federal programs. The Commission agrees with the AG that existing federal incentives for light, medium, and heavy-duty vehicles lessen the need for ComEd to provide rebates for the purchase of these vehicles (AG Ex. 1.4). While the Commission acknowledges there is still a need for C&I and public sector EV rebates to meet the EVA's goal of 1 million additional EVs by 2030, ComEd is directed to reduce the budgets for the light-duty, medium-duty, and heavy-duty C&I and Public Sector EV Purchase rebates to $10 million, $10 million, and $6 million, respectively.

ComEd commits to allotting 40% of the overall C&I and Public Sector EV Purchase Sub-program to EJ/R3/low-income communities and objects to LVEJO's recommendation. LVEJO recommends that 60% or at least 50% of the funding in this

particular sub-program within the C&I and Public Sector Program be budgeted to EJ/R3/low-income communities. The Commission agrees with LVEJO and finds that ComEd shall direct at least 50% of this sub-program's funding to EJ/R3/low-income communities.

Staff requests that the school bus and transit sub-programs be "expanded" to IQ or low-income communities. The Commission has directed that at least 50% of the funds of this sub-program be directed to EJ/R3/low-income communities, so it appears Staff's concern is resolved to an extent.

(ii) C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program

ComEd's sub-program as proposed is currently only available to EJ/R3 customers. Staff and many Intervenors urge the Commission to expand eligibility to other types of customers. ComEd is concerned that adding a larger pool of customers to this program would stretch the budget too thin to be effective. Considering the arguments of Intervenors to expand eligibility to this sub-program and dramatically increase the budget, ComEd's concerns are valid. The record shows there is a very real need for make-ready infrastructure and that the high costs of that infrastructure are a barrier to charger installation. The record further shows that members of EJ/R3 communities will need to charge their EVs wherever they drive and not just within their own communities, and that transportation emissions do not respect geographic boundaries. Accordingly, the Commission agrees that eligibility for this program should be expanded. Expanding eligibility in this sub-program will also further the objective of Section 45(d)(i) of the EVA.

In an effort to expand eligibility to the program yet still ensure that EJ/R3 communities are prioritized, the Commission adopts Staff's proposal to set aside dedicated funding for EJ/R3/low-income communities and non-EJ/R3/low-income communities. AEE's and ChargePoint's respective proposals to expand eligibility of the sub-program to all C&I and Public Sector customers and provide higher incentives for those entities located in or primarily serving EJ/R3 communities does not effectively guarantee that program funding will go towards ensuring EJ interests as contemplated by Section 45(d)(2). Similar proposals are likewise rejected. The Commission directs ComEd to include the new bifurcated sub-program in its BE Plan compliance filing.

The Commission does not, however, accept Staff's proposed budget (see Section V.C.1.), and therefore the Commission finds that $14 million of the funding in this sub-program should be directed to EJ/R3/low-income communities and $6 million to non-EJ/R3/low-income communities. The Commission also agrees with the CTA/City's arguments that public transit authorities should be able to access this make-ready infrastructure funding with respect to both.

The Commission approves in part parties' requests to increase ComEd's budget to this sub-program in this BE Plan. AEE states that make-ready programs are both a fundamental and common component of utility electrification plans. As AG witnesses Borden and Lane note, utility EV programs in other states have focused heavily on make-ready spending. AG Ex. 1.0 at 13-15. Utilities are well-situated to implement make-ready programs that defray the cost of EV charging infrastructure and thereby facilitate broad and equitable access to EV charging. IEPA Ex. 1.0 at 10. As such, while utilities can and

must play several roles in supporting the electrification of transportation in Illinois, the Commission observes that one of the most important roles that utilities can play is to offer robust, widely accessible make-ready infrastructure development incentives.

Recognizing the unique and important role ComEd has in supporting make-ready infrastructure for EV charging, and that support for make-ready infrastructure might not be readily available elsewhere, the Company's original sub-program budget is hereby doubled. The Commission maintains Staff's proposal to bifurcate funds in the C&I and Public Sector EV Charging Infrastructure Sub-program, but not Staff's proposed budget. As such, the Commission approves a sub-program budget of $14 million for EJ/R3/low-income communities and $6 million for non-EJ/R3/low-income communities (*see* Section V.C.1.).

BOMA/Chicago's proposal and Staff's modifications to that proposal are addressed in Section V.B.1.

After consideration of record evidence, the Commission finds ComEd's mechanism for determining whether an applicant is primarily serving an EJ/R3 community reasonable, and it is adopted. Staff also supports ComEd's mechanism. ChargePoint and EVgo's alternative recommendations appear problematic or not fully supported by the record.

CJCP raises a concern that MHDVs are not guaranteed any funding and that all funding for the program may be used by public charging stations serving light-duty vehicles. The Commission agrees with ComEd that this concern is speculative.

The Commission rejects CJCP's proposals to require ComEd to implement the payment technology regulations such as those developed by the California Air Resources Board. ChargePoint has thoroughly explained why the Commission should not adopt CJCP's chip reader proposal. Also, CJCP has not demonstrated that ComEd's BE Plan would pose a barrier to equitable access to EV charging. CJCP's proposal is not adopted.

Another issue raised relates to whether the term "customer" should be replaced with the term "site host" in the eligibility requirements. ComEd's clarification regarding the definition of "retail customer" and how that applies regarding the per-customer cap is dispositive and this concern appears resolved.

LVEJO recommends that the Commission require ComEd to integrate some form of public outreach requirement for applicants of rebates for make-ready infrastructure for public chargers. ComEd is open to including such criterion. The Commission directs ComEd to include such criterion in its final program design.

The Commission rejects the CTA's proposal to cover the full cost of make-ready infrastructure on the CTA's side of the meter. The Commission finds this request unfairly preferential to a specific customer, and unreasonable given the budget.

ComEd's proposed C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program as modified is approved.

(iii) C&I and Public Sector Technology Adoption Sub-program

This program is denied. *See* Section V.C.5.a.

(iv) C&I and Public Sector Infrastructure Readiness Sub-program

This program is denied. *See* Section V.C.5.a.

3. Customer Education and Awareness Program

a. ComEd's Position

According to ComEd, the Customer Education and Awareness Program is designed to increase customer awareness of electrification opportunities and resources, including EVs, as well as available incentives from the BE Plan Programs, in addition to providing support for customers in decision-making. ComEd states that this program will encompass education and awareness activities such as informational marketing activities, customer fleet electrification assessments, and educational tools to support customer decision-making in the BE realm. Moreover, ComEd plans to engage in targeted outreach to low-income customers and customers in EJ and R3 communities to help secure robust participation from individuals in those groups. ComEd also commits to ensuring activities under this program are competitively neutral. Finally, ComEd notes that it has agreed to receive community input on this program and share materials with interested parties.

Under this program, ComEd plans to provide online self-service tools that will help educate customers and guide them in decision-making processes. ComEd notes that it has an existing, basic residential EV Toolkit resource that can serve as a guide for the type of resources it hopes to provide to the public including increased awareness of and education in the BE space. As part of the BE Plan, ComEd's Fleet Electrification Toolkit was available as of January 1, 2023. The Fleet Electrification Toolkit allows potential EV fleet adopters to gauge possible savings and learn about charging and the pros and cons of owning an EV generally, according to ComEd. ComEd claims that it will continue to implement and expand these initiatives and similar efforts.

ComEd proposed a budget of approximately $9 million per year for the Customer Education and Awareness Program. According to ComEd, it has already implemented multiple resources outside the scope of this proposed program, including a Residential Customer EV Toolkit, EV Companion, EVs for Education, and more. ComEd states that it intends to maintain these tools and promote education through them while the tools under this program are being developed.

ComEd notes that CJCP argue that insufficient details have been provided as to how ComEd intends to provide outreach to communities and individuals. However, ComEd explains, it is inefficient to fully design a customer outreach and education plan before the Commission approves the BE Plan, including all of its programs and sub-programs. ComEd says that designing an education and outreach program requires significant resources and time, and the particular components of such a plan are highly dependent on the types of incentives that ComEd is ultimately permitted to offer as part of its BE Plan, and to which customers those incentives may be offered. ComEd has committed to varying types of education for its customers, including offering materials both offline and online and offering materials in different languages. ComEd states that it will ensure that its educational materials are effective for all types of customers.

In response to Staff's arguments for a lower budget and additional details on particular education and outreach efforts, ComEd argues that it would be inefficient to design an educational marketing program for BE Plan incentives before the Commission approves those incentives. However, ComEd commits to sharing educational materials with Staff and other stakeholders before those materials are used. ComEd disagrees with Staff's recommendation to reduce the budget for this program to less than half of what ComEd has proposed. According to ComEd, Staff's proposal appears to be based on the assumption that, if the budget for all other BE Plan programs is reduced (as Staff has proposed), ComEd will necessarily need to conduct proportionally less education and outreach. ComEd argues that is not a reasonable assumption. ComEd explains that this is the first BE Plan, and the first time that customers will be able to receive these particular incentives from ComEd. ComEd also argues that Staff's assumption is unreasonable in light of Staff's proposal to sub-divide several of ComEd's proposed programs – which in turn would require customers to navigate a more complex set of options to determine what incentives are available, and whether they are eligible for any of them.

b. Staff's Position

Staff expresses concern that the Customer Education and Awareness Program proposed by ComEd did not contain sufficient information to allow the Commission and stakeholders to evaluate whether implemented outreach and education efforts are successful. Staff Ex. 3.0 at 20. Although the Company committed to some changes recommended by Staff and Intervenors in its surrebuttal (ComEd Ex. 12.0 at 21), ComEd still has not provided details that would support use of past programs as the basis for its Customer Education and Awareness Program. Staff Ex. 14.0 at 17. Staff asserts that the Commission should approve a $4 million annual budget for the Customer Education and Awareness Program. However, Staff's recommendation should not be interpreted to mean Staff agrees that the contents of the program as described are sufficient. Staff continues to recommend the inclusion of additional details being provided in a compliance filing.

Staff notes that Section 45(d)(8) of the EVA supports approval of CJCP's proposal (EDF Ex. 1.0 REV. at 41) that ComEd expand fleet assessment services and hire a dedicated liaison as a single point of contact for the C&I Fleet Assessment Sub-program. Staff Ex. 15.0 at 20. ComEd agrees that additional outreach will be required for fleets and fleet managers and that a simple and streamlined approach will need to be designed for smaller fleets to serve those critical customers. ComEd Ex. 7.0 at 32. Staff agrees that the unique operating characteristics of medium-duty and heavy-duty EVs warrant additional communication and interface between the fleet operators/owners and the utility. Staff Ex. 15.0 at 18-20.

c. AG's Position

ComEd proposes to spend $9 million on this program. The spending under this program would go towards education and awareness marketing costs, conducting fleet assessments for commercial and industrial customers, and developing self-service customer education tools that the Company would make available online. ComEd Ex. 1.01 at 42-43. Staff recommends that this amount be reduced to $4 million. The AG

agrees with Staff's reduction and argues that further reductions are needed to ensure the overall budget does not exceed the retail rate cap.

d. CJCP'S Position

Section 45(d)(x) of the EVA states that a BE Plan is required to address "customer education, outreach, and incentive programs that increase awareness of the programs and the benefits of transportation electrification, including direct outreach to eligible communities." 20 ILCS 627/45(d)(x). CJCP state ComEd's original filing contemplates that its customer education and awareness activities would include distributing information on the benefits of electrification and providing technical assistance to customers. They state that within its customer education and awareness plan, ComEd expressed an intention to expand its residential electrification toolkit to fleets – a "web-based resource that allows potential EV fleet adopters to estimate vehicle costs and savings, explore charging options, learn about the pros and cons of EVs, discover rate options, and more." ComEd Ex. 2.0 at 36. In addition, CJCP point out that ComEd expressed an intention to offer fleet assessment services that "will make available third-party electrification feasibility assessments for C&I [commercial and industrial] customers...[in which] a third-party vendor will work with eligible customers to collect, evaluate, and analyze fleet operations data and provide an assessment of the customer's electrification opportunity, costs, and benefits." ComEd Ex. 2.0 at 35.

In responding to ComEd's initial depiction of its customer, education, and awareness plan, Clean Jobs Coalition Parties point out that ComEd's intentions for the breadth of interaction with customers was appropriate, but that many details still needed to be worked out. EDF Ex. 1.0 REV at 34. In particular, CJCP noted that development of the critically important Fleet Electrification Toolkit had not yet commenced, and that there were no specific marketing plans for targeting low-income customers and customers in EJ and R3 communities. EDF Ex. 1.0 REV at 34:712-714. CJCP point to the fact that other intervenors concurred; for example, Staff witness King states that "ComEd provides relatively little information in its BE Plan about its Consumer Education and Awareness Program and that the utility "proposes to spend $9 million on the program but does not provide significant details on how that money will be spent." Staff Ex. 3.0 at 18. In addition, CJCP agree with LVEJO witness Pino, who states that "the Plan does not explicitly address working with community organizations on education and outreach." LVEJO Ex. 1.0 at 8-9. CJCP state that in surrebuttal testimony, ComEd addresses some of those points and states that it "generally agrees with the recommendations provided [by, e.g., King and Pino] and commits to seeking community input as it develops education and awareness materials, providing offline options for customers to learn about programs and offering materials in multiple languages (including on ComEd's website)." ComEd Ex. 12.0 REV at 21.

CJCP also point to ComEd's statement that it "appreciates the feedback regarding the need for strategies tailored toward reaching and providing assistance to small businesses and businesses operating in EJ and R3 communities" and that it "is open to considering the specific recommendations made, including crafting materials in coordination with community groups, providing materials in multiple formats, proactively reaching out to customers and community leaders, including in-person outreach, and ensuring any related vendors are adequately equipped to serve these communities."

ComEd Ex. 7.0 at 31. While ComEd's consideration of these suggestions is a step in the right direction, CJCP again reiterate the need to put more detail into how the utility intends to provide outreach to communities and individuals that are all too often left behind by utility programs.

CJCP state the Commission workshop process that preceded this proceeding, which was intended to inform the utilities' BE Plans and which culminated in a report the Commission is required to rely on in its assessment of those plans, revealed real deficits in trust, based on vulnerable communities and constituencies' past experience, that utilities must overcome in their outreach. As CJCP point out, the report issued as part of the workshop process notes "[t]he importance of building trust with the Utilities delivering [BE] programs was discussed, including the need for the Utilities to support [EV] education and outreach as part of their programs – both in partnering with trusted community-based groups to deliver the education, and to educate the community groups themselves." Staff Report to the Commission at 31. CJCP point to the fact that this need is reflected by Warehouse Workers for Justice, whose observation that "participants highlighted the fact that communities do not trust utility companies to meaningfully engage with directly impacted community members because they have historically been some of the last to receive infrastructure updates under the jurisdiction of ComEd and Ameren" should give the utilities and the Commission pause. BE Workshops Staff Report, Appendix C: Stakeholder Feedback Received at 252. CJCP state that while it is encouraging that ComEd seems to be taking suggestions from LVEJO and others under advisement, being "open to considering" these recommendations does not amount to a firm promise that ComEd will build out its outreach plans in a way that addresses community needs and effectively incorporates recommendations from communities, individuals, and their representatives that are best placed to understand what is needed to ensure that they equitably benefit from ComEd's programs. The Commission should require ComEd to develop outreach plans that include the specific recommendations of LVEJO and others, which is in line with what ComEd appears to intend.

CJCP also contend that fleet outreach needs to be increased. Efforts described by ComEd, including the Fleet Electrification Toolkit and the fleet assessment strategy, are steps in the right direction, according to CJCP, but without more assurance that these tools will be tailored to different circumstances, they are unlikely to be successful. As stated in Dr. MacDougall's testimony on behalf of CJCP, "having those tools available is unlikely to be sufficient for ComEd to effectively reach and prioritize the fleets operating in communities that are underserved and/or suffering disproportionate impacts from air pollution" because "[i]n particular, small businesses and independent owner-operators may need additional specialized support in order to successfully make the transition to electric vehicles." EDF Ex. 1.0 REV at 34. CJCP state that having education and outreach plans that include assistance to ensure fleets of all sizes can understand the benefits and mechanics of EVs, as well as what different rate structures available and how those rates will respectively impact bills, as well as how to mitigate significant bill impacts with different technologies, and how to navigate the regulatory and application processes for subprograms, will be critically important to ensuring that fleets can successfully transition to EVs.

When designing this customer education and outreach, CJCP state that ComEd should also recognize that different approaches need to be taken for residential and C&I customers – and even within those categories. CJCP posit that a residential customer living in a single-family home might need a different type or amount of information than a lower income individual or resident of a multi-unit dwelling; similarly, fleet customers operating MHDVs will have different needs than residential customers or even light-duty fleets; and, of course, different businesses operating MHDVs will have different needs and levels of technological knowledge and capacity. As such, CJCP urge ComEd to accommodate these differences in usage and understanding when designing their education and outreach programs. CJCP witness MacDougall testified that "trucks and buses have physical and operational differences compared to passenger vehicles that give rise to distinct needs," as well as that "medium and heavy-duty vehicles have highly varied operational profiles. As a result of this variation, they will have a wide diversity of charging needs,..[and] some of these vehicles will be operated by large companies with extensive experience managing high levels of electric consumption, while others will be operated by entities that are entirely new to the large C&I space." EDF Ex. 1.0 REV at 8-9. CJCP state that given these inherent differences—as well as the significant impact that the load from these vehicles will have if not carefully managed — ComEd should ensure that its education and outreach is well structured to recognize and accommodate those differences.

Finally, CJCP state ComEd should take into consideration in its customer education and outreach programs the requirement in Section 45(d) that BE Plans consider "opportunities for coordination and cohesion with electric vehicle and electric vehicle charging equipment incentives established by any agency, department, board, or commission of the State, any other unit of government in the State, any national programs, or any unit of the federal government." 20 ILCS 627/45(d)(viii). As such, CJCP state to the extent feasible, ComEd's customer education for both residential and C&I customers should include information about other available state and federal programs to help mitigate upfront costs. Among other things, CJCP point out that ComEd should highlight incentives that can be stacked, in order to ensure that equitable deployment of vehicles and charging stations are more fully realized. As well, CJCP state utilities have a good understanding of state energy policy and changes in state and federal law that they can convey to fleets to help them better "understand the upgrades they need to make and how to use the new vehicles they will ultimately procure in a manner that is well integrated with the grid and that yields maximum benefits for themselves, other ratepayers, and society." EDF Ex. 1.0 REV at 10.

Clean Jobs Coalition Parties point to the fact that Staff made several recommendations regarding the Customer Education and Awareness Program relevant to the proposed fleet assessment services. First, Staff supports CJCP's recommendation that ComEd expand its fleet assessment services proposal to provide additional outreach to fleets and hire dedicated liaisons to serve as a single point of contact for fleets at the utility. Staff IB at 41. Second, Staff proposes reducing the Customer Education and Awareness Program budget from $9 million per year to $4 million per year. Staff IB at 41. Third, Staff recommends rejecting CJCP's recommendations regarding medium- and heavy-duty infrastructure including proactively contacting fleets regarding electrification and providing additional support for small businesses and fleets operating in EJ/R3

communities that may lack the knowledge or capacity to electrify without that support, instead arguing that the Commission should reject any proposal "that could increase the C&I and Public Sector EV Charging Infrastructure sub-program budget beyond what is approved in the Commission's Final Order." Staff IB at 50-51.

Collectively, CJCP point out, Staff's recommendations are internally inconsistent. Staff supports expanded fleet assessment services while recommending that the related Customer Education and Awareness program budget be slashed by more than half and supports additional fleet outreach while opposing proactive outreach to fleets. As Dr. MacDougall's testimony makes clear, and Staff agrees, MHDVs have unique needs and grid impacts, and electrifying these vehicles will require regular communication between the utility and fleet operators throughout the electrification process. EDF Ex. 1.0 REV at 8-10; Staff IB at 41. On top of this, CJCP state, small fleets—many of which lack dedicated fleet managers, particularly fleet managers with any experience in fleet electrification — may need additional support, including proactive outreach by the utility, to make them aware of programs to support electrification such as ComEd's proposed BE Plan. EDF Ex. 1.0 REV at 34-35; Staff IB at 41. In addition, CJCP point out that Staff makes no recommendation regarding how ComEd could provide these services as part of this program while simultaneously shrinking the sub-program budget by approximately 56%. Shrinking the budget in this way, aver CJCP, would require ComEd to largely forsake the remaining portions of its Customer Education and Awareness Program, a prospect CJCP find highly objectionable given the importance of marketing, education, and outreach in making the BE Plan as a whole successful. Clean Jobs Coalition Parties find more outreach is needed to serve critical customers; this will include providing opportunities for meaningful stakeholder input, including community representatives, to flesh out the details of this program. But, state CJCP, this alone is no reason to harshly cut ComEd's proposed budget and ensure little chance of program success before it even begins. Therefore, CJCP's recommendations regarding expanded fleet assessment services, increased technical support for small businesses and fleets operating in EJ/R3 communities, and proactive fleet outreach should be adopted, and Staff's recommendations to the contrary should be rejected.

e. ChargePoint's Position

ChargePoint supports ComEd's proposed Customer Education and Awareness Program and appreciates that ComEd confirmed, consistent with ChargePoint's recommendation, that all activities under this program will be vendor neutral. ChargePoint recommends that the Commission approve ComEd's vendor-neutral approach.

In order for ComEd's BE Plan programs to be successful, ChargePoint asserts it is important that customers are made aware of them. However, ChargePoint notes that, if the Commission approves ComEd's proposal to exclude most nonresidential customers from the Make-Ready Rebate Sub-program, many nonresidential customers that learn about the program through ComEd's Customer Education and Awareness efforts will be understandably confused and frustrated that they cannot participate despite contributing to the cost of the program through their rates. According to ChargePoint, avoiding this potential backlash is yet another reason that the Commission should direct ComEd to allow all nonresidential customers to participate in the Make-Ready Rebate Sub-program

and increase the budget for the program to $30 million to ensure that there are sufficient funds available through the program (while reserving sufficient funds for customers in eligible communities).

f. WeaveGrid's Position

WeaveGrid states that the Commission should approve the full budget for the Customer Education and Awareness Program. WeaveGrid additionally recommends that ComEd should continue to pursue efforts that help make it easier for customers to electrify and use energy at optimal times that align with the goals in the EVA.

g. LVEJO's Position

LVEJO generally supports the commitments and proposed changes to the Customer Education and Awareness Program that ComEd provided in their surrebuttal testimony. This includes commitments to seeking community stakeholder input in developing education materials, offering materials in multiple languages both online and offline. LVEJO encourages the Commission to formalize these commitments into the final BE Plan itself. While these commitments and assurances help to address issues with the initial proposal for the program, ComEd's proposal is still lacking in necessary detail. In particular, the BE Plan needs more details about the means and methods ComEd will use for their community outreach efforts. In LVEJO's view, stating that they will perform community outreach in designing their materials is not as useful as providing a more thorough plan of how they intend to perform that outreach, including such details as what form of process they intend to use, whether they will rely more on public feedback sessions or directly reaching out to community organizations, and what their proposed timeline for the process will be. LVEJO states that the Commission should require ComEd to include a more thorough and detailed plan for this program for the Commission's approval.

h. Commission Analysis and Conclusion

Overall, parties support inclusion of the Customer Education and Awareness Program. As with other programs, Staff and the AG continue to oppose ComEd's proposed budget as too large. WeaveGrid proposes that the budget for this program be increased. The budget is addressed in Section V.C.1.

Staff, LVEJO, and CJCP argue that ComEd did not provide sufficient detail for the Customer Education and Awareness Program. It appears that many of these concerns were addressed by the Company in surrebuttal testimony. ComEd agrees to seek community stakeholder input in developing materials, offer materials in multiple languages, and offer both online and offline resources. Staff and Intervenors continue to argue that ComEd should provide more detail on the means and methods for community outreach. ComEd states that it will design those materials after approval of the BE Plan and share the materials with stakeholders before they are used. The Commission finds this sufficient. Furthermore, the Commission agrees, and ComEd has committed, that these materials shall be competitively neutral.

In Staff's request for more detail, Staff further requested that ComEd provide information sufficient to allow the parties or the Commission to ascertain the relative success of past programs on which the Company claims to base BE Plan outreach. The

Commission sees no reason such information cannot be provided and directs ComEd to provide such information in its compliance filing.

CJCP argues that fleet outreach needs to be increased. ComEd points out that its BE Plan includes the Fleet Electrification Toolkit, the fleet assessment strategy and will "take whatever educational steps are needed to educate fleet customers regarding available incentives." ComEd RB at 32. The Commission finds ComEd's commitments sufficient for approval of this program and will leave the level of implementation detail to ComEd.

The Commission agrees with some of the parties that the budget for Customer Education and Awareness of $9 million is not supported by sufficient details to justify a specific amount of spending. The Commission acknowledges that education and awareness raising is crucial part of increasing EV adoption and implementation of ComEd's BE plan. The Commission notes that the exact details of ComEd's educational and outreach programs will be developed after the BE Plan is adopted and can be adjusted to the approved amount of spending, taking into account parties' and Commission's concerns of the Plan affordability. The Commission also notes that some of the proposed programs have been disapproved, thus further justifying a reduction in education and awareness as related to those programs. Staff recommends the overall budget of $4 million that is supported by the AG. Staff IB at 41; AG RB at 8. ComEd is concerned that cutting its proposed budget in half will undermine some of its proposed educational and outreach activities and objects to the suggestion that ComEd will necessarily need to conduct proportionally less education and outreach if the budget is reduced. ComEd RB at 33. The Commission notes that while at this point the exact budget for education and outreach activities might not be easily identifiable, the overall budget reductions and rejected programs in this Order might not necessarily require cutting proposed education budget in half or proportionally to the reduced overall size of the budget. However, the overall concern of the impact on rates and affordability requires the Commission to direct ComEd to design its education and awareness outreach programs in a way that is cost cautious. Therefore, the Commission reduces ComEd's proposed budget for Customer Education and Awareness to $6 million.

The Customer Education and Awareness Program is approved as modified.

4. BE Pilot Program

a. ComEd's Position

ComEd states that the full scope of the potential of BE is not known at this time. As such, ComEd argues that it is imperative to continue to research, experiment, and pursue innovative electrification strategies. To better understand the capabilities of BE, according to ComEd, the BE Pilot Program will test concepts that could help customers and the State of Illinois.

ComEd proposes to conduct at least the following five specific pilots: (1) School Bus Vehicle to Grid; (2) Residential Optimized Charging; (3) Curbside Charging; (4) Ridesharing (or other pilot program aimed at providing EV access to low-income and EJ/R3 customers for whom car ownership is not an option); and (5) Backup Power Capabilities. ComEd's previous proposals considered a pilot program to measure air

quality monitoring, but, in response to the feedback of the parties, ComEd determined that this type of work may not be a good fit within a BE Plan. ComEd states that the Curbside and Ridesharing pilot programs were added due to feedback to incorporate more programs for low-income customers and customers in EJ/R3 communities who may not have access to EVs.

ComEd argues that the purpose of these pilots is to test approaches that could be scaled into a future program under the BE Plan, while also assessing whether the pilot approach is an effective strategy in BE Plans. According to ComEd, the School Bus Vehicle to Grid pilot program is designed to examine the extent to which school buses can provide grid services, including providing energy to the grid during peak conditions, as a storage capacity resource and estimating potential grid revenues available to electric school buses. ComEd states that the Residential Optimized Charging pilot proposes to examine the feasibility of allowing customers to passively modify the level of charge they receive within a charging session to optimize savings. According to ComEd, this would also improve the overall grid efficiency by shifting EV charging to hours in which lower cost resources are available to meet their needs. ComEd claims that the Backup Power Capabilities pilot will examine the bidirectional EV charging advertised by certain EV models while charging at stations and the performance of those EVs as backup power sources. ComEd added the Curbside Charging pilot, in part, in response to FLO witness Bloom's testimony encouraging a curbside charging pilot to test how to equitably deploy curbside chargers in hard-to-reach communities, according to ComEd. Finally, ComEd notes that it added the Ridesharing pilot, in part, in response to Staff witness King's recommendation that ComEd include a ridesharing pilot program for EV vehicles to ensure access to EVs for low-income and other customers for whom EV ownership is not an option.

ComEd argues that it has thoughtfully proposed pilot focus areas that could prove to be impactful and innovative in the BE technology space. ComEd explains that the more detailed design work within these pilot focus areas will be completed once the pilots have been approved by the Commission. ComEd points out that it plans to issue requests for information to inform pilot designs, use existing program evaluation criteria to evaluate pilot proposals, meet with interested parties to discuss feedback, and submit planning details on each of the proposed pilot projects to interested parties at least 30 days before ComEd plans to commence the pilot. ComEd states that it also plans to report annually on the BE Pilot Program, including details on each specific pilot focus area, in the Annual Report. ComEd proposes to invest $5 million per year into the research and development of BE pilot programs.

ComEd notes that Staff supports ComEd's proposed $5 million annual budget for the BE Pilot Program but has provided its own list of pilots that it believes ComEd should pursue in this program. ComEd notes that Staff is recommending adding two additional pilots, beyond what ComEd has proposed, without suggesting where the funds would come from to support such programming. ComEd argues that Staff continues to recommend ComEd do more with less while also accusing it of failing to meet the requirements of the EVA. ComEd concludes that Staff's recommendations exceed ComEd's capacity to execute a successful BE Pilot Program within the budget proposed and therefore should be disregarded.

In response to CJCP's arguments in favor of a submetering pilot, ComEd notes that it is unable to offer a submetering program in the absence of a waiver of Commission Rules, and there are significant open questions concerning the mechanics of such a program.

Finally, ComEd disagrees with AEE's assertions that the pilot program budget should be larger, and the feedback process is insufficient.

b. Staff's Position

Staff states that the Commission should direct ComEd to pursue the following pilots:

- Air Quality Mapping Pilot with Localized Emissions Assessment (see Section V.D.2.f.ii.)
- School Bus Vehicle to Grid Pilot
- Residential Optimized Charging Pilot
- Submetering Pilot
- Curbside Pilot
- Ridesharing Pilot (or other pilot program aimed at providing EV access to low income and EJ/R3 customers for whom car ownership is not an option) (see Sections V.D.1. and V.D.2.)
- Energy Management Systems Pilot

The Commission should approve Staff's proposal to establish a BE Pilot Program review and approval process including a mechanism to share pilot design details with stakeholders. Staff Ex. 15.0 at 11. The Commission is authorized to consider approval of "other such programs as defined by the Commission." 20 ILCS 627/45(b)(15).

In its direct testimony, Staff noted that ComEd did not intend to seek Commission approval for new projects for the BE Pilot Program, nor did the program include any criteria by which potential new projects will be reviewed and approved. Staff also raised the related issue that the Company may exceed the program budget. Staff Ex. 4.0 at 12-13.

In rebuttal testimony, Staff proposed ComEd engage with Staff and stakeholders to agree upon a pilot program review and approval process and/or criteria shortly after the BE Plan is approved and to file the agreed upon process and criteria as a compliance filing in Docket Nos. 22-0432/0442. Given that the design details for the various pilots have not been provided in this proceeding, Staff recommends the Commission direct ComEd to do the following:

> After pilot design has been completed, ComEd will submit planning details (i.e., preliminary project plan) on each of the proposed pilot projects to the Director of the Commission's Integrated Distribution Planning Division and to other stakeholders to review and discuss at least 30 days before the

> Company plans to commence the proposed pilot. The project plan should address at a minimum:
>
> (1) Expected outcome(s) and applicability to the BE Plan and/or P.A. 102-0662 objectives;
>
> (2) Projected timeline and duration of the project;
>
> (3) Initial cost estimate for the project; and
>
> (4) Leveraged resources (e.g., partnership with other organizations, past pilot projects to provide lessons learned information) to reduce costs and project duration.

Staff states that Commission should approve the Staff proposal establishing a BE Pilot Program review and approval process.

For the above reasons, the Commission should reject the AEE and CJCP proposals to require ComEd to provide more detail about the pilot program projects to ensure that they are effectively designed to be scaled in the future provided the Commission adopts the Staff recommended BE Pilot Program review and approval process agreed to by ComEd. That review and approval process will provide ample opportunity to flesh out the details of the pilot projects and is the appropriate time to address questions such as scalability.

The Commission should approve CJCP's proposal that ComEd undertake a pilot program that explores how to effectively facilitate submetering, including necessary changes to billing systems and development of practices to support submetering, such as automated subtractive billing, while also updating billing to accommodate DERs and, in the future, allowing net-energy metering customers to utilize submeters in effort to support the intent of 20 ILCS 627/45(a). Staff Ex. 17.0 at 44. This pilot program will further the objectives of Section 45(a) of the EVA.

The AG also recommends the Company undertake submetering to complement a TOU rate. The AG testified that, "[w]ithout segregating EV load from the rest of household load, a customer who needs to run air-conditioning or other electric load during on-peak hours, but still charges off-peak, may actually be worse off than if they were on a non-TOU rate." AG Ex. 1.0 at 54.

Although separately metering EV load is one approach to ascertain the success of TOU rates, implementing submetering instead could help alleviate some of the costs associated with another meter. Considering Illinois' goal to significantly increase EV ownership, it is important to ensure incentives are in place such that the "increased electricity usage and demand do not place significant additional burdens on the electric system but rather, create benefits for Illinois residents." 20 ILCS 627/45(a). Therefore, the Commission should accept CJCP's proposal that ComEd undertake a pilot that explores the use of submetering and reject the AG's recommendation of separate meters.

The Commission should direct ComEd to consider the WeaveGrid proposal in the final design of the Residential Optimized Charging pilot as an alternative to Rate BESH for participants in the Residential EV Charging Infrastructure Sub-program. WeaveGrid Ex. 1.0 at 16-17. This proposal will further the aims of Section 45(d)(ii) of the EVA.

ComEd clarified that the Residential Optimized EV Charging pilot "is an initial focus area and detailed pilot design will be done after the BE Plan is approved by the Commission." ComEd Ex. 6.0 at 27. However, in surrebuttal testimony, ComEd stated that "in order to participate in the Residential Optimized Charging pilot, a customer must take service under one of two ComEd rates, either Rate BES or Rate BESH. To the extent this constitutes "tying," ComEd requests a waiver of Section 452.270." ComEd Ex. 14.0 at 24. The Commission should reject ComEd's proposal to require customers participating in the Residential Optimized Charging pilot to take service under one of two ComEd rates. Further, it is premature for ComEd to ask that the Commission approve a waiver of Section 452.270, as the Company has stated that details of pilot programs should be determined after the BE Plan. Staff also disagrees with ComEd's proposal that customers participating in the Residential Optimized Charging pilot be required to take service either under ComEd's rate BES or BESH. The Company has provided no justification for this requirement and no reasoning why customers enrolled with an ARES should be prohibited from also participating in the pilot.

Staff supports "testing and development of emerging BE concepts provided the Company has thoroughly examined the costs and benefits of the new project consistent with the goals of the [EVA]." Staff Ex. 15.0 at 13. Accordingly, the Commission should direct ComEd to consider the WeaveGrid proposal in the final design of the Residential Optimized Charging pilot. The Commission should reject ComEd's proposal to require customers participating in the Residential Optimized Charging pilot to take service under one of two ComEd rates and deny the Company's request for a waiver of Section 452.270.

Staff also supports the FLO proposal to include a curbside EV charging station pilot in the BE Pilot Program. FLO Ex. 1.0 at 4. This pilot program will further the objectives of Section 45(d)(i) of the EVA.

Curbside EV charging stations would provide EV owners 24 hours/7 days per week access to charge a vehicle overnight without the need for infrastructure changes in individual residential homes. FLO cited curbside EV charging stations pilot projects which had been successfully implemented in New York City, New York state and Los Angeles, California. FLO Ex. 1.0 at 13-14.

A curbside EV charging station pilot may address the needs of customers who do have residences with a garage, driveway, or carport, while also providing greater access to EV charging by using public rights-of-way, parking areas within the neighborhood, or via other community-designated street parking locations. Staff Ex. 15.0 at 13-14. Because the FLO proposal increases access to EV charging the Commission should approve the FLO proposal to include a curbside EV charging station pilot in the BE Pilot Program.

The Commission should direct ComEd to include EV EMS concept as one of the pilots in its proposed pilot program. "EV EMS, also known as Automated Load Management (ALM), refers to the use of behind-the-meter software (e.g., power sharing) and/or hardware (e.g., integrated or located battery storage) solutions to limit EV charging demand at the service connection to a predetermined level below the aggregated charging capacity of the EVSE." NRDC Ex. 1.0 at 28. Using "EV EMS can help mitigate upgrade costs on old/outdated utility infrastructure usually used to supply power to low-

income and disadvantaged communities, thereby making EV charging infrastructure more affordable for these communities." *Id*. at 29.

ComEd does not explicitly include EV EMS in its proposed BE Plan. However, in responding to stakeholders' concerns, ComEd supports incorporating batteries in some charging stations' designs. EVgo Ex. 1.04. However, ComEd suggested it is open to incorporating EV EMS in its Customer Education and Awareness Program within its BE Plan. ComEd Ex. 7 at 19. Staff agrees with CJCP on the importance of EV EMS and agrees that incorporating EV EMS into ComEd's BE Plan will improve the plan. Staff Ex. 16.0 at 19-20. However, Staff recognizes that ComEd "does not currently have technology or structures in place that would allow for mitigating utility side make ready infrastructure through the use of EV [EMS] to limit the host site's peak demand." NRDC Ex. 1.0 at 29. Notwithstanding ComEd's constraints, Staff recommends that the Commission direct ComEd include the EV EMS concept as one of the pilots in its proposed pilot program because it will improve the BE Plan and make charging infrastructure more affordable to low income and disadvantaged communities. The review and approval process will provide an opportunity for how it might be incorporated given ComEd's technical or structural limitations.

c. AG's Position

ComEd proposed to spend $8 million on this program. ComEd Ex. 12.0 REV at 4-5. The portfolio expenses would include "non-program specific, cross-cutting activities that support the overall BE Plan," such as "labor and contracting to support portfolio planning, and reporting and associated system development, legal services, financial, and customer support/experience activities." ComEd Ex. 1.01 at 44. Staff proposed to reduce the budget for this program to $3.6 million. The AG agreed with Staff's reduction and argued that further reductions are needed to ensure the overall budget does not exceed the retail rate cap.

d. CJCP's Position

CJCP state that while the greater specificity with respect to the nature of the pilots ComEd will undertake in its revised BE Plan represents an improvement over its original proposal, the revised proposal still represents a missed opportunity in several material respects. First, CJCP state the selection of these particular five programs is not well justified and appears to be supported by input from a stakeholder process that was less than transparent; Ms. Borggren's response in her testimony refers generally and vaguely to "feedback from Staff and Intervenors." ComEd Ex. 12.0 REV at 22. As CJCP witness MacDougall observed in her rebuttal testimony, the "pilot development process must include input from stakeholders, including community members, to ensure that each pilot has clear goals and metrics, and is aligned with the needs of both the community and the electric grid. ComEd should make it clear in its [BE Plan] how and when this stakeholder process will happen." EDF Ex. 2.0 at 18. Because there is so little detail associated with ComEd's conclusions here, CJCP point out, it is impossible to assess the extent of the stakeholder input received in selecting the particular pilots that the Company is now proposing, nor to assess the appropriateness of its decision to disregard other pilot proposals. However, the limited insight that CJCP can glean through Ms. Borggren's

surrebuttal testimony suggests that certain rejected pilot proposals may not have been given meaningful consideration, to the detriment of ratepayers and communities.

CJCP state ComEd's proposal for pilot implementation post-BE Plan approval continues to come up short with respect to stakeholder involvement. CJCP point to the fact ComEd proposes to share planning details for specific pilots with Staff and other interested parties "to review and discuss at least 30 days before the Company plans to commence the proposed pilot." ComEd Ex. 12.0 REV at 24. Though CJCP admit that Staff endorses this proposal in its Initial Brief, Staff IB at 43, such a process contains two major flaws. First, CJCP state ComEd fails to define what constitutes an "interested party" for the purposes of this pilot development process, which may create the false impression that it is up to the utility to decide who, other than Staff, it deems worthy of providing feedback on its pilot plans. As CJCP witness MacDougall discusses in her direct testimony, "[p]ilots are not just a nice-to-have program addition, but rather an important tool for utilities, customers, and stakeholders to implement new technologies, policies, price signals, and other programs at a manageable scale and study the results to inform future decisions and utility offerings," and "[r]obust stakeholder input is critical for ensuring that these pilots are integrated into, and informing, ComEd's [BE Plans] over time, rather than being simply one-off projects." EDF Ex. 2.0 at 17. Indeed, state CJCP, a pilot development process that allows ComEd to unilaterally decide who can provide this stakeholder input would not meet these goals. Second, state CJCP, the 30-day deadline between the plans being shared with stakeholders and the pilots beginning creates a real risk of this process being nothing more than a rubber stamp. Per CJCP, if a stakeholder identified large problems or omissions in one of the pilots, such a short timeline would likely require implementing the pilot as-is or delaying the entire process. CJCP state the Commission should address these substantial flaws in ComEd and Staff's proposed pilot approval process by clarifying that stakeholder feedback cannot be limited to those parties unilaterally identified by ComEd and instead meaningfully engages all self-identified interested parties, including those parties to this proceeding as well as the communities, individuals, businesses, agencies, and other organizations that may be affected by the pilot, and by establishing a timeline for stakeholder feedback and pilot implementation that will actually allow stakeholder feedback to inform and improve pilot implementation.

CJCP witness MacDougall articulated the importance of submetering as a cost-effective tool to support EV load management. EDF Ex. 1.0 REV at 39. CJCP state the need to be able to rely on submetering as a basis for billing is all the more acute as a consequence of the Company's proposal to create two new EV rate classes for commercial charging customers, because the Company's proposal for new rate classes would not only require customers to pay the cost of an additional meter to participate, but, if a given customer were to make use of both L2 chargers and DCFC at the same premises, would require such a customer to pay for two separate additional meters. EDF Ex. 1.0 REV at 39; EDF Ex. 1.4. As discussed by CJCP, the rationale for dividing commercial charging customers into two separate classes based on, of all things, charger capacity, is dubious – and when combined with the Company's reliance on additional meters that customers would have to pay to obtain, the resulting cost burden on participating customers is both onerous and unnecessary.

Setting aside the merits of the rate class proposal as a whole, CJCP state this needless cost burden for metering could be alleviated by relying on the submetering capabilities inherent in EVSEs. EDF Ex. 1.0 REV at 38, fn.33.

Per CJCP, the use of this submetering capability "can significantly reduce the cost barrier to transitioning to electric vehicles by allowing EV charging customers to take service under EV-specific rates (such as a [TOU] rate) without having to install a costly separate utility meter." EDF Ex. 1.0 REV at 39.

Given the general importance of submetering in the vehicle electrification context, as well as its elevated importance in light of ComEd's specific proposals, Dr. MacDougall recommended that a pilot could be used to address challenges that currently make the Company believe it cannot rely on submetering, stating that "[i]f ComEd is not prepared to rely on submetering functionality integrated into EVSE equipment for this purpose, the Commission should require ComEd to undertake a pilot that explores how to effectively facilitate submetering, including changes to billing systems and practices to support sub-metering, such as automated subtractive billing, while also updating billing to accommodate DERs and, in the future, allowing net-energy metering customers to utilize sub-meters should be contemplated." EDF Ex. 1.0 REV at 39.

CJCP point out that ComEd witness Borggren summarily rejected Dr. MacDougall's proposal, indicating that "ComEd does not feel it can pursue [pilots for submetering and energy management systems] at this time, due to budget constraints, the need for rule waivers, and ongoing IT work." ComEd Ex. 12.0 REV at 23. When CJCP stakeholder EDF asked Ms. Borggren to clarify this vague assertion in a data request, Ms. Borggren's responses revealed that despite citing "budget constraints," ComEd had not weighed the cost of conducting a submetering pilot, and the request that she specify the type of rule waiver that would be needed was met by multiple objections from the Company. EDF Group Cross Ex. 1.0 at 10-11. The Clean Jobs Coalition Parties view such testimony and responses as unjustifiably uncooperative and preclusive. The only specific reason for not pursuing this important pilot, per CJCP, is that Ms. Borggren was able to state with specificity was the nature of the purported IT work, which respect to which Ms. Borggren stated that "ComEd is currently transitioning between Customer Information Management Systems, which would make a submetering pilot particularly difficult at this time." EDF Group Cross Ex. 1.0 at 11. CJCP state that Ms. Borggren's responses also suggest that the Company has not made any serious effort to gauge the value of submetering (and thus the value of the pilot that it is summarily rejecting), stating that "[i]t is not possible to say for certain whether any individual customer would save money if their EV charger was submetered and billed on a different rate than the remainder of their energy usage," EDF Group Cross Ex. 1.0 at 10-11, and seemingly fails to appreciate that such purported uncertainty is a reason to give the matter some serious consideration, not a reason to proceed with onerous metering rules while leaving opportunities for cost savings unexamined.

When a utility entering into a new area of business ignores emerging best practices that have taken root in service territories with more developed markets, CJCP state that it does its ratepayers a grave disservice. As Dr. MacDougall conclusively demonstrated and as ComEd did not attempt to refute, submetering is such an emerging best practice. In fact, Clean Jobs Coalition Parties state, the Company has intensified the negative

consequences of this error by proposing a charging class construct that will require some customers to procure not simply one new utility meter but potentially more than one for the same premises. CJCP states ComEd has declined to take the steps it could take to remedy this error, has declined to articulate a plan for taking such steps in the future, and has failed to satisfactorily account for its refusal to take such steps. As such, CJCP urge the Commission not to approve a BE Plan with such a glaring deficiency without requiring the Company to provide a credible path forward for remedying this deficiency in the future.

e. CTA/City's Position

With respect to the "Rideshare Pilot" proposed by Staff, the CTA notes that mass transit, such as provided by the CTA, already is aggregating riders in a single, shared vehicle, rather than in numerous personal vehicles. Electrification of the CTA bus fleet will reduce emissions in the EJ/R3 communities. CTA/City request that any ridesharing pilot should include input from the CTA and funding to acquire additional electric buses.

f. AEE's Position

AEE strongly supports ComEd's proposed BE pilots, including its School Bus Vehicle to Grid and Backup Power Capabilities pilots in particular. Those pilots will each allow the Company to explore V2G capabilities. V2G — which involves EVs transmitting power back to buildings and the grid — is a promising capability because it can help ensure that EVs benefit the grid and provide ratepayer value by providing services such as peak capacity, flexibility services (e.g. intra-day balancing), resiliency, and minute-to-minute frequency regulation that strengthen the grid, avoid outages, and provide ratepayer value. AEE Ex. 1.0 Corr. at 19.

While AEE recommends that the Commission approve ComEd's proposed pilots, AEE questions whether ComEd's proposed budget is sufficient for the Company to carry out even one, let alone multiple, robust pilots. Importantly, AEE notes that ComEd has not finalized nearly any details regarding its pilot proposals — including, for example, the amount of funding allocated to each pilot, costs that will be covered by ratepayer funding, the number of participants, eligibility criteria, or types and levels of incentives that will be made available to participants. AEE states that these details can fundamentally impact the reasonableness of ComEd's proposal and its associated request for ratepayer funding. According to AEE, without these details it is impossible for interested parties, and this Commission, to determine whether ComEd's pilots will indeed "incorporate learnings from other jurisdictions" as ComEd asserts, or simply retread ground that numerous other utilities have already covered. *See* AEE Ex. 1.0 Corr. at 20-21 (describing utilities across the country that have implemented school bus V2G pilots). AEE therefore recommends that the Commission direct ComEd to return to the Commission with an implementation plan for each of its proposed V2G pilots.

AEE observes that ComEd insists that the details of its proposed pilots will be developed through a design and evaluation process that will occur following the Commission's final Order in this case and states that it intends to follow the pilot proposal acceptance and evaluation methodology it applies in the context of its EE Program. ComEd Ex. 7.0 at 32-34. In its surrebuttal testimony, ComEd commits to meeting with interested parties and Staff to discuss feedback to its pilot proposal acceptance and evaluation methodology and to filing "the agreed upon pilot process and criteria as a

compliance filing" in this docket. ComEd Ex. 12.0 at 23. ComEd also commits to submit planning details (a preliminary project plan) on each of its proposed pilots to Staff and interested parties for review "at least 30 days before the Company plans to commence the proposed pilot." ComEd Ex. 12.0 at 24.

AEE states that while ComEd's surrebuttal proposal is a modest improvement on its original filing, it does not provide interested parties a meaningful opportunity to inform or improve pilot design. According to AEE, it is highly unlikely that ComEd will be in a position to modify its pilots based on stakeholder feedback received mere weeks before the pilot is slated to launch. And while AEE does not doubt ComEd's genuine interest in incorporating stakeholder feedback, in the event that ComEd chooses to ignore the feedback it receives, stakeholders would be left without recourse. AEE therefore states that ComEd's surrebuttal proposal provides an inadequate process for ensuring that the Company's pilots are reasonable and is no substitute for an implementation plan filed with the Commission.

AEE also notes that while ComEd asserts that its pilots will "test approaches that could be scaled up into future programs," the Company has not articulated a pathway for scaling its proposed V2G pilots into permanent programs or presented a strategy for incorporating learnings from its pilots into utility operations. AEE is concerned that unless the Commission encourages ComEd to develop a long-term strategy for leveraging V2G capabilities through permanent programs (as opposed to one-off pilots), ComEd's ratepayers risk paying for charging infrastructure capacity that does not leverage the value of bidirectional capabilities, undermining the value that ratepayers (including non-EV owners) will realize from that infrastructure. AEE therefore recommends that the Commission direct ComEd to return to the Commission with a plan for scaling its V2G pilots into a permanent program (or set of programs) that leverage EVs and bidirectional infrastructure as grid resources in coordination with other distributed energy resources ("DERs").

g. WeaveGrid's Position

WeaveGrid expressed support for the initial pilot concepts included in ComEd's BE Plan. WeaveGrid likewise supports the five pilot concepts included in ComEd's surrebuttal testimony. WeaveGrid states that ComEd should enable pilots to grow in scope and scale if they meet their intended objectives, potentially by tying them into existing programs where possible. WeaveGrid likewise recommends that ComEd be provided with budget flexibility to increase spending if certain pilots are successful. WeaveGrid states that the revised pilot concepts and pilot process appropriately incorporated intervenor feedback, and will enable ComEd to meet the goals of the EVA.

h. FLO's Position

FLO proposes the adoption of curbside charging (infrastructure sited in the public right-of-way) as a pilot program for ComEd's BE Plan. Curbside charging stations provide 24/7 charging access to EV drivers, particularly those who would not otherwise have access to EV charging infrastructure at home (e.g., individuals and families living in multi-family housing or who otherwise do not have access to a garage, carport, or private driveway). Installing curbside charging stations throughout streets on which overnight parking is permitted can allow lower-voltage chargers to charge a vehicle overnight,

without necessarily requiring additional transmission and distribution infrastructure. Moreover, expanding curbside charging capability across ComEd's service territory would also directly address a requirement in P.A. 102-0662 to encourage widespread adoption of EVs by ensuring public access to charging equipment throughout Illinois, especially in low-income and environmental justice communities where there is a higher concentration of people living in multi-family housing units.

FLO explains that there exist several common barriers to installing charging stations at multi-family housing, including insufficient access to power and the high costs of crucial infrastructure upgrades to serve larger on-site power loads, among others. The disparities in ownership of EVs become even more pronounced when considering income levels and racial ethnicity, in addition to housing type. Indeed, curbside charging is a critical solution to serving low-income and environmental justice communities, and to breaking down disparities and barriers that have historically prevented access to EVs.

FLO recommends that the Commission direct that ComEd's BE pilot program include a curbside charging pilot.

i. LVEJO's Position

ComEd's revised BE Plan includes several changes to their proposed BE pilot programs, including the addition of an EV Ridesharing pilot program. This program is explicitly ridesharing aimed at providing EV access to low-income and EJ/R3 customers for whom car ownership is not an option. LVEJO fully supports the creation of a pilot program with this particular focus. LVEJO states that the higher level of individuals in EJ/R3 communities for whom car ownership is not an option is a concern that LVEJO has brought up previously in this proceeding. It is encouraging that ComEd is attempting to design a pilot program to benefit these particular customers, and it should help to bolster the BE Plan's (and any future BE Plans) positive impact on low-income and EJ/R3 communities. However, LVEJO encourages ComEd to perform more community outreach and stakeholder feedback in determining if an EV ridesharing pilot is the best way to address the needs of this specific population. The Commission should direct ComEd to do a transparent, public feedback process before they finalize their pilot programs.

j. Commission Analysis and Conclusion

The Commission recognizes that the proposed pilot programs are described at a high level and will be more fully developed later. The Commission adopts Staff's recommended BE Pilot Program review and approval process that is agreed to by ComEd. This process will provide Staff and interested parties an opportunity to inform or improve pilot design. The Commission directs ComEd to work with Staff, Intervenors, and other interested parties in developing the pilot programs.

While the Commission approves ComEd's proposed Residential Optimized Charging pilot program, the Commission does not approve ComEd's proposed requirement that participating customers take supply service under only Rate BES or Rate BESH. The Commission agrees with Staff and ICEA that ComEd provided no justification for why two ComEd supply rates are acceptable (especially Rate BES, which is not time-variant) but no ARES product or service is similarly acceptable. The Commission directs

ComEd to allow any customers participating in the Residential Optimized Charging pilot to take supply service from any supplier on any rate or product selected by the customer.

The Commission sees value in an EV EMS pilot. This is directly related to EV and the Commission directs that the EV EMS pilot be implemented with this BE Plan. The Commission also adopts CJCP's proposal to include a submetering pilot in this first BE Plan. Staff and the AG support incorporating submetering into ComEd's proposed BE Plan. Conducting a submetering pilot in the early stages of the BE Plan process will provide a valuable opportunity to address and resolve any technical challenges or reservations that the Company may have with respect to submetering before it is implemented on a larger scale.

The Commission also approves Staff's proposal to include an Air Quality Mapping Pilot to obtain localized emission data in this first BE Plan. The Commission agrees with Staff that it will enable collecting more accurate data on localized conditions in eligible communities and will provide necessary information earlier on to inform the future BE Plan updates.

The Commission rejects AEE's recommendation to increase funding for the BE Pilot Program because an increase in the BE Plan budget would place more burden on ratepayers. Nor does the Commission feel it necessary to remove funding from other programs to increase the BE Pilot Program. Additionally, AEE's request that ComEd provide a plan for scaling its V2G pilots into a permanent program is premature and rejected.

Accordingly, the Commission approves eight pilot programs to be included in ComEd's BE Plan: (1) School Bus Vehicle to Grid; (2) Residential Optimized Charging; (3) Curbside Charging; (4) Ridesharing (or other pilot program aimed at providing EV access to low-income and EJ/R3 customers for whom car ownership is not an option); (5) Backup Power Capabilities; (6) EV EMS; (7) submetering; and (8) Air Quality Mapping Pilot.

5. Portfolio

a. ComEd's Position

ComEd argues that a BE Plan of this scale requires a range of implementation efforts, and associated costs. To that point, ComEd notes that the Portfolio portion of the BE Plan will support cross-cutting activities that are not specific to any individual program, but rather support the overall BE Plan. According to ComEd, these efforts include labor and contracting to support portfolio planning, reporting and associated system development, legal services, financial services, and customer support and experience activities. ComEd claims that the Portfolio costs do not include any program-specific administration costs, as the sub-program budgets include those costs.

ComEd anticipates that Portfolio costs will average approximately $8 million annually across the three-year BE Plan. However, ComEd notes that it is possible that these costs will vary over time, particularly as Portfolio costs may be higher in the early years of the BE Plan to fully stand up its programs.

b. Staff's Position

The Commission should approve a $3.6 million annual budget for portfolio-level costs. Staff Ex. 17.1 at 1. Portfolio-level costs are necessary to support the implementation of the BE Plan and should be approved by the Commission at the level recommended by Staff.

c. AG's Position

The AG agrees with Staff's reduction of annual portfolio budget to $3.6 million but argues that further reductions are needed to ensure the overall budget does not exceed the proposed retail rate cap. AG RB at 9.

d. Commission Analysis and Conclusion

While the Commission acknowledges that portfolio costs will support the overall BE Plan, the Commission finds that ComEd did not provide sufficient information to meet its burden to justify an $8 million spending for its portfolio-level expense. ComEd provided no details why such a high amount is necessary and how it was calculated; ComEd notes that program-specific administration costs are already included in sub-program budgets. ComEd Ex. 1.01 at 44. The portfolio-level costs of $8 million are, thus, not approved. The parties acknowledge that some portfolio-level expenses might be necessary, and Staff and the AG support a $3.6 million annual portfolio budget. However, neither ComEd nor Staff explain how they calculated their proposed amounts and neither explain how the portfolio costs will be distinguished from the subprogram administrative expenses that are budgeted elsewhere. The Commission does not have a sufficient record in this docket to identify an amount that is justified and supported by the record, that will not be duplicative of the costs already covered in the sub-programs and, thus, at this point is unable to approve any modified amount for portfolio-level expenses without ComEd providing detailed justification for a specific amount. The portfolio costs of $8 million are not approved, as further noted in Section V.C.1. of this Order.

B. Other Staff and Intervenor Proposals

1. BOMA/Chicago Proposal

a. ComEd's Position

ComEd notes that BOMA/Chicago is seeking $10 million each year in "dedicated funding" to support the installation of EV chargers in BOMA/Chicago buildings and garages. Although Staff nominally indicated support for BOMA/Chicago's proposal, ComEd observes that Staff has argued elsewhere that the overall budget of the BE Plan should be drastically reduced, from $100 million per year to approximately $44 million, and has not offered a budget proposal that would accommodate an additional $10 million program. ComEd notes that no other party supported this proposal.

ComEd suggests that proposals like BOMA/Chicago's could potentially be accommodated in subsequent BE plans. For purposes of this BE Plan, however, ComEd argues that funding is already extremely tight, and $10 million cannot simply be pulled from one of the existing sub-programs without risking adverse effects on communities that may need this technology or infrastructure the most.

b. Staff's Position

Staff states that the Commission should approve, as modified, BOMA/Chicago's proposal to work with ComEd to utilize the make-ready infrastructure incentives to transform the Chicago Central Business District into an all-EV transportation hub. Staff Ex. 15.0 at 24-26. The BOMA/Chicago proposal includes the installation of EV charging stations as well as a request that ComEd work with BOMA/Chicago members to build a network of EV charging stations in downtown Chicago. The development of this infrastructure would serve multiple P.A. 102-0662 objectives. Specifically, the proposal would reduce the level of pollution due to medium-duty and heavy-duty vehicles in a major transportation hub and serve the transportation needs of citizens from eligible communities who work in and travel through the downtown area. Staff Ex. 15.0 at 24-26.

Additionally, BOMA/Chicago notes that "the City of Chicago recently adopted changes to its Chicago Zoning Ordinance to require that at least 20% of new parking spaces be either [EVSE]-Ready or EVSE-Installed." BOMA/Chicago IB at 8. According to a recent survey of BOMA/Chicago members, the vast majority of the survey respondents with garages, have five or fewer EV charging stations in their garages, which BOMA/Chicago notes is insufficient to meet the anticipated demand or comply with anticipated ordinances. *Id*. at 7.

As a result of these developments, Staff recommends the Commission direct ComEd to work with BOMA/Chicago members and other interested parties to develop a three-to-five-year EV charging infrastructure implementation plan for the Chicago Central Business District, within six months after the approval of the BE Plan. This implementation plan would offer a collaborative and strategic approach to properly identify which garages are in need of new EV charging infrastructure and provide a high-level schedule for make-ready investment under the BE Plan C&I and Public Sector EV Charging Infrastructure Sub-Program. Staff supports BOMA/Chicago's recommendation. Section 45(d)(i) states, in relevant part:

> Make-ready investments to facilitate the rapid deployment of charging equipment throughout the State, facilitate the electrification of public transit and other vehicle fleets in the light-duty, medium-duty, and heavy-duty sectors, and align with Agency-issued rebates for charging equipment.

20 ILCS 627/45(d)(i).

In response to the BOMA/Chicago proposal, ComEd states that its inaugural BE Plan can be adjusted over time, based on market demand, and ComEd's approach can be further adjusted in subsequent BE Plans, based on experience and learnings from the first plan. ComEd Ex. 7.0 at 9-10.

Given that EV adoption requires the charging station/EV owner, electric utility, and government entities to work in concert with each other, Staff recommends further modifications to BOMA/Chicago's proposal to focus on utilizing make-ready EV charging infrastructure incentives to build the EV charging station hub within the context of ComEd's proposed EV Charging Infrastructure Sub-program. Specifically, Staff recommends that members of BOMA/Chicago or other organizations be allowed to apply

for incentives collectively rather than individually. A charging station hub located in one of the most heavily traversed areas of the state can also help achieve the EVA's goals of electrifying and decarbonizing the transportation section (20 ILCS 627/45(a)(3-4)) and BOMA/Chicago's proposal could facilitate those efforts.

For all these reasons, the Commission should approve the BOMA/Chicago proposal as modified and direct ComEd to work with BOMA/Chicago members to develop make-ready EV charging infrastructure changes in the Chicago Central Business District.

c. BOMA/Chicago's Position

To support beneficial electrification and specifically the effort to put one million EVs on the road by 2030, BOMA/Chicago proposed that Illinois should have a solid infrastructure of EV chargers in strategic locations, especially in the Central Business District which serves as the central hub for all communities within the city and metropolitan region. BOMA/Chicago proposed its "BOMA/Chicago Beneficial Electrification Program" (or "Program") to provide make-ready infrastructure incentives for EV charging stations in BOMA/Chicago buildings. As the trade association representing over 200 office, institutional and cultural buildings in Chicago's Central Business District, BOMA/Chicago should play an instrumental role in adopting EV charging station infrastructure. Incentivizing EV charging infrastructure within BOMA/Chicago building garages will support downtown workers, visitors, and tourists with existing EV's, encourage additional EV purchases, provide a safe and convenient place to park, and create high-quality jobs. To accomplish this, BOMA/Chicago is seeking dedicated funding of $10 million each year of ComEd's inaugural BE Plan. BOMA/Chicago proposes ComEd establish a new Commercial and Public Sector EV Charging Infrastructure Sub-program or provide funding to the BOMA/Chicago BE Program under a new Commercial and Public Sector EV Charging Infrastructure Program for BOMA/Chicago buildings. Staff witness Jenkins agrees and recommends the Commission approve BOMA/Chicago's recommendations with slight modifications, and ChargePoint recommends expanding eligibility for the Make-Ready Rebate Sub-program to all customers and that this would allow BOMA/Chicago members to qualify for incentives to deploy chargers in their buildings in the Chicago Central Business District, consistent with the goal of BOMA/Chicago's dedicated funding proposal.

According to a recent survey of BOMA/Chicago buildings with approximately one third of building members responding, 62% of buildings had parking garages representing 18,817 parking spaces or an estimated total of 56,000 parking spaces across all 240 commercial office, institutional and public buildings in downtown Chicago. While 63% of buildings with garages have electric vehicle charging stations, the vast majority (74%) have 5 or less charging stations in their garages, certainly not enough to meet anticipated demand or compliance with anticipated ordinances.

In addition to addressing rising demand of EV charging points and the barriers to mass adoption, the City of Chicago recently adopted changes to its Chicago Zoning Ordinance to require that at least 20% of new parking spaces be either EVSE-Ready or EVSE-Installed. According to the City of Chicago's Zoning Ordinance Section 17-10-1011-B Nonresidential Buildings, "[n]ew construction of a building containing uses other than residential uses where 30 or more parking spaces are provided shall install

equipment so that at least 20 percent of the parking spaces are either EVSE-Ready or EVSE-Installed." BOMA/Chicago Ex. 1.0 at 6-7. As more electric vehicles are purchased there will be a similar demand for electric vehicle charging stations as more people return to offices and visit our city. Additionally, the installation costs are significant, with charging stations ranging from $5,000 to $10,000, in addition to related consulting, electrical and infrastructure costs, which are also significant. These costs are in addition to current costs of maintaining and operating a building in a historically unprecedented market still facing significant challenges as a result of the COVID-19 pandemic.

From a practical standpoint, BOMA/Chicago maintains that providing options for charging in the most densely populated area in Chicago provides mobility to everyone, including EJ and R3 communities. BOMA/Chicago buildings and garages offer convenient, safe, and economic locations for EV chargers. As stated above, providing incentives to purchase electric vehicles is only half of the equation. Incentivizing EV charging station make-ready infrastructure in Chicago's Central Business District will support existing electric vehicles while encouraging new EV purchases. BOMA/Chicago seeks to work with ComEd to implement BOMA/Chicago's BE Program to connect with buildings to create jobs and to promote the adoption of EV charging in downtown Chicago.

BOMA/Chicago agrees with Staff's recommendation to modify BOMA/Chicago's proposal to focus on utilizing make-ready EV charging infrastructure incentives to build the EV charging station hub within the context of ComEd's proposed EV Charging Infrastructure Sub-program, and Staff's specific recommendation that members of BOMA/Chicago or other organizations be allowed to apply for incentives collectively rather than individually. However, to address Staff's concern that BOMA/Chicago is not the only organization with which ComEd might coordinate, BOMA/Chicago notes that in order to transform the Chicago Central Business District into an all-EV transportation hub, enlisting the assistance of BOMA/Chicago and its members is really the only viable avenue. Representing approximately 240 member buildings, its members make up over 80 percent of the total rentable space in downtown Chicago.

d. Commission Analysis and Conclusion

The Commission recognizes that BOMA/Chicago's proposal would help achieve the EVA's goals of electrifying and decarbonizing the transportation section and be beneficial to Chicago. However, given the already large overall budget and the rejection of certain Intervenors' proposals to increase the EV infrastructure budget, another $10 million dollars each year in dedicated funding to support the installation of EV chargers as proposed by BOMA/Chicago is not adopted in this inaugural BE Plan.

Staff proposes that the Commission direct ComEd to work with BOMA/Chicago members and other interested parties to develop a three-to-five-year EV charging infrastructure implementation plan for the Chicago Central Business District, within six months after approval of the BE plan. This proposal will provide a collaborative approach as to which garages are most in need of new EV charging infrastructure. The Commission approves this recommendation. The Commission further approves Staff's recommendation that members of BOMA/Chicago or other organizations be allowed to apply for incentives collectively rather than individually under the C&I and Public Sector EV charging Infrastructure Sub-Program.

2. CJCP Proposals

a. ComEd's Position

CJCP offer a range of proposals that are generally related to the BE Plan, but ComEd argues that they should not be adopted in this proceeding.

First, CJCP argue that the BE Plan should include a program to incentivize deployment of load management technologies. ComEd supports the use of EV EMS and ALM but notes that they are not eligible for incentives under the BE Plan because the focus in this inaugural BE Plan should be on encouraging the adoption of technologies that drive electrification. However, ComEd notes that nothing in the BE Plan precludes customers from using these technologies, and ComEd is open to incorporating them in the Customer Education and Awareness Program.

Second, CJCP recommend that ComEd institute standardization of data across the service territories of ComEd and Ameren to prevent parties from having to reformat data depending on where service is taking place. ComEd argues that it is not clear where this fits into the BE Plan as a whole, and this effort could take significant time and resources, negatively impacting the Plan. Moreover, as Staff pointed out, Ameren is not a party to this proceeding, and the Commission should not adopt a program or proposal in this case that impacts Ameren.

Third, CJCP also argue that the BE Plan should be tailored to support Charge de Move ("CHAdeMo") plugs and should require recipients of incentives for charging stations to demonstrate use of the ISO 15118 and Open Charge Point Protocol ("OCPP") communication protocols. In addition, CJCP recommend that the BE Plan require chargers to be UL-listed and ENERGY STAR® -certified, with additional cybersecurity standards for charging stations receiving incentives through the BE Plan. However, ComEd argues that because the market for charging stations is still developing in Illinois, it is premature to adopt technical specifications at this time. Moreover, ComEd points out that the BE Plan no longer includes rebates or incentives for charging stations, per the Interim Order. Instead, the BE Plan is limited to incentives for make-ready infrastructure to support the installation of charging stations. Given this tenuous tie to the charging stations themselves, ComEd argues that it would be inappropriate to impose technical requirements on the charging stations at this point in time. ComEd suggests that these kinds of technical requirements are better determined by state and federal lawmakers, in venues that are equally applicable across utilities.

Fourth, CJCP would also like the BE Plan to include a plan for make-ready infrastructure specifically with MHDVs in mind. ComEd notes that Staff opposes such a measure, arguing that any increase in make-ready infrastructure could increase the C&I and Public Sector EV Charging Infrastructure beyond what is approved in the Order and could negatively impact other programs. Moreover, ComEd argues that budget flexibility in the BE Plan renders this largely moot, as funds can be shifted to help address this issue.

Fifth, CJCP also propose that ComEd undergo extensive annual load research and distribution grid impact studies in order to mitigate grid impact and design programs that incentivize effective grid use by customers. ComEd responds that this will add significant

costs to the BE Plan and will likely negatively impact programs designed to providing EV charging infrastructure to eligible communities.

Finally, CJCP claim that "ComEd has not taken sufficient steps … to minimize impacts on ratepayers, including low-income ratepayers, arising from the transition to EVs." CJCP IB at 33. ComEd disagrees with this assertion.

b. Staff's Position

Staff states that the Commission should reject the CJCP proposal that ComEd coordinate with other programs in P.A. 102-0662 to provide a package of incentives that include rebates or other incentives for DERs that are co-located with the vehicle, and condition incentives upon the customer committing those resources in a way that achieves a specified level of performance in providing grid services. EDF Ex. 1.0 REV. at 30.

The CJCP proposal would be more appropriately considered in ComEd's Multi-Year Integrated Grid Plan ("MYIGP") proceeding than in this proceeding considering BE because the Company supports the deployment of DERs through other means, outside of the scope of the BE Plan. ComEd Ex. 6.0 at 28.

Staff states that the Commission should also reject the CJCP proposal regarding medium-duty and heavy-duty infrastructure changes to the BE Plan. EDF Ex. 1.0 REV. at 42. Given that the final design of the BE Plan is not yet complete, the Commission should decline to approve proposals like the one advanced by CJCP that could increase the C&I and Public Sector EV Charging Infrastructure Sub-program budget beyond what is approved in the Commission's final Order, and which may in turn negatively impact programs designed to provide EV charging infrastructure for eligible communities if funds are shifted from those programs to fund the CJCP proposal. Staff Ex. 15.0 at 20-21. Additionally, the budget flexibility within the BE Plan permits resources to be reallocated to serve the MDHD EV infrastructure demands as necessary, so the CJCP's proposal has been rendered moot and thus unnecessary.

Staff further asserts that the Commission should reject the CJCP proposal pertaining to the electric power grid. Staff Ex. 15.0 at 21-22. Given that the final design of the BE Plan is not complete at this time, CJCP's proposal would increase BE Plan costs which may have the unintended consequence of negatively impacting programs designed to provide EV charging infrastructure for eligible communities. Staff Ex. 15.0 at 21-22.

Additionally, the CJCP proposal related to the electric power grid is more appropriate in the MYIGP Plan proceedings than in this proceeding considering BE. Therefore, to avoid unnecessary confusion and the potential for miscommunication between the BE Plan and the MYIGP, the Commission should reject the CJCP proposal related to the electric power grid.

According to Staff, the Commission should reject the CJCP proposal requiring standardization of data formats across the service territories of ComEd and Ameren to prevent third parties from having to reformat the data for different parts of the State. EDF Ex. 1.0 REV. at 40. Given the nascent stage of the BE Plan as a whole, it is difficult to ascertain any one specific area of concern that would be addressed by the CJCP

proposal. Further, the Commission should not adopt a program in this proceeding that would impact Ameren, as Ameren is not a party to this proceeding.

Staff states that the Commission should also reject the CJCP proposal related to make-ready infrastructure. Staff Ex. 15.0 at 35. CJCP proposes that ComEd adopt rules "that make electrical equipment on the utility-side of the meter needed to support EV charging (outside of single-family homes) part of the normal course of utility business." NRDC Ex. 2.0 REV. at 4.

Essentially, CJCP seeks to treat all EV-related costs as if they were costs associated with standard service, to be borne by all ratepayers, regardless of EV adoption or participation in an EV program. In Staff's opinion, the Commission should decline to do so, because Section 45 of the EVA does not prescribe a shift away from the accepted principle that costs should be borne by the ratepayers who cause those costs, nor does it contemplate that EV infrastructure costs should be borne by all ratepayers, regardless of whether a ratepayer participates in an EV program. Staff Ex. 13.0 at 20-21 (*see* 220 ILCS 5/16- 108(c), "Charges for delivery services shall be cost based, and shall allow the electric utility to recover the costs of providing delivery services through its charges to its delivery service customers that use the facilities and services associated with such costs.").

Staff recommends that the Commission reject CJCP's proposal to revise the rules to treat EV charging costs as a "normal" utility business cost to be collected from all ratepayers.

c. CJCP's Position

CJCP note that ComEd remains opposed to including any substantive consideration of load management technologies in its BE Plan. CJCP refers to ComEd witness Borggren's statement that nothing in the BE Plan prevents customers from installing these technologies alongside their EV chargers, but that they are "not eligible for incentives under the Plan, due to the focus on the technologies that drive electrification versus demand management." ComEd Ex. 7.0 at 19. The Company also, according to CJCP, does not believe a load management plan should be included in its current BE Plan proposal, its 2024 BE Plan proposal, or a 2024 rate design investigation, as "[l]oad management is neither rate design, nor specific to EV charging." ComEd Ex. 11.0 REV at 26-27. CJCP contends ComEd's position violates the terms and the spirit of EVA Section 45(d)(iii), which specifically requires consideration of "optimized charging programs" that encourage peak avoidance and demand response, 20 ILCS 627/45(d)(iii), and ignores the value load management technologies can provide to reduce system costs to the benefit of all ratepayers, in line with Section 45(d)(v). As Clean Jobs Coalition Parties witness Nelson explained, with a State target to have one million EVs registered by 2030, load management by the State's largest electric utility company "will become substantially more complex and will involve transitioning from managing thousands of electric vehicles and chargers to millions." NRDC Ex. 1.0 REV at 27. CJCP believe it is essential that ComEd "plan for future projected EV load and ensure that the grid can accommodate the increased load reliably and cost effectively." NRDC Ex. 1.0 REV at 27.

CJCP witness Nelson further explained the reasons for and details pertaining to a load management plan in his direct and rebuttal testimonies. NRDC Ex. 1.0 REV 27-31;

NRDC Ex. 3.0 at 9-11. EVA Section 45(d)(i) directs ComEd to address make-ready investments to facilitate the rapid deployment of charging equipment. As Mr. Nelson stated, EV EMS can help defer or avoid additional distribution infrastructure for increasing EV charging load - especially important in low-income communities with outdated utility infrastructure. As Mr. Nelson explained, the use of EV EMS can be further supported by ComEd's adoption of a standard site evaluation methodology for non-residential charging sites, designed to determine whether EV EMS could cost-effectively meet the customer's charging needs; if so, the customer could incorporate the results into its project. Mr. Nelson further asserted that EV EMS costs also should be eligible for rebates.

According to CJCP, ComEd has also failed to include in its BE Plan any plans to support the deployment of DERs, another important tool for avoiding greater-than-necessary distribution system investments. In the EV charging context, as CJCP witness MacDougall described, DERs include solar panels installed near charging stations to provide power to charging stations and battery storage that can store excess power from the solar panels and/or charge from the grid during low-demand, low-cost periods and later provide power to the charging stations. EDF Ex. 1.0 REV at 28. Continuing, Dr. MacDougall stated that this allows EV operators, "even EV operators with somewhat inflexible charging needs, to decrease their demand from the grid while continuing to charge in a way that meets their operational needs." EDF Ex. 1.0 REV at 28. As she noted, research shows that DERs in this space can have a significant impact. Dr. MacDougall cited a study in California which found that a combination of managed charging and DERs could mitigate the peak demand of a single fleet of 50 class 8 vehicles by 4 MW. EDF Ex. 1.0 REV at 28-29. If deployed alongside charging stations at a meaningful scale throughout ComEd's service territory, Dr. MacDougall asserted that DERs have an enormous potential for avoided distribution system capacity needs that would otherwise demand ratepayer funds as more EVs enter service and require charging infrastructure. But despite this potential, as Clean Jobs Coalition Parties point out, ComEd rejected the opportunity to include any consideration of DERs in its BE Plan, with Ms. Washington instead stating only that "ComEd supports the deployment of DER through other means, outside the scope of the BE Plan." ComEd Ex. 6.0 at 28.

CJCP note that Staff requests that recommendations CJCP put forward be rejected. Contrary to Staff's assertion, CJCP assert they are not advocating for a shift of funds from eligible communities, and to suggest otherwise is a clear misstatement of CJCP's advocacy, without any basis in any document they have filed. In fact, Clean Jobs Coalition Parties claim funds are more likely to be taken away from eligible communities in the severely constrained budget that Staff continues to advocate, which is not grounded in a correct interpretation of the EV Act. Moreover, Clean Jobs Coalition Parties point out that Staff has provided no evidence to support the implication that coordination with other DER programs will increase the BE Plan budget. Finally, according to CJCP, Staff's concern about coordinated load management and resource program planning ignores the fact that such careful planning has enormous potential to save ratepayers money by avoiding infrastructure build out that would have otherwise been unnecessary.

It is the position of CJCP that ComEd has not taken sufficient steps in its BE Plan proposal to minimize impacts on ratepayers, including low-income ratepayers, arising from the transition to EVs. They contend that existing load management and DER

technologies allow customers to manage their load in a way that most efficiently uses the existing distribution grid and mitigates utility system upgrade needs, minimizing costs for all ratepayers. Clean Jobs Coalition Parties urge the Commission to direct ComEd to develop and file a comprehensive EV rate design and load management plan, include in its BE Plan a program to incentivize the deployment of load management technologies including ALM/EMS, and ensure robust coordination with DER programs in P.A. 102-0662 to bring the benefits of DERs to bear in their BE Plan. Clean Jobs Coalition Parties suggest that these DER incentives can be conditioned on the resources achieving a specified level of performance such as peak load reduction and limited in value to the cost of the supplemental line extension allowance or other distribution system investments that are avoided through the use of the technology.

CJCP further state that customers would be better able to engage in passive load management, at lower cost, if ComEd allowed EV charging customers to be billed for electricity usage on EV-specific rates through submetering. As proposed, CJCP state, ComEd's BE Plan will require customers to install new utility meters, despite the existence of lower cost alternatives. For example, CJCP point out that a customer seeking to participate in ComEd's proposed EV Charging Delivery Classes with both L2 and DCFC chargers at a single site will need to install separate utility meters for those two charger types. EDF Ex. 1.4 at 2. CJCP state that submetering instead relies on the metering capabilities of the charging station itself, rather than a utility meter, to measure that charging station's electricity consumption. EDF Ex. 1.0 REV at 37. Where EV-specific rates are available, CJCP state submetering allows customers to access lower-cost charging during off-peak periods without installing a costly separate meter. EDF Ex. 1.0 REV at 39. And, evidence from CJCP show these up-front savings through avoiding the need for a second meter can be significant, with average savings totaling hundreds to thousands of dollars in two pilots in California and Minnesota. EDF Ex. 2.0 at 18. Clean Jobs Coalition Parties urge submetering to be paired with required automated subtractive billing, which separates out submetered electricity usage data from a customer's other usage without the need for manual calculations by the utility, as well as adequate monitoring of energy usage and standardization of data formats, EDF Ex. 1.0 at 39-40.

Clean Jobs Coalition Parties urge the Commission to direct ComEd and Ameren to work with EVSPs to agree on standardized data formats for transmitting charging data from the EVSP to the utility, "as this would minimize workload associated with converting data to a format compatible with ComEd's systems. EDF Ex. 2.0 at 15. CJCP point out that Staff opposes this recommendation as "it is difficult to ascertain any one specific area of concern that would be addressed by the [CJCP] proposal" and "the Commission should not adopt a program in this proceeding that would impact Ameren, as Ameren is not a party to this proceeding." Staff IB at 52.

With respect to Staff's first objection, CJCP point out the record does in fact reflect a "specific area of concern," namely the administrative burden for both EVSPs and utilities of handling and sharing this submetered charging data in the absence of standardized data formats. EDF Ex. 1.5 at 32. Given the preexisting and ongoing use or consideration of submetering in several states, CJCP state this is an ideal area for ComEd to learn from the EVSPs, as well as from utilities with experience in submetering EV charging, about their experience.

With respect to Staff's second objection, Clean Jobs Coalition Parties made an identical recommendation regarding standardized data formats in its sponsored testimony in the other proceeding referenced by Staff. Docket No. 22-0431/0443, EDF Ex. 1.0, at 32. CJCP state the Commission clearly has the authority to direct ComEd to include such coordination with Ameren in its BE Plan in this proceeding, and to provide the equivalent direction to Ameren in its own proceeding. And, CJCP point out if the Commission found that it did not have such authority, it would still have the authority to direct ComEd alone to complete such coordination with interested EVSPs.

Section 45(d)(vii) of the EV Act states that a utility BE Plan must address "whether to establish charging standards for type of plugs eligible for investment or incentive programs, and if so, what standards." 20 ILCS 627/45(d)(vii). In its BE Plan, CJCP point out that ComEd rejects the opportunity to implement any such standards, with Ms. Washington stating that the Company "is not recommending including charging standards for the type of plugs eligible for investment or incentive programs in its BE Plan. Given the nascent, evolving status of the EV ecosystem, CJCP point to the fact that ComEd does not believe it would be appropriate to set any standards or requirements that would influence customers' choices of EVs or EV charging infrastructure." ComEd Ex. 1.0 at 21. Further, CJCP highlight ComEd's position that because the Commission's Interim Order prevents ComEd from providing direct incentives for the purchase and installation of publicly available EV charging stations, "it would be inappropriate for the Commission to impose requirements on EV charging equipment or charging services that are unrelated to their interaction with the grid." ComEd Ex. 11.0 REV at 11. CJCP aver this position has significant flaws, ignores prevailing standards in other jurisdictions and industry best practices, and creates significant risk of stranded assets and unreasonable use of ratepayer funds.

As per CJCP, ComEd's position – that if it is not subsidizing chargers it should not require those chargers to meet certain standards – defies the intent of the EVA, and ignores the reality of its own BE Plan. CJCP point out that the Act clearly contemplates the utilities, including ComEd, adopting standards as part of their BE Plans. And, CJCP state that, although the Commission's Interim Order prevents ComEd from directly incentivizing the purchase and installation of non-residential charging stations, the BE Plan continues to incentivize deployment of such charging stations indirectly, through sub-programs such as the C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program. As such, CJCP state ensuring that charging stations served by the make-ready infrastructure and distribution grid upgrades supported by the BE Plan meet prevailing standards for interoperability, communications, safety, EE, and cybersecurity is critical for ensuring ratepayer dollars are being efficiently and effectively deployed through ComEd's BE Plan.

Indeed, state CJCP, the failure to propose any standards for charging connectors is a potentially flawed use of ratepayer funds that ignore obvious trends in the EV market. CJCP point out that CCS/J1772 connectors are the dominant standard for EV chargers, with the vast majority of EV models available today and expected in the future in the U.S. compatible with CCS/J1772. Staff Ex. 5.0 at 14. CHAdeMO-compatible vehicles, CJCP state, meanwhile, represent a small and shrinking market segment, with automakers and charging providers moving away from the standard. Staff Ex. 5.0 at 11. Federal

regulators and utility Commissioners in other states have already recognized the market shift towards CCS/J1772. CJCP point to the draft standards for the NEVI Formula Program would allow, but not require, funds to go towards CHAdeMO chargers in year one of the program before exclusively funding CCS chargers going forward. EDF Ex. 1.0 REV at 38. CJCP admit that some level of support for targeted investment in CHAdeMO connectors may be necessary for equity purposes, given the number of used EVs expected to remain in service that rely on CHAdeMO. EDF Ex. 1.0 REV. However, CJCP state this need must be balanced with ensuring ratepayer funds are efficiently and effectively deployed through the BE Plan; the reality is that a program completely devoid of any connector standards may overinvest in non-CCS/J1772 connectors, including CHAdeMO, which constitute a small and shrinking portion of the market, and will not be a reasonable use of ratepayer dollars in most contexts. As such, CJCP encourage ComEd's approach to be narrowly tailored to support CHAdeMO plugs where analysis shows that equity considerations would be furthered by the inclusion of CHAdeMO plugs, and otherwise require the deployment of CCS/J1772 plugs for light-duty public charging use cases.

Beyond charging station connector standards, CJCP point out that ComEd also rejected the opportunity to require any standards for communications protocols, EE, safety, or cybersecurity requirements for charging stations, stating that "the role of setting standards or requirements for EV charging equipment and charging services is better left to the market or, where an appropriate issue for regulation, to state and federal policymakers." ComEd Ex. 11.0 REV at 11. However, CJCP state this position ignores the statutory language specifically requiring the BE Plan to consider "whether to establish charging standards for type of plugs eligible for investment or incentive programs, and if so, what standards." 20 ILCS 627/45(d)(vii). As such, CJCP aver, this language makes clear the legislative intention that the utilities implement such standards where appropriate.

CJCP believe implementing standards for communications protocols is in the interest of ratepayers. The two communications standards that Clean Jobs Coalition Parties recommend ComEd's BE Plan require for charging stations receiving incentives are ISO 15118, which standardizes communication between the EV and the charging station, and OCPP, which standardizes communication between the charging station and the charging station operator. EDF Ex. 2.0 at 10-11. CJCP state ISO 15118 allows charging stations to be directly compatible with a wide range of EVs; without it, drivers would be more likely to experience difficulty connecting their EVs to chargers and/or paying for charging sessions, sometimes completely failing to complete a charging session. *Id.* at 11. Per CJCP, this could leave stations without ISO 15118 underutilized, and thereby result in any ratepayer funds put towards such stations not being used in the most responsible, efficient manner. Relatedly, CJCP state, OCPP means that if a station operator goes out of business, a new operator can take over operation of the existing charging stations rather than being locked out by the former operator's proprietary software. *Id.* at 10-11. Without OCPP, per CJCP, if a station operator goes out of business there may be no way to continue operation of that station, and any ratepayer money that went towards the station or associated grid infrastructure would become a stranded asset.

Compared to the risk of wasted ratepayer funds as a result of failing to impose standards, CJCP state the cost of implementing these standards is miniscule. Indeed, per CJCP, there is no direct cost to ratepayers in the aggregate, as the cost of complying with these standards would be borne by the charging station developer, not ComEd ratepayers. And CJCP state these compliance costs for the developer are small to non-existent, with OCPP having no additional hardware needs and free open-source software, and ISO 15118 having minimal additional hardware costs. Requiring ISO 15118 and OCPP is also not unprecedented; CJCP cite evidence that both are already required in other jurisdictions. In California, point out CJCP, the largest EV market in the U.S., the CPUC has required all ratepayer-funded charging stations be compatible with OCPP and be ISO 15118-ready by July 1, 2023. EDF Ex. 1.3 at 45. In addition, CJCP point to the draft regulations for the NEVI Formula Program similarly require compatibility with these two standards. EDF Ex. 1.0 REV at 38. Although the federal regulations are still in draft form, CJCP state there was support from stakeholders to retain both standards in the final rule, and this final rule is expected imminently. This, combined with the consistency of the draft regulations with those already finalized in California, clearly demonstrate to CJCP the trajectory of the market towards these standards that ComEd's BE Plan is ignoring, to the detriment of its ratepayers.

According to CJCP, ComEd also wrongly rejected the opportunity to implement safety standards through requiring chargers be UL-listed or receive similar certification from another 39 NRTL. CJCP state charging stations certified by UL or another NRTL have been tested to ensure minimal risk of fire, shock, and other personal injury from their operation. EDF Ex. 2.0 at 13. Indeed, state CJCP, this requirement would align with California requirements for charging stations receiving incentives from the California Energy Commission, and with those proposed for the NEVI program. *Id*.

CJCP believe it is detrimental that ComEd similarly rejected the opportunity to include EE standards (specifically, ENERGY STAR® certification) for charging stations in its BE Plan. Multiple Intervenors, including the Clean Jobs Coalition Parties, support requiring ENERGY STAR® certification for charging stations receiving incentives through ComEd's BE Plan. EDF Ex. 2.0 at 11-12; Staff Ex. 16.0 at 10. CJCP point out that certified charging stations use less power when in standby mode, generating lifetime savings for station operators of hundreds to thousands of dollars while also reducing demand on the grid. EDF Ex. 2.0 at 12. Given the current state of the market, the Clean Jobs Coalition Parties recommend that ComEd require ENERGY STAR® certification for L2 charging stations deployed through the BE Plan that many fleets conducting overnight charging will utilize and recommend but not require such certification for DCFC stations, with a plan to set a deadline to require certification for DCFC stations as the market develops and this certification become available for L3 charging. CJCP state objections from parties regarding ENERGY STAR® certification may not be persuasive, given that EVSE providers who must look after their bottom line might be faced with a situation in which their products may be ineligible for incentives in the face of such a requirement. And, the Clean Jobs Coalition Parties' recommendation of requiring ENERGY STAR® certification only for L2 chargers at present and setting a timeline for a similar requirement for DCFCs should not inhibit infrastructure deployment by CTA in the near term while allowing the agency to engage in the future consideration of DCFC certification requirements.

CJCP further recommend that ComEd require ratepayer-supported stations implement the up-to-date catalog of cybersecurity standards from the National Institute of Standards and Technology ("NIST"), as well as Transport Layer Security ("TLS"). Together, CJCP state these standards would ensure sensitive customer information accessible to charging stations, such as payment information, is protected from cyberattacks. EDF Ex. 1.0 REV at 40. Per CJCP, these standards would also ensure that chargers that are in communication with utility systems as part of any demand response programs do not provide an avenue for cyberattacks against the utility itself. Further, point out CJCP, the EVA explicitly calls for consideration of such communications as part of its BE Plan, including "signals that allow [EV] charging to respond to local system conditions, manage critical peak periods, serve as a demand response or peak resource, and maximize renewable energy use and integration into the grid." 20 ILCS 627/45(d)(ii). Finally, CJCP state cybersecurity protections would provide security to the users of charging stations supported by the BE Plan, while ensuring that necessary protections are already in place if ComEd were to implement future programs that incorporate such communication and control.

CJCP aver that the failure to require these standards, despite widespread industry and regulatory recognition that they are achievable and valuable, represents a significant omission from ComEd's BE Plan that creates significant stranded asset risk and leaves customer information vulnerable. CJCP urge the Commission to require ComEd to include these baseline standards now, while further stakeholder work takes place at the state and federal level to further refine which, if any, additional standards are appropriate.

As a threshold matter, CJCP state, it should be recognized that no party in this proceeding is recommending that ComEd "develop" any standards, but rather that the utility include in its BE Plan standards that already exist and have been proposed or implemented in other jurisdictions.

CJCP state ComEd also has an obligation to appropriately and efficiently spend ratepayer dollars. CJCP point to Staff witness Balogun, who explained in testimony, "[i]t is important that ratepayer-funded incentives for public charging stations only be provided for charging stations that will remain useful to ComEd's ratepayers over time." Staff Ex. 5.0 at 18. As such, CJCP aver, protecting ratepayer dollars in the context of its BE Plan must include taking reasonable steps to ensure charging stations supported by that money are functional, accessible to drivers, and able to remain used and useful as the charging marketplace continues to evolve. Unfortunately, CJCP state, ComEd's wholesale rejection of standards does not do this.

With respect to connector standards, CJCP generally agree with Staff that the Commission should direct ComEd to adopt the CCS standard for publicly accessible DCFCs, with two caveats. However, CJCP clarify that ComEd should be allowed to provide incentives for the installation of CHAdeMO chargers where analysis shows that equity would be furthered by the inclusion of CHAdeMO plugs. And, CJCP point out that, given the evolving nature of the medium- and heavy-duty EV ecosystem and the continuing development of charging standards for these vehicles, this standard should not be applied to charging stations intended to serve medium- and heavy-duty EVs.

Clean Jobs Coalition Parties agree with ChargePoint that given the energy and cost savings and safety and reliability benefits, all residential L2 charging stations supported through ComEd's Residential EV Charging Infrastructure Sub-program should be ENERGY STAR® certified and certified by a NRTL. ChargePoint IB at 27. Because these same benefits exist in the non-residential charging context, CJCP state these requirements should extend to the C&I and Public Sector Charging Infrastructure Sub-program as well.

CJCP agree with Staff's recommendation that the Commission order ComEd to "require [EV] charging station operators who are incentivized under its BE Plan to provide a scope of information regarding cybersecurity practices to ComEd that aligns with what ComEd requires of its vendors." Staff IB at 71. This should be in addition to the specific cybersecurity standards recommended by the Clean Jobs Coalition Parties, namely the NIST catalog of standards and Transport Layer Security. EDF Ex. 1.0 REV at 40.

Finally, CJCP state ComEd's plan still does not do enough to ensure charging stations supported through the BE Plan allow for sufficiently equitable payment methods (see Section V.A.2 of this Order). Clean Jobs Coalition Parties raised concerns with EV driver payment methods, which ComEd's BE Plan did not address.

Electrify America objected to Clean Jobs Coalition Parties' proposal, stating that "public EV charging operators are already incentivized by the market to be customer friendly and to provide easy and accessible payment options to their customers." Electrify America IB at 15. However, CJCP point out that this "leave it to the market" position ignores reality - it would have the effect of undermining the legislature's stated intent in the EVA to "increase access to electrification for all consumers" and is antagonistic to one of the EVA's specific reasons for incentivizing BE: "Widespread adoption of electric vehicles requires increasing public access to charging equipment throughout Illinois, especially in low-income and environmental justice communities, where levels of air pollution burden tend to be higher." 20 ILCS 627/45(a). Recognizing that cash payments at public charging stations are unrealistic, CJCP witness Baumhefner testified that "prepaid cash cards are the only alternative to cash payment for unbanked individuals," which "will require EMV chip readers because most prepaid debit cards lack contactless capability." NRDC Ex. 2.0 REV at 49. CJCP state it is important for low-income EV drivers should have a realistic opportunity to pay for charging at utility customer-funded charging sites. ComEd's BE Plan should include the following language, as CJCP witness Baumhefner proposed: "Qualifying installations must have credit card capability, which at a minimum shall include a credit card reader device physically located on either the electric vehicle supply equipment (EVSE) unit or a kiosk used to service that EVSE that accepts the Euro MasterCard Visa (EMV) chip and contactless payment from major debit and credit cards." NRDC Ex. 2.0 REV at 50. CJCP state that adoption of this payment standard will enable many more low-income EV drivers to have practical access to public charging stations by accepting a common, sometimes only, method of payment. The Commission should adopt Clean Jobs Coalition Parties' proposed payment standard.

d. Commission Analysis and Conclusion

The Commission notes that it has approved a pilot program related to EV EMS (see Section V.A.4). However, CJCP's request that the Commission require ComEd to

develop and file a comprehensive load management plan in its BE Plan is best addressed in the Company's MYIGP.

The Commission denies CJCP's proposal that there be standardization of data across the service territories of ComEd and Ameren. This proposal lacks specificity and Ameren is not a party to this proceeding.

CJCP's recommendations regarding payment methods are addressed in Section V.A.2.

ComEd did not include any charging standards for the type of plugs eligible for investment or incentive programs in its BE Plan. Staff recommends that the Commission adopt the CCS standard for EVSE connectors in L3 or DCFC public EV charging stations (see Section V.D.1) as a requirement to receive an incentive under the BE Plan. CJCP supports Staff's proposal but argues that ComEd's approach be tailored to support CHAdeMo plugs where analysis shows equity considerations would be furthered.

The Commission notes that ComEd and Tesla point out that ComEd's BE Plan does not rebate this type of charging equipment. Nevertheless, Section 45(d)(vii) of the EVA requires the BE Plan to consider "whether to establish charging standards for type of plugs eligible for investment or incentive programs, and if so, what standards." 20 ILCS 627/45(d)(vii). It is not required that charging standards for type of plugs needs to be decided in this BE Plan considering ComEd's proposals. However, there is value in the CJCP proposal, which adopts standards but allows more flexibility based on equity considerations. The Commission encourages ComEd to work with Staff and stakeholders to consider such standards in future BE Plans.

CJCP further recommend that the Commission implement standards for communications protocols such as ISO 15118 and OCCP. The Commission finds that given the NEVI Standards and Requirements rule is now final and adopted by the Federal Highway Administration and the U.S. Department of Transportation, adopting such standards is not premature and it is appropriate to do so. EDF Motion and Att. A. CJCP witness MacDougall demonstrated that these communications standards serve to standardize communication between the EV and the charging station and station operator, thereby increasing the practical availability of charging stations to EV drivers. EDF Ex. 2.0 p. 10-11. The Commission adopts such standards and directs ComEd to incorporate them in its current BE Plan.

CJCP's proposal regarding submetering is addressed in Section V.A.4.

Cybersecurity recommendations are addressed in Section V.B.5.

CJCP's recommendations regarding reliability standards are addressed in Section V.B.3.

3. Reliability and Availability Proposals

a. ComEd's Position

Staff recommends that ComEd implement several regulations and requirements for public charging stations including: (1) the stations must be certified ENERGY STAR®; (2) the stations must have an uptime reliability standard of minimum 97%; and (3) the station operators must have at least two or more ports. ComEd believes these

recommendations are not appropriate at this time. ComEd states that it "is not proposing to own any charging stations and, consistent with the Commission's Interim Order, is not directly incentivizing any publicly accessible chargers under the Revised BE Plan." ComEd Ex. 11.0 REV at 20.

ComEd believes that it is premature to set the technical standards that FLO suggests, given that this is the first BE Plan. Moreover, though FLO points to jurisdictions in which utilities have attached reliability requirements to their EV charging programs with some success, ComEd maintains that charging equipment requirements are better left to state or federal policy makers. ComEd argues this is particularly true in light of the fact that the Interim Order determined that ComEd cannot offer rebates to install and maintain charging points as part of its BE Plan, giving ComEd even less control over such things such as charging stations.

b. Staff's Position

Staff also states that ComEd's BE Plan, as presently constructed, does not contain reliability, availability, and tracking requirements that public charging stations must meet to be eligible to receive ComEd incentives and the Company provided differing and contradictory proposals regarding make-ready infrastructure incentives, EV Supply Equipment ("EVSE") connectors, and charging station and EVSE reliability requirements, specifically ENERGY STAR® certification and uptime reliability standards. The Commission should adopt Staff's recommendations on these issues and require ComEd to implement appropriate regulations and requirements to ensure that activities in its BE Plan will provide safe, efficient, and reliable services to its customers. Specifically, the Commission should modify ComEd's BE Plan to:

(1) require that public EV charging stations for which owners or operators receive incentives be certified by ENERGY STAR®;

(2) institute an uptime reliability standard of 97% for publicly accessible chargers receiving ComEd incentives;

(3) require public charger incentive recipients to submit annual reliability reports to ComEd; and

(4) require public charging stations for which owners or operators receive incentives to have at least two or more EVSE ports.

The Commission should modify ComEd's BE Plan to require public EV charging stations for which owners or operators receive incentives be certified by ENERGY STAR®. Staff Ex. 5.0 at 27. ENERGY STAR® is the government-backed symbol for EE, providing simple, credible, and unbiased information that consumers and businesses rely on to make well-informed decisions. Staff Ex. 16.0 at 10. ENERGY STAR® EVSE not only provide energy savings to the owners of EV chargers but also have environmental benefits and cost savings for the owners of the public charging stations.

Staff notes that EVSE carrying the ENERGY STAR® rating typically are 10 to 20 percent more energy efficient than non-rated models. Staff maintains that the potential cost savings realized through greater energy efficiency over the useful life of the EVSE should be considered in addition to as the installation costs. Using an ENERGY STAR®EVSE allows customers to save more money over the EVSE's useful life, when

compared to non-ENERGY STAR® EVSEs and have an added benefit of helping the environment. *Id*. at 11. Additionally, ENERGY STAR® certified charging stations are presently the most reliable on the market. *Id*. at 10.

ComEd does not support ENERGY STAR® charger requirements. ComEd Ex 11.0 at 15-16. The Company states there are concerns about the availability of ENERGY STAR® certified chargers to meet the needs of more specialized end-users and argued these issues are better left to state and federal policymakers. *Id*. at 16.

Staff disagrees with ComEd on both these points. First, ComEd does not dispute Staff's assertion that ENERGY STAR® appliances (i.e., EVSE) not only provide energy saving to the owners of EV chargers, but they also have environmental benefits and provide cost savings for the owners of the public charging stations. Second, none of the companies identified by ComEd specifically opposed the use of ENERGY STAR®-certified chargers in residential and nonresidential charging stations under ComEd's BE Plan. Staff notes that only FLO Services, Tesla, and the CTA raise any issues with the ENERGY STAR® certification's requirement advanced by Staff.

FLO agrees that residential charging stations should be ENERGY STAR® certified. FLO Ex. 2.0 at 7. FLO argues, however, that "if ComEd launches a nonresidential pilot program, like the curbside charging pilot discussed in my direct testimony, technology-specific limitations like requiring an ENERGY STAR[®] rating should not apply because the purpose of a pilot is to test things like consumer receptivity and use cases, not to deploy specific technology at scale." *Id*. Specifically, FLO notes that some of nonresidential curbside Level 2 ("L2") chargers use "a unique locking mechanism to prevent tampering and potential vandalism, which results in the use of slightly higher levels of energy while in standby mode than would be allowable for the ENERGY STAR[®] certification threshold." *Id*. at 8. Additionally, FLO argues that "any ENERGY STAR[®] certification structure applicable to all charger types should include a ramp-up that would provide more time for companies like it and others who develop chargers with unique customer benefits to adequately certify their products while still being able to participate in ComEd's BE Plan." *Id*. at 9.

FLO is the only stakeholder in this proceeding that suggested that some of its EVSE are not currently able to meet ENERGY STAR® certification requirement recommended by the Staff. FLO recommends the Commission identify the circumstances and types of charging stations required to obtain certification if it decides to impose such requirements. FLO's concerns are specific to the curbside pilot programs but Staff notes ComEd and FLO are unsure if or when ComEd's proposed curbside charging pilot program will become a full program in ComEd's BE Plan. According to ComEd, the specific details for each pilot program are yet to be designed. ComEd Ex. 12.0 REV at 23. Moreover, assuming the Commission approves the curbside charging pilot to which FLO referred in testimony, there is no set timeline for when it will be scaled up into any program in ComEd's BE Plan, so it is not clear that FLO's concern is immediate Thus, even if FLO's equipment for the future curbside charging pilot is not ENERGY STAR® certified, that should not prevent the Commission from directing ComEd to require residential and public EV charging stations for which owners and operators receive incentives to be certified by ENERGY STAR® now. The benefits of the ENERGY STAR®-certified EVSE to the EV owners/operators should not be withheld

because of uncertainty about when some of the FLO's EVSE could be ENERGY STAR® certified. The fact that FLO's equipment, which it proposes to use for the future curbside charging pilot, is not ENERGY STAR® certified should not prevent the Commission from requiring that public EV charging stations for which owners or operators receive incentives be certified by ENERGY STAR®. The benefits of ENERGY STAR®-certified EVSE to the EV owners/operators should not be lost because of uncertainty about when some of the FLO's ESVE would be ENERGY STAR® certified.

The CTA argues that Staff does not clearly indicate if the standards should apply only to public charging stations or all charging stations, including those that are not available to the public. CTA Ex. 5.0 at 4-5. CTA testified the proposed certification is not appropriate for mass transit bus charging. *Id*. at 5. CTA explains that "buses will be charged using overhead pantographs that are neither designed nor appropriate for general public use," and "[i]t also is dangerous for the general public to have access within these active facilities. In addition, because the charging is done via an overhead pantograph designed for buses, it is not possible for the public to charge their vehicles with the equipment." *Id*.

Staff agrees with CTA that the EV charging system in CTA's charging stations is unique and believes that CTA's facilities are not public charging stations because they are not publicly accessible and because they might be dangerous for the general public. However, nothing in CTA's testimony suggests that ENERGY STAR® certification should not be required in residential and public stations.

Staff asserts that the Commission should modify ComEd's BE Plan to require a minimum 97% uptime reliability standard for public EV charging stations for which owners or operators receive incentives from ComEd BE Plan. Staff Ex. 5.0 at 3, 15-22, 26-29; Staff Ex. 16.0 at 5.

EVSE uptime is the amount of time the electric charging infrastructure is fully functioning and available for charging over a certain time period. This time period is referred to as "In-Service Time," and In-Service Time is a measure of how long the EVSE remains in service. Staff Ex. 5.0 at 15. Establishing an uptime reliability standard for public charging stations will help ensure the charging stations reliably provide a public benefit to drivers, as broken chargers do not advance the goals of the EVA to increase EV adoption and decarbonize the transportation sector. Additionally, broken chargers can create "charger anxiety" which is the concern that a charger will not work when an EV driver wants or needs to use it. Charger anxiety undermines the purpose of providing ratepayer-funded incentives for installing public charging stations to help address range anxiety and promote EV adoption. *Id*. at 18. Staff testified, "[i]t is important that ratepayer-funded incentives for public charging stations only be provided for charging stations that will remain useful to ComEd's ratepayers over time." *Id*. Ensuring that public charging stations maintain at least 97% uptime will provide a high degree of certainty to EV owners and the public that chargers in such public charging stations will be available and functioning when needed. *Id*. at 22.

In rebuttal testimony ComEd states, the Company is "willing to: (i) provide preferences to applicants that commit to maintaining the uptime and making the reports as part of the initial application for an incentive; or (ii) for applicants that seek incentives

in multiple years, consider the applicant's past performance in determining whether subsequent incentives will be awarded." ComEd Ex. 6.0 at 22.

In surrebuttal testimony, the Company further explained, "ComEd was willing to consider mandating some of the requirements in the application process but wanted to gather feedback from parties on the benefits of requiring these equipment standards and reporting requirements against the burdens of information collection and other considerations." ComEd Ex. 11.0 REV at 13. Despite the Company's willingness to consider Staff's recommendation, it believes it is too early to set technical requirement standards. Additionally, "ComEd continues to believe that EV charging equipment requirements and charging service requirements are better left to state or federal policymakers…[.]" *Id*. Ultimately, regarding Staff's recommended uptime requirement, the Company concluded, "[i]n light of divergent feedback from charging providers and the Commission Interim Order, ComEd disagrees with these recommendations and, to the extent the Commission finds requirements are necessary, would be open to meeting with stakeholders to align any desired technical requirements with federal or state programs once those requirements are established." *Id*. at 14.

Contrary to the suggestion by ComEd, none of the Intervenors in this proceeding explicitly disagrees with Staff's 97% uptime requirement recommendation. In fact, FLO proposes that ComEd's BE Plan include reliability requirements for EV charging equipment. FLO argued that "reliability requirements are aimed at, among other things, monitoring whether disparate impacts are occurring in the reliability of charging stations in low-income, [EJ], and R3 communities, with the intent of minimizing the amount of time customers may experience outages." FLO IB at 7.

The EVA provides that IEPA's grant of rebates for charging stations must be provided "consistent with the Commission-approved [BE] Plans." 20 ILCS 627/55(a). FLO argues that "one interpretation of that provision could be that the Commission can set reliability standards within BE Plans that rebate providing entities should then follow. Adopting a single set of requirements at the outset of the coordinated statewide programs will help standardize customer experiences and ensure cohesive reliability overall." FLO IB at 14. Given the above explanations and discussions, the Commission should modify ComEd's BE Plan to require a minimum 97% uptime reliability standard for public EV charging stations for which owners or operators receive incentives from the ComEd BE Plan.

For all the reasons articulated above and because ComEd seems open to accepting uptime requirements if the Commission requires it, Staff asserts that the Commission should direct ComEd to modify its BE Plan to impose a minimum 97% uptime reliability standard for public EV charging stations for which owners or operators receive incentives from ComEd BE Plan.

ComEd testified it would support a stakeholder process outside of this proceeding to align any requirements at a statewide level, instead of on a program by-program basis. ComEd Ex. 11.0 REV at 13. Staff asserts that ComEd proposal should be rejected. The Commission should not delay the adoption of uptime reliability and ENERGY STAR® certification standards. The Commission should instead modify ComEd's BE Plan to require public EV charging stations be certified by ENERGY STAR® and a minimum

97% uptime reliability standard for public EV charging stations for which owners or operators receive incentives from ComEd BE Plan. Staff Ex. 5.0 at 3, 15-22, 26-29; Staff Ex. 16.0 at 5. None of the Intervenors dispute Staff's showing that establishing a reliability standard for public charging stations will provide public benefit to EV owners/drivers. Staff believes that broken chargers do not advance the goals of the EVA of increasing EV adoption and decarbonizing the transportation sector. Broken chargers can create "charger anxiety" – a concern that a charger will not work when an EV driver wants or needs to use it. The Commission should not delay the adoption of uptime reliability standards. Rather than a stakeholder process following this proceeding, a more efficient approach would be for the Commission to adopt uptime reliability standards in this docket consistent with Staff's recommendation of a 97% uptime requirement, which in turn is consistent with the NEVI uptime requirement, for all public charging stations for which owners and operators receive ComEd incentives. Stakeholders can discuss modifications, if any, to the uptime reliability standards as part of the stakeholder collaboration process (which starts in early April of 2024) recommended by Staff (and agreed to by ComEd) leading up to ComEd's BE Plan update filing. Requiring stakeholder workshops on uptime reliability standards immediately following Commission approval of ComEd's BE Plan will result in unnecessary delays in the implementation of the uptime reliability standards and ComEd's BE Plan while creating an unnecessary administrative burden on Commission Staff. The Commission should reject such an approach.

The Commission should direct ComEd to modify its BE Plan to require annual reliability reports about public charging stations and ancillary equipment that qualified for and for which owner and operators received incentives in its BE Plan. Staff Ex. 16.0 at 32. Staff believes that this information will allow Staff, the Commission, and the public to know the state and the reliability of the public EV charging stations that qualified for and for which owner and operators received incentives under ComEd's BE Plan. Staff recommends that the annual report include, but not be limited to, the following information:

(1) The total number EV charging stations that have the highest EV customer or public complaints.

(2) Name and address of the top 5 public EV charging station locations that have the highest EV customer or public complaints.

(3) Statistics of each public EV charging station that has received incentives from ComEd over the course of its BE Plan inception, which shall include:

   a. the location and address of the EV charging station;

   b. the total number of EVSEs at the EV charging station site;

   c. the number of EVSE ports at the EV charging station;

   d. the duration and total number of vandalisms experienced per year and summary of the cause of the vandalism;

   e. the duration and total number per year of power supply outages due to ComEd and reasons for each outage;

f. the duration and the number of maintenance activities carried out per year and reasons for the maintenance (e.g., routine/planned or unplanned); and

g. the quarterly and annual percentage uptime for each EV charging station.

Staff Ex. 16.0 at 32-33.

ComEd's testimony regarding Staff's recommendation for reliability reports on the public charging stations that qualified for and for which owner and operators received incentives in its BE Plan in an annual report was inconsistent. In one instance, ComEd testifies, "[m]uch of this information is not available to ComEd and…these kind of reporting requirements would be particularly onerous for the operators of the charging stations. The customer specific information that ComEd would have access to, ComEd considers to be [personally identifiable information] and, absent appropriate aggregation, would not be suitable for inclusion in the annual report." ComEd Ex. 11.0 REV at 20. In another instance, however, ComEd testifies, "[t]o the extent ComEd requires recipients of incentives for publicly accessible chargers to report annual reliability information, ComEd will provide information regarding the availability and reliability of EVSE systems and EV charging stations in its annual report. As discussed above, the benefit of this type of detailed information must be balanced against the burden of collecting, verifying, utilizing, and reporting such information." *Id*. at 25. ComEd also stated, "if ComEd were to require providers of publicly accessible chargers to report annual reliability information, then ComEd would include that information in its annual report." *Id*. at 20. Finally, on one hand, ComEd commits to include information regarding "the availability and reliability of EVSE systems and EV charging stations" incentivized through ComEd's BE Plan, if ComEd requires recipients of incentives to report annual reliability information, as requested[.]'' ComEd IB at 82. However, in another instance, ComEd states that "[s]everal parties proposed that the Annual Report include information regarding the reliability of charging stations and equipment. This proposal should not be adopted…." ComEd IB at 83.

Staff recommends that ComEd require public EV charging station owners/operators who receive incentives under ComEd's BE Plan to provide annual safety and reliability reports on their charging stations. The information to be required should include but is not limited to: the performance of EVSEs at the location; rate of equipment/station vandalism; the charging station's percentage uptime; age of the EV charging equipment; and complaints from the EV customers. Staff Ex. 5.0 at 27. Staff believes that this information will be available to ComEd.

ComEd argues that "[d]ue to the nascent nature of the EV charging ecosystem, it would not be appropriate for an individual utility to develop standards related to EV charging plugs." ComEd IB at 36. ComEd claims that "[a]t this early stage, flexibility is critical to enable robust participation in the BE Plan and accelerate EV adoption and EV infrastructure deployment in Northern Illinois." *Id*. This statement is difficult to reconcile with ComEd's surrebuttal testimony. The Company testified that "if the Commission adopts a CCS [Combined Charging System] standard for publicly accessible DCFC [Direct Current Fast Charging] charging stations incentivized through the BE Plan, then

ComEd would not object." ComEd Ex. 11.0 REV at 15. Staff's recommendation that "the Commission modify ComEd's BE Plan to adopt the CCS standard" was based in part on both ComEd's stated willingness to adopt the CCS standard for EVSE connectors in Level 3 ("L3") or DCFC public EV charging stations, and the fact that none of the Intervenors in this proceeding raised concerns about adoption of that standard. Staff IB at 84. If ComEd has changed its position on the requirement for CCS standards for publicly accessible DCFC charging stations incentivized through the BE Plan, the Commission should find that ComEd's proposed BE Plan fails to address Section 45(d)(vii) of the EVA, in which case Staff recommends the Commission modify ComEd's BE Plan to adopt CCS standards.

c. CJCP's Position

CJCP positions on these issues are addressed in Section V.B.2.

d. FLO's Position

To ensure the long-term success of a curbside charging pilot program, as well as any public charging stations receiving installation incentives under the ComEd plan, EV charging stations must be reliable and consistently available to the public. As such, FLO proposes the inclusion of reliability requirements for EV charging equipment, including reporting requirements.

To ensure successful deployment of and consistent access to public charging stations for EV drivers, FLO recommends adopting a uniform standard which measures EV charging station reliability requirements in terms of "uptime," i.e., the time a charger is available for use (or is already in use) with accompanying reporting and evaluation requirements. Specifically, FLO recommends that ComEd institute reliability requirements consistent with the requirements of the NEVI Program, as defined and updated over time by the Federal Highway Administration ("FHWA") via guidelines and regulations.

The FHWA's proposed guidance for the NEVI Program outlines a formula for charging stations to use to meet a minimum uptime requirement over a specified period of time. In establishing these standards, the FHWA settled on a balanced requirement of 97% uptime on a 12-month cycle, which equates to 354 days of availability in a year (8,498 hours). Charging stations are also required to adhere to that requirement for a minimum of five years, with a specified formula to calculate uptime. The proposed uptime calculation formula allows for exceptions for issues outside the charging station operator's control, including grid, cellular, or WiFi infrastructure failure, or vehicle inoperability, if it can be shown that the issue is with the vehicle and not the charger. The FHWA proposal also requires charging companies to report uptime on a standardized and ongoing basis to assess whether charging companies are meeting such uptime requirement.

FLO's proposal goes a step further and recommends the consideration of certain factors, such as vandalism, to ensure an accurate assessment of a charging station's reliability. For example, if outage time caused by vandalism is included in uptime calculation requirements, a charging company may be disincentivized to locate chargers in areas with higher rates of vandalism. This disincentive could run counter to P.A. 102-0662's equity requirements and could delay the deployment of EV charging stations in

much-needed areas. Thus, FLO recommends that, if reliability requirements are to be adopted, vandalism should be added as an exclusion to the uptime calculation formula in addition to the upstream infrastructure failures currently identified in the FHWA proposal.

FLO's proposed reliability requirements are aimed at, among other things, monitoring whether disparate impacts are occurring in the reliability of charging stations in low-income, EJ, and R3 communities, with the intent of minimizing the amount of time customers may experience outages.

e. Electrify America's Position

Electrify America opposes Staff's request that the Commission require ComEd to implement safety and reliability "regulations and requirements" in its BE Plan for public charging stations receiving ComEd incentives including: (1) requiring ENERGY STAR® certification requirements; (2) setting a 97% uptime reliability standard (3) requirements to submit annual safety and reliability requiring public charger customers to engage in information gathering and reporting; and (4) requiring a minimum number Electric Vehicle Supply Equipment ("EVSE") ports. Staff IB at 18. Electrify America states that by including its discussion under the "policy considerations" portion of its brief, Staff acknowledges that there is no requirement under P.A. 102-0662 or the EVA for ComEd to consider or include Staff's proposed standards. Electrify America further states that the charging equipment and service standards Staff seeks to have ComEd impose are inappropriate because such standard setting is better left to the market and, where appropriate, state and federal regulators with jurisdiction over such standard setting. *See* ComEd Ex. 6.0 at 18; ComEd Ex. 11.0 REV at 10-16; Tesla Ex. 2.0 at 8-11; EVgo Ex. 2.0 at 14-15. Doing so will help prevent "patchwork" regulation that would be onerous on public charging station operators and discourage investment in publicly available EV infrastructure in Illinois. ComEd itself is not a regulatory body such that it can impose "regulations" upon its customers and Electrify America states it is not appropriate for ComEd to impose "requirements" upon customers that are not reasonably related to the incentives being provided. Electrify America RB at 10-11. Further, EA states the scope of the Commission's authority is over utilities and the Commission should avoid engaging in standard setting for public charging stations without express statutory authority to do so. *Ill. Bell Tel. Co. v. Ill. Commerce Comm'n*, 362 Ill. App. 3d 652, 656-67 (4th Dist. 2005) (explaining an administrative agency like the Commission "is a creature of statute and only has the powers that the statute confers.").

With respect to Staff's request for an uptime reliability standard, Electrify America counters Staff's suggestion that intervenors have not disagreed with Staff's proposed 97% uptime requirement for public charging stations receiving incentives under the BE Plan. Electrify America contends that Staff supports its request for an uptime reliability standard by claiming that "broken chargers" can cause "charger anxiety" (Staff IB at 22), but Electrify America and other EV service providers ("EVSPs") have networked chargers that provide near real time service status updates of charging stations and individual chargers at stations via their mobile phone applications ("Apps"). In addition, commonly-used websites and Apps exist to provide information regarding the number and type of chargers and charger availability. Given the widespread use of App-based services and the desire for EVSPs to provide a good customer experience, any further mandate is unnecessary.

Electrify America further contends that in its proposal for annual safety and reliability reporting, Staff seeks a long, onerous list of information, while glossing over arguments regarding the burden such reporting would place upon charging station operators. Contrary to Staff's assertion that the information being sought will be "available to ComEd," much of the included information will require burdensome reporting obligations to be placed on charging station operators such that it may discourage EV charging infrastructure growth and participation in incentives under the BE Plan. Such reporting obligations would place a significant soft cost upon EVSPs, including the time and investments necessary to collect the information and provide reports, and could require sharing commercially sensitive information. Electrify America Ex. 2.0 at 20; ComEd Ex. 11.0 REV at 20. Additionally, some of the information Staff is requesting, such as information regarding vandalism, root causes of equipment outages, and operation and maintenance activities can be difficult to identify and provide with accuracy and can be particularly onerous for EVSPs like Electrify America who operate in hundreds of utility territories. Electrify America takes the position that any reliability reporting requirements adopted as part of the BE Plan should not place unnecessary burdens upon EV charging customers. To the extent reliability reporting requirements are adopted they should be limited to information available to ComEd through meters without further burdens placed on customers.

f. Commission Analysis and Conclusion

The Commission adopts Staff's recommendation of requiring ENERGY STAR® certification for public L2 chargers receiving incentives through the BE Plan. The Commission recommends ENERGY STAR® certification for DCFC chargers but does not require it at this time. The Commission agrees with CJCP that it is premature to set such a standard for DCFC stations but encourages ComEd to work with Staff and interested parties to include such a standard in future BE Plans.

The Commission further adopts Staff's recommendation to require public charging stations for which owners or operators receive incentives to have at least two or more EVSE ports. Other than general objections to setting any technical requirements for public charging stations receiving incentives via ComEd's BE Plan, no party appears to object to this specific standard, and it is adopted.

With respect to Staff's uptime proposal, the record shows that the regulations to establish minimum standards and requirements for projects funded under the NEVI program, including uptime requirements, are now final. While ComEd's BE Plan does not contain incentives for charging stations, but rather make-ready infrastructure, the Commission does not find it necessary to wait to adopt the uptime standard supported by Staff. The Commission hereby adopts Staff's proposal to institute a 97% uptime reliability standard for public EV charging stations for which owners or operators receive incentives from ComEd's BE Plan. The Commission agrees with Staff's rationale for establishing an uptime reliability standard. Establishing an uptime reliability standard for public charging stations will help ensure the charging stations reliably provide a public benefit to drivers, as broken chargers do not advance the goals of the EVA to increase EV adoption and decarbonize the transportation sector. Additionally, broken chargers can create "charger anxiety" which is the concern that a charger will not work when an EV driver wants or needs to use it. Charger anxiety undermines the purpose of providing ratepayer-

funded incentives for installing public charging stations to help address range anxiety and promote EV adoption. It is important that ratepayer-funded incentives for make-ready infrastructure only be provided for public charging stations that will remain useful to ComEd's ratepayers over time. Ensuring that public charging stations maintain at least 97% uptime will provide a high degree of certainty to EV owners and the public that chargers in such public charging stations will be available and functioning when needed.

4. Electrify America Proposal

a. ComEd's Position

Electrify America recommends the Commission direct ComEd to include broader tariff language concerning ancillary loads in the EV tariffs. Electrify America wants the language to clarify that non-EV charging ancillary equipment in support of EV charging station operations 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 in support of EV charging station operation and load optimization." Electrify America IB at 20. ComEd does not oppose Electrify America's proposed tariff language, or in the event the Commission does not accept Electrify America's proposal, does not oppose allowing customers to seek a waiver in cases where the auxiliary equipment might exceed the 10% threshold.

b. Staff's Position

The Commission should approve Electrify America's proposed EV tariff language. Staff Ex. 17.0 at 3.

Electrify America proposes changes to the Company's tariff language regarding ancillary load of EV charging because the language proposed by the Company does not account for the variety of non-EV charging loads including security lighting, cooling fans, solar canopies, etc. Staff Ex. 17.0 at 11. Electrify America proposed alternative language that could reduce potential confusion about whether a station meets the 10% ancillary load of EV charging threshold, when factoring in load associated with the EV charging stations (i.e., security measure) and also could potentially ease concerns of customers who may have been deterred by the original language. Staff Ex. 17.0 at 11.

The Company agreed to modify ComEd's proposed tariff language and acknowledged that "the customer's primary purpose should be to provide charging services and that some ancillary load is to be expected." ComEd Ex. 15.0 at 23.

c. Electrify America's Position

Electrify America expressed support for ComEd's Watt-Hour Delivery Class proposal as a demand-based alternative for nonresidential EV charging customers, but stated that regardless of what demand-based alternative is adopted by the Commission through this proceeding the tariff language associated with that alternative should include the following clarifying language regarding ancillary load:

> non-[EV] charging ancillary equipment in support of station operation includes, but is not necessarily 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 in support of EV charging station operation and load optimization.

Electrify America RB at 5, n.2. Electrify America contends the proposed language will clarify what is and is not included in the EV charging ancillary load threshold. *Id*. (noting the language will "reduce potential confusion about whether a station meets the 10% ancillary load of EV charging threshold"). Given the lack of opposition to the clarifying language regarding ancillary load, the Commission should direct ComEd to include the broader tariff language in the EV tariffs.

d. Commission Analysis and Conclusion

The proposed tariff language by Electrify America is uncontested and it is approved.

5. Cybersecurity

a. ComEd's Position

Staff recommends that the Commission require EV charging station operators who are incentivized under ComEd's BE Plan to provide a scope of information regarding cybersecurity practices. ComEd believes it is too premature to be setting technical specifications at this time. ComEd Ex. 11.0 REV at 13. Additionally, ComEd states that the BE Plan does not offer rebates for charging stations – just the make-ready infrastructure – per the Interim Order, and therefore ComEd does not believe that imposing such requirements on ComEd is appropriate.

b. Staff's Position

Staff states that the Commission should order ComEd to require EV charging station operators who are incentivized under its BE Plan to provide a scope of information regarding their cybersecurity practices to ComEd that aligns with what ComEd requires of its vendors. In addition, the Commission should direct ComEd to monitor the EV charging station deployments in its service territory and include in its analysis the findings and recommendations contained in Cybersecurity for Electric Vehicle Charging Infrastructure, Sandia National Laboratories Report SAND2022-9315 , Securing Vehicle Charging Infrastructure, Sandia National Laboratories 2021 SAND2021 5745 PE , and Cybersecurity Considerations for Distributed Energy Resources on the U.S. Electric Grid, October 2022.

CJCP support the notion that cybersecurity measures are important in protecting charging stations and customer data. CJCP emphasized, "[t]he importance of putting in place communication, payment, safety, and cybersecurity standards that allow for a seamless customer experience while also ensuring that charging stations remain used and useful in the future." EDF Ex. 1.0 REV at 5. CJCP further emphasized that "[s]afety and cybersecurity standards support the safe, secure operation of chargers." *Id*. at 36.

ComEd stated that:

> … ComEd would, if directed by the Commission, consider requiring EV charging station operators to provide a scope of

> information regarding cybersecurity practices that aligns with what ComEd asks of our vendors. Specifically, ComEd is willing to consider either: (i) requiring this information as a prerequisite to receiving an incentive; or (ii) as part of the selection methodology discussed in the rebuttal testimony of ComEd witness Borggren (ComEd Ex. 7.0), providing a preference for applicants that provide this information.

ComEd Ex. 6.0 at 21.

Staff asserts that cybersecurity must be considered in the early stages of EV infrastructure development. The biggest impacts are realized when cybersecurity considerations are implemented at the outset. This docket provides an opportunity to increase EV adoption and improve operations of EV Charging Stations by implementing essential cybersecurity measures.

Staff states that the Commission should order ComEd to require EV charging station operators who are incentivized under its BE Plan to provide a scope of information regarding cybersecurity practices to ComEd that aligns with what ComEd requires of its vendors.

c. ChargePoint's Position

ChargePoint urges the Commission to reject Staff's recommendation that ComEd "require electric vehicle charging station operators who are incentivized under its BE Plan to provide a scope of information regarding their cybersecurity practices to ComEd that aligns with what ComEd requires of its vendors." Staff IB at 35. According to ChargePoint, this proposal is very different from what Staff witness Harmening recommended in his direct testimony, which was that ComEd develop and follow a plan to review the cybersecurity of vendors (not operators, which are typically site hosts). Staff Ex. 11.0 at 6. Mr. Harmening pivots in his rebuttal testimony to recommending that EV charging station operators provide cybersecurity information, with no explanation for why he believes ComEd customers are equipped to provide such information. Staff Ex. 22.0 at 3. ChargePoint argues that the complete lack of evidentiary support for the recommendation Staff makes in its Initial Brief – not to mention the lack of specificity as to what cybersecurity protocols would be required – is reason enough to reject it.

ChargePoint explains that there are numerous examples of electric loads that plug into ComEd's grid which take customer payments or handle customer sensitive data (e.g., gas pumps, ATMs, grocery stores, etc.), that are not required to clear their cybersecurity practices with ComEd. ChargePoint Ex. 2.0 at 47. Moreover, notes ChargePoint, it is important to remember that ComEd has not proposed any programs in this BE Plan that involve ComEd directly communicating with EV charging stations such that cybersecurity practices might be required to protect ComEd's systems. Finally, ChargePoint again asserts that the Commission does not regulate the transaction between EV charging station site hosts and EV drivers, so it would be inappropriate for the Commission to impose any programmatic requirements on such transactions, including cybersecurity requirements. ChargePoint argues that the Commission should therefore reject Staff's vague and unspecific cybersecurity requirements.

d. Commission Analysis and Conclusion

Two pilot programs involve direct communication with charging stations. Staff and CJCP argue that the Commission should adopt cybersecurity measures for any charging station accepting incentives under the BE Plan. The Commission agrees that cybersecurity is of utmost importance, and Staff's proposal is supported by the record. The Commission, thus, directs ComEd to require cybersecurity information from EV charging station operators similar to what ComEd asks their vendors to provide, as a prerequisite to those operators receiving an incentive. Further, to the extent ComEd directly communicates with charging stations for programs under the BE Plan, the Commission directs ComEd to work with Staff to ensure that appropriate cybersecurity measures are in place.

C. General Aspects of the BE Plan

1. BE Plan Budget

a. ComEd's Position

ComEd notes it has carefully considered the requirements of the EVA and stakeholder feedback in developing and updating the BE Plan throughout this proceeding. ComEd is confident that the planned scope and scale of the programs, and the dollar-value of the rebates to be offered, are appropriately designed to fulfill the goals of the EVA and bring benefits of BE to all customers, including in particular low-income individuals and those living in EJ and R3 communities. ComEd also notes that it has proposed a level of flexibility within the BE Plan period, with respect to the funding allocated to each of the various programs and the dollar values of the rebates that are offered. According to ComEd, this flexibility will enable it to respond to customer uptake, by shifting budget to programs with high demand where appropriate, while ensuring that total spend remains within budget and that funds remain available for particular subsets of customers that face the highest barriers to adoption.

ComEd points out that, in some cases, Staff and Intervenors suggested conflicting modifications. To the extent that ComEd has not incorporated these modifications, ComEd argues that they should not be adopted. ComEd states that its proposals best balance the urgency of the statutory directives, the statutory guidance regarding the relevant considerations in the design of a BE Plan, and the impacts of the proposed BE Plan on ComEd customers.

ComEd claims this BE Plan Budget was developed — and revised over the course of the proceeding — to achieve the benefits of BE technology while adhering to the guidance detailed in the EVA. According to ComEd, its BE Plan Programs are designed to promote customer access to BE technology, as well as equity and EJ, and the proposed annual budgets for the BE Plan programs and sub-programs are designed accordingly while satisfying other EVA requirements. ComEd proposes a total budget for its BE Plan of $100 million annually for the three years of the plan period (2023 through 2025). ComEd claims it has elected to target 50% of the Residential Program funding and 40% of the C&I and Public Sector Program funding toward customers located in or primarily serving EJ or R3 communities, and its BE Plan is designed to ensure that at least 40% of

the investment in make-ready infrastructure incentives facilitate the accessibility of charging equipment in low-income, EJ, or R3 communities.

ComEd argues that the variety of perspectives across the Staff and Intervenor proposals indicates that ComEd's BE Plan is generally reasonable – the programs within it are comprehensive and targeted to appropriate recipients.

ComEd argues that in reviewing these proposals, the Commission should keep in mind that this is the first BE Plan. ComEd states that it is confident that its proposed BE Plan is a strong starting point, and will be adjusted over time, including via subsequent proceedings, to respond to market demand and experience gained from implementing the proposed programs.

ComEd notes that Staff, in suggesting that ComEd's budget is "unlawfully excessive," conspicuously fails to cite to a specific law or regulation that ComEd has violated in establishing its budget, and its characterization of the BE Plan as enriching shareholders is specious and unsupported. ComEd argues that its proposed budget is not unlawful. To the contrary, according to ComEd, it is appropriately attuned to the magnitude and urgency of the task set before the Commission and ComEd by the General Assembly, and ComEd's proposal includes mechanisms – like regulatory asset treatment – that mitigate the impact on customers.

In response to Staff's proposed revisions to the budget proposal, ComEd notes that while ComEd has used the general term "low-income" throughout its testimony and briefs, Staff uses the term "income qualified." It appears to ComEd that Staff uses the term "income qualified" to mean individuals who are determined to be eligible for incentives under the BE Plan, based on their individual income level. Thus, in ComEd's view, the variation in terms is a distinction without a difference.

With respect to Staff's proposal to expand programs to include IQ communities, it appears to ComEd that the specific program at issue is the C&I and Public Sector EJ/R3 Charging Infrastructure Sub-program. However, ComEd points out that this Sub-program provides incentives for installation of charging stations located in or primarily serving EJ or R3 communities. ComEd notes that EJ and R3 communities are geographic areas, as those terms are defined in the EVA. 20 ILCS 627/45(b). ComEd argues that Staff has not explained, in testimony or in brief, how ComEd should determine whether a geographic area (as opposed to an individual) is "income qualified," or how that definition would differ from the definition of EJ and R3 communities used in the EVA. Thus, although ComEd wholeheartedly agrees that low-income populations are in need of BE technology, ComEd contends that this particular proposal to "expand" the program to include "income qualified communities" should be rejected.

ComEd also argues that there is no need to separate out EJ/R3-related programs from non-EJ/R3-related programs at the budget level, as Staff proposed. ComEd has committed to certain spending targets for the EJ and R3 communities and intends to meet these targets. It is therefore not necessary to track individual program budgets with such detail. Additionally, ComEd has requested budget flexibility, and claims that creating this unnecessary rigidity in the budget will ultimately harm EJ and R3 communities if there proves to be more need than anticipated.

ComEd notes that Staff has also recommended creating an entirely new program, to be funded with what it alleges will be the savings from cutting the budget, for make-ready facilities for non-EJ/R3/IQ customers. ComEd contends that, while make-ready infrastructure is important, it is not possible to expand this BE Plan to reach every customer at this time. ComEd says it has prioritized the communities that need this infrastructure the most, and to attempt to include more customers in that ambit will adversely affect the eligible communities.

ComEd further argues that Staff is misguided in trying to limit the entire budget to the retail rate cap. ComEd contends that, because the Commission determined the retail rate cap applies to the development of EV infrastructure and not the program as a whole, it would be needlessly restrictive to set a spending limit of $44 million for this BE Plan. In order to aggressively spur the adoption of EVs and other BE technology, and meet the goals set forth in the EVA, significant incentives and educational measures are necessary. According to ComEd, Staff's reduced budget would make it more difficult to reach those goals.

ComEd explains that Staff's proposed budget would also forgo benefits for customers and society. After correcting for calculation errors (corrections which Staff recognizes and does not rebut, *see* Staff IB at 103), Staff's analysis shows a total net benefit value of $47 million from Staff's proposed budget. ComEd points out that this value is far lower than any of the calculated total net benefit values for ComEd's proposed BE Plan.

ComEd contends that Staff is also misguided in removing all the non-transportation measures. According to ComEd, these are important and integral components to the BE Plan and will help customers in the long term by facilitating widespread adoption of BE technology. ComEd also disagrees with the contention that spending should be extremely conservative because this is the first rendition of the BE Plan. On the contrary, ComEd claims it is trying to stand up programs that will stand the test of time, and to needlessly cut spending will likely create a program that does not incorporate best practices and get the intended results.

In sum, ComEd concludes that Staff's proposed budget is unnecessarily limited, it would forgo benefits for customers and society that ComEd's BE Plan is designed to achieve consistent with the goals of the EVA, and it should be disregarded. ComEd argues that, in contrast, ComEd's budget is much more thorough and anticipates the needs of customers as the BE Plan is rolled out.

The AG also challenges ComEd's proposed BE Plan budget, arguing that ComEd's budget of $100 million is not permitted under the EVA and is "unreasonably high when compared to similarly situated utilities." AG IB at 14. ComEd observes that the AG argues, contrary to the findings of the Interim Order, that ComEd's proposed budget violates the statutory limit on BE Plan budgets set forth in the EVA and that the budget for the BE Plan as a whole should be limited to the retail rate cap. ComEd argues that the Interim Order was correctly decided. ComEd notes that the Interim Order found that the "plain language of the statute clearly states that the retail rate cap applies to development of EV infrastructure," not the BE Plan as a whole. Interim Order at 38. ComEd contends that the AG offers nothing new -- it simply rehashes the arguments the

Commission has already considered and rejected. ComEd concludes that the Commission should not reverse itself. ComEd Rep. Br. at 48. Moreover, ComEd argues, the Commission has already determined that the Interim Order conclusively resolved this issue for the purposes of this case. ComEd notes that the portion of the Interim Order that interpreted the EVA provisions concerning the retail rate cap related to Staff's request for an interim order, not its motion to dismiss, and the Commission explicitly concluded that "the matters resolved herein shall be considered final." *Id*. In light of this finding, ComEd contends it is it is improper for the AG to attempt to relitigate this issue in this context.

ComEd also notes that the AG argues that ComEd's proposed budget includes programs that do not further the goals of the EVA or are in conflict with other sections of P.A. 102-0662, in particular the non-transportation programs, an argument that ComEd addressed in detail.

ComEd also challenges the AG's argument that ComEd's proposed budget exceeds the spending levels on similar utility-run programs in other states. ComEd notes that, in this same allegation, the AG provided two examples of utilities with higher annual per-capita spending levels. ComEd argues that by the AG's own data, ComEd is clearly not proposing an unreasonable budget. Further, ComEd points out that when its budget is considered relative to its total megawatt-hour sales — a comparison which accounts for the varying composition and size of residential, commercial, and industrial customers in the utilities' customer bases — its budget ranks fifth among the ten utilities sampled by the AG. Moreover, ComEd explains that it is attempting to stand up a program that will help achieve the ambitious goals of the EVA and provide long term support to BE technology in Illinois. ComEd says it is to be expected that such a program would require a significant investment to achieve such lofty goals.

The AG also argues that various federal and state programs overlap with the BE Plan, rendering its programs duplicative. The AG argues that it cannot be cost-effective to include incentives in the BE Plan if other entities also offer incentives for similar measures and indicates that the budget for such programs should be reduced. However, ComEd argues that the AG ignores the record evidence demonstrating that the BE Plan will produce benefits that exceed its costs by nearly $200 million. ComEd contends that the AG also fundamentally misunderstands how incentives work. ComEd explains that the availability of more incentives, or more significant incentives, will encourage more people and businesses to invest in BE technologies, accelerating the adoption of those technologies in accordance with the statutory guidance. According to ComEd, it is a common practice for individuals to "stack" incentives in a way that makes a program or purchase more valuable or attractive to them.

Moreover, ComEd states that it considered the potential availability of incentives from other sources in developing the BE Plan but concluded that additional incentives are appropriate in light of the ongoing uncertainty with respect to the existence and size of those programs going forward, as well as their efficacy. ComEd argues that this uncertainty instructs that the BE Plan should not reflect an undue reliance on other programs in order to help facilitate customer adoption of BE measures.

In place of ComEd's budget, the AG recommends a budget of $28 million. ComEd points out that the amount is equal to the AG's proposed – and incorrect – calculation of the retail rate impact cap.

b. Staff's Position

Staff states that the Commission should reject ComEd's proposed $300 million BE Plan budget, which comprises $100 million annually, and instead approve Staff's BE Plan three-year budget proposal of $133.07 million as set forth in Staff Exhibit 17.1.

Staff asserts that ComEd's desire to spend on BE initiatives must be balanced against both the anticipated benefits to consumers – rather than shareholders – of that spending, as well as the anticipated impact on ratepayers. In Staff's opinion, ComEd's $100 million annual budget is unnecessary – apart from being unlawfully excessive – given all of the funding (federal and state) that is now available to help spur EV adoption. Staff Ex. 17.0 at 37. It is important to consider the fact that this is the first in what will be an iterative series of BE plans. 20 ILCS 625/45(f). Information obtained from prior BE plans will be used to evaluate the effectiveness of plan elements and programs for use in subsequent plans. 20 ILCS 627/45(g). Accordingly, the first plan should be viewed as at least somewhat experimental since the effectiveness of programs has yet to be evaluated. Spending should be at a level that will provide some assurance that ratepayers will not be required to pay for ineffective programs, which is difficult to do before programs have been developed, implemented and proven. Staff's proposed budget reflects these realities, while ComEd's puts substantial sums of ratepayer money at risk. Moreover, ComEd's budget would enrich shareholders at the expense of ratepayers. Furthermore, Staff calculates the retail rate impact cap at $44.4 million and believes ComEd's budget should be more in line with that calculation. Staff believes the Company can adequately address all BE Plan initiatives under the Staff revised budget proposal. Although most programs were reduced, the percentages ComEd originally proposed are still reflected in Staff's budget proposal in most cases. Staff Ex. 17.0 at 37.

Section 45(d)(3) and (d)(4) requires the Commission to consider whether the Company's investments are designed to support at least a 40% investment of make-ready infrastructure and support at least a 5% investment target. 20 ILCS 627/45(d)(3); 20 ILCS 627/45(d)(4). Staff's budget proposal achieves these objectives and accounts for several key elements that are missing from ComEd's budget proposal. These missing elements include:

(1) the inclusion of income qualified ("IQ") customers in several programs consistent with statute;

(2) the distinction of EJ/R3/IQ customers from non-EJ/R3/IQ customers in certain program budgets to clearly track whether spending requirements in those areas are being met and to align with Staff's recommended flexibility provisions;

(3) the addition of a make-ready facilities program for non-EJ/R3/IQ C&I customers, funded by left over monies after Staff's proposed budget cuts (named C&I and Public Sector EV Charging Infrastructure Sub-program (non-EJ/R3/IQ)); and

(4) the deletion of all non-transportation related spending, consistent with Staff Exhibit 1.0 and Staff's [Combined] Motion.

Staff Ex. 17.0 at 37-38.

ComEd also noted this is the first iteration of its plan, stating "the Commission should keep in mind that this is the first BE Plan. ComEd is confident that its proposed BE Plan is a strong starting point, and will be adjusted over time, including via subsequent proceedings, to respond to market demand and experience gained from implementing the proposed programs." ComEd IB at 22. ComEd fails to explain why it needs to spend $100 million as a "starting point" when it has no past performance to help guide the proposed programs, nor does it explain why it would be unable to implement a strong and successful BE Plan with Staff's much more reasonable – and indeed lawful - budget of $44.4 million. Staff urges the Commission to reject ComEd's proposed budget of $100 million per year, and instead approve Staff's balanced and well-measured budget which offers a more appropriate "starting point" for the first of many BE Plans. Staff's annual budget of $44.4 million aligns with the statutory retail rate impact cap and is a logical and appropriate starting point for the Company's first BE Plan. Staff's budget balances the Company's vision and overall impact on ratepayers and should be approved.

c. AG's Position

The AG requests that the Commission reduce the BE Plan budget to $28 million, which the AG maintains is a more reasonable and prudent spending level that complies with the requirements of the EVA. The AG argues that the Commission should reject ComEd's budget proposal for three reasons. First, ComEd's proposed spending levels violate the statutory limit on BE Plan budgets set forth in the EVA. Second, ComEd's proposed budget includes programs that do not further the goals of the EVA or conflict with other sections of P.A. 102-0662. Third, ComEd's proposed budget far exceeds the spending levels on similar utility-run programs in other states.

In determining the appropriate amount of the BE Plan budget, the AG explains that the Commission should recognize that the EVA establishes an upper limit on the amount of ratepayer money a utility can spend. Relying on the language of the EVA, the AG and Staff maintain that the budget for the BE Plan as a whole should be limited to the retail rate cap to control ComEd's spending and limit the impact to ratepayers. AG Ex. 2.0 at 9; Staff Ex. 17.0 at 38. The Interim Order, however, concluded that the retail rate cap should apply "only to those programs related to EV infrastructure" rather than the BE Plan as a whole. Interim Order at 37–38. The AG maintains that this conclusion is erroneous and recommended the Commission reject the Company's BE Plan because it exceeds the retail rate cap as a matter of law.

But even if the Interim Order's conclusion were upheld and the BE Plan were to include spending that is not constrained by the retail rate cap, the AG explains that the record in this case shows that ComEd's BE Plan should be limited to the "development of EV infrastructure" that is subject to the retail rate cap. *See* 20 ILCS 627/45(g). The AG and Staff have demonstrated that spending on programs unrelated to EVs and transportation should be removed from the BE Plan because they are not authorized by the EVA and because they are imprudent and unreasonable. AG Ex. 2.0 at 16-17; Staff Ex. 12.0 at 7-8. Once the non-transportation programs are removed from the BE Plan,

what remains are programs that "support the 'development of EV infrastructure' in the state," even if they are not spending directly on the infrastructure itself. Staff Ex. 13.0 at 8 (citing 20 ILCS 627/45(g)).

The AG notes that in ComEd's view, the cost of EV purchase rebates under the C&I and Public Sector EV Purchase Sub-program as well as Customer Education and Awareness Program costs, the BE Pilot Program spending, and the Portfolio-level spending do not count against the retail rate cap because they "are not actually EV infrastructure programs." ComEd Ex. 14.0 REV at 11. But as Staff witness Struck explained in detail, EV purchase rebates increase the demand for, and adoption, of EVs, which thereby increases the development of EV charging infrastructure. Staff Ex. 13.2. Likewise, spending to promote adoption of EVs by increasing customer education and awareness, and portfolio-level spending to support the BE Plan as a whole, contribute to the development of EV infrastructure. *Id*. Thus, the record shows that, other than the non-transportation programs (which should be stricken from the BE Plan), the entire BE Plan is intended to develop EV infrastructure and should therefore be subject to the retail rate cap.

The AG argues that BE Plan budget should also be reduced because it is unreasonably high in comparison to spending levels for similar programs adopted by other utilities. AG Ex. 1.0R at 13. ComEd proposes to spend $24.54 per customer per year on BE programs, which is significantly more expensive than what most utilities in the United States spend. *Id*. at 12. For example, this is approximately 50% higher than the program costs approved for Consolidated Edison in New York and Pacific Gas & Electric in California. *See id*. The AG points out that only two utilities, both of which are in California, have higher annual per-capita spending levels. *Id*. at 13. The AG further notes that ComEd's BE Plan spending is also excessive when viewed as a percentage of annual revenues. The AG's witnesses showed that ComEd's proposed BE Plan budget would equal nearly 2% of total annual revenues, higher than any other utility examined. AG Ex. 2.0 at 6-7.

In addition to being an outlier when compared to other utilities, the AG demonstrates that ComEd's spending levels are unreasonable and imprudent because they do not account for already existing state and federal incentives. ComEd's BE Plan "proposes to offer a host of incentives for measures that are already incentivized." AG Ex. 2.0 at 7. For example, ComEd proposes to spend $50 million on commercial EV purchase rebates, transit bus purchase rebates, and school bus purchase rebates. *See* ComEd Ex. 12.0 REV at 4-5. ComEd also proposes to spend approximately $16 million on incentives for charging equipment and make-ready infrastructure. *Id*. But each of these spending measures overlaps with (and needlessly duplicates) existing incentives provided in the Inflation Reduction Act ("IRA"), and in other federal and state rebate programs. AG Ex. 1.4; AG Ex. 2.0 at 7-8. In short, ComEd has shown "little to no recognition of, or coordination with, existing incentives." AG Ex. 2.0 at 8.

Despite extensive record evidence of the enormous levels of federal and state spending on EV adoption, ComEd argues that its duplicative BE Plan programs are still necessary for two reasons. First, ComEd argues that "uncertainty exists" with respect to what funds will be available under the IEPA's Charging Rebate Program as well as whether any vehicles will qualify for the Clean Vehicle Credit offered under the federal

IRA. ComEd IB at 25. Second, ComEd argues that state incentives are structured as post-purchase rebates, and federal incentives are structured as tax credits, meaning that the recipient would need to make an "upfront outlay of cash" and/or have federal tax liability in order to claim the credit, which could make the incentive less effective for low-income individuals. *Id*. at 26.

But the AG explains that a closer examination reveals that ComEd's arguments are an attempt at misdirection. Regarding the IEPA's Charging Rebate Program, ComEd is prohibited from offering overlapping incentives, so the structure of that program to ComEd's BE Plan is irrelevant. Interim Order at 23–24. Similarly, ComEd's BE Plan does not provide for vehicle purchase rebates to individuals. *Id*.; *see also* ComEd IB at 10 (noting that ComEd is not advocating for the adoption of the Residential EV Purchase Sub-program as part of its BE Plan). Thus, the timing and availability of post-purchase rebates and federal tax credits for individuals, low-income or otherwise, to purchase vehicles is irrelevant. With respect to vehicle purchase incentives for commercial and industrial customers, upfront cash outlays and a lack of tax liability are far less likely to be barriers than they would be for low-income individuals. Plus, by arguing there will not be any vehicles that qualify for the tax credits, ComEd appears to be claiming that the signature federal climate initiative is destined to fail and will not drive meaningful EV adoption, not only in Illinois but anywhere in the United States. The AG asserts that the Commission should reject these specious arguments.

The AG explains that ComEd has, in essence, developed a BE Plan using ratepayer funds that assumes no spending at all from other sources despite historic levels of state and federal budgeted investment to promote EV adoption in the coming years. While the AG does not suggest that ComEd can never provide incentives that overlap with other programs, ComEd's unwillingness to set rebates at levels that reflect these available sources of funding is a plainly unreasonable approach. AG Ex. 2.0 at 8. Put another way, it cannot be cost effective to allocate significant ratepayer funds towards incentives that already exist. Thus, the AG requests that the Commission reduce ComEd's spending on programs that are duplicative of existing state and federal incentives.

As an alternative to ComEd's excessive spending proposal, the AG recommends that the Commission reduce the BE Plan budget to fit within the retail rate cap. The AG notes that Staff proposed an alternative budget that would significantly reduce ComEd's BE Plan spending to $44.4 million, which is Staff's calculation of the retail rate cap. To achieve the necessary reductions, Staff proposes to remove non-transportation electrification programs as well as programs prohibited by the Interim Order from the BE Plan entirely, and also proposed to reduce the budgets for the C&I and Public Sector, Customer Education and Awareness, and Portfolio Programs. Staff Ex. 17.0 at 38-39; Staff Ex. 17.1. The AG agrees with Staff's approach to reduce ComEd's spending to not exceed the retail rate cap. However, the AG maintains that this retail rate cap should be $28 million rather than $44.4 million. Thus, the AG recommends that the Commission further reduce Staff's alternative budget proposal by 37%, spread across the five programs pro rata, to ensure that BE Plan spending does not exceed the retail rate cap of $28 million.

d. CJCP's Position

CJCP note several parties continue to advocate for a significantly reduced budget for ComEd's BE Plan. CJCP state the contentions that limiting application of the retail rate cap on programs related to EV infrastructure will effectively allow ComEd to operate the majority of their BE Plans unchecked and that "revenue requirements" should only include distribution revenue are erroneous. First, CJCP point out the Interim Order issued in this proceeding answered dispositively, for purposes of this case, the question of how to interpret the retail rate cap. Moreover, CJCP state the Commission's interpretation is correct—the qualifying language regarding EV infrastructure is clear, such that only those programs that regard EV infrastructure are subject to the retail cap. In addition, per CJCP, the AG's contention that programs such as education and outreach — while critically important — should count towards "development" of EV infrastructure is incorrect. CJCP state it is difficult to prove with 100% certainty that such programs will result in deployment of EV infrastructure — as such, it cannot reasonably be said that these types of programs, which are often combined with more general education on the benefits of vehicle electrification and available rebates and incentives, will "certainly support" EV infrastructure deployment. Clean Jobs Coalition Parties contend that the Interim Order correctly decided this issue.

In addition, Clean Jobs Coalition Parties believe that the AG's dismissive portrayal of the importance of a cost-benefit analysis is inappropriate. It is not clear to CJCP why the AG seems to believe societal benefits are an insufficient basis on which to predicate a cost-benefit analysis of a BE Plan. Indeed, state CJCP, the ability of a BE Plan to result in an effective, equitable transition to EVs — with resulting reductions in emissions that harm air quality and the climate — should be the backbone of what makes a successful utility proposal. CJCP contends the EVA's requirements for the cost-benefit analysis recognize this by requiring this analysis to include "the societal value of reduced carbon emissions and surface-level pollutants, particularly in environmental justice communities." 20 ILCS 627/45(d). CJCP state the fact that the AG implies those societal benefits are immaterial is troubling; for a party that purports to be concerned with how this BE Plan will affect customers in ComEd's service territory, this dismissal is hypocritical and is at odds with the legislature's clearly stated intent.

With respect to revenue requirement, CJCP state that while the AG appears to believe their interpretation is settled by past precedent and that their interpretation is readily apparent in the plain language of the statute, that is far from the case. CJCP aver that despite the AG purporting to rely on sound interpretive principles, namely that a statute "must be given its plain and ordinary meaning," and that the law should be "viewed as a whole, construing words and phrases in context to other relevant statutory provisions and not in isolation," AG IB at 25, citing *Oswald v. Hamer*, 2018 IL 122203, ¶ 10, those principles compel the opposite conclusion from the one the AG advocates. CJCP posit the clear language of the statute states that the rate cap should be based on total annual revenue requirement — not annual revenue requirement or delivery revenue requirement, both of which could more reasonably have been read as qualifying language.

Per CJCP, BE Plans are meant to be a mechanism to help facilitate electrification more broadly. CJCP contend that artificially constraining ComEd's ability to do that by

utilizing selective and strained interpretations of what the statute includes, will do little to accomplish the goals of the EVA.

e. AEE's Position

AEE agrees with Staff that the EVA commits to the Commission's discretion the determination of an overall BE Plan Budget. Staff IB at 67. AEE notes however that the General Assembly included in the EVA a provision that both guides and constrains the Commission's discretion. 20 ILCS 627/45(g) dictates that ComEd may not spend more than $44.4 million per year (1% of its total revenue requirement) on the development of EV charging infrastructure. 20 ILCS 627/45(g); *see also* Staff IB at 68 (correctly describing the retail rate impact cap as a "guidepost", but incorrectly suggesting that the retail rate impact cap applies to the entire BE Plan budget).

AEE asserts that ComEd proposes a total annual BE Plan budget of $100 million, but allocates only $16 million to programs that will support the development of EV charging infrastructure — namely, its Residential Charging Infrastructure Incentive and C&I and Public Sector EV Charging Infrastructure Incentive Sub-programs. ComEd Init. Br. at 22. According to AEE, ComEd's charging infrastructure sub-programs budget falls nearly $30 million short of the retail rate cap; in other words, the utility proposes to invest only approximately 36% of the total amount that the legislature permits. While the Act does not expressly prohibit ComEd from spending only a fraction of the amount delineated by the retail rate cap, AEE submits that ComEd's proposal cannot reasonably effectuate the legislature's intent. AEE notes that the prefatory language of the EVA sets a goal of one million electric vehicles in Illinois by 2030 in order to decrease reliance on fossil fuels, reduce pollution from the transportation sector and increase access to electrification for all customers, (20 ILCS 627/45(a)) and to that end, observes:

- Expanded infrastructure investment will help Illinois more rapidly decarbonize the transportation sector; (20 ILCS 627/45(a)(5));
- Widespread adoption of electric vehicles requires increasing public access to charging equipment throughout Illinois, especially in low-income and environmental justice communities, where levels of air pollution tend to be higher; (20 ILCS 627/45(a)(7)); and
- Widespread adoption of electric vehicles and charging equipment has the potential to provide customers with fuel cost savings and electric utility customers with cost-saving benefits. (20 ILCS 627/45(a)(8)).

AEE asserts that by committing only 16% of its BE Plan to the development of charging infrastructure — a small fraction of the total amount that the legislature permits — ComEd therefore puts the objectives of the EVA at risk. AEE (and several other parties) explain that supporting the broad deployment of charging infrastructure should be the central focus of ComEd's BE Plan (*see* AEE Exhibit 1.0 Corr. at 16; AG Exhibit 1.0 at 27; EDF Ex. 1.0 at 12-13), because widely accessible charging infrastructure is the key catalyst that will unlock widespread EV adoption. AEE recommends that the Commission direct ComEd to revise its budget such that the Company's total spending on make-ready infrastructure incentive sub-programs is closer to the retail rate impact cap.

AEE notes that despite supporting ComEd's proposal to provide make-ready charging infrastructure incentives, Staff and the AG each recommend that the Commission significantly reduce ComEd's BE Plan budget, including corresponding reductions to ComEd's make-ready infrastructure incentive sub-program budgets. According to AEE, both parties largely predicate their recommendation on the (incorrect) legal position that the retail rate cap constrains ComEd's total spending on its BE Plan, and not just the Company's spending on EV charging infrastructure.

AEE requests that the Commission reject both recommendations. AEE states that the Commission has already resolved the interpretation of the retail rate cap through an Interim Order. Challenging the Interim Order's legal conclusions via post-hearing briefing, however, constitutes an impermissible collateral attack on that order. Illinois courts have held that "[a] collateral attack on a judgment is an attempt to impeach that judgment in an action other than in which it was rendered . . . an attack on a judgment or decree is collateral where that action or proceeding has an independent purpose and contemplates some other relief or result." *Buford v. Chief, Park Dist. Police*, 18 Ill. 2d 265, 271 (1960). Here, while the parties remain in the same docketed Commission proceeding, AEE states that post-hearing briefing (and, ultimately, the Commission's final Order) concerns an action that is separate and distinct from briefing on Staff's Combined Motion (and the Interim Order) — the two actions have independent purposes. Whereas the Interim Order concerned fundamental legal questions underpinning this proceeding, AEE states that the final Order will resolve the remaining factual and legal issues in this proceeding based on the legal conclusions the Interim Order reached. Moreover, according to AEE, Staff's and the AG's arguments undermine the very purpose of the Interim Order, which was for the Commission to resolve those fundamental legal questions early such that parties could evaluate ComEd's BE Plan and develop the record in light of the Commission's determination. *See* Combined Motion to Dismiss at 2-3 ("In the interest of administrative efficiency, Staff respectfully requests an Interim Order to provide a Commission ruling on how the statutory retail rate cap should be interpreted so that the parties can consider ComEd's BE Plan and the record in this proceeding can be developed in light of that cap."). AEE states that the Commission should therefore reject Staff's and the AG's continued insistence on their interpretation of the retail rate cap and decline to adopt a total BE Plan Budget based on that interpretation.

AEE states further that while Staff errs with respect to its interpretation and application of the retail rate cap, it nevertheless raises important questions regarding the limits on ComEd's overall BE spending. Staff argues that the General Assembly could not have intended to give ComEd a "blank check" with respect to BE investments, (Staff IB at 69) and observes that even if ComEd is required to demonstrate that its total BE Plan spending is cost-effective, passing a cost-benefit test does not guarantee that the spending associated with the BE Plan will be affordable for the ratepayers who will pay increased rates. Finally, Staff asserts that in light of the fact that this is ComEd's inaugural BE Plan, it should be viewed as "experimental since the effectiveness of programs has yet to be evaluated." Staff IB at 54. Accordingly, Staff recommends a smaller total budget that reduces the risk of ratepayers paying for ineffective programs. Staff IB at 55.

According to AEE, Staff raises valid concerns but its analysis suffers from a fundamental flaw: it pre-supposes that ComEd's charging infrastructure sub-programs

must constitute a small fraction of its overall spending. In fact, the Commission can balance Staff's concerns with respect to the impact of ComEd's BE Plan on ratepayers, with the EVA's emphasis on the importance of make-ready infrastructure investments in order to achieve the state's policy goals. AEE recommends that the Commission direct ComEd to revise its BE Plan budget such that its make-ready infrastructure sub-program budget is closer to the $44.4 million retail rate cap, and direct reductions to the budgets for programs unrelated to the development of charging infrastructure.

f. ChargePoint's Position

ChargePoint concludes that the only BE Plan spending that counts against the retail rate cap is spending on EV charging infrastructure, specifically, the nonresidential Make-Ready Infrastructure Rebate Sub-program and the Residential EV Charging Infrastructure Sub-program. Pursuant to the Interim Order, none of ComEd's other proposed programs count against the retail rate impact limit.

ChargePoint states that, while Illinois' utilities likely will not need to spend 1% of their revenue requirements on EV charging infrastructure in perpetuity, now is the time for a substantial investment in EV charging infrastructure to jump start EV adoption in ComEd's service territory. At a high level, according to ChargePoint, ComEd's proposed $100 million annual budget for its first BE Plan is commensurate with the General Assembly's vision. However, ChargePoint notes that ComEd has proposed to spend only $16 million on EV charging infrastructure through the Make-Ready Infrastructure Rebate and the Residential EV Charging Infrastructure Sub-programs ($10 million for Make-Ready Infrastructure Rebate and $6 million for Residential EV Charging Infrastructure). ChargePoint also notes that this proposed level of investment is barely one-third of the approximately $44 million that ComEd is authorized by statute to spend on EV charging infrastructure and falls far short of the General Assembly's vision.

According to ChargePoint, ComEd witness Borggren acknowledges that demand for Make-Ready Infrastructure Rebate funds is high, but states, without explanation, that "the budget remains fixed, due to potential rate cap implications." To the contrary, ChargePoint asserts, ComEd's proposed level of spending on EV charging infrastructure falls far below the retail rate cap. ChargePoint also argues that the Commission has sufficient discretion to direct ComEd to increase the budget for the Make-Ready Infrastructure Rebate program to $30 million and increase the budget for the Residential EV Charging Infrastructure program to $14 million. Not only does the Commission have sufficient discretion to require these budget changes, argues ChargePoint, the Commission should require these changes to ensure that ComEd's investment in EV charging infrastructure is commensurate with the scale of the General Assembly's vision for an investment of up to $44 million in EV charging infrastructure.

ChargePoint would also not oppose reducing the budgets of the non-transportation programs that ComEd has proposed, or removing these programs altogether from the BE Plan, which comprise $12 million of ComEd's proposed budget, to mitigate the rate impact of increasing ComEd's investment in EV charging infrastructure to a level consistent with the intent of the EVA. ChargePoint also would not oppose reducing the budgets for residential and nonresidential vehicle rebates in order to increase the budgets of the charging infrastructure programs, if necessary.

ChargePoint explains that there is no support in the EVA for Staff's view that the first BE Plan is an experiment or that ComEd's level of investment should be lower for the first BE Plan. To the contrary, argues ChargePoint, the EVA recognizes that a substantial investment in EV charging infrastructure – up to $44 million – is urgently needed to meet Illinois goal of one million EVs on the road by 2030. ChargePoint further argues that the purpose of this proceeding (among other things) is to "provide some assurance that ratepayers will not be required to pay for ineffective programs" by evaluating the programs through the Commission's litigation process, which includes a wide variety of stakeholders.

Finally, ChargePoint explains that one hallmark of many ineffective programs is an inadequate budget that hamstrings the program so that it fails to make any meaningful impact. As an example, ChargePoint states that, while it greatly appreciates that Staff recommends requiring ComEd to provide make-ready incentives to all nonresidential customers, Staff's recommended budget of only $1.5 million for customers not located in eligible communities will meet a tiny fraction of the anticipated demand from nonresidential customers. According to ChargePoint, the likely result of such an inadequate budget would be frustration and dissatisfaction from the many customers who would be expected to pay for the cost of the BE Plan through their rates but unable to participate due to severe budget constraints. Although it does not oppose reducing or eliminating the budget for the proposed non-transportation programs or the vehicle rebate programs, ChargePoint asserts that it would be unreasonable to reduce the budget of ComEd's EV charging infrastructure programs (i.e., the Make-Ready Infrastructure Rebate program and the Residential EV Charging Infrastructure program) simply because this is the first time ComEd has offered such programs.

g. Commission Analysis and Conclusion

As an initial matter, the Commission notes that Staff and the AG proposed budgets based on their respective interpretations of the retail rate cap that the Commission rejected in the Interim Order. Accordingly, the Commission rejects the AG's $28 million budget and Staff's $44.4 million budget on that basis.

Staff finds fault with ComEd's lack of explanation of why a $100 million budget is a good starting point for the first BE Plan and urges the Commission to drastically reduce the budget. The Commission notes that Staff supports many of the programs in the BE Plan, and in fact suggests additional programs be added. Considering the breadth and scope of ComEd's BE Plan and the corresponding expected benefits, the $100 million budget does not necessarily appear overly large.

On exceptions, ComEd argues that it supports an $84 million budget, but only if the Commission grants ComEd regulatory asset treatment. The testimony ComEd refers to in its Brief on Exceptions does not provide any alternative lower budget plan should the Commission reject regulatory asset treatment. *See* ComEd Ex. 4.0 at 14; ComEd Ex 9.0 at 10; ComEd Ex. 14.0 REV at 1-2, 13-14. All ComEd's analysis in this testimony shows is that the budget would need to be drastically reduced to achieve the *same* level of estimated up front customer rate or bill impacts as ComEd's proposal would have using regulatory asset treatment. ComEd does not provide any specifics on how the budget should be reduced or what, if any, programs should be removed should the Commission

not approve ComEd's cost recovery proposal. Moreover, the Commission notes that ComEd has repeatedly asserted that reductions to the budget would compromise the scope and breadth of the BE Plan and contravene the purpose of P.A. 102-0662's ambitious energy, equity, and environmental goals.

P.A. 102-0662 shows the General Assembly's intent to advance BE, especially in EJ/R3/low-income communities, and that requires a certain amount of investment. However, the Commission acknowledges Staff's and the AG's concerns over the size of the budget, and to somewhat mitigate the impact to ratepayers the $6 million in funding for the Residential EV Purchase Sub-Program shall be removed from the budget and not reallocated to other programs as ComEd proposes. The Commission is approving a limited portion of the Company's proposed non-transportation programs in this BE Plan (*see* Section V.C.5.a). Specifically, the Commission approves ComEd's original $2 million for residential heat pumps (Residential BE Technology Adoption Sub-program Supplemental Rebate for High Efficiency Heat Pumps) and ComEd's original $1 million to only fund make-ready investments tied directly to heat pump installations (Residential BE Infrastructure Readiness Sub-program Residential BE Infrastructure Rebate) (*see* Section V.A.1). Accordingly, the original funding amounts for the rejected non-transportation programs remaining in ComEd's revised BE Plan should also be removed from the budget, which is $7 million.

In addition, the Commission approves a reduced budget for Customer Education and Awareness of $6 million, as discussed in Section V.A.3.

The Commission does not approve the $8 million portfolio costs as discussed in Section V.A.5. The Commission accepts Staff's proposal to bifurcate funds in the C&I and Public Sector EV Charging Infrastructure Sub-program, but not Staff's proposed budget. The Commission approves $14 million of the funding in this sub-program to be directed to EJ/R3/low-income communities and $6 million to non-EJ/R3/low-income communities. *See* Section V.A.2. The Commission rejects Staff's proposal to bifurcate funds in the Residential EV Charging Infrastructure Sub-Program. *See* Section V.A.1.

Thus, based on the above, the Commission approves an overall annual budget of $77 million, as follows:

BE Plan Programs	BE Plan Sub-programs	Eligible Measures	ComEd Proposed Initial Annual Budget	Change	Approved Annual Budget
1. Residential Program	Residential EV Purchase Sub-program	Passenger Vehicle Rebate	$6M	($6M)	
	Residential EV Charging Infrastructure Sub-program	Residential Charging Infrastructure Rebate	$5M		$5M
	Residential BE Technology Adoption Sub-program	Supplemental Rebate for High Efficiency Heat Pumps	$2M		$2M
		Other Res. BE Technology Rebate	$1M	($1M)	

	Residential BE Infrastructure Readiness Sub-program	Residential BE Infrastructure Rebate	$1M		$1M
		Residential Program Total	**$15M**	**($7M)**	**$8M**
2. C&I and Public Sector Program	C&I and Public Sector EV Purchase Sub-program	LDV Rebate	$12.5M	($2.5M)	$10M
		MDV Rebate	$12.5M	($2.5M)	$10M
		HDV Rebate	$10M	($4M)	$6M
		School Bus Rebate	$6M		$6M
		Transit Rebate	$6M		$6M
	C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program	EJ/R3 EV Charging *Make-Ready* Infrastructure Rebate, L2 and DCFC	$10M	$10M	$20M
	C&I and Public Sector BE Technology Adoption Sub- program	Commercial & Industrial BE Rebate Pool (Custom)	$2M	($2M)	
	C&I BE Infrastructure Readiness Sub-program	High Efficiency Electric Forklift Infrastructure Rebate	$4M	($4M)	
		Small Business BE Infrastructure Rebate			
		C&I and Public Sector Program Total	**$63M**	**($5M)**	**$58M**
3. Customer Education and Awareness			$9M	($3M)	$6M
4. BE Pilot Program			$5M		$5M
5. Portfolio			$8M	($8M)	
		Total	**$100M**	**($23M)**	**$77M**

2. Budget Flexibility

a. ComEd's Position

ComEd argues that it has designed a customer-focused and comprehensive BE Plan, based on feedback and stakeholder input, but because this is the first BE Plan, ComEd anticipates that some flexibility will be needed to respond to actual "market conditions, customer interest, emerging best practices, and other unforeseen circumstances" that arise during the BE Plan period. For that reason, ComEd requests a degree of flexibility to the BE Plan budget from year to year — as well as within the current spending year — pursuant to EVA spending requirements and limitations. In particular, any unused funds at the close of one BE Plan year would be rolled over to the following year, provided that the retail rate impact cap would not be violated, according to ComEd. In addition, ComEd states that up to 25% more than the total annual budget may be spent in a given year, with the budget for subsequent years being correspondingly reduced, with the same caveat related to the retail rate impact cap. ComEd notes that it generally agreed with certain conditions on ComEd's budget flexibility that Staff proposed.

The first of Staff's proposed conditions is that ComEd must continue to comply with the requirements in the EVA, including the requirements that annual spending be lower

than the statutory retail rate impact cap and that the portfolio of programs remains cost-beneficial. ComEd notes that it agreed to this condition. Furthermore, ComEd notes that only the Residential Program and the C&I and Public Sector Program include funding for the development of EV infrastructure, and combined those costs are within the 1% retail rate impact cap set forth in the EVA. ComEd argues that the total benefits of the BE Plan significantly outweigh its costs.

The second of Staff's proposed conditions is that there be no shifting in funding between incentives targeted to low-income/EJ/R3 recipients and other recipients. ComEd states that it agrees that BE Plan funding targeted for low-income customers or those residing in EJ or R3 communities should be received by those groups throughout the life of the BE Plan. According to ComEd, in the event that the measures implemented for low-income, EJ, and R3 customers have a lower uptake than anticipated in a given year, ComEd will roll those unspent dollars into a future year to be spent on low-income, EJ, and R3 programs. ComEd argues that this will ensure that BE Plan spending for these recipients is targeted at no less than a combined 50% of the Residential Program and 40% of the C&I and Public Sector Program funding over the full three-year period of the Plan.

The third of Staff's proposed conditions is that there be no shifting of funds from transportation to non-transportation BE initiatives. ComEd states that it will commit to this proposed condition for the first two years of the BE Plan. If, however, it proves difficult to encourage low-income, EJ, and R3 customers to participate in transportation initiatives to ensure their overall benefit from the BE Plan, ComEd states that it will increase funding for non-transportation initiatives aimed at those communities, to make sure that dollars targeted for those groups are indeed spent for their benefit.

The fourth of Staff's proposed conditions is that there be no shifting of funds into the BE Pilot Program. ComEd notes that it accepted this proposal.

The fifth of Staff's proposed conditions is that the BE Plan spend must be equal to or less than the overall budget. ComEd notes that its BE Plan costs will be regularly reviewed by the Commission in reconciliation proceedings, ensuring that the costs borne by customers will be contained within the approved budget.

Finally, the last of Staff's proposed conditions is that the annual report for the BE Plan include a budget to actual cost comparison. ComEd states that it intends to include a high-level summary comparison of budget and actual costs for each program and sub-program in the annual report. Furthermore, ComEd notes that the annual report will also explain any changes to the budget. In light of these commitments and agreements, ComEd argues that there are no further contested issues with respect to the proposal to permit flexibility within the BE Plan budget. ComEd argues that the Commission should approve that proposal.

The AG argues that the Commission should bar ComEd from transferring funds between non-transportation and transportation programs, because, the AG contends, this type of transfer would allow ComEd to improperly increase the rate of return it receives on its EE Plan spending. But the issue of whether and how ComEd can claim, for purposes of determining whether ComEd has met the Cumulative Persisting Annual Savings and Applicable Annual Incremental Goals under Section 8-103B, which governs

ComEd's EE Plan, energy savings resulting from the adoption of measures incentivized by the BE Plan, is outside the scope of this proceeding. To the extent these issues need to be addressed, the appropriate venue is in a case concerning the EE Plan, or through the existing Illinois EE Stakeholder Advisory Group process.

The AG also recommends that the Commission not allow ComEd to spend additional dollars on its non-transportation programs without first explicitly barring ComEd from counting savings towards its EE Plan goals. There is no need to place restrictions on ComEd's BE Plan with respect to its EE Plan. The two plans can work in tandem and achieve goals for the customers of Illinois that will benefit everyone. Again, ComEd merely reserves the right to shift funds between non-transportation and transportation to ensure it is meeting spending goals with respect to LI/EJ/R3 communities.

b. Staff's Position

Staff states that the Commission should grant ComEd the flexibility to shift funds between its programs and sub-programs and between BE Plan years within each BE Plan period, subject to certain conditions recommended by Staff. Staff Ex. 7.0, Section III.

First, the Company must continue to comply with the objectives and requirements set forth in the EVA because it has an inherent obligation to do so while operating its BE Plan. These objectives and requirements include annual spending that is below the statutory retail rate cap of 1% per year of the Company's total annual revenue requirements. They also include the Company ensuring that the portfolio of programs remain cost-beneficial.

Second, Staff states, funds that have been reserved to benefit low-income customer or EJ/R3 communities cannot be shifted to activities that benefit non-low-income customers or non-EJ/R3 communities. The EVA addresses equity and there are numerous references to low-income customers and communities, and EJ communities in the BE goals in Section 45(a); in the description of stakeholder workshops in Section 45(c); in the objectives of the EVA and in the minimum requirements that the BE Plan must address in Section 45(d); and in the description of workforce equity actions in Section 45(h). Staff Ex. 7.0 at 24. Directing funds earmarked for low-income customers or for EJ or R3 communities to activities that benefit non-low-income customers or non-EJ or non-R3 communities would contravene the General Assembly's intent as set forth in the EVA. However, the difference between the Company's position and Staff's position on this condition for budget flexibility is the percentages that should target low-income customers and EJ and R3 communities. Both Staff and the Company believe that a target of 50% of ComEd's residential program is reasonable; however, the Company proposes a target of 40% of its C&I and Public Sector Program, while Staff believes that a target of approximately 70% is more appropriate, considering the increase in available federal funding and taking into account LVEJO's recommendation to allot at least 60% of the C&I and Public Sector EV Purchase Sub-program to low-income customers, and EJ and R3 communities. LVEJO Ex. 1.0 at 7; Staff Ex. 17.1.

Third, if the Commission approves non-transportation programs despite Staff's and the AG's strong opposition, the Company cannot shift funds from programs or sub-programs for transportation activities to programs or sub-programs for non-transportation activities. Staff notes that the Company agreed to this modification but only for the first

two years of the BE Plan. Before the third year, if the Company has determined that it has not been able to drive low-income/EJ/R3 participation in transportation activities, the Company would like to roll over those funds to benefit low-income/EJ/R3 non-transportation activities. ComEd Ex. 12.0 REV at 9-10. However, the Company's proposal does not adequately address the policy concerns that both Staff and the AG expressed with the Company's BE Plan having non-transportation components. Staff Ex. 1.0; AG Ex. 1.0 at 30-38. If the Company is allowed to shift budgets for transportation activities to non-transportation activities, effectively increasing funding for non-transportation programs after the Commission enters a final Order in this proceeding, it could enable the Company to bypass the spending cap for EE imposed under Section 8-103B(m), making it easier for the Company to earn financial performance incentives that increase the return on equity ("ROE") component of its EE formula rate. 220 ILCS 5/8-103B(g)(7).

Fourth, the Company cannot shift funds to any BE Pilot program given the unproven nature of pilot programs.

Fifth, Staff asserts, the Company's overall BE Plan program spend must be less than or equal to the overall BE Plan budget approved by the Commission for the BE Plan period. The Commission will consider the Company's BE Plan, including the related budget and cost-effectiveness, in this proceeding. When the Commission approves the overall budget, the Company's spending should be within the overall approved budget so that there are cost controls and accountability. If the Company were permitted to spend above the approved budget, it would subvert the purpose of the Commission's review of the plan to determine whether the proposed BE Plan investments and expenditures meet these statutory objectives and requirements.

Sixth, the Company should include a budget to actual cost comparison for each program as part of its annual report, including portfolio-level costs and related sub-programs, for the year ended. If the Company revises the filing year's budget, ComEd should include an explanation of the changes to each program and related sub-program, including addressing whether the portfolio of revised programs will continue to be cost beneficial and will continue to comply with the EVA. The Company should meet this condition to ensure that the Company complies with all conditions on an annual basis. The Company noted that this commitment will be added to the Company's "…BE Plan annual report section in its post-final order compliance filing" (ComEd Ex. 6.0 at 25), and Staff has no objections to this statement provided that there is an opportunity to review the Company's draft compliance BE Plan prior to it being filed to ensure it matches what the Company said it would include, consistent with Staff's recommended compliance filing process. Staff Ex. 12.0. In addition, the Company has stated that it has not set targets for low-income/EJ/R3 customers at the sub-program level (Staff Cross Ex. 1.0 at 27), so it is unclear which sub-program and related budget are targeted to low-income/EJ/R3 customers. The Commission should order ComEd to distinguish funds targeted to low-income/EJ/R3 customers from non-EJ/R3/low-income customers at the sub-program level, so it is clear which funds are targeted to EJ/R3/low-income customers and in order to clearly track whether spending requirements in these areas are being met and to align with Staff's budget flexibility conditions. Staff Ex. 17.0 at 38. If the Commission adopts Staff's budget proposal set forth in Staff Exhibit. 17.1 then this issue is already addressed

as Staff's budget clearly lays out the budget targets of individual sub-programs for low-income/EJ/R3 customers.

ComEd generally agreed with these six conditions (ComEd IB, 23) subject to certain caveats (ComEd RB at 51-53) and no party objected to budget flexibility. The Commission should reject ComEd's caveats and approve Staff's budget flexibility request subject to all six of Staff's recommended conditions.

WeaveGrid however, took issue with Staff's fourth condition, arguing that prohibiting the shifting of funds into the BE Pilot Program would limit the Company's ability to scale successful pilots during this plan, and arguing that it should be eliminated. Staff disagrees. Under this condition, the Company would still be able to shift budgeted funds from the BE Pilot Program in one year to another year. Staff Ex. 18.0 at 29. If there are pilot programs that the Company wishes to scale up and others that it wishes to scale down, the Company should be allowed to shift funds between these pilots in a BE Plan year and across BE Plan years which will enable the Company to scale successful pilots. Furthermore, if the Company wishes to spend more than the Commission-approved overall BE Plan budget on scaling up pilots it deems successful, the Company may simply file a petition with the Commission at such time as it anticipates its spending to exceed the Commission-approved budget. The Company did not take issue with this recommendation. However, the Company should not be allowed to shift funding reserved for non-pilot programs and sub-programs to the BE Pilot Program.

Staff explains that pilot programs, by their very nature, are intended to be short-term programs. If the Company deems a pilot successful, the pilot would presumably be fully implemented, incorporated into the BE Plan as a program or sub-program, and included in a benefit-cost analysis for the portfolio of BE programs. In contrast, if the Company deems the pilot a failure, it would be eliminated, and ratepayers would pay only those costs that the Company had budgeted for its Pilot Program.

Regarding other parties' recommendations, Staff states that the Commission should direct ComEd to develop incentive criteria in response to the CTA's concern about the payout of incentives for work performed over multiple years. Staff Ex. 18.0 at 30. The Commission should reject ChargePoint's recommendation that any proposals to modify program budgets by more than 10% should require a formal review by and approval process through the Commission. ChargePoint Ex. 1.0 at 30.

CTA/City state that the work funded by ComEd's financial incentives could extend over multiple years. CTA Ex. 3.0 at 5. Therefore, CTA/City request that ComEd revise its BE Plan to state that when rebates are for purchases that cannot be completed in one year, the rebate will be paid out when the purchase is completed. CTA Ex. 3.0 at 9. The Company agreed to "further explore this issue in the detailed program design phase." ComEd Ex. 7.0 at 29. Staff states that the Commission should adopt the CTA's recommendation with certain modifications. Staff Ex. 18.0 at 30. According to Staff, the Commission should direct ComEd to develop incentive criteria that would require its C&I customers to provide ComEd with a statement of work ("SOW") from the C&I customers' chosen vendor. This SOW should contain the scope of the work, tasks to be completed, deliverables, and a timeline that will allow for the payout of incentives as each phase of a project is completed with the final payout, including an adjustment to the incentive

amount, if necessary, when the final cost is known at the end of the project. To be clear, a "phase" should result in actual EV-related work being completed. As part of its incentive criteria, Staff states, ComEd should also request at minimum quarterly updates from its C&I customers on the status of these projects together with revised timelines if necessary. With this information, Staff avers, ComEd should adjust its budgets each year to consider expected payouts to its C&I customers, while meeting the conditions that were described earlier for budget flexibility.

ChargePoint recommends that any proposals to modify program budgets by more than 10% should require a formal review by and approval process through the Commission. ChargePoint Ex. 1.0 at 30. The Commission should reject ChargePoint's recommendation because the flexibility conditions that Staff proposed provide an approach to budget flexibility that is more informative and more cost effective than requiring the Company to seek Commission approval through a separate proceeding each time the Company expects to spend 10% over its annual budget. Staff Ex. 18.0 at 30-31. Staff states that the Company should notify the Commission if it anticipates any revisions to its annual budget annually through its Annual Report. So long as the Company meets the budget flexibility conditions described earlier, then the Commission should allow the Company to increase its budget in some years and decrease its budget in other years within a BE Plan period. If the Company wants to spend more than its entire-Commission-approved BE Plan period budget, then it would be appropriate for the Company to seek Commission approval at that time.

Budget flexibility will give the Company the ability to adapt its programs in response to new information and insights in order to better achieve the objectives of the EVA in a timelier manner. If the Commission grants ComEd budget flexibility, ComEd will be able to adjust its programs and related budgets timelier, before the BE Plan updates are due (July 1, 2024 and every three years thereafter). For these reasons, Staff concludes, the Commission should grant ComEd the flexibility to shift funds between its programs and sub-programs and between BE Plan years within each BE Plan period, subject to the above conditions.

c. AG's Position

The AG requests that the Commission allow the Company to shift budgets between programs and plan years, but subject to the six restrictions provided by Staff witness Poon in her testimony, including Poon's third condition to restrict budget transfers from transportation electrification activities to non-transportation electrification activities. Staff Ex. 7.0 at 22-23.

The AG asserts that the Commission should adopt the position of the AG and Staff and bar the Company from transferring funds from transportation electrification programs to non-transportation programs throughout the duration of the BE Plan cycle. The AG and Staff both assert that allowing the Company to shift budget from transportation electrification to non-transportation electrification programs will undermine ComEd's existing energy efficiency plan.

d. ChargePoint's Position

ChargePoint does not oppose ComEd's proposals regarding budget flexibility.

e. WeaveGrid's Position

WeaveGrid states that ComEd should have budget flexibility to increase spending if certain pilot programs are successful. Staff proposes to limit moving more funding to pilot programs. While WeaveGrid is generally supportive of Staff's argument that there should be conditions that limit moving funds between initiatives with separate policy goals, the restriction could limit the ability to scale successful pilots during this BE Plan. WeaveGrid states that ComEd should have the ability to increase spending in this program cycle on pilot programs if they are successfully meeting goals.

f. Commission Analysis and Conclusion

The Commission notes that generally parties support budget flexibility. Staff proposes certain conditions to ComEd's budget flexibility.

Staff asserts that ComEd must continue to comply with the objectives and requirements set forth in the EVA, which include annual spending that is below the statutory retail rate cap of 1% per year of the Company's total annual revenue requirements and that the portfolio of programs remain cost-beneficial. ComEd agrees to this condition. The Commission notes, however, that Staff's interpretation of the retail rate cap and what is cost-beneficial differs from the Commission's determination in the Interim Order and in this Order. Accordingly, the Commission adopts this condition as interpreted by the Commission in this Order and not Staff's opinion.

Next Staff requests that there be no shifting in funding between incentives targeted to low-income/EJ/R3 recipients and other recipients. ComEd agrees to this condition and it is approved. Questions regarding the applicable percentages that should target low-income customers and EJ and R3 communities are addressed in Sections V.A.1 and 2 of this Order.

Staff and the AG argue that funds should not be transferred between transportation and non-transportation programs. The Commission agrees.

Staff also recommends that there be no shifting of funds into the BE Pilot Program. ComEd accepts this condition, and it is approved. With respect WeaveGrid's concerns, if a pilot program is successful and merits full implementation, an increase in funding can be brought to the Commission's attention in a petition.

Staff further proposes that ComEd's BE Plan spend must be equal to or less than the overall budget. ComEd does not object to this condition. ComEd's BE Plan spend must be equal to or less than the overall budget as set by the Commission. The Commission agrees that ComEd can petition the Commission if it seeks to increase the budget.

Finally, Staff proposes conditions that the Annual Report for the BE Plan include a budget to actual cost comparison. ComEd agrees to this condition, and it is approved.

3. Rebate Levels

a. ComEd's Position

Recognizing that the upfront cost of investing in BE technology can be too great for many individuals, ComEd notes that it included rebates in the BE Plan to help

overcome this barrier, and support widespread adoption of BE measures, especially for low-income customers and those residing in EJ and R3 communities, in alignment with the goals outlined in Section 45 of the EVA. According to ComEd, the dollar value of the rebates to be offered under ComEd's proposed BE Plan were carefully and thoughtfully designed after consideration of a multitude of factors, including the existing financial incentives offered by both the state and federal governments, as well as the ongoing uncertainty as to the continued availability of those incentives and/or the scope of those programs moving forward.

For example, ComEd notes that uncertainty exists with respect to the annual funds that will be made available through appropriations over time for state programs such as the IEPA new Charging Rebate Program. Moreover, the ability for customers to receive federal tax credits for BE measures remains in flux, according to ComEd, as it is not clear how many EV makes and models would qualify for an incentive under the IRA's Clean Vehicle Credit. See Pub. L. No. 117-169 (2022). In August 2022, the Alliance for Automotive Innovation reported that 70% of the EVs available in the U.S. would be ineligible for these federal rebates with the passage of the IRA, and none would qualify for credits when the IRA's supply chain and sourcing requirements take effect in 2024, ComEd notes.

In addition, ComEd points out that the currently-available rebates from the State of Illinois take the form of post-purchase rebates, while the available federal incentives take the form of tax credits. ComEd notes that these delivery methods are not likely to incentivize adoption of EVs by individuals with lower incomes, who may not be willing to make the upfront outlay of cash while waiting for a state rebate, and/or may not be able to realize the value of the federal tax credit because they may not have a large enough federal tax liability.

In other words, ComEd argues, the available state and federal incentives cannot be assumed to be sufficient to support the growth in adoption of EVs necessary to meet the EVA's goal of one million EVs on the road in Illinois by 2030, nor can they be assumed to address the equity and environmental justice goals set forth in the EVA. Given the uncertainties and the ambitious BE goals set by the General Assembly, ComEd notes that it set the initial rebates in the BE Plan at levels that do not reflect an undue reliance on these other programs to facilitate the adoption of BE technology.

ComEd claims it will maintain flexibility in the BE Plan to adjust rebate levels as needed. ComEd argues that this flexibility would enable it to modify the dollar value of rebates within the Plan period if it appears that a larger or smaller rebate would more effectively spur adoption, and enable it to reallocate funding among BE Plan programs to respond to factors including changes in the availability of state or federal incentives.

The AG asserts that some of ComEd's rebate levels need to be reduced. First, the AG argues that the Commission should reduce the value of the rebate included in the Residential EV Charging Sub-program for non-LI/EJ/R3 customers. The AG argues that this rebate contains significantly more compensation than is necessary to incentivize participation. The AG also argues that this rebate is not commensurate with those offered by other utilities, and ComEd has not proven it is necessary to assist in EV adoption. ComEd disagrees with this position. ComEd proposes to offer a $2,500 rebate for

residential customers to purchase and install an EV charging station. However, the amount of the rebate will be capped at the actual cost of the charger and installation, which in many cases could be much lower than the $2,500 maximum set by the program. ComEd Ex. 12.0 REV. at 12. Moreover, ComEd has elected to maintain flexibility to adjust rebate levels to respond to actual market and policy demands.

CTA/City recommend that all CTA buses should be eligible for the $120,000 per bus rebate under the C&I and Public Sector EV Purchase Sub-program because the entire CTA fleet serves EJ/R3 communities. Provided CTA can demonstrate that each of its buses primarily serves the EJ or R3 communities, this would not pose a problem. However, it seems unlikely that every single transit bus the CTA operates primarily serves EJ/R3 communities. ComEd created two different levels of rebates for that very reason. If a CTA bus does not primarily serve the EJ/R3 communities, it should only be eligible for the $80,000 rebate as described in the sub-program.

ChargePoint argues that ComEd should expand the C&I Public Sector EJ/R3 Charging Infrastructure Sub-program to all residential customers and provide rebates for $6,000 per port for L2 chargers and $800 per kW for DCFCs for any nonresidential customers that do not qualify for the higher incentive levels. At this time, ComEd cannot reasonably expand this sub-program to all residential and nonresidential customers.

ComEd argues that the rebates it has proposed are appropriately sized to achieve the goals of the EVA, in light of the existing barriers to adoption of BE technology and the current uncertainties regarding the availability and impact of existing state and federal incentives outside the BE Plan. ComEd argues that the Commission should approve the rebates at the levels it has proposed, including providing it the flexibility to modify the amount of any individual rebate to account for uptake during the Plan period or other factors such as changes in the landscape of state and federal incentives.

b. AG's Position

The AG requests that the Commission reduce the value of the rebate included in the Residential EV Charging Infrastructure Sub-program for non-low-income customers to offset the cost of installation of EV chargers to a level commensurate with the rebates offered by other utilities. Through ComEd's Residential EV Charging Infrastructure Sub-program, the Company proposes to provide residential customers a rebate of up to $2,500 for non-low-income customers and up to $3,750 for low-income/EJ/R3 customers for the installation of electric vehicle charging stations. ComEd Ex. 1.01 at 34, 36. The AG states that the rebates appear designed to incent the adoption of L2 chargers, the installation of which can cost up to $4,500 if a customer needs to receive electrical upgrades to support the charging infrastructure. AG Ex. 1.0R at 25.

The AG asserts that the Commission should reduce the size of ComEd's rebates associated with the Residential EV Charging Infrastructure Sub-program for non-low-income customers to a level commensurate with rebates offered by other utilities for three reasons. First, the AG maintains that Company has not established that residential customers require L2 chargers. As described by the AG's witnesses, while L1 is the slowest method of charging, it is sufficient for drivers who charge overnight and travel 30-40 miles per day. *Id*. The AG asserts, however, that nowhere in this proceeding did ComEd identify how many customers drive in excess of 30-40 miles per day and thus

require an L2 charger. Thus, the AG argues that the Company proposes to provide a large rebate for a program that it has not proven is necessary to assist in EV adoption.

Second, the AG explains that ComEd's rebates are much higher than those provided by other utilities. Only three other delivery utilities — Portland General Electric, Connecticut Light & Power, and Public Service — offer rebates for residential chargers and their rebate levels are substantially lower than those proposed by ComEd. AG Ex. 1.0R at 24.

Finally, the AG argues that the rebates for non-low-income customers should be reduced because data from other jurisdictions indicates that non-low-income customers will be incentivized to purchase a L2 charger with a much smaller rebate. As explained by the AG's witnesses, Baltimore Gas and Electric Company in Maryland, an Exelon company and affiliate of ComEd, has had success with a $300 rebate for L2 chargers, $2,200 less than ComEd's proposed maximum rebate, and received an average of 70 rebate applications per month. AG Ex. 2.0 at 11-12. The AG further notes that Baltimore Gas and Electric Company's $300 charger rebate was so popular with customers that it oversubscribed its approved allotted number of residential rebates and had to begin wait-listing customers. *Id*. at 12.

To address these issues, the AG requests that the Commission reduce the size of ComEd's rebates associated with the Residential EV Charging Infrastructure Sub-program for non-low-income customers to a level commensurate with the rebates offered by other utilities. The AG asserts that the evidence shows that a smaller, more-focused rebate will adequately incentivize participation in the program while allowing for more program participation overall or reductions in ComEd's BE Plan budget. The AG asserts that reduction in the rebate for non-low-income customers was an appropriate remedy because, under ComEd's proposal, the Company would provide significantly more money than what is needed to incent the adoption of L2 chargers, thus resulting in wasteful spending that could either be removed from the BE Plan to limit the rate-impact that non-participants will experience or transferred to other programs that offer appropriately sized rebates. The AG states that while the EVA contains ambitious electrification goals for Illinois, these goals do not require ratepayers to overpay for achievement of the goals.

c. ChargePoint's Position

ChargePoint supports ComEd's proposal to provide rebates through the Residential EV Charging Infrastructure subprogram of up to $3,750 for low-income customers and customers in eligible communities and up to $2,500 for all other residential customers. ChargePoint explains that providing incentives up to these amounts to cover a customer's actual cost of installing a L2 charging station, the Residential EV Charging Infrastructure Sub-program will encourage EV adoption and the installation of networked chargers that customers can use to manage their charging and do as much of their charging during off-peak hours as possible.

ChargePoint also supports ComEd's proposal to provide rebates through the nonresidential Make-Ready Infrastructure Rebate program of up to $8,000 per port for L2 chargers and up to $1,000 per kW for DCFCs for public sector customers and customers in eligible communities, with all rebates capped at the actual cost of the make-ready infrastructure. ChargePoint recommends that the Commission direct ComEd to open the

Make-Ready Infrastructure Rebate program to all residential customers and to provide rebates of $6,000 per port for L2 chargers and up to $800 per kW for DCFCs for any nonresidential customers that do not qualify for the higher incentive levels, with all rebates capped at the actual cost of the make-ready infrastructure. ChargePoint argues that by covering a substantial portion of the upfront cost of installing EV chargers – i.e., the cost of the make-ready infrastructure – these rebate levels will encourage more site hosts to install EV charging stations for the benefit of EV drivers and to encourage EV adoption.

d. Commission Analysis and Conclusion

The Commission finds that ComEd's rebate levels appear reasonable and are approved. There is insufficient information at this time as to how successful the rebate programs may be and the Commission is disinclined to adjust the proposed rebate levels based on particular parties' interests.

The AG recommends that the Commission reduce the size of ComEd's rebates associated with the Residential EV Charging Infrastructure Sub-program for non-low-income customers to a level commensurate with the rebates offered by other utilities, but does not specify a dollar amount. The AG's recommendation is not fully developed in the record and it is rejected. If the rebate levels are found to be overly high, as the AG suggests, then this can be addressed in the next BE Plan. Furthermore, budget flexibility will allow ComEd to adjust the rebate programs to more effectively further the goals of the EVA as the programs develop.

4. Retail Rate Cap

a. Staff's Position

Staff states that the Commission should set an annual ceiling on BE Plan spending equal to or less than 1% of the Company's total delivery revenue requirements. It should reject ChargePoint's and ComEd's proposal that BE Plan spending that is not related to infrastructure, such as vehicle rebates, non-transportation related equipment rebates, education and outreach, and program administration costs, should not count against the retail rate impact cap. Staff Ex. 13.0 at 7-9.

Should the Commission adopt Staff's recommendation as set forth in Section IV.B. to reject non-transportation programs from the BE Plan, the issue of what programs should be subject to the spending cap is largely moot. If no non-transportation programs are included, the programs that are included are, by definition, transportation programs that are subject to the retail rate cap. This is clearly the most logical and practical interpretation of the statute and the one the Commission should adopt. The alternative approach advocated by ComEd simply defies logic - ComEd suggests the EVA poses no limitations on the type of programs ComEd offers nor any limitation on how much the Company can spend on those programs, despite the fact that the EVA imposes an explicit cap on expenditures under the BE Plan. 20 ILCS 627/45(g). It is inconceivable that the General Assembly intended the EVA to allow recovery for any electrification programs ComEd deems worthy of inclusion but at the same time impose a spending limit applicable only to electric vehicle spending comprising a small fraction of the proposed annual budget of $100 million. Even if the Commission determines that ComEd can include electrification programs unrelated to transportation in the BE Plan mandated by the EVA,

and even if the Commission determines that ComEd can spend in excess of the retail rate impact cap of 1%, the Commission must still determine whether it should.

ComEd's proposal, supported by ChargePoint, to limit the application of the retail rate impact cap and essentially allow spending at any level is inappropriate because it would create a disconnect between the costs ComEd would recover for its BE Plan and the rate impact limitation placed upon those costs by the retail rate impact cap. Staff states that this would render the retail rate impact cap ineffective for anything beyond line extensions, make-ready infrastructure, and rebates for charging equipment and thus, effectively meaningless.

Furthermore, while some of the programs identified by ChargePoint may not be infrastructure itself, those programs certainly support the "development of [EV] infrastructure" in the state. 20 ILCS 627/45(g). ChargePoint and ComEd's narrow reading of the statute, which focuses only on the words, "electric vehicle infrastructure" while ignoring the critical word "development," should be rejected. ComEd Ex. 14.0 REV at 11; ChargePoint Ex. 1.0 at 14. For example, ComEd proposed $9 million annually for a Customer Education and Awareness Program. This proposed program, among other things, will "include targeted outreach to engage low-income customers, customers in [EJ] or R3 communities to help promote their adoption of BE measures and close any knowledge gap afflicting areas that currently have low levels of EV adoption or public EV infrastructure." ComEd Ex. 1.01 at 42. Presumably, the intended result of addressing a knowledge gap in eligible communities is an increased demand for EVs and associated infrastructure in such communities, leading to additional "development of EV infrastructure" in the area. In addition, as part of this program ComEd intends to make available a Fleet Electrification Toolkit that "is a web-based resource that allows potential EV fleet adopters to estimate vehicle costs and savings, explore charging options, learn about the pros and cons of EVs, discover rate options, and more." *Id*. at 43. The purpose of this educational resource is to drive fleets to purchase EVs and associated EV infrastructure. While these efforts do not constitute infrastructure in the strictest sense of the word, they certainly support the "development of EV infrastructure" in the state, and thus should count against the retail rate impact cap. In fact, all of the Staff supported BE Plan programs support the development of electric vehicle infrastructure and should be subject to the retail rate impact cap (see Staff Exhibit 13.2 for explanations of how each of the sub-programs support the development of EV infrastructure).

Even if the Commission decides to approve non-transportation programs in ComEd's BE Plan, despite Staff's strong opposition and despite the conflict this creates with Ameren's BE Plan, and even if the Commission determines that the retail rate cap, as described by statute, applies only to transportation infrastructure, the Commission has substantial discretion to determine what an appropriate spending level is for the BE Plan, inclusive of both transportation and non-transportation programs. The statute provides that the Commission "may approve the plan if it finds that the plan will achieve the [enumerated] goals ... and contains the [required] information …[.]" 20 ILCS 627/45(d); *see also Krautsack v. Anderson*, 223 Ill. 2d 541, 544 (2006) (use of the word "may" in a statute connotes discretion). Accordingly, determining a proper spending level is, within the constraints of the rate cap, committed to the Commission's sound discretion.

In determining what level of spending is appropriate, the plain language of the statute provides a logical framework for determining the amount of money the General Assembly intended to be spent on BE. Staff urges the Commission to exercise its discretion to approve a budget that will reduce the impact to ComEd ratepayers; the retail rate cap established by the statute is, in Staff's opinion, the logical guidepost for establishing what the maximum budget should be – 1% of the total revenue requirements. The retail rate cap provides a reasonable – and indeed the only – benchmark in the EVA for what a utility should spend on its BE Plan rather than what it could spend. ComEd has provided no justification for why its initial BE Plan should cost ratepayers more than twice the amount contemplated by the General Assembly.

Staff states that it is important to note that a benefit-cost analysis ("BCA"), discussed in detail in Section V.D.3. is not duplicative of nor is it a replacement for a spending limit. BCA is not a statement of an amount or limit, but rather a relation of value to describe or analyze a project. *See Hunt-Lima Drainage & Levee Dist. v. Roskamp*, 2022 IL App (3d) 210294, ¶ 34 ("A benefit-cost analysis often includes mathematical components, but it cannot be undertaken using a purely mathematical scale."). The General Assembly could, and very clearly did, impose both a cost cap on BE Plans and a requirement that BE plans be cost-beneficial.

According to Staff, a benefit-cost analysis only considers whether the benefits anticipated to derive from the BE Plan outweigh the costs, regardless of what the spending level is. It does not consider whether the financial price to implement the plan at a particular spending level is affordable for the ratepayers who will pay the increased rates. Moreover, "benefits" under the EVA are not only monetary, but can also be societal, including "reduced carbon emissions and surface-level pollutants." 20 ILCS 627/45(d). Thus, the BE Plan might be cost-beneficial on its face but still result in rate impacts that are so onerous as to be ill-advised.

Staff states that the Commission should reject the AG's proposal to interpret the phrase "total annual revenue requirements" to mean the utility's delivery service revenue requirement. Instead, the Commission should approve Staff and ComEd's methodology to determine the total revenue amounts that should be used to calculate the retail rate impact cap.

The Commission also should approve ComEd's proposal to recalculate the 1% retail rate impact cap with each BE Plan update filing using the revenue requirements that are applicable at that time. Staff Ex. 2.0 at 9. For example, ComEd would recalculate the 1% cap ahead of its July 1, 2024, BE Plan update filing and for each update filing in the future using the revenue requirements that are applicable at that time. ComEd Ex. 4.0 at 7. Commission approval of the statutory retail rate impact cap for each BE Plan cycle will provide the Company with greater certainty over the course of each BE Plan as to what the statutory cap is for each year so that it can appropriately manage its expenditures to ensure the Company does not exceed the rate impact cap in any given year. Staff Ex. 2.0 at 9. Given the Company's budget flexibility request which Staff supports with certain conditions, Staff believes it will be particularly important for the Company to know in advance what the statutory rate impact cap amount is for each year of the BE Plan.

b. AG's Position

The AG recommends that the retail rate cap should be $28 million and should apply to the entire BE Plan. Section 45(g) of the EVA provides that the "retail rate impact from the development of electric vehicle infrastructure shall not exceed 1% per year of the total annual revenue requirements of the utility." 20 ILCS 627/45(g). The Commission issued a ruling on the scope and amount of the retail rate cap in the Interim Order, finding that the retail rate cap did not necessarily constrain all spending under the BE Plan and that it should be determined based on ComEd's revenue requirements as well as various pass-through charges and riders. *See* Interim Order at 38. The AG maintains that the Commission erred in its conclusions in the Interim Order and now has the opportunity to properly construe the retail rate cap in its final Order.

In construing statutory language, the "primary objective is to ascertain and give effect to the intent of the legislature." *Oswald v. Hamer*, 2018 IL 122203, ¶ 10. "The most reliable indicator of legislative intent is the language of the statute, which must be given its plain and ordinary meaning," and the statute must be "viewed as a whole, construing words and phrases in context to other relevant statutory provisions and not in isolation." *Id*. In ascertaining the intent of the legislature, it is relevant to "consider the reason for the law, the problems sought to be remedied, the purposes to be achieved, and the consequences of construing the statute one way or another." *Id*. Thus, the Commission "may consider the consequences that would result in interpreting the statute one way or the other." *Corbett v. Cty. of Lake*, 2017 IL 121536, ¶ 35. If a "literal reading of a statute produces absurd results, the literal reading should yield," and the statute must be construed in such a way that "avoids absurd or unjust results." *People v. Hanna*, 207 Ill. 2d 486, 498 (2003). Viewing the EVA through the lens of these principles, the correct interpretation snaps into focus.

The AG argues that all costs incurred by the Company under the BE Plan should be subject to the retail rate cap. In denying Staff's Combined Motion, the Interim Order found the "plain language of the statute clearly states that the retail rate cap applies to development of EV infrastructure," although it did not make any findings as to which of ComEd's BE Plan programs should be considered the "development of EV infrastructure." Interim Order at 38. ComEd attempted to stretch the limit of this interpretation by claiming that the retail rate cap should only apply to spending on programs that fit its narrow definition of "EV infrastructure": specifically, the Residential EV Charging Infrastructure Sub-program and the C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program. ComEd Ex. 4.0 at 5. In ComEd's interpretation, spending on non-transportation electrification programs, rebates for EV purchases, customer education and awareness, pilots, and program costs, according to ComEd, are not subject to any maximum spending limit. ComEd Ex. 14.0 REV at 11:200–206. As a practical matter, this means only 16% of the $100 million that ComEd seeks to spend would be subject to the retail rate cap.

The AG points out that this is an absurd result. Although the word "rebate" is found nowhere in Section 45 of the EVA, ComEd claimed it could spend unlimited amounts on rebates for EV purchases that are not specifically delegated to the IEPA. The EVA does not contain a single specific reference to building and industrial electrification measures, yet ComEd would like to be able to spend unlimited amounts on such measures, thereby undermining both the retail rate cap in the EVA and the spending cap in the EE section

of the Act. Meanwhile, the retail rate cap would limit spending on programs supporting the development of electric plant infrastructure, such as electric plant and charging equipment, which are the primary focus of the substantive requirements of the EVA.

The AG explains that such a constrained reading of the retail rate cap would also allow for unlimited spending under the BE Plan. The Interim Order stated that "[a]ny BE Plan programs approved by the Commission must be cost-beneficial" under the cost-benefit analysis provision in Section 45(d) of the EVA. Interim Order at 38. The Interim Order asserts that this "is still a restraint on the amount of spending" while acknowledging that it "is not a rate cap." *Id*. But the cost-benefit analysis provision in the EVA provides virtually no constraint on the amount a utility can spend so long as it can prove that the ratepayer and societal benefits outweigh the costs. See 20 ILCS 627/45(d). Under the proposed BE Plan, ComEd's intends to spend more than five times as much on programs that, in its own interpretation, are not related to the development of EV infrastructure. But ComEd could conceivably spend many multiples of its current proposal, or hundreds of millions of dollars per year, as long as it can point to the societal benefits of switching from internal combustion engine vehicles to EVs to satisfy the cost-benefit analysis. Applying the retail rate cap only to programs that directly build infrastructure incentivizes the utility to spend on programs that are barely discussed, if they are mentioned at all, in the EVA.

The AG further notes if the BCA alone provided the necessary safeguard against rate impacts, then it would make no sense for the General Assembly to enact the rate cap provision in Section 45(g), which limits spending to "1% per year of the total annual revenue requirements of the utility." The Interim Order makes no attempt to explain why the General Assembly would have included a superfluous rate cap to limit spending on the types of programs that are the core focus of the EVA while providing no constraint for spending on any other types of electrification programs.

The AG offers a better interpretation of the rate cap provision that is harmonious with the EVA as a whole and does not result in the absurd and redundant interpretations urged by ComEd.

The AG further argues that the "plain and ordinary meaning" of the term "total annual revenue requirements" is that it refers to ComEd's delivery service revenue requirement. As a distribution-only utility, ComEd's revenue requirement is the amount (revenues) that base rates are designed to produce based on a test year. *See* 83 Ill. Adm. Code 285. In ComEd's 2021 formula rate case, the Commission said, "Section 16-108.5 establishes the annual process by which ComEd's revenue requirements are first estimated for each rate year, and then finally fixed and reconciled when actual investments and costs are known." *Commonwealth Edison Co.*, Docket No. 21-0367, Order at 2 (Dec. 1, 2021) (the "*ComEd 2021 Rate Case*"). In addition, with each formula rate order the Commission includes an Appendix A setting the filing year revenue requirement and an Appendix B setting the reconciliation year revenue requirement, with rates based upon both revenue requirements. *Id*., Apps. A, B. Thus, the AG shows how the Commission's usage of the term "revenue requirements" with respect to ComEd is limited to the delivery service revenue requirements used to set base rates. *Id*.

The AG then notes that this usage is consistent with how the Illinois Supreme Court has described a utility's revenue requirement under Commission practice and law in Article IX of the Act. *Bus. & Prof'l People v. Ill. Com. Comm'n*, 146 Ill. 2d 175, 195–196 (1991). Nothing in the Court's definition of "revenue requirement" includes riders, adjustments, and pass-through charges.

The AG next points out that its interpretation is also consistent with the usage of the phrase "revenue requirement" in P.A. 102-0662. 220 ILCS 5/16-108.18(d)(4). The statute permits changes to the revenue requirements under the MYRP under certain specific conditions. 220 ILCS 5/16-108.18(d)(15). Finally, the Commission must determine "the utility's actual revenue requirement for the applicable calendar year" of a MYRP based on certain provisions. 220 ILCS 5/16-108.18(f)(6). The AG shows that, in each case, term "revenue requirements" as used in P.A. 102-0662 is limited solely to the utility's delivery service revenue requirement used to set base rates.

While the Interim Order accused the AG of reading "into the statute a limitation that does not exist in its plain language," the AG notes that it provided no evidence or explanation for why the term "total annual revenue requirements" should include riders and pass-through charges that are not commonly understood to be part of the utility's "revenue requirement." Interim Order at 38. Riders, by definition, can fluctuate from month to month and are determined outside the revenue requirement because they, in part, are designed to track costs that the utility cannot reasonably control and that do not affect other aspects of the utility's costs. *Citizens Util. Bd. v. Ill. Com. Comm'n*, 166 Ill. 2d 111, 138 (1995). Clearly, electricity supply and transmission charges, as well as the multiple other rider charges, are not established in the revenue requirements, but rather established in separate proceedings based on costs that are independent of the revenue requirement and base rates. Moreover, most of the tariff sheets and other governing documents for the riders and surcharges that would be included in the calculation contain no mention of the term "revenue requirements" whatsoever.

The AG explains that departing from the ordinary understanding of the term "revenue requirements" would lead to the absurd result of having a retail rate cap that is subject to potentially massive fluctuations as it is updated in 2024 and every three years thereafter. For example, the budget for each BE Plan cycle would need to be adjusted up or down depending on supply markets (which are currently volatile) and other factors beyond the utility and the Commission's control. If the retail rate impact cap is predicated on amounts that may fluctuate wildly (because it includes costs that are, by their very nature, unpredictable and uncertain), the budget for the BE Plan and the impact on ratepayers in real terms will be difficult to foresee and manage when the BE Plan is updated. Indeed, this would contradict the General Assembly's rationale for including a rate cap in the first place.

To prevent these unintended results and to give effect to the "plain and ordinary meaning" of the term "total annual revenue requirements" in the context of a distribution-only utility, the AG argues that Commission should find that the retail rate cap is equal to 1% of ComEd's delivery service revenue requirement. In their rebuttal testimony, the AG's witnesses recommended that the retail rate cap be limited to $28 million based on ComEd's 2023 revenue requirement of approximately $2.86 billion. AG Ex. 2.0 at 9. Therefore, the AG requests that the Commission order that the retail rate cap is $28

million for the current BE Plan, which is equal to 1% of that total annual revenue requirement as established in ComEd's most recent rate case.

c. ChargePoint's Position

ChargePoint asserts that Staff and the AG ask the Commission to adopt precisely the position the Commission rejected in its Interim Order: namely, that the retail rate cap applies to all BE Plan spending. ChargePoint expresses frustration that Staff and the AG have briefed the issues as if they were still unresolved simply because they disagree with the Commission's determination in the Interim Order after they urged the Commission to resolve these issues through an interim order for the sake of administrative efficiency. ChargePoint argues that it would be arbitrary and capricious and a massive waste of party and Commission resources for the Commission to reverse legal holdings it made a mere two months ago in November 2022. ChargePoint does not repeat its arguments set out in response to the Staff Combined Motion, but rather urges the Commission to uphold its well-reasoned Interim Order.

ChargePoint also explains that the AG contends that the Interim Order found that the retail rate cap applies only to the development of EV infrastructure, but that "it did not make any findings as to which of ComEd's BE Plan programs should be considered the 'development of EV infrastructure.'" AG IB at 26. ChargePoint argues that the AG is mistaken, as the Staff Combined Motion specifically challenged ComEd's position that only the two "Charging Infrastructure Sub-programs" (i.e., the Residential EV Charging Infrastructure Sub-program and the Make-Ready Infrastructure Rebate Sub-program) counted against the retail rate cap, arguing that all BE Plan spending – not just spending on these two programs – supports the development of EV infrastructure and the Commission rejected Staff's challenge in this specific context. In other words, states ChargePoint, when the Commission found that the retail rate cap only applies to the development of EV infrastructure, it did so with a clear understanding that the context behind the controversy was ComEd's position that only its two charging infrastructure subprograms counted toward the cap and the Commission rejected Staff's challenge of ComEd's position. According to ChargePoint, the AG's contention that this issue remains unresolved or unclear in some way completely ignores this context. ChargePoint recommends that the Commission should uphold its finding that only BE Plan spending on EV charging infrastructure counts against the retail rate cap, which, asserts ChargePoint, in the context of ComEd's BE Plan and the Interim Order, means that only the Residential EV Charging Infrastructure and nonresidential Make-Ready Infrastructure Rebate Sub-programs count against the $44 million cap.

ChargePoint also notes that the AG asks the Commission to reverse its determination that the phrase "total annual revenue requirements" refers to all of ComEd's revenue requirements, including riders. In support, according to ChargePoint, the AG rehashes the very arguments the Commission rejected in both its Interim Order and its denial of the AG's Petition for Rehearing and provides the Commission with no justification for reversing a legal conclusion it made in this proceeding just two months ago. ChargePoint again asserts that it would be both arbitrary and capricious and a waste of Commission and party resources to reverse the Interim Order. ChargePoint does not repeat its own arguments on this issue, but rather urges the Commission to uphold its conclusion in the Interim Order.

d. Commission Analysis and Conclusions

The Commission considered and rejected Staff and the AG's arguments regarding the retail rate cap in the Interim Order and will not reverse that decision here.

5. Other Issues

a. Types of Programs Included in the BE Plan

(i) ComEd's Position

ComEd argues that its BE Plan is comprehensive and encompasses infrastructure and incentives to support the adoption of not only EVs, but also non-transportation BE technology. Staff and the AG have argued that BE plans should include only incentives and infrastructure to support transportation electrification. ComEd points out that the Commission properly rejected these arguments, when presented in the context of Staff's Combined Motion, and should reject them again here. As the Interim Order concluded, the Commission has the legal authority under the EVA to adopt a BE Plan that provides incentives for non-transportation electrification, ComEd argues. Interim Order at 15. According to ComEd, the record evidence makes clear that the non-transportation initiatives included in ComEd's BE Plan are in line with the General Assembly's goals of "lower[ing] carbon dioxide emissions, [and] replac[ing] fossil fuel use." 20 ILCS 627/45(b).

ComEd again points out that its BE Plan includes incentives to support the adoption of non-transportation electrification measures by residential and C&I customers. According to ComEd, the C&I BE Infrastructure Readiness Sub-program offers financial incentives for small business customers located in EJ or R3 communities to help cover the costs of upgrading infrastructure to support adoption of heat pumps, electric water heaters, commercial food service equipment, and high efficiency electric forklift equipment. ComEd also notes that the Residential BE Technology Adoption Sub-program supports adoption of heat pumps, electric lawn equipment, induction cooking equipment, and electric clothes dryers by residential customers.

ComEd argues that these electrification technologies are critical components of an effective BE Plan, because carbon dioxide emissions from non-electric end uses in the residential, commercial, and industrial sectors in the State of Illinois are greater than the carbon dioxide emissions of non-electric transportation in the State. In other words, ComEd argues, non-transportation end-uses must electrify in order to achieve the goals set forth by the General Assembly in the EVA, including "decrease[d] reliance on fossil fuels, [and] increase[d] access to electrification for all customers." 20 ILCS 627/45(a). According to ComEd, the inclusion of non-transportation electrification within the BE Plan will result in substantial emissions reductions.

In addition, ComEd points out, the non-transportation programs included in ComEd's BE Plan are within the scope of BE as defined in the plain language of the EVA to include "programs that lower carbon dioxide emissions, replace fossil fuel use, create cost savings, improve electric grid operations, reduce increases to peak demand, improve electric usage load shape, and align electric usage with times of renewable generation." 20 ILCS 627/45(b).

Although Staff and AG witnesses suggest that inclusion of non-transportation initiatives in the BE Plan could circumvent the spending cap on EE expenditures under

Section 8-103B of the Act, ComEd points out that measures funded through its EE Plan will continue to be subject to the funding limitations of Section 8-103B, while measures under the BE Plan will be subject to their own funding limitations. ComEd argues its proposal would permit customers to "braid" incentives offered under these two plans, as is already done today with other, similar incentives. ComEd points out that braiding funding simply provides the ability to reach more customers, accelerating the adoption of electrification in accordance with the statutory guidance.

ComEd argues that the Commission should approve its BE Plan as proposed, to include non-transportation electrification measures in addition to measures related to transportation electrification.

(ii) Staff's Position

As discussed in detail in Section IV.B, above, Staff opposes inclusion of any non-transportation programs in ComEd's BE Plan, as those programs are both outside the intended scope of the EVA and duplicative of programs authorized as part of ComEd's EE Programs. If, however, the Commission elects to approve non-transportation programs as part of ComEd's BE Plan over Staff's objection, the Commission should order ComEd to adopt the following modifications to its non-transportation sub-programs:

(1) ComEd should not be allowed to fund rebates through its BE Plan for any EE measure for which rebates are offered under its EE plan.

(2) For BE Plan electrification measures implemented through existing EE programs, the non-incentive costs associated with such existing EE programs should be funded entirely from the EE plan.

(3) ComEd should follow EE electrification policies in the implementation of its BE Plan, where it reasonably makes sense to, and ComEd should collaborate with Staff and interested stakeholders to determine the cases in which it reasonably makes sense.

(4) ComEd should only be allowed to promote direct installation of low-income electrification measures in applications for which all measure installations within each home are collectively expected to lower total energy bills.

(5) The budget for non-transportation subprograms should be significantly reduced under ComEd's BE Plan, and such budget should be capped and not subject to ComEd's flexibility request. In other words, while ComEd should be authorized to shift funding from the non-transportation subprograms to other approved transportation subprograms, it should not be allowed to shift funding from transportation subprograms to the non-transportation subprograms.

(6) ComEd should be required to demonstrate that rebates will only be provided for non-transportation electrification measures that provide a meaningful impact on emissions reductions and are not expected to have a high level of free ridership.

(7) ComEd should be required to demonstrate that any new BE Pilot Program project in the non-transportation electrification area clearly demonstrate how the project outcomes will meet the goals and objectives of the EVA.

Staff Ex. 1.0 at 25-26. The Company did not respond to Staff's modifications originally raised in Staff's direct testimony until ComEd's Reply Brief and thus Staff had no opportunity to respond to the Company's unfounded criticisms.

(iii) AG's Position

ComEd proposed several programs and sub-programs that the AG supports as a general matter. For example, the AG does not object to either the C&I and Public Sector EV Purchase Sub-program or the C&I and Public Sector EJ/R3 Make-Ready Infrastructure Sub-program. The AG also did not object to the Customer Awareness and Education and BE Pilot Programs, and the AG recognizes that certain portfolio-level costs will be incurred in establishing and administering the BE Plan. However, the Company proposes to spend $82 million on these programs combined, which is nearly three times the retail rate cap. Therefore, the AG argues that the overall spending level on these programs must be reduced to comply with the retail rate cap.

However, the AG requests that the Commission remove other programs on legal and/or policy grounds. The AG urges the Commission to reject the Company's non-transportation electrification programs: the Residential BE Technology Adoption, the Residential BE Infrastructure Readiness, the C&I and Public Sector BE Technology Adoption, and the C&I BE Infrastructure Readiness Sub-programs. The AG maintains throughout this proceeding that these non-transportation programs are not authorized under the EVA. Even if the EVA did allow such programs, the AG argues that the Commission should reject them because they would conflict with existing electrification programs offered pursuant to the EE sections of the Act.

The AG argues that, following traditional principles of statutory interpretation, the most plausible reading of the EVA is that the BE Plan can only include BE programs related to EVs and transportation. Reading the EVA "in context to other relevant statutory provisions and not in isolation," it is far from clear that the legislature intended to permit non-transportation programs as part of the BE Plan. *See Oswald*, 2018 IL 122203, ¶ 10. Indeed, the opposite view emerges upon a close and holistic reading.

The EVA does not authorize any and all BE programs. Instead, the Commission may only approve a BE Plan consisting of BE programs that meet the goals, considerations, and requirements of Section 45 of the EVA. 20 ILCS 627/45(d). But the Commission would have no statutory basis for approving the Company's non-transportation programs because the substantive provisions of the EVA are exclusively focused on EVs and transportation.

The AG explains that a review of those requirements makes evident that the General Assembly only intended to authorize BE programs specifically targeted at EV adoption and transportation electrification.

In contrast to the EVA, Section 8-103B of the Act, which governs the Company's EE program, clearly provides for the adoption of non-transportation programs. Section 8-

103B(b-27) allows an electric utility to offer through its energy efficiency plan "measures that electrify space heating, water heating, cooling, drying, cooking, industrial processes, and other building and industrial end uses that would otherwise be served by combustion of fossil fuel at the premises." 220 ILCS 5/8-103B(b-27). The AG notes that similar language is entirely absent from the EVA. This is despite the fact that the General Assembly took great care in the EVA to express specific goals and requirements for transportation electrification, from the number of EVs it is targeting, to the specific ways that managed EV charging can benefit the grid, to the total rate impact of the transportation electrification programs. *See* 20 ILCS 627/45(a)(1), (d)(ii), (g). Where the General Assembly wanted to empower utilities to implement non-transportation electrification measures as part of P.A. 102-0662, it specifically did so—as part of the EE sections.

In addition, the AG explains that the General Assembly included important constraints for the EE electrification programs to ensure that Illinois ratepayers benefit from a utility's spending of ratepayer funds. These critical protections are similarly absent in the EVA. For example, prior to installing an electrification measure, the EE statute requires ComEd to "provide a customer with an estimate of the impact of the new measure on the customer's average monthly electric bill and total annual energy expenses." 220 ILCS 5/8-103B(b-27). In contrast, the EVA does not contain any similar consumer protections to ensure that customers are able to afford the added electricity consumption of non-transportation measures. To the AG, the absence of such protections make evident that the General Assembly did not imagine these measures being offered through the BE Plans in the EVA. Section 8-103B(m) also contains a hard cap on the amount that utilities can collect from ratepayers to spend on EE programs. See 220 ILCS 5/8-103B(m). Under ComEd's interpretation, the EVA exempts non-transportation electrification measures from the retail rate cap which would leave the Company free of any accountability and statutory spending limitations (subject only to a BCA) for non-transportation measures. ComEd's interpretation results in this absurd and inconsistent outcome. The AG argues that it defies reason to interpret the EVA to allow ComEd to spend on non-transportation electrification without any consumer protections when Section 8-103B provides for consumer protections for exactly the same sorts of electrification measures.

The AG argues that the foregoing analysis demonstrates the General Assembly provided very specific instructions throughout the EVA for the problems it seeks to solve, the stakeholder input that must be considered as part of the BE Plan, the particular items that a BE Plan must address, and the considerations the Commission should apply when determining whether to approve a BE Plan. In each case, the language of the statute evinces a clear and overwhelming focus on transportation electrification, up to and including the fact that the General Assembly chose to add the BE Plan provisions as part of the EVA. In stark contrast, there is no reference anywhere in the EVA to a specific non-transportation measure such as space heating, cooking, or industrial processes. When reading the EVA as a whole, the best interpretation is that the BE Plans filed thereunder must relate solely to EVs and transportation.

The Interim Order rejected this approach and instead pointed out that the definition of BE programs is broad and not limited to transportation. Interim Order at 15. The EVA

defines BE programs to mean "programs that lower carbon dioxide emissions, replace fossil fuel use, create cost savings, improve electric grid operations, reduce increases to peak demand, improve electric usage load shape, and align electric usage with times of renewable generation." 20 ILCS 627/45(b). The definition then goes on to provide a "non-exhaustive list of programs" that fall within the definition, some of which do not relate to transportation. Interim Order at 13, 15 (citing 20 ILCS 627/45(b)). The Interim Order acknowledged that "reasonable parties greatly differ on the intent of the General Assembly," but said that the "broadly worded plain language of the statute is determinative, and the Commission need not speculate in this instance as to the intent of the General Assembly." Interim Order at 15.

The AG argues that this is an erroneous conclusion because the intent of the General Assembly is far from clear, as the Commission itself recognized in noting that "reasonable parties greatly differ" as to the meaning and scope of the EVA. Given established rules of statutory construction that require the Commission read the whole text of the statute in its proper context, *Oswald*, 2018 IL 122203, ¶ 10, the AG requests that the Commission conclude that ComEd's proposed non-transportation programs exceed the intended scope of the EVA and that these programs were expressly assigned to the utility's EE plans under Section 8-103B of the Act.

The Company's non-transportation programs should also be removed from the BE Plan for policy reasons. Even if the Commission does not modify its findings from the Interim Order, the AG argued that it should nevertheless reject ComEd's non-transportation programs as a matter of policy because inclusion of these measures in the Company's BE Plan would result in ComEd violating Section 8-103B(m) of the Act and severely undermining ComEd's existing EE plan. At minimum, the AG argues, the Commission should bar ComEd from counting the EE savings produced by the BE Plan programs towards the Company's EE goals.

Section 8-103B(m) of the Act caps how much ratepayer funding ComEd can use to accomplish its EE savings goals in a given plan cycle. 220 ILCS 5/8-103B(m). Currently, ComEd spends up to this cap in each year of its program with its annual budgets equaling more than $420 million. AG Ex. 2.0 at 13 n. 35. However, through its proposed BE Plan, the Company states that it will use additional ratepayer funding to subsidize the adoption of non-transportation electrification measures through multiple incentives from both its BE and EE Plans and count the entirety of the savings generated by the dual rebates to its EE goals. ComEd Ex. 7.0 at 4–5. This additional ratepayer-funded spending will cause ComEd to exceed the amount of funds it is allowed to spend under Section 8-103B(m) to accomplish its statutorily-mandated EE goals. Thus, the Company's non-transportation electrification proposal violates the cost cap on ratepayer funds expressly prescribed in Section 8-103B(m).

In response, ComEd argues that its usage of additional ratepayer funds from the BE Plan is not a violation of Section 8-103B(m) because the Company currently utilizes outside funding, like that from the IHWAP, to subsidize its existing EE programs and that this total spending exceeds the cost cap. *See* ComEd Ex. 7.0 at 4-5. This argument fails because the funds utilized through the IHWAP program are not ratepayer funds. The IHWAP program is funded by the federal government, not ratepayers. AG Ex. 1.0 at 34. Meanwhile, Section 8-103B(m) specifically controls how much the Company can spend

and charge ratepayers on EE measures by "limit[ing] the estimated average net increase [to rates] due to cost of the measures." 220 ILCS 5/8-103B(m). This means that EE spending that creates a rate impact over what is statutorily allowed will be partially disallowed so that ratepayers are not charged more than the rate impact cap. Here, ComEd proposes to treat ratepayer-funded BE Plan money as additional spending on EE measures. When the rate impact of the increased spending on EE measures is calculated across the Company's BE and EE plans, it will exceed what is allowed under the Act.

The AG asserts that ComEd attempts to obscure the difference in funds provided through programs like IHWAP and those included in the BE Plan by asserting that "the federal government is not a self-funded entity — IHWAP gets its funding from taxpayers, who are also ratepayers." ComEd Ex. 12.0 at 13-14. The AG points out that this argument completely ignores the limitation provided in Section 8-103B(m). The taxes ratepayers pay to the federal government have absolutely no impact on the rate of increase in their utility rates, thus IHWAP funds do not count against the cap given in Section 8-103B(m). Meanwhile, BE Plan costs are directly recovered from ratepayers and thus count towards the cap on costs that can be collected from ratepayers for the execution of EE plans provided for in Section 8-103B(m).

The AG explains how permitting the Company to pursue non-transportation electrification in its current BE Plan will also have the effect of unreasonably increasing the Company's rate of return for its EE investments. ComEd can receive an increased ROE on its EE investments, with the return increasing as ComEd generates additional EE savings under the EE Plan. 220 ILCS 5/8-103B(g)(7)(A). If ComEd is allowed to count the savings generated by its BE Plan towards its EE goals, it will not only result in a violation of the cap in Section 8-103B(m), but it would also increase ComEd's ratepayer-funded return above what the Company would have earned under execution of the EE Plan without the additional BE Plan spending. In essence, ComEd's proposal allows the Company to use ratepayer funds from its BE Plan to increase the amount of money ratepayers must give to the Company as profit for accomplishing its EE goals. The AG maintains that this is inconsistent with the legislative scheme created by the EVA and Section 8-103B — and is grossly unfair to consumers, especially considering that ComEd is also proposing to include its BE Plan costs in a regulatory asset, thus creating another return for the Company that will increase ratepayer costs by $81 million. AG Ex. 1.0 at 57-58.

The AG further points out that ComEd's proposal frustrates the EE savings goals negotiated by stakeholders and approved by the Commission in Docket No. 21-0155. The parties in that docket submitted a negotiated stipulation and draft plan where they agreed to a framework for ComEd's 2022-2025 EE Plan based on the particular budget calculated pursuant to Section 8-103B(m). That plan, which was negotiated over many months, includes a target amount of energy savings that was based on an identified budget for each year of the plan cycle. AG Ex. 2.0 at 15. However, through its BE Plan, the Company now seeks to include substantial additional financial resources to accomplish the goals agreed to in the stipulation, with the amount of available funds essentially uncapped, subject only to a BCA. Thus, ComEd completely dislodges the basis on which the parties to that proceeding agreed to spending levels and savings goals by introducing significantly more money to accomplish these goals.

The AG also expresses concern that the Company's proposal to create separate rebates for the same measures through its BE and EE Plans will create confusion for program participants. Program participants, and in particular low-income ratepayers, will find it difficult to know what rebates they are eligible for and across which plan.

In response, ComEd asserts that the Commission should approve its non-transportation electrification programs because they will help to reduce carbon dioxide. The AG asserts that this argument fails to recognize the pitfalls of allowing the Company to offer non-transportation electrification programs and ignores that the Act already directs that utility EE plans can include non-transportation electrification intended to reduce emissions. Thus, to the AG, the General Assembly sought to accomplish the goal ComEd sets out to achieve through the Company's EE Plan — not in the BE Plan.

The AG also agrees with the arguments that Staff offered in opposition to the inclusion of non-transportation electrification programs in the Company's BE Plan.

To remedy the various problems created by the inclusion of non-transportation electrification in the Company's BE Plan, the AG requests that the Commission reject the Company's proposal to include non-transportation electrification measures in its BE Plan. To the AG, eliminating these measures will alleviate the tension between the Company's BE and EE Plans. If the Commission allows the Company to include these programs in its BE Plan, the AG argues that it should, at minimum, order ComEd to not count the EE savings created by its BE Plan towards its EE Plan goals. The AG explains that the Company's proposal to count EE savings stemming from its BE Plan programs is particularly pernicious because it allows ComEd the ability to improperly comingle two programs in a way that forces ratepayers to pay higher profits and additional costs for the Company's EE investments.

(iv) Commission Analysis and Conclusion

The Commission found in the Interim Order that non-transportation programs are not legally precluded by the EVA, contrary to Staff and the AG's assertions. The Commission will not reverse that decision here. The Interim Order left open the possibility that the non-transportation programs in ComEd's BE Plan could be excluded for other reasons.

The Commission acknowledges arguments raised by Staff and the AG that inclusion of ComEd's proposed non-transportation programs could frustrate the goals of ComEd's EE Plan. Based on evidence presented by ComEd and CJCP, the Commission approves a limited set of the Company's proposed non-transportation programs, specifically, residential heat pumps and the associated make ready infrastructure. *See* Section V.A.1. To ensure approval of the residential heat pump and related make-ready aspects of the Company's plan do not undermine the Company's efforts pursuant to 220 ILCS 5/8-103B and the Commission-approved EE savings goals that were negotiated by the Company and stakeholders in Docket No. 21-0155, the Commission directs the Company to keep the BE Plan residential heat pumps and make-ready separate from the Company's 8-103B obligations (as described Section V.A.1).

The Commission is cognizant of concerns that the overall budget is too large. Removal of the $7 million allocated to the other non-transportation programs in this first BE Plan will to some extent mitigate the impact on ratepayers.

b. Treatment of EV Charging Revenues

(i) ComEd's Position

ComEd points out that the EVA provides that "[t]he Commission shall consider revenues from [EVs] in the utility's service territory in evaluating the retail rate impact" of a BE Plan. 20 ILCS 627/45(g). It notes that the retail rate impact cap limits the cost of EV infrastructure to 1% of the total annual revenue requirements of the utility. ComEd explains that its calculation of the retail rate impact cap does not incorporate assumptions about the revenues from EV charging and is therefore conservative. Because this is ComEd's first BE Plan, ComEd contends it does not have data regarding customer enrollment in BE programs, or data regarding any resulting revenues. As a result, ComEd notes, any estimate of increased revenue from EV charging would be speculative.

ComEd argues that its approach to the treatment of EV charging revenues is conservative and is appropriate in this initial BE Plan proceeding. In the future, ComEd notes, more data may become available that would enable a non-speculative calculation. ComEd argues that the Commission should recognize ComEd's calculation of the rate impact cap as appropriate for purposes of this proceeding.

(ii) Staff's Position

Staff states that the Commission should reject ChargePoint's proposal to impute estimated EV charging revenues in the total revenue requirements used to calculate the retail rate cap calculation. ChargePoint's proposal is unnecessary, because EV charging revenues should already be included in ComEd's total revenue requirements. Staff Ex. 13.0 at 6-7.

(iii) AG's Position

The AG maintains that estimated revenues from EV charging should not be added to ComEd's annual revenue requirement for purposes of increasing the retail rate cap. The EVA provides that the Commission "shall consider revenues from electric vehicles in the utility's service territory in evaluating the retail rate impact." 20 ILCS 627/45(g). ChargePoint argues that, in light of this provision, "the Commission should direct ComEd to include reasonable estimates of expected revenues from EVs in its calculation of the retail rate cap." ChargePoint IB at 19. ComEd and Staff both opposed ChargePoint's position. The AG likewise argues that estimated revenues from EV charging should not be added to ComEd's annual revenue requirement for purposes of increasing the retail rate cap.

The AG requests that the Commission reject ChargePoint's proposal because it shows a fundamental misunderstanding about how rates are set. First, the formula rate and MYRP revenue requirements are based on the costs of service and estimated revenues are designed to recover that cost of service. If there is a disparity between estimated and actual revenues, that difference is captured in either the reconciliation or a decoupling or "volume balancing adjustment." See 220 ILCS 5/16-108.5(d); 220 ILCS 5/16-108.18(f); 220 ILCS 5/16-105.7; *Commonwealth Edison Co*., Docket No. 22-0138,

Order (Dec. 1, 2022). The revenue requirement is not changed because revenues increase or decrease, although an adjustment to the rates may be made the following year.

The AG also explains that it would be unreasonable to add "estimated" increases to charging revenues because such amounts are entirely speculative. Moreover, an adjustment to add actual increases to charging revenue would be unnecessary because, as Staff pointed out, any increases to EV charging revenues as a result of the BE Plan would already be reflected in rates based on ComEd's revenue requirements.

(iv) ChargePoint's Position

ChargePoint explains that immediately prior to the sentence in the EVA defining the retail rate impact, the statute states: "The Commission shall consider revenues from [EVs] in the utility's service territory in evaluating the retail rate impact." ChargePoint alleges that ComEd has not accounted for expected revenues from EVs in calculating its retail rate cap. According to ChargePoint, the fact that ComEd does not yet have actual data on EV charging revenue is not a reason to ignore the clear statutory directive to consider such revenues in the retail rate cap calculation. ChargePoint recommends that the Commission direct ComEd to include reasonable estimates of expected revenues from EVs in its calculation of the retail rate cap.

(v) Commission Analysis and Conclusion

The Commission agrees with the AG that ChargePoint appears to misunderstand rate-setting under P.A. 10-0662. As Staff notes, increases in EV charging revenues should already be included in ComEd's total revenue requirements. Staff Ex. 13.0 at 6-7. "Estimates" of increased revenue from EV charging would be speculative in the first BE Plan. ChargePoint's recommendation is unnecessary and is denied.

c. Consistency with Ameren

(i) ComEd's Position

ComEd notes that it is aware that Ameren has also proposed a BE Plan, in a separate docket and a separate proceeding before the Commission. ComEd argues that there is no statutory requirement that ComEd's BE Plan be consistent with the plan offered by Ameren. ComEd contends that there is no evidence in the record of this proceeding concerning the components of Ameren's BE Plan, because no party has offered such evidence. ComEd points out that there is no evidence as to why Ameren chose to structure its plan in any particular way, or the relative merits or disadvantages of the Ameren proposals in comparison to ComEd's. Therefore, ComEd argues, its BE Plan should be evaluated on its own merits, against the requirements of the EVA.

ComEd argues that the Commission's decision in this case must be based on the evidentiary record before it in this case. ComEd cites 220 ILCS 5/10-201(e)(iv), which says a court "shall reverse" a Commission order if the Commission's findings "are not supported by substantial evidence based on the entire record of evidence presented to or before the Commission". ComEd points out that, in addressing a similar argument in a different recent proceeding, the Commission concluded that the "fact that a different [result] is being adopted in the Ameren proceeding is immaterial to the appropriate [result] in this proceeding." Docket No. 22-0067, Order at 35.

ComEd argues that the Commission therefore may not, and should not, evaluate ComEd's BE Plan against that of Ameren.

(ii) Staff's Position

Staff states that the Commission should approve methodologies for determining the retail rate cap that are consistent between Ameren's and ComEd's plans. Of course, the Commission should consider that Ameren and ComEd are different companies with different service territories and different operating characteristics and should not require consistency simply for the sake of consistency without considering whether consistency actually makes sense. The companies propose, and Staff supports, different programs and different approaches in their respective BE Plans. Notwithstanding any differences in BE Plans or operating characteristics, however, the method for determining the types of cost that should count against the retail rate cap should be consistent between Ameren and ComEd.

Staff states that the retail rate cap should – indeed, as a matter of statute, must – apply to the entirety of a utility's BE Plan. Unlike ComEd's BE Plan, Ameren's entire plan is focused on promoting EV adoption and use and expanding EV infrastructure in Illinois and includes no non-transportation programs; in Staff's opinion, this is proper under the EVA. In Section 5 of the EVA, the General Assembly articulated the legislative goals to be furthered by the legislation, finding that "the adoption and use of electric vehicles would benefit the State of Illinois by (i) improving the health and environmental quality of the residents of Illinois through reduced pollution, (ii) reducing the operating costs of vehicle transportation, and (iii) shifting the demand for imported petroleum to locally produced electricity." 20 ILCS 627/5.

Similarly, Section 45 reflects a clear legislative intent to promote EV adoption and EV infrastructure development. The Commission should only approve programs that further that statutory intent. *See, e.g., Skaperdas v. County Casualty Ins*. Co., 2015 IL 117021, ¶15 (2015) ("When construing a statute, the primary objective is to ascertain and give effect to the legislature's intent, best indicated by the plain and ordinary language of the statute.") Each of the ten requirements for BE Plans listed in Section 45 explicitly relate to EVs, EV charging, or transportation. 20 ILCS 627/45(d)(i)-(x). Likewise, the definition of "beneficial electrification programs" lists fifteen portfolio components, more than half of which explicitly relate to EVs or EV charging. 20 ILCS 627/45(b)(3), (6), (7), (8), (9), (11), (12), (14). Further, six of the eight objectives the Commission is required to consider when evaluating proposed BE Plans relate explicitly to EVs, EV charging, or transportation. 20 ILCS 627/45(d)(3)-(8). After the BE Plans are adopted, Section 45 of the EVA requires utilities to update the Commission regarding the "transportation investments" made under BE Plans. 20 ILCS 627/45(f). Finally, the EVA specifically limits the retail rate impact associated with EV infrastructure investments pursuant to BE Plans. 20 ILCS 627/45(g). Finally, and perhaps not least important, the Commission's authority to approve BE plans derives from a statute entitled the Electric Vehicle Act.

Staff's proposed modifications to ComEd's BE Plan and budget recognize that ComEd is a different company than Ameren and is respectful of the differences in operations and service territory. Staff's recommendations do, however, ask the Commission to modify ComEd's plan to bring it in line with the changes Ameren agreed

to voluntarily. As noted, Ameren proposes a BE Plan that does not include the components in ComEd's BE Plan which Staff strenuously opposes:

- It does not include any non-transportation programs;
- The total BE Plan spend is under the 1% retail rate impact cap;
- It does not propose creation of a regulatory asset;
- It does not propose creation of a Rider.

The Commission should modify ComEd's BE Plan to mirror these aspects of Ameren's BE Plan. Doing so will allow each utility to develop and implement a plan that is reflective of the unique characteristics of its service territory, operations, and customers, while ensuring that the framework for the BE Plans is uniform across the state.

(iii) Commission Analysis and Conclusion

ComEd and Staff agree that ComEd and Ameren can have different programs and different approaches in their respective BE Plans. Within that general context, ComEd and Ameren's BE Plans need not be consistent. Staff's recommendations to modify ComEd's BE Plan, which would bring ComEd's BE Plan more in line with Ameren's BE Plan, are addressed in other sections of this Order and in the Interim Order. Specifically, inclusion of non-transportation programs is addressed in the Interim Order and in Section V.C.5.a of this Order. Issues related to the retail rate impact cap are addressed in the Interim Order and in Sections V.C.4 and V.C.1 of this Order. ComEd's proposed new rider and creation of a regulatory asset are addressed in Sections VI.A.1 and VI.A.2, respectively.

D. Statutory Requirements

1. Compliance with EVA Section 45(d)(i)-(x)

a. ComEd's Position

ComEd acknowledges that its BE Plan must specifically address, at a minimum, ten statutory objectives discussed in Section 45(d)(i)-(x).

(i) Section 45(d)(i)

Section 45(d)(i) of the EVA provides that a BE Plan must address "[m]ake-ready investments to facilitate the rapid deployment of charging equipment throughout the State, facilitate the electrification of public transit and other vehicle fleets in the light-duty, medium-duty, and heavy-duty sectors, and align with Agency-issued rebates for charging equipment." 20 ILCS 627/45(d)(i).

ComEd argues that its BE Plan facilitates the rapid deployment of charging equipment throughout the ComEd service territory through its EV Charging Delivery Classes, the Residential EV Charging Infrastructure and C&I and Public Sector EJ/R3 EV Charging Make-Ready Infrastructure Sub-programs, and the Customer Education and Awareness program. ComEd argues its new EV Charging Delivery Classes are intended to spur the development of public charging infrastructure. ComEd states that the BE Plan provides direct rebates for customer investment in charging capability through the Residential EV Charging Infrastructure and the C&I and Public Sector EJ/R3 EV Charging

Make-Ready Infrastructure Sub-programs. ComEd also points out that the Customer Education and Awareness Program will ensure customers are aware of program offerings, educate customers on the value of transportation electrification, and assist customers with the planning of their fleet electrification and deployment of charging equipment necessary to support fleet electrification.

ComEd states that the C&I and Public Sector EV Purchase Sub-program will facilitate the electrification of public transit and other vehicle fleets in the light-duty, medium-duty, and heavy-duty sectors by providing EV purchase rebates tailored to each vehicle class that will spur EV adoption.

ComEd argues that the BE Plan aligns with rebates for charging equipment by the IEPA because ComEd took into consideration existing state and federal incentives for EVs and EV charging infrastructure when determining the proposed BE Plan budget. ComEd points out that the BE Plan includes the ComEd's EV Toolkit that shares information to residential customers on available federal and state incentives for EV purchase and EV charging infrastructure.

(ii) Section 45(d)(ii)

Section 45(d)(ii) of the EVA provides that a BE Plan must address "development and implementation of [BE] programs, including time-of-use rates and their benefit for electric vehicle users and for all customers, optimized charging programs to achieve savings identified, and new contracts and compensation for services in those programs, through signals that allow electric vehicle charging to respond to local system conditions, manage critical peak periods, serve as a demand response or peak resource, and maximize renewable energy use and integration into the grid." 20 ILCS 627/45(d)(ii).

ComEd explains that the Residential EV Charging Infrastructure Sub-program is paired with participation in an hourly pricing rate to provide a signal of the best time to charge an EV. ComEd states that ComEd's existing $/kW-based distribution rate for C&I customers receiving rebates also provides a clear signal to use electricity at times of low overall system usage. ComEd points out that the Residential Optimized Charging pilot will allow participants to respond automatically to system conditions and price signals.

(iii) Section 45(d)(iii)

Section 45(d)(iii) provides that a BE Plan must address "optional commercial tariffs utilizing alternatives to traditional demand-based rate structures to facilitate charging for light duty, heavy duty, and fleet electric vehicles." 20 ILCS 627/45(d)(iii). ComEd argues that its BE Plan addresses the objectives of 45(d)(iii) through the EV Charging Delivery Classes, or through its alternative Watt-Hour Delivery Class proposal. ComEd states that the new EV Charging Delivery classes offer an alternative to traditional demand based-rate structure for enrolled C&I customers by offering C&I customers the option to have their delivery service charge based on volumetric rates. ComEd states that the alternative Watt-Hour Delivery Class proposal would also allow EV charging customers to elect to take delivery service under a class that recovers distribution facilities costs based upon a volumetric $/kWh charge.

(iv) Section 45(d)(iv)

Section 45(d)(iv) provides that a BE Plan must address "financial and other challenges to [EV] usage in low-income communities, and strategies for overcoming those challenges, particularly in communities and for people for whom car ownership is not an option." 20 ILCS 627/45(d)(iv). ComEd argues that the Residential EV Charging Infrastructure and C&I and Public Sector EV Purchase Sub-programs address financial and other challenges to EV adoption in low-income communities by providing enhanced rebates for low-income customers and customers located in or serving EJ or R3 communities in recognition of the barriers to EV adoption in for these customers, and the importance of air quality improvements in these areas. ComEd also points out that the, the C&I and Public Sector EJ/R3 EV Charging Make-Ready Infrastructure Sub-program is dedicated solely to EJ and R3 communities. ComEd notes that the Customer Education and Awareness program includes specific, directed outreach to low-income customers and EJ and R3 communities to ensure that customers are aware of the incentives available to them.

ComEd contends that customers for whom car ownership is not an option will benefit from the BE Plan through the increased adoption of EV transit and school buses. ComEd notes that the C&I and Public Sector EV Purchase Sub-program dedicates $8 million for transit buses and $6 million for school buses while the C&I and Public Sector EJ/R3 EV Charging Make-Ready Infrastructure Sub-program provides make-ready infrastructure rebates that can be used by transit operators for L2 or DCFC infrastructure. ComEd further notes that the BE Pilot Program will include a Ridesharing pilot program aimed at providing EV access to low-income and EJ/R3 customers for whom car ownership is not an option.

(v) Section 45(d)(v)

Section 45(d)(v) of the EVA provides that a BE Plan must address "methods of minimizing ratepayer impacts and exempting or minimizing, to the extent possible, low-income ratepayers from the costs associated with facilitating the expansion of electric vehicle charging." 20 ILCS 627/45(d)(v). ComEd argues that its proposal for regulatory asset treatment of the BE Plan minimizes the rate impacts of the BE Plan. ComEd states ComEd's BE Plan was specifically designed to ensure the impact on customers' bills or rates will be reasonable, considering the policy goals the BE Plan meets and the benefits it delivers.

(vi) Section 45(d)(vi)

Section 45(d)(vi) of the EVA provides that a BE Plan must address "plans to increase access to [L3] Public Electric Vehicle Charging Infrastructure to serve vehicles that need quicker charging times and vehicles of persons who have no other access to charging infrastructure, regardless of whether those projects participate in optimized charging programs." 20 ILCS 627/45(d)(vi). ComEd states that the EV Charging Delivery Classes and the C&I and Public Sector EJ/R3 Charging Make-Ready Infrastructure Sub-program will reduce barriers to the development of public charging thereby increasing access to charging infrastructure.

(vii) Section 45(d)(vii)

Section 45(d)(vii) of the EVA provides that a BE Plan must consider "[w]hether to establish charging standards for type of plugs eligible for investment or incentive programs, and if so, what standards." 20 ILCS 627/45(d)(vii). ComEd argues that, due to the nascent nature of the EV charging ecosystem, it would not be appropriate for an individual utility to develop standards related to EV charging plugs. ComEd argues that it is only a participant in a developing ecosystem, and at this early stage of EV charging, flexibility is critical to enable robust participation in the BE Plan and accelerate EV adoption and EV infrastructure deployment in northern Illinois.

(viii) Section 45(d)(viii)

Section 45(d)(viii) provides that a BE Plan must address "opportunities for coordination and cohesion with [EV] and [EV] charging equipment incentives established by any agency, department, board, or commission of the State, any other unit of government in the State, any national programs, or any unit of the federal government." 20 ILCS 627/45(d)(viii). ComEd states ComEd continuously looks for opportunities to coordinate and collaborate with federal and state agencies to accelerate beneficial electrification in northern Illinois, and will, through the Customer Education and Awareness Program, help publicize federal and state incentive opportunities to ComEd customers. ComEd points out that the EV Toolkit's Savings, Benefits, & Incentives portal shares federal and state incentives for EV purchases and charging infrastructure. ComEd notes it will consider incorporating an information clearinghouse tool into its Digital Advising Tools on other available incentives for various vehicle types.

(ix) Section 45(d)(ix)

Section 45(d)(ix) of the EVA provides that a BE Plan must address "ideas for the development of online tools, applications, and data sharing that provide essential information to those charging [EVs], and enable an automated charging response to price signals, emission signals, real-time renewable generation production, and other Commission-approved or customer-desired indicators of beneficial charging times." 20 ILCS 627/45(d)(ix). ComEd states that the Customer Education and Awareness Program and BE Pilot Program include online tools, applications, and data sharing mechanisms to enable automated charging in response to desired signals. ComEd points out that the Residential Optimized Charging pilot will allow participating customers to automatically moderate their charging level in response to price signals.

(x) Section 45(d)(x)

Section 45(d)(x) of the EVA provides that a BE Plan must address "customer education, outreach, and incentive programs that increase awareness of the programs and the benefits of transportation electrification, including direct outreach to eligible communities." 20 ILCS 627/45(d)(x). ComEd notes that customer education efforts are key component of ComEd's BE Plan. ComEd states that the Customer Education and Awareness Program will provide online resources, marketing, and education, including direct outreach to those customers and communities who can benefit most from the BE Plan. ComEd states the Customer Education and Awareness Program will expand its digital advising tools including its EV Toolkit, create online resources for fleet vehicles,

provide fleet assessment support, provide marketing and outreach about the BE Plan programs, and utilize direct, targeted outreach to eligible communities.

b. Staff's Position

(i) Section 45(d)(i)

Staff states that the Commission should find that ComEd's BE Plan does not adequately address the requirement set forth in Section 45(d)(i) of the EVA and make modifications to ensure that it does. The Commission should modify ComEd's BE Plan to address Staff's concerns, specifically Staff recommends the following modifications be incorporated into ComEd's BE Plan compliance filing to satisfy the statutory requirement set forth in Section 45(d)(i):

(1) ComEd should include primary facilities in its definition of the utility-side make-ready infrastructure and continue to have as customer-side make-ready the electrical items and associated labor for items listed in ComEd Ex. 5.04. The Act defines [m]ake-ready infrastructure as "the electrical and construction work necessary between the distribution circuit to the connection point of charging equipment." 20 ILCS 627/45(b), and

(2) ComEd should provide customer-side make-ready infrastructure incentives, as required by the definition of make-ready infrastructure investment, to all its customers, including its nonresidential customers in non-EJ/non-R3 communities. Specifically, ComEd should include in its BE Plan compliance filing the new sub-program "C&I EV Infrastructure (non-EJ/R3/IQ) sub-program.".

Staff Ex. 16.0 at 3.

ComEd was inconsistent about what it describes as the utility-side of the make-ready infrastructure. ComEd Ex. 5.0 at 8-9; Staff Ex. 16.0 at 14. Staff disagreed with ComEd's description of the make-ready facilities/infrastructure, testifying "make-ready infrastructure" as defined in the EVA refers to a service connection between the utility's distribution system/circuit and the connecting stub to charging equipment (i.e., EVSE). Staff Ex. 16.0 at 12-13.

In surrebuttal testimony, ComEd stated, "[t]his is a matter of semantics in terms of what constitutes utility side make-ready facilities. While I do not disagree with [Staff] that the definition of utility side make-ready facilities as provided in the [EVA] includes the term primary facilities, ComEd already provides primary facilities as standard service for all customers." ComEd Ex. 15 at 24. ComEd "will provide make-ready facilities as nonstandard and recover the costs directly from customers choosing ComEd-provided make-ready facilities through Rider NS Nonstandard Services and Facilities ("Rider NS")" for the EV Charging Delivery Service Class. ComEd Ex. 15 at 10. Staff notes ComEd would only provide, as standard practice, utility-side make-ready infrastructure for nonresidential customers in non-EJ/R3 communities. The customer-side make-ready infrastructure will be provided as nonstandard practice without any relief from ComEd.

ComEd's surrebuttal testimony shows inconsistency between what ComEd describes as make-ready infrastructure and the way that term is defined and used in the EVA. In one instance, ComEd states, "[i]n ComEd's view utility side make-ready includes

the secondary line from the transformer." ComEd Ex. 15.0 at 14, figure 1. This definition appears to exclude primary facilities and connections. However, in another instance, ComEd states, "… [I do not disagree with [Staff] that the definition of utility side make-ready facilities as provided in the [EVA] includes the term primary facilities …." ComEd Ex. 15 at 24.

Staff understands that (1) ComEd agrees utility-side make-ready facilities as defined in the EVA is inclusive of primary facilities; and (2) under specific criteria, ComEd will provide utility-side make-ready facilities as standard service for all customers.

In its surrebuttal testimony, ComEd revised its BE Plan to remove the rebate proposed for C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program and instead proposed rebates for make-ready work for its customers in EJ/R3 communities. ComEd Ex. 12.0 REV at 4.

Staff appreciates ComEd for revising parts of its BE Plan but notes the C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-programs are only available to participants in EJ/R3 communities. ComEd offers no incentives or relief for C&I and Public Sector Make-ready works for non-EJ/R3 communities. Staff recommends ComEd provide customer-side make-ready infrastructure incentives, as required by the definition of make-ready infrastructure investment, to all its customers, including its nonresidential customers in non-EJ/non-R3 communities. ComEd should include in its BE Plan compliance filing the new sub-program "C&I EV Infrastructure (non-EJ/R3/IQ) subprogram" as described in Section V.A.2.b of Staff's Initial Brief. Multiple parties support inclusion of a less geographically restrictive sub-program for make-ready infrastructure incentives. *See* CJCP IB at 18; Tesla IB at 10; ChargePoint IB at 8; AEE IB at 5-6. In fact, ComEd seems to be the only party to this proceeding that opposes such a sub-program. Accordingly, the Commission should direct ComEd to include in its BE Plan compliance filing the new sub-program "C&I EV Infrastructure (non-EJ/R3/IQ) subprogram."

(ii) Section 45(d)(ii)

Staff states that ComEd addresses Section 45(d)(ii) by Rate BESH, the Residential Charging Infrastructure Sub-program, the BE Pilot Program, and the School Bus Vehicle to Grid Pilot. ComEd Ex. 1.0 at 16-17. Staff concludes ComEd's BE Plan addresses Section 45(d)(ii). However, the BE Plan addresses the requirements of this section only minimally, so Staff recommends the Commission modify the BE Plan to require ComEd to develop and propose a TOU distribution rate consistent with Section 45(d)(ii) in its next rate design investigation case, such that residential and small commercial customers will be incentivized to charge their EVs at times beneficial to the grid. Staff Ex. 6.0 at 5. In addition, the Commission should direct ComEd to consider the following in the development of such TOU rate:

(1) that any TOU rate developed contains differences between peak and off peak that are significant enough to encourage customers to shift usage without deterring customers from signing up for the rate,

(2) the rate's on-peak and off-peak periods should coincide with the distribution system on-peak and off-peak periods, and

(3) the Company's rate proposal should include an incentive for EV owners (i.e., monthly/annual bill credits) to go on the rate, but the rate should not be available exclusively to EV owners.

Staff Ex. 6.0 at 6. If the Commission directs ComEd to design a distribution-only TOU delivery rate in its next rate design investigation case, consistent with both Section 45(d)(ii) and Staff's recommendations, ComEd's BE Plan will more fully address the intent of 20 ILCS 627/45(d)(ii). Staff Ex. 17.0 at 34.

(iii) Section 45(d)(iii)

Staff notes that ComEd addresses Section 45(d)(iii) through the Company's two proposed EV Charging Delivery classes (ComEd Ex. 1.0 at 17), or alternatively, the revision of its Watt-Hour Delivery Class tariff. ComEd Ex. 15.0 at 2. The Commission should find that the Company's BE Plan addresses Section 45(d)(iii) only if the Commission approves one of these alternatives. Staff recommends the Commission reject ComEd's two proposed EV Charging Classes, as those are more appropriately addressed in a rate design docket, and instead approve ComEd's alternative proposal to allow EV charging customers to participate in the Watt Hour Delivery Class. In addition, the Commission should direct ComEd to implement the revised tariff no later than six months after the Commission's final Order in this proceeding as discussed later in this brief.

(iv) Section 45(d)(iv)

To address this requirement of Section 45(d)(iv), the Company committed to including a pilot program targeting low-income and eligible customers for whom car ownership is not an option (ComEd Ex. 12.0 REV at 22) and agreed to include small multifamily residences in its Residential EV Charging Infrastructure Sub-program. ComEd Ex. 12.0 REV at 15-16. Staff states that the Commission should direct ComEd to reflect those commitments in its compliance filing BE Plan so that the BE Plan satisfies the requirement of Section 45(d)(iv).

Staff recommended ComEd consider a vehicle sharing program to address potential obstacles to EV usage in eligible communities and for customers for whom car ownership is not an option. Staff Ex. 3.0 at 15-16. ComEd stated the Company was open to considering such a program (ComEd Ex. 7.0 at 18), but as Staff noted, ComEd initially made no commitment to include these or other strategies designed to overcome challenges to EV usage as part of its BE Plan. Staff Ex. 14.0 at 25. In its surrebuttal testimony, the Company committed to include a Ridesharing pilot or "or other pilot program aimed at providing EV access to low income and EJ/R3 customers for whom car ownership is not an option." ComEd Ex. 12.0 REV at 22-23.

In response to the concerns raised by LVEJO and Staff that ComEd's BE Plan did not include adequate options for residents of small multifamily properties (LVEJO Ex. 1.0 at 6-7; Staff Ex. 14.0 at 18-19), the Company also clarified that it "will specifically include small multifamily properties as eligible under [the Residential EV Charging Infrastructure] Sub-program and will use the suggested Illinois Solar for All program as a reference point." ComEd Ex. 12.0 REV at 16.

Because ComEd committed to provide options for residents of small multifamily properties and has agreed to include a pilot focused on vehicle sharing or other similar method of ensuring EV access for low-income and eligible customers for whom car ownership is not an option, Staff states that the Commission should direct ComEd to include these commitments in its compliance BE Plan and find that ComEd's compliance BE Plan satisfies the minimum information requirement set forth in Section 45(d)(iv) if it does so.

(v) Section 45(d)(v)

Staff argues that the Commission should find that ComEd has failed to make the requisite showing required by Section 45(d)(v) and, to remedy this deficiency, the Commission should modify ComEd's BE Plan to incorporate Staff's recommendation that ComEd prepare an analysis that (1) considers economic costs and benefits and (2) isolates ratepayer impacts. Staff Ex. 17.0 at 35.

Importantly, Staff notes, there are several sections of the EVA that require the Company's BE Plan to address methods of minimizing ratepayer impacts. Section 45(d) states that, when the Commission is determining whether the BE Plan is cost-beneficial, "[t]he calculation of costs and benefits should be based on net impacts, including the impact on customer rates." 20 ILCS 647/45(d). Given the sheer magnitude of ComEd's proposed BE Plan, the net impact on customer rates will be significant. Staff Ex. 3.0 at 22. Additionally, Section 45(d)(1) requires the Commission to consider whether the investments and other expenditures will "maximize total energy cost savings and rate reductions so that nonparticipants can benefit" (20 ILCS 627/45(d)(1)).

ComEd asserted that the Company "has already performed analyses of costs and benefits, and of ratepayer impacts." ComEd Ex. 13.0 REV at 16. While ComEd's BCA includes economic costs and benefits, it fails to properly isolate the effects on ratepayers. For example, it treats emissions reductions as a benefit, even though they have no effect on rates. In addition, while the Company provided the table "Estimated Residential Bill Impact and C&I Rate Impact of ComEd Proposal" (ComEd Ex. 14.0 REV at 10), this table considers only accounting costs. Thus, the true effect on rates is unclear. Staff Ex. 6.0 at 13. In Section V.D.3.b, Staff offers an example of what type of analysis would address Staff's concerns.

For these reasons the Commission should approve Staff's recommendation and modify ComEd's BE Plan to require ComEd to prepare an analysis that considers economic costs and benefits and isolates ratepayer impacts. Staff Ex. 17.0 at 35. This issue is discussed in more detail in Section V.D.3.b.

(vi) Section 45(d)(vi)

Staff states that the Commission should find ComEd's BE Plan meets the requirement set forth in Section 45(d)(vi) of the EVA. In surrebuttal testimony, ComEd stated it "proposes to revise its existing C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program to be dedicated to rebates for make-ready work. As proposed, the incentives will go towards make-ready work on the customer or the ComEd side of the meter." ComEd Ex. 12.0 REV at 3-4. Additionally, ComEd proposes to incorporate nonresidential customers into its existing watt-hour class. These customers

include nonresidential customers who own and operate L3 Public EV Charging stations. ComEd 15.0 at 10.

(vii) Section 45(d)(vii)

Staff also states that the Commission should find that ComEd's proposed BE Plan addresses the required information set forth in Sections 45(d)(vii) of the EVA, but only if the Commission directs ComEd to adopt the Combined Charging System ("CCS") standard for EVSE connectors in a L3 or DCFC public EV charging station before such charging stations qualify for an incentive under ComEd's proposed BE Plan.

Initially, ComEd did not include charging standards for the type of plugs eligible for investment or incentive programs in its BE Plan. ComEd Ex. 1.0 at 21. ComEd stated that "[g]iven the nascent, evolving status of the EV ecosystem, ComEd does not believe it would be appropriate to set any standards or requirements that would influence customers' choices of EVs or EV charging infrastructure." *Id*. at 21. Instead, ComEd stated that it "will continue to monitor and track trends in charging standards and revisit the issue in updates to its BE Plan." *Id*.

In surrebuttal testimony, the Company indicated that, "if the Commission adopts a CCS standard for publicly accessible DCFC charging stations incentivized through the BE Plan, then ComEd would not object." ComEd Ex. 11.0 REV at 15. ComEd further stated that, "'no party provided feedback raising concerns with the CCS standard for publicly accessible DCFC charging stations and as discussed in my [r]ebuttal [t]estimony, both federal and state incentives for publicly accessible chargers are aligned on using CCS for DCFC." *Id*.

Based on ComEd's willingness to adopt the CCS standard for EVSE connectors in L3 or DCFC public EV charging stations, as well as the fact that none of the Intervenors in this proceeding raised concerns about the adoption, Staff recommends that the Commission modify ComEd's BE Plan to adopt CCS standard. If it does so, Staff recommends the Commission find ComEd's proposed BE Plan addresses the required information in Sections 45(d)(vii) of the EVA.

(viii) Section 45(d)(viii)

Staff states that ComEd's BE Plan does not include detail regarding how it will satisfy Section 45(d)(viii). ComEd's BE Plan describes online tools to share information on federal and state incentives with customers (ComEd Ex. 1.01 at 49), but specific incentives are not discussed in the BE Plan itself, despite the fact that ComEd considered specific incentives. Staff Ex. 3.1 at 3. Similarly, while ComEd has generally provided information regarding programs that may assist it in achieving goals related to BE, those programs are not reflected in the BE Plan. Staff recommended the inclusion of such incentives Staff Ex. 3.0 at 17.

Although the Company stated that "ComEd agrees in spirit with this recommendation" (ComEd Ex. 6.0 at 8), the Company did not alter its BE Plan to include the relevant information. While, as ComEd points out, incentives are subject to change, including specific incentives in ComEd's BE Plan is informative to stakeholders and identifies a clear and accountable role for utilities in ensuring that its ratepayers benefit from other entities' offerings. Staff Ex. 14.0 at 11.

ComEd did not address this issue in surrebuttal testimony, other than to note that the Company addresses the objective and points to the example of the EV Toolkit's Savings, Benefits, & Incentives portal which shares federal and state incentives for EV purchases and charging infrastructure. ComEd Ex. 11.0 REV at 5-8. However, according to the Company, the EV Toolkit is not part of its BE Plan. Staff Ex. 3.1 at 6. Similarly, the Company did not address either the concerns raised by Staff in testimony that there is a lack of detail in its BE Plan regarding how it will satisfy this requirement or Staff's recommendation that the Commission order ComEd to include the relevant information requested by Staff in its BE Plan compliance filing. Doing so would be informative to stakeholders but more importantly would identify a clear and accountable role for the Company in ensuring that its ratepayers benefit from other entities' offerings. Staff Ex. 14.0 at 11.

The Commission should find that ComEd has provided the minimum information required by 20 ILCS 627/45(d)(viii) only if the Company includes the information on coordination with outside incentives provided in discovery as well as relevant coordination with programs from the Infrastructure Investment and Jobs Act ("IIJA") and the IRA in its BE Plan filed as a compliance filing. Staff Ex. 3.0 at 17. The Commission should order that the Company include this information in a compliance filing.

Staff also supports the IEPA recommendation as general implementation guidance to coordinate activities with known state and federal EV programs. Staff Ex. 15.0 at 32-34. ComEd responded to the IEPA recommendations by stating that the Company will continue to identify and promote opportunities for coordination and cohesion with state and federal incentives. ComEd Ex. 6.0 at 8.

(ix) Section 45(d)(ix)

Staff recommends that the Commission find that the ComEd BE Plan addresses the required information set forth in Section 45(d)(ix). Staff Ex. 15.0 at 4.

(x) Section 45(d)(x)

Staff recommends that the Commission find that ComEd's BE Plan does not include the information required by Section 45(d)(x) and modify ComEd's BE Plan. The Commission should further require ComEd to reflect these Staff's modifications in its compliance filing consistent with the process outlined in Staff rebuttal testimony (Staff Ex. 12.0). If the Company does so, the Company will satisfy the requirement. (Staff Ex. 14.0, 17.)

Staff raised concerns that the Company's BE Plan provided insufficient detail regarding its education and outreach programs and, as a result, the Company would be unable to provide information sufficient to determine the relative success of past programs on which the Company claims to base BE Plan outreach. Staff Ex. 3.1 at 6. Additionally, the Company did not describe how it would conduct outreach to organizations with specific BE needs, such as auto dealers, fleet managers, schools or school bus operators, and transit facilities. Staff Ex. 3.1 at 7; Staff Ex. 3.0 at 17-18.

Staff agreed with concerns and supported recommendations raised by some Intervenors. Specifically, LVEJO recommended that ComEd include greater detail in its description of its Customer Education and Awareness Program about how it will work with

community organizations to reach EJ and R3 communities. LVEJO Ex. 1.0 at 8-9. LVEJO also recommend that the Company offer materials in multiple languages; and that the program include a customer support function that ensures equitable access for customers who do not use the internet. *Id*. Staff agreed, noting that the statutory focus on "direct outreach to eligible communities" Section 45(d)(x)) suggests it is necessary for ComEd to describe its planned efforts in sufficient detail to assure the Commission and stakeholders that the requirement is met. Staff Ex. 14.0 at 14. ComEd noted that it "anticipates" conducting BE Plan marketing in both English and Spanish and that it "anticipates" using offline outreach as well. Staff Ex. 3.1 at 4-5. However, Staff notes, ComEd's BE Plan does not seem to corroborate such promises.

CJCP raise similar concerns regarding the lack of detail regarding education and outreach and the need to coordinate with EJ and R3 communities. EDF Ex. 1.0 at 34-35. Staff has agreed with these concerns and noted the importance of coordination with eligible communities. Staff Ex. 14.0 at 15.

ChargePoint recommends that educational and marketing materials be developed in a competitively neutral manner (ChargePoint Ex. 1.0 at 28-29). Staff also agreed with this recommendation, noting that competitive neutrality is particularly important given that the market for EVs and EVSE is relatively new, and many customers and potential customers do not have full information regarding available products. Competitive neutrality should not be construed to preclude any materials that favor ENERGY STAR® certified products over uncertified ones.

In its rebuttal testimony, the Company argued sharing relevant details of its education and outreach programs "would require ComEd to invest significant resources into implementing potential programs prior to Commission approval." ComEd Ex. 7.0 at 31. Although the information requested should not require any implementation (Staff Ex. 14.0 at 13), ComEd refused to provide the necessary information such as web traffic data on programs that the Company has already implemented and on which they claim to base BE efforts. ComEd Ex. 12.0 REV at 21-22.

Despite this refusal, the Company "commits to seeking community input as it develops education and awareness materials, providing offline options for customers to learn about programs and offering materials in multiple languages (including on ComEd's website)" and agrees to ensure competitive neutrality of activities under Customer Education and Awareness Program. ComEd Ex. 12.0 REV at 21.

WeaveGrid recommended expanding the budget for ComEd's proposed Customer Education and Awareness Program from the proposed $9 million to $15 million. WeaveGrid Ex. 1.0 at 20. Staff disagrees with this proposal. Although WeaveGrid identifies a number of possible uses for these additional funds, ComEd did not provide information indicating how the $9 million it allotted for Customer Education and Awareness Program will be divided among these or similar activities, so there is no reason to believe even more money is necessary. Staff Ex. 14.0 at 15.

Although the commitments that ComEd makes in its surrebuttal testimony assuage some of the concerns expressed by Staff and other Intervenors, there is still insufficient detail provided on the Customer Education and Awareness Program to satisfy the minimum information requirement set forth in Section 45(d)(x). Despite testimony

requesting additional information from Staff, LVEJO, and CJCP, ComEd did not provide additional detail in their Initial Brief regarding planned outreach, nor did it provide information sufficient to allow the parties or the Commission to ascertain the relative success of past programs on which the Company claims to base BE Plan outreach. As Staff noted, providing this information would not require the Company to implement anything prior to approval. Staff Ex. 14.0 at 13.

c. AG's Position

(i) Section 45(d)(ii)

Pursuant to Section 45(d)(ii) of the EVA, a utility's BE Plans must address, at minimum, "the development and implementation of [BE] programs, including [TOU] rates and their benefit for electric vehicle users and for all customers, optimized charging programs to achieve savings identified, and new contracts and compensation for services in those programs, through signals that allow electric vehicle charging to respond to local system conditions, manage critical peak periods, serve as a demand response or peak resource, and maximize renewable energy use and integration into the grid." 20 ILCS 627/45(d)(ii). ComEd asserted that it addresses this section by requiring residential customers who receive the Residential EV Charging Infrastructure Sub-program to take service under Rate BESH and through the provision of Rate BESH and the Company's $/kW-based distribution rate for commercial and industrial customers which ComEd asserted provides a clear signal to use electricity at times of low overall system usage. ComEd Ex. 11.0 REV at 6.

Regarding Section 45(d)(ii), the AG asserts in Section VII.C.1 of this Order that the Company does not need to require all residential ratepayers to participate in Rate BESH to satisfy this statutory requirement. Further, the AG maintains that the Commission must develop and propose a distribution-only TOU rate as part of its next rate design investigation to satisfy Section 45(d)(ii) and its goal of providing price signals that reduce charging at times when distribution system utilization is high.

(ii) Section 45(d)(viii)

The AG also asserts that the Company's proposed budget violates Section 45(d)(viii) because it fails to account for existing state and federal incentives. *See* supra Section V.C.1.

d. CJCP's Position

(i) Section 45(d)(i)

As Clean Jobs Coalition Parties note, EVA Section 45(d)(i) directs ComEd to address make-ready investments to facilitate the rapid deployment of charging equipment. They assert that EV EMS can help defer or avoid certain customer-side and utility-side distribution infrastructure to accommodate increasing EV charging load. This factor, according to CJCP, is especially important in low-income communities which are often served by outdated utility infrastructure and which would require costly upgrades in order to accommodate EV charging load. CJCP state that EV EMS deployment can mitigate these upgrade costs and make charging infrastructure more affordable in these communities. NRDC Ex. 1.0 at 28-29. Clean Jobs Coalition Parties aver that the Company can further support the use of EV EMS by adopting a standard site evaluation

methodology applicable to all non-residential EV charging sites, including those not receiving Company funding for make-ready infrastructure; the evaluation would determine if EV EMS could cost-effectively meet the customer's charging needs; and the customer could then incorporate the results into the project. The Company also should make incremental EV EMS costs eligible for rebates, which, according to CJCP, will be a net gain for ratepayers if the costs avoided by the use of EV EMS exceed the rebate amount. NRDC Ex. 1.0 at 30.

(ii) Sections 45(d)(ii)-(iii)

As Clean Jobs Coalition Parties point out, EVA Section 45(d)(ii) states that a BE Plan must address, in part, "optimized charging programs…that allow [EV] charging to respond to local system conditions, manage critical peak periods, serve as a demand response or peak resource, and maximize renewable energy use and integration into the grid." 20 ILCS 627/45(d)(ii). Section 45(d)(iii) adds to this "optional commercial tariffs utilizing alternatives to traditional demand-based rate structures to facilitate charging for light duty, heavy duty, and fleet electric vehicles." 20 ILCS 627/45(d)(iii). Clean Jobs Coalition Parties argue that ComEd's contention that the Company's Residential Optimized Charging pilot is sufficient to meet the EVA's statutory requirements is erroneous because, among other reasons, it leaves aside customer and industrial customers. As Clean Jobs Coalition Parties point out, C&I customers are a large percentage of ComEd's base; and the medium- and heavy-duty EVs in this customer class need to be carefully considered, given their emissions impact and their potential impact on grid operations. CJCP assert that, as such, their prospective omission from the pilot is problematic, and, further, it is not persuasive that ComEd states "for [C&I] customers that receive rebates, ComEd's existing $/kW-based distribution rate similarly provides a clear signal to use electricity at times of low overall system usage." ComEd IB at 33. The structure of this rate, CJCP note, fails to provide a time-variant price, resulting in little incentive to charge strategically. Similarly, according to CJCP, ComEd continues to propose EV Charging Delivery Classes and its alternative Watt-Hour Delivery Class, both of which would offer rate options that do not include any time variant usage factors. As such, Clean Jobs Coalition Parties believe these options would be inadequate substitutes for a well-designed optimized charging pilot for these customers. Clean Jobs Coalition Parties assert that more detail and an expanded scope for the Optimized Charging pilot are appropriate before the Commission finds that the statutory requirements have been met.

EVA Section 45(d)(ii) requires ComEd to address programs that "maximize renewable energy use and integration into the grid." In direct testimony, CJCP witness MacDougall articulated the role of vehicle-to-grid in maximizing renewable energy use and integration. Dr. MacDougall pointed out that BE must be viewed in the context of the energy transition as a whole, a process in which electric utilities must play a central role, noting that simultaneously with BE, energy supply is also shifting from traditional large fossil-fueled power plants to decentralized renewable generation. EDF Ex. 1.0 REV at 6. As Dr. MacDougall testified, the best way to minimize the cost of the transition to decentralized renewable generation is to identify technologies that can increase the flexibility of consumption and leverage those technologies to make optimal use of renewable generation resources as well as maximize the use of grid capacity to mitigate

unnecessary and expensive grid expansion – and that failure to take advantage of these technologies could unnecessarily increase costs for all ratepayers. EDF Ex. 1.0 REV at 6-7. Dr. MacDougall highlighted the role of EVs, and particularly electric trucks and buses, in this transition to more renewables, stating that "[a]s batteries on wheels, they have tremendous promise as a resource; in the aggregate, they represent flexible demand that can be deployed on various time scales to maximize reliance on renewable generation and reduce the need for system capacity..." EDF Ex. 1.0 REV at 7. In summary, Clean Jobs Coalition Parties contend that ComEd's relative lack of interest in managing EV charging load through its programs can be expected not only to increase the cost of electrification to ratepayers, but also to hinder large-scale reliance on renewable generation and increase the cost to ratepayers of transitioning to such non-polluting generation resources.

e. Electrify America's Position

(i) Section 45(d)(ii)

With respect to TOU rates for C&I customers, Electrify America agrees with ComEd that currently available Rate BESH together with time-variant supply rates and capacity demand charges based on usage during PJM summer hours "provide[s] a clear signal to use electricity at times of low overall system usage," incentivizes overnight EV charging for EV use cases and charging segments with sufficient demand elasticity such as fleets, and addresses the requirements in Section 45(d)(ii) in connection with C&I EV charging customers for whom the rate is available. ComEd Ex. 11.0 (REV) at 6 (citing to ComEd Ex. 1.01 at 47; ComEd Ex. 2.0 at 15-16, 39; ComEd Ex. 1.0 at 15-17).

(ii) Section 45(d)(iii)

Electrify America agrees that ComEd's proposal for an optional Watt-Hour Delivery Class meets the requirements of Section 45(d)(iii). Electrify America contends the Watt-Hour Delivery Class proposal provides an alternative to traditional demand-based structures, allowing customers in the class to be billed on a "per KWh" basis, while avoiding many of the issues and risks raised by ComEd's original proposal to establish new EV charging delivery classes. ComEd Ex. 15.1; Electrify America Exs. 2.01-2.02. Significantly, Section 45(a)(ii) requires commercial tariffs utilizing alternatives to demand-based rates be "optional." Electrify America points out that under the Watt-Hour Delivery Class proposal, taking service under the Watt-Hour Delivery Class will, in fact, be optional as customers will be able to choose whether to take service under the class and will have the option of switching back to an appropriate kW-based nonresidential delivery class after a year.

(iii) Section 45(d)(vii)

Section 45(d)(vii) requires the BE Plan to address "whether to establish charging standards for type of plugs eligible for investment or incentive programs, and if so, what standards." Electrify America contends that it does not make sense to set standards related to plugs (or other EV charging equipment standards) for publicly available EV charging equipment receiving incentives under ComEd's BE Plan when the incentives those customers will receive will be limited to rebates for make-ready infrastructure and will not be related to the plugs/charging equipment itself. Electrify America also notes

that Section 45(d)(vii) does not require that the BE Plan establish standards for plugs receiving BE Plan incentives. Rather, it requires that the BE Plan address whether to establish such standards, which ComEd has done. 20 ILCS 627/45(d)(vii).

Parties to this proceeding have also proposed other, non-plug related, equipment and service standards. Electrify America states that other equipment standards for charging stations are inappropriate and unnecessary and the Commission should not include any such requirements within its final Order. Electrify America contends that the Commission's jurisdiction is limited by statute and that the Commission should therefore not engage in standard setting related to EVSPs in the absence of direct statutory authorization to do so. *Bus. & Prof'l People for the Public Interest v. Ill. Commerce Comm'n*, 136 Ill. 2d 192, 203 (1989); *Ameren Illinois Co. v. Illinois Com. Comm'n*, 33 N.E.3d 987, 1005 (Ill. App. 4th Dist. 2015) ("There must be a statute expressly granting the agency the power to do the act in question."); *Resource Tech. Corp. v. Commonwealth Edison Co*., 795 N.E.2d 936, 941 (Ill. App. 1st Dist. 2003) ("An administrative agency derives its power to act solely from the statute by which it was created . . . ." (quoting *Chemed Corp. v. State of Ill.*, 542 N.E. 2d 492 (1989)); *Ill. Bell Tel. Co. v. Ill. Commerce Comm'n*, 362 Ill. App. 3d 652, 656-67 (4th Dist. 2005) ("An administrative agency is a creature of statute and only has the powers that the statute confers."). The EVA provides for a BE Plan to consider whether to establish standards for "type of plugs eligible for investment or incentive programs" but other than that confers no authority upon ComEd or the Commission to establish standards for EVSPs. Electrify America contends that any standard setting for EV charging equipment and charging services is better left to the market and, where appropriate, to state and federal policy makers with jurisdiction to impose such requirements.

Electrify America further states that establishing standards in a setting like this could result in "patchwork" requirements for EVSPs, thereby increasing the economic and administrative burdens of investing in EV infrastructure and presenting a challenge to the rapid deployment of EV charging infrastructure. It points out that it operates in over 200 different utility territories where it must comply with applicable regulations and requirements. One of the primary functions of the EVA is the "[w]idespread adoption of [EVs]" in a way that "stimulate[s], innovation, competition, and increased choices in charging equipment and networks [and] attract[s] private capital investments and create[s] high-quality jobs in Illinois." 20 ILCS 627/45(a)(10). Rather than achieve these outcomes, standard-setting for EV charging equipment will only result in additional administrative and economic burdens and serve to disincentivize investment in charging equipment and networks. Electrify America IB at 16 (citing ComEd Ex. 6.0 at 18-22; ComEd Ex. 11.0 REV at 10-16; 20 ILCS 627/45(d)(5),(8)).

In response to the CJCP proposal for the adoption of payment technology standards, Electrify America argues CJCP makes the unsupported assumption that individuals in EJ/R3 communities will not be able to use charging stations "without payment standards that will accommodate their payment methods" and that CJCP provides no support or evidence that public EV charging stations in Illinois do not meet consumer payment needs in EJ/R3 communities or that they will not continue to do so. Electrify America states EVSPs have market-based incentives to meet customer needs, including those related to having a wide range of available payment technologies.

Electrify America further supports ComEd's point that proposed payment technology standards are not appropriate for the first BE Plan in a developing EV and EV charging technology ecosystem, nothing that EV charging infrastructure continues to rapidly evolve and change to keep up with the developments in EV vehicles, loads, and technologies. Id.

However, Electrify America does not support Staff's request for the Commission to require EV charging station operators incentivized under the BE Plan to provide a scope of information regarding their cybersecurity practices to ComEd that aligns with what ComEd requires of its vendors. Electrify America explains that it generally supports measures to keep EV drivers, utility companies, charging stations, and the grid secure from cybersecurity threats. However, it further stated that similar to standards for plugs and payment technologies, standards for cybersecurity are best left to state and federal policy makers rather than individual utilities. Utility-specific standards are not scalable for EVSPs operating nationally. Electrify America states it operates in more than 200 utility territories, which if allowed to adopt differing cybersecurity standards, could lead to a dizzying patchwork of cybersecurity reporting and data-collection requirements and that platforms such as the NEVI program exist that are better positioned to standardize cybersecurity requirements for EV charging station operators.

f. ChargePoint's Position

(i) Section 45(d)(i)

ChargePoint asserts that ComEd's proposed Make-Ready Infrastructure Rebate program is unlikely "to facilitate the rapid deployment of charging equipment" if the Commission approves ComEd's proposal to limit eligibility to public sector customers and customer in eligible communities. 20 ILCS 627/45(d)(i). According to ChargePoint, facilitating the rapid deployment of chargers requires providing make-ready support to all nonresidential customers willing to host EV chargers and ensuring there are sufficient funds to support all interested customers. To meet this statutory consideration, ChargePoint recommends that the Commission direct ComEd to allow all nonresidential customers to participate in the Make-Ready Infrastructure Rebate program, with higher incentives for public sector customers and customers in eligible communities, and increase the budget for the program to $30 million.

ChargePoint explains that it is indifferent as to whether this goal is achieved by expanding the eligibility requirements of the Make-Ready Infrastructure Rebate subprogram to include all customers (ChargePoint's recommendation) or by creating a new subprogram that is available to all customers (Staff's recommendation). Regardless of the mechanism, ChargePoint argues that it is critical that any nonresidential customer that is willing to host EV charging stations be eligible for make-ready incentives, especially given that all nonresidential customers will be asked to pay for the BE Plan.

ChargePoint recommends that the Commission disregard ComEd's arguments that its proposed EV Charging Delivery Classes address this criterion. According to ChargePoint, ComEd has been clear that it proposed the EV Charging Delivery Classes pursuant to the Act and not pursuant to the EVA. ChargePoint therefore urges the Commission to not allow ComEd to use this proposal to satisfy the requirements of the EVA. Disregarding the EV Charging Delivery Class proposal, asserts ChargePoint, it is

clear that ComEd's proposal to provide make-ready incentives to a limited subset of nonresidential customers falls short of the directive of Section 45(d)(i).

(ii) Section 45(d)(iii)

According to ChargePoint, ComEd's proposal to allow EV charging site hosts to take service on its Watt-Hour Delivery Class rate satisfies the statutory consideration in Section 45(d)(iii) by providing a volumetric rate option as an alternative to traditional demand-based rates. ChargePoint recommends that the Commission approve ComEd's proposal to open the Watt-Hour Delivery Class to EV charging customers and reject is EV Charging Delivery Classes proposal.

ChargePoint again argues that ComEd's proposed Make-Ready Infrastructure Rebate program would only increase access to public L3 chargers (DCFCs) in eligible communities. According to ChargePoint, ComEd should prioritize eligible communities by providing higher incentives for customers in eligible communities and reserving funds for such customers, but it should not exclude other willing site hosts from the program. ChargePoint recommends that, consistent with its arguments with respect to Section 45(d)(i), the Commission should disregard ComEd's contention that its EV Charging Delivery Classes proposal, which ComEd states is not part of the BE Plan, satisfies Section 45(d)(vi) of the EVA.

(iii) Section 45(d)(iii)

According to ChargePoint, ComEd's proposal to allow EV charging site hosts to take service on its Watt-Hour Delivery Class rate satisfies this statutory consideration by providing a volumetric rate option as an alternative to traditional demand-based rates.

g. Tesla's Position

(i) Section 45(d)(i)

Tesla states that, as discussed in Section V.A.2., Tesla recommends an expanded C&I and Public Sector EJ/R3 Charging Infrastructure Sub-program given ComEd's proposal to offer its sub-program exclusively to EJ/R3 communities is not consistent with the spirit and intent of Section 45 read as a whole. Tesla explains that, while it unequivocally agrees that special emphasis should be made to EJ/R3 communities, Tesla also finds that the statute provides flexibility to offer incentives that will benefit the entire ComEd service territory.

Tesla further notes that it agrees with the CTA's concerns regarding the EJ/R3 geographic restrictions of the proposed program. Specifically, Tesla stated that CTA witness Tomford testified that the entire CTA system should qualify for EJ/R3 make-ready incentives given the CTA provides affordable and reliable public transit options to low-income and minority populations, regardless of where they reside, and regardless of their point of origin or destination on the CTA system. CTA Ex. 4.0 at 6. Similarly, Tesla, along with other third-party developers, finds that charging infrastructure needs to be supported more broadly across the entire ComEd service territory, and throughout the entire State, to facilitate the achievement of Illinois's ambitious EV adoption targets.

Tesla states that it supports Staff's proposed modifications to ComEd's BE Plan to satisfy the statutory requirement set forth in Section 45(d)(i). As Staff appropriately notes,

ComEd revised parts of its BE Plan to offer rebates for make-ready work for its customers in EJ/R3 communities, but ComEd still fails to offer incentives or relief for non-EJ/R3 communities. Accordingly, Tesla states that it agrees that Staff's modifications should be incorporated into ComEd's BE Plan compliance filing. Staff Initial Br. at 75.

(ii) Section 45(d)(iii)

Tesla explains that ComEd is willing to allow nonresidential customers whose primary purpose is to provide EV Charging Services to be eligible to take delivery service under the existing Watthour Delivery Service Class. ComEd Ex. 15 at 10. Tesla stated that it supports ComEd's Watthour Delivery Service Class proposal, as presented in ComEd Ex. 15.01, and appreciates ComEd's creative approach to satisfying parties' concerns regarding the EV Charging Delivery Classes as initially proposed.

To that end, Tesla states that it supports Staff's recommendation that the Commission should reject ComEd's two proposed EV Charging classes and instead approve ComEd's alternative proposal to allow non-residential customers whose primary purpose is to provide EV charging services to be eligible to take delivery service under the Watthour Delivery Service Class.

Lastly, Tesla stated that it would encourage ComEd to use best efforts to implement this proposal before 2024, though acknowledging that ComEd is currently undergoing a transition from its current customer information system to a new one, as well as other several IT changes associated with P.A. 102-0662. ComEd Ex. 10 at 12. Tesla states that it appreciates and strongly supports Staff's recommendation that the Commission should direct ComEd to implement the revised tariff no later than six months after the Commission's final Order in this proceeding.

(iii) Section 45(d)(vii)

Tesla explained that it continues to strongly support ComEd's position of flexibility towards EV charger equipment eligibility for incentives under the BE Plan. Indeed, Tesla agrees with ComEd that "[a]t this early stage, flexibility is critical to enable robust participation in the BE Plan and accelerate EV adoption and EV infrastructure deployment in Northern Illinois." ComEd IB at 36.

Tesla maintains that it opposes certain recommendations regarding equipment eligibility given the relatively nascent nature of the EV charging network. Specifically, Tesla stated that it disagrees with ChargePoint and CJCP that L2 charging equipment should require ENERGY STAR® certification in order to receive incentives under the BE Plan. Tesla finds that, at this early stage, requiring this type of certification would do more to restrict customer choice between L2 charging equipment than improve EE. L2 chargers are typically low power devices when idle, using only a few watts without a vehicle plugged in, and thus it is unproven that L2 chargers without ENERGY STAR® certification use considerably more energy. Tesla explained that, without quantitative support showing a significant difference between the idle energy draw of L2 chargers with and without the ENERGY STAR® certification, it finds that requiring this type of equipment eligibility standard would be unjustified. If data is developed showing that certified chargers do in fact use significantly less energy, Tesla states that it would be open to ComEd revising its BE Plan to include this type of equipment eligibility standard.

Tesla states that it also disagrees with Staff's recommendation that ComEd adopt the CCS standard for EV supply equipment connectors in L3 or DCFC public EV charging stations before such charging stations qualify for an incentive under the BE Plan. Tesla explains that Staff's recommendation is inappropriate given the incentives for EV charging equipment that were initially offered in the BE Plan were subsequently disallowed and thus the Commission should not direct ComEd to adopt an eligibility requirement related to a piece of equipment that is not being directly rebated as part of the sub-program. Tesla states that, while Staff points to ComEd's statement in surrebuttal testimony that "no party provided feedback raising concerns with the CCS standard for publicly accessible DCFC charging stations" (Staff IB at 83-84), Tesla avers that was because ComEd's BE Plan does not expressly rebate this type of charging equipment. Tesla instead underscored that ComEd's position throughout this proceeding has remained agnostic to charging equipment standards, both before and after the disallowance of charging equipment rebates.

Lastly, Tesla notes that, in the medium and heavy-duty space, it is unclear at this time what charging standard would be used for both public and private charging infrastructure. Indeed, CTA/City explained that "CTA's electric buses are charged using a gantry and pantograph" system. CTA/City IB at 15. Tesla finds that this further supports an open and flexible approach and agrees with ComEd that "due to the nascent nature of the EV charging ecosystem, it would not be appropriate for an individual utility to develop standards related to EV charging plugs." ComEd IB at 36.

h. EVgo's Position

(i) Section 45(d)(iii)

EVgo disagrees with ComEd's assertion that the EV Charging Delivery Classes meet the statutory requirement in Section 45(d)(iii). EVgo shares Staff's assessment that ComEd's proposed EV Charging Delivery Classes do not satisfy the statutory requirements of section 45(d)(iii) because ComEd presented these delivery classes as a means "to complement the BE Plan," rather than as a direct part of the BE Plan. EVgo notes that ComEd did not submit a proposed EV Charging Delivery Class tariff for consideration with its BE Plan. EVgo states that ComEd's alternative proposal, to modify its existing Watt-Hour Delivery Class to make it available to EV charging customers, is consistent with this requirement of the EVA.

(ii) Section 45(d)(vii)

EVgo agrees with ComEd that it is unnecessary at this time to establish standards for charging equipment. EVgo notes that several of the disparate standards proposed by parties in this proceeding contradict with existing program requirements established by other State agencies, including under the IEPA's charging programs, as well as with the proposed minimum standards issued by the Federal Highways Administration for the NEVI Formula Program, which will be administered by state departments of transportation. EVgo explains that imposing such requirements now, while standards are still being developed across state and federal agencies, is premature and unnecessarily risks causing customer confusion and creating market uncertainty.

i. Commission Analysis and Conclusion

(i) Section 45(d)(i)

The Commission agrees with Staff that ComEd was inconsistent with its definition of the utility-side make-ready infrastructure. The Commission agrees with Staff that utility-side make-ready facilities as defined in the EVA is inclusive of primary facilities. The Commission further adopts, with budgetary modification, Staff's recommendation to bifurcate the C&I EV Charging Infrastructure Sub-program (see Section V.A.2.). With this modification, the Commission finds ComEd has complied with Section 45(d)(i).

(ii) Section 45(d)(ii)

ComEd asserts that it has complied with Section 45(d)(ii) through its Residential EV Charging Infrastructure Sub-program, its existing $/kw-based distribution rate for C&I customers receiving rebates, and the Residential Optimized Charging pilot. While the Commission has made modifications to these programs, the Commission agrees that ComEd has complied with the requirements of Section 45(d)(ii). The Commission further notes that it approves Staff's request that ComEd design a distribution-only TOU delivery rate in its next rate design investigation (*see* Section VII.C.1.).

(iii) Section 45(d)(iii)

ComEd states it complies with Section 45(d)(iii) through its proposed EV Charging Delivery Classes, or alternatively, the Watt-Hour Delivery Class tariff. The Commission approves the Watt-Hour Delivery Class alternative (*see* Section VII.A.2.). Accordingly, the Commission finds ComEd has complied with this section.

(iv) Section 45(d)(iv)

ComEd has committed to provide options for residents of small multifamily properties and agreed to include a Ridesharing pilot program, the Commission finds ComEd has complied with this section.

(v) Section 45(d)(v)

The EVA explicitly requires the BE Plan to address at a minimum "methods of minimizing ratepayer impacts and exempting or minimizing, to the extent possible, low-income ratepayers from the costs associated with facilitating the expansion of electric vehicle charging." 20 ILCS 627/45(d)(v). Based on the record, the Commission agrees with Staff that the Company has failed to make the requisite showing required by Section 45(d)(v). The Commission's decision in Section V.D.3. will go toward compliance with this section. The Commission, however, also directs ComEd to propose in their compliance filing the methods of minimizing ratepayer impacts and exempting or minimizing low-income ratepayers from the costs associated with the BE Plan as required in the EVA. Based on the foregoing, the Commission finds that ComEd will have addressed the requirements of Section 45(d)(v) upon submission of its compliance filing.

(vi) Section 45(d)(vi)

ComEd's BE Plan C&I and Public Sector EJ/R3 Charging Make-Ready Infrastructure Sub-program will reduce barriers to the development of public charging. Additionally, ComEd proposes to incorporate nonresidential customers into its existing

Watt-Hour Delivery Class. As such, the Commission finds ComEd has complied with this section.

(vii) Section 45(d)(vii)

This section requires that the BE Plan consider "[w]hether to establish charging standards for type of plugs eligible for investment or incentive programs, and if so, what standards." 20 ILCS 627/45(d)(vii). As noted in Section V.B.2., ComEd's current BE Plan does not rebate this type of charging equipment. Because the rebate factor is a separate issue from whether standards should be adopted does not mean that certain charging standards should not be adopted. As Staff and CJCP point out, and the Commission finds, the CCS/J1772 connectors are the dominant standard for EV chargers, and the vast majority of EV models available today and expected in the future in the U.S. are compatible with CCS/J1772. As CJCP point out, the need for standards must be balanced with ensuring ratepayer funds are efficiently and effectively deployed through the BE Plan. The Commission finds that a program without any connector standards may overinvest in non-CCS/J1772 connectors, including CHAdeMO, which constitute a small and shrinking portion of the market, and will not be a reasonable use of ratepayer dollars in most contexts. As such, the Commission believes ComEd's approach should be narrowly tailored to support CHAdeMO plugs where analysis shows that equity considerations would be furthered by the inclusion of CHAdeMO plugs, and otherwise to require the deployment of CCS/J1772 plugs for light-duty public charging use cases. In addition to adopting charging standards for type of plugs under ComEd's BE Plan, the Commission directs ComEd to work with Staff and stakeholders to review and update such standards as appropriate in future BE Plans.

(viii) Section 45(d)(viii)

ComEd asserts that it will look for opportunities to coordinate and collaborate with federal and state agencies. ComEd points out that, through the Customer Awareness and Education Program, ComEd will help publicize federal and state incentive opportunities to ComEd customers. While this program confirms ComEd's commitment to passing on information to customers, it does not fully address ComEd's "opportunities for coordination and cohesion with [EV] and [EV] charging equipment incentives established by any agency, department, board, or commission of the State, any other unit of government in the State, any national programs, or any unit of the federal government." 20 ILCS 627/45(d)(viii). Accordingly, the Commission adopts Staff's recommendation that the Company include information on coordination with outside incentives provided in discovery as well as relevant coordination with programs from the IIJA and the IRA in its BE Plan filed as a compliance filing.

(ix) Section 45(d)(ix)

No party contests that ComEd complied with this Section 45(d)(ix). The Commission finds that ComEd's BE Plan addresses the required information.

(x) Section 45(d)(x)

Staff and Intervenors criticize the level of detail ComEd provided in its Consumer Education and Awareness Program. This issue is addressed in Section V.A.3. The

Commission finds that ComEd has provided the minimal information necessary to satisfy this statutory requirement.

2. EVA Public Interest Criteria Section 45(d)(1)-(8)

a. ComEd's Position

(i) Section 45(d)1)

Section 45(d)(1) of the EVA provides that a BE Plan is in the public interest if it is designed and reasonably expected to "maximize total energy cost savings and rate reductions so that nonparticipants can benefit." 20 ILCS 627/45(d)(1). ComEd contends that its BE Plan includes several measures designed and reasonably expected to maximize total energy savings and rate reductions to benefit nonparticipants. ComEd notes that Residential EV Charging Infrastructure Sub-program, Residential Optimized Charging Pilot, and existing time-variant pricing for C&I customers provide strong incentives to maximize total energy cost savings and rate reductions by timing their charging in the most cost-effective manner. ComEd argues this will mitigate costs to customers from paying for additional grid investments and mitigate the capacity charge in customers' bills.

ComEd points out that all residents of ComEd's service territory will benefit from the positive externalities of local air quality improvements, grid stability benefits, and carbon emission reductions that will result from the BE Plan's implementation.

ComEd states that the new EV Charging Delivery Classes are designed to minimize rate impacts and subsidization against rate classes. ComEd notes new EV Charging Delivery Classes will prevent residential customers from bearing the cost of make-ready improvements that support EV infrastructure for enrolled customers.

ComEd points out that the estimated rate impacts to customers are reasonable, and the inclusion of certain costs into a regulatory asset will further mitigate bill impact of the BE Plan.

(ii) Section 45(d)(2)

Section 45(d)(2) of the EVA provides that a BE Plan is in the public interest if it is designed and reasonably expected to "address [EJ] interests by ensuring there are significant opportunities for residents and businesses in eligible communities to directly participate in and benefit from [BE] programs." 20 ILCS 627/45(d)(2). ComEd states that each of the BE Programs is designed to promote EJ and equity. ComEd notes that the Residential and the C&I and Public Sector Programs include enhanced rebate levels for communities located in or serving EJ or R3 communities. ComEd points out that the Customer Education and Awareness Program includes targeted outreach to EJ and R3 communities.

(iii) Section 45(d)(3)

Section 45(d)(3) of the EVA provides that a BE Plan is in the public interest if it is designed and reasonably expected to "support at least a 40% investment of make-ready infrastructure incentives to facilitate the rapid deployment of charging equipment in or serving [EJ], low-income, and eligible communities; however, nothing in this subsection is intended to require a specific amount of spending in a particular geographic area." 20

ILCS 627/45(d)(3). ComEd contends that ComEd's BE Plan supports at least 40% investment of make-ready infrastructure incentives to facilitate the distribution of charging equipment in or serving EJ or R3 communities. ComEd notes that over 50% of the funding for make-ready infrastructure incentives are dedicated to customers located in or primarily serving EJ or R3 communities.

(iv) Section 45(d)(4)

Section 45(d)(4) of the EVA provides that a BE Plan is in the public interest if it is designed and reasonably expected to "support at least a 5% investment target in electrifying medium-duty and heavy-duty school bus and diesel public transportation vehicles located in or serving [EJ], low-income, and eligible communities in order to provide those communities and businesses with greater economic investment, transportation opportunities, and a cleaner environment so they can directly benefit from transportation electrification efforts; however, nothing in this subsection is intended to require a specific amount of spending in a particular geographic area." 20 ILCS 627/45(d)(4).

ComEd explains that its BE Plan directs at least 5% of funding toward electrifying medium-duty, heavy-duty, school bus, and public transportation bus incentives for those located in or primarily serving EJ or R3 communities. ComEd argues that the 5% investment target for low-income customers and EJ or R3 communities (equivalent to $5 million) will be greatly exceeded. ComEd notes its BE Plan provides for elevated rebates for customers located in or primarily serving EJ or R3 communities in the C&I Public Sector EV Purchase Sub-program, which sets aside $14 million for school bus and public transit bus purchase incentives, and $10 million and $13 million for heavy-duty purchase rebates and medium-duty purchase rebates, respectively. ComEd also notes eligibility for the $10 million C&I and Public Sector EJ/R3 Charging Make-Ready Infrastructure Sub-program is exclusively dedicated to customers located in or primarily serving EJ or R3 communities.

(v) Section 45(d)(5)

Section 45(d)(5) provides that a BE Plan is in the public interest if it is designed and reasonably expected to "stimulate innovation, competition, private investment, and increased consumer choices in electric vehicle charging equipment and networks." 20 ILCS 627/45(d)(5). ComEd argues that its BE Plan meets the objectives of Section 45(d)(5) through the Residential EV Charging Infrastructure Sub-program and the C&I and Public Sector EV Purchase Sub-program. ComEd argues that its Residential EV Charging Infrastructure Sub-program will create a large market for certified suppliers of EV chargers and encourage new suppliers to enter the market. ComEd argues that its C&I and Public Sector EV Purchase Sub-program will assist and increase the levels of EV adoption across various vehicle types, creating a larger market for charging equipment, network vendors, and stimulating innovation, competition, private investment, and increased consumer choices.

(vi) Section 45(d)(6)

Section 45(d)(6) provides that a BE Plan is in the public interest if it is designed and reasonably expected to "contribute to the reduction of carbon emissions and meeting

air quality standards, including improving air quality in eligible communities who disproportionately suffer from emissions from the medium-duty and heavy-duty transportation sector." 20 ILCS 627/45(d)(6). ComEd contends that its BE Plan will contribute to the reduction of carbon emissions and improve air quality in eligible communities.

ComEd points out that the C&I and Public Sector EV Purchase Sub-program directs significant portion of the sub-program's funds to rebates for medium- and heavy-duty vehicle fleets, and transit and school buses. ComEd notes the C&I and Public Sector EJ/R3 EV Charging Make-Ready Infrastructure Sub-program will put L2 and DCFC vehicle charges closer within reach. ComEd notes that both of these sub-programs provide either enhanced incentives or dedicated funding to customers located in or primarily serving EJ or R3 communities. ComEd mentions that potential EV adopters will be informed about the environmental impact of EVs through the Customer Education Awareness Program.

(vii) Section 45(d)(7)

Section 45(d)(7) provides that a BE Plan is in the public interest if it is designed and reasonably expected to "support the efficient and cost-effective use of the electric grid in a manner that supports electric vehicle charging operations." 20 ILCS 627/45(d)(7). ComEd states ComEd's BE Plan will support the efficient and cost-effective use of the electric grid. ComEd notes that customers enrolled in the Residential EV Charging Infrastructure Sub-program will receive price signals that will encourage more efficient and cost-effective use of energy. ComEd notes the Residential Optimized Charging pilot will integrate innovative technology that will allow vehicles to automatically adapt to system conditions. ComEd notes BE adopters have the option to enroll in hourly pricing. ComEd points out that the Customer Education and Awareness Program provides customers with helpful information to choose the appropriate rate tariff to match their EV charging needs.

(viii) Section 45(d)(8)

Section 45(d)(8) provides that a BE Plan is in the public interest if it is designed and reasonably expected to "[p]rovide resources to support private investment in charging equipment for uses in public and private charging applications, including residential, multi-family, fleet, transit, community, and corridor applications." 20 ILCS 627/45(d)(8). ComEd states that the Residential EV Charging Infrastructure Sub-program. ComEd notes the Customer Education and Awareness Program will provide educational resources to understand and examine EV and charging options.

b. Staff's Position

(i) Section 45(d)(1)

Staff states that the Commission should direct the Company to include in its compliance filing an analysis to demonstrate whether the investments and other expenditures in its BE Plan are designed and reasonably expected to maximize total energy cost savings and rate reductions so that nonparticipants can benefit, pursuant to Section 45(d)(1). The Commission should also limit the rate impact of ComEd's BE Plan on nonparticipants by approving Staff's reduced budget proposal as discussed in Section

V.C.1. Staff reviewed ComEd's BE Plan but, because ComEd did not perform any analysis of impacts on nonparticipant ratepayers, Staff had no basis to conclude that ComEd's proposed BE Plan's investments and other expenditures are designed and reasonably expected to maximize total energy cost savings and rate reductions so that nonparticipants can benefit. Staff Ex. 2.0 at 4.

In its rebuttal testimony, ComEd contends that Section 45(d)(1) does not require expected rates for nonparticipants to be lower after the BE Plan is implemented than they would have been if the BE Plan were not approved and implemented; Staff does not suggest otherwise. Instead, the Company asserts this criterion can be satisfied by appropriately including programs and structures that are designed to provide cost savings and associated rate reductions, in comparison to a scenario in which those programs and structures were not included, and from which nonparticipants can benefit. Specifically, ComEd suggests that overall opportunities for nonparticipants to benefit are driven by several factors, including reduced carbon emissions and surface-level pollutants. ComEd Ex. 8.0 at 12-13.

However, Staff states, rather than providing an analysis to show that the investments and other expenditures in ComEd's BE Plan are designed and reasonably expected to maximize total energy cost savings and rate reductions so that nonparticipants can benefit, ComEd takes issue with the need to do so. ComEd contends that ComEd's BE Plan need not ensure rate reductions are enjoyed by both participants and nonparticipants in BE Plan programs so long as the BE Plan is designed in such a way that any resulting rate increases for nonparticipants are smaller than they would have been otherwise. Staff Ex. 13.0 at 10-11.

ComEd contends that its BE Plan includes several measures to maximize total energy cost savings and rate reductions to benefit nonparticipants. Essentially, ComEd points to TOU pricing and the Residential Optimized Charging pilot as efforts which help mitigate additional grid investments that would otherwise be needed. While it is not unreasonable to assume TOU pricing and the Residential Optimized Charging Pilot could have this effect, ComEd did not perform any analysis of impacts on nonparticipant ratepayers.

Staff disagrees with ComEd's interpretation of the statute. As a practical matter, there is simply no way to ascertain, after the BE Plan is implemented, what rates would have been absent the BE Plan; customer rates are based on the vast number of components in the utility's rate base and these components are not static. Instead, this provision should be interpreted to mean that, to the extent the BE Plan results in cost savings or other benefits, those benefits should be shared by all ratepayers and not limited to only those that participated in a program. As such, the Commission should ensure that benefits are not serving simply to enrich a particular customer or recipient.

Even if ComEd is correct that the Company only needs to demonstrate the BE Plan is designed so that any resulting rate increases for nonparticipants are smaller than they would otherwise have been, the Commission cannot properly make this determination absent any analysis of the impact on nonparticipant ratepayers. ComEd did not provide any additional information on this issue in its Initial Brief. Instead, ComEd criticizes Staff for not identifying a method for analyzing ratepayer impact. ComEd's allegation is

contradicted by the record evidence, and indeed ignores the fact that the obligation to demonstrate compliance with EVA is the Company's, not Staff's, as the party seeking relief – here, ComEd - generally bears the burden of proof. *People v. Orth*, 124 Ill. 2d 326, 337 (1988). Staff witness Sanders testified that a ratepayer impact measure ("RIM") or similar test would provide sufficient information on the long-term impact on customer rates (Staff Ex. 6.0) and reiterated and expanded on this in his rebuttal testimony (Staff Ex. 17.0). In his rebuttal testimony, Staff witness King also recommended ComEd provide an analysis of ratepayer impact and recommended the Commission direct ComEd to provide the RIM results or results of a similar test that separates effects on ratepayers for each of its programs and BE Plan as a whole, as reiterated in Mr. Sanders' rebuttal testimony, if it did not agree to do so voluntarily. Staff Ex. 14.0 at 31.

Staff concludes that ComEd has failed to make a required showing and the Commission should direct the Company to include in its compliance filing an analysis to demonstrate whether the investments and other expenditures in its BE Plan are designed and reasonably expected to maximize total energy cost savings and rate reductions so that nonparticipants can benefit pursuant to 20 ILCS 627/45(d)(1). The Commission should also limit the rate impact of ComEd's BE Plan on nonparticipants by approving Staff's reduced budget proposal as discussed in Section V. C. 1.

(ii) Section 45(d)(2)

The Commission also should direct the Company to include in its compliance filing a pilot addressing issues raised by Staff and to work with Staff to develop rules that will prevent abuse of the incentives offered in the BE Plan's sub-programs to be included in its compliance filing so that it satisfies the objective set forth in Section 45(d)(2).

Initially Staff was concerned that some of the sub-programs that the Company used to achieve this objective could be impacted by the Interim Order; that remaining incentives mostly required purchase or ownership of an EV; and that limited funds were unlikely to go to members of eligible communities in the proportion expected by ComEd. Staff Ex. 3.0 at 8-9. To address these concerns, Staff recommended the Company include a vehicle sharing program or other program that would allow participation without requiring vehicle ownership in addition to the Company's transit vehicle incentives and that the Company ensure that incentivized vehicles remain in its service territory. Staff Ex. 3.0 at 9-10.

ComEd modified its BE Plan to include a pilot to explore vehicle sharing. ComEd Ex. 12.0 REV at 22-23. Additionally, the Company agreed that it would limit rebates to ComEd customers and stated that the Company "would be open to meeting with Staff prior to implementation to discuss potential guidelines, as Staff recommends, if Staff can offer a practicable pathway to enforcing such guidelines." ComEd Ex. 12.0 REV at 17-18.

The Commission should direct the Company to include the results of such meetings with Staff as well as the vehicle sharing pilot described in surrebuttal testimony in a compliance filing so that it meets the objective set forth in Section 45(d)(2).

(iii) Section 45(d)(3)

The Company provided differing and contradictory information regarding what sub-programs in its BE Plan meet the objective in Section 45(d)(3). Specifically, it is unclear whether incentives provided through the C&I BE Infrastructure Readiness Sub-program, Residential BE Infrastructure Readiness Sub-program, C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program, and Residential EV Charging Infrastructure Sub-program all target this objective or if only incentives from the latter two sub-programs should count toward this goal. Staff Ex. 14.0 at 20-21. Staff believes only incentives from the latter two should count, as reflected in Staff's proposed budget. Staff has repeatedly expressed concerns over the inclusion of non-transportation measures in the Company's BE Plan and firmly believes that such measures should not be included. Even if the Commission approves these programs despite Staff's objections, ComEd's proposed C&I BE Infrastructure Readiness Sub-program and Residential BE Infrastructure Readiness Sub-program are not related to EVs, do not "facilitate the rapid deployment of charging equipment" contemplated by the statute (Staff Ex. 14.0 at 20-21; Staff Ex. 16.0 at 15-16) and thus do not qualify as make-ready infrastructure incentives for purposes of meeting the objective set forth in 20 ILCS 627/45(d)(3).

The sub-programs in Staff's proposed BE Plan budget (Staff Ex. 17.1) that satisfy the requirements of Section 45(d)(3) are the C&I and Public Sector Infrastructure Sub-programs and the Residential EV Charging Infrastructure Sub-program. The former has $3.8 million allocated to eligible communities and $1.3 million allocated for others. The latter has $2.13 million allocated to eligible communities and $2.13 million allocated for others. All figures exclude administration costs. Assuming that 50% of Residential EV Charging Infrastructure incentives fund make-ready infrastructure rather than charging equipment for all customers, $4.84 million out of $7.17 million, or 67%, of make-ready infrastructure incentives will be allocated to eligible and/or low-income customers. Even if all of the Residential EV Charging Infrastructure rebates allocated to eligible and/or low-income customers cover charging equipment instead of make-ready infrastructure, at least 40% of total make-ready infrastructure incentives will still be allocated to eligible and/or low-income communities because of the amount of make ready infrastructure incentives targeting eligible communities in the C&I and Public Sector program. Staff Ex. 14.0 at 21-22.

The Commission should modify ComEd's BE Plan to reflect Staff's proposed budget (Staff Ex. 17.1) to meet this objective (Staff Ex. 14.0 at 21-22). Specifically, the Commission should approve of the methodology Staff used to calculate whether this 40% investment target has been met. The Commission should order the Company to track the proportions of residential incentives covering make-ready infrastructure versus charging equipment for eligible communities as well as others and include this information in its annual report. The Commission should also approve ComEd's method of determining when make-ready infrastructure primarily serves eligible and/or low-income communities proposed by ComEd and reject the one proposed by EVgo. Staff Ex. 14.0 at 22-23.

Staff also recommends that ComEd be directed to include data in its annual report on the proportion of incentives from these programs covering make-ready infrastructure to enable evaluation of whether the assumption that these proportions are equal is

accurate for future filings. In addition, ComEd should track and report on the share of overall project costs that make-ready infrastructure represents. *Id*.

EVgo Services recommends that ComEd define sites that are "primarily serving" low-income/EJ/R3 communities as those within the communities as defined by statute or within a "one-mile buffer zone." EVgo Ex. 1.00 at 18. Additionally, EVgo recommends that ComEd develop a scoring rubric under which it or an implementation contractor will evaluate applications to its C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program. As ComEd notes, such a definition would result in disproportionate benefits accruing to entities locating chargers in downtown Chicago and other areas which are not EJ and R3 communities. ComEd Ex. 7.0 at 26. EVgo recommends adopting a one-mile buffer zone, using a method employed by PSEG Long Island ("PSEGLI"). EVgo Ex. 1.0 at 18. However, as employed by PSEGLI, the buffer zone is only considered for DCFC installations; L2 installations are based on whether the "[l]ocation is within the geo-boundary defining a l[ow-income]/EJ community, or can be demonstrated to be sufficiently close to an LI/EJ community to directly support the needs of those residents, for ports based on J1772 plugs." Staff Ex. 14.0 at 22-23.

In rebuttal, ComEd clarified that the Company will determine charging stations to primarily serve "an EJ/R3 community, if the applicant demonstrates that over 50% of the driving done by vehicles to be served by the charging infrastructure will be in EJ/R3 communities." ComEd Ex. 7.0 at 25. Staff supports this methodology. Staff Ex. 14.0 at 22-23.

Staff states that the Commission should:

- find that non-transportation initiatives in ComEd's BE Plan do not qualify as make-ready infrastructure incentives for purposes of meeting the objective set forth in 20 ILCS 627/45(d)(3);
- find that Staff's proposed budget (Staff Ex. 17.1) meets this objective;
- approve Staff's method of performing this calculation;
- order the Company to track the proportions of residential incentives covering make-ready infrastructure versus charging equipment for eligible communities as well as others (Staff Ex. 14.0 at 21-22); and
- approve the method of determining when make-ready infrastructure primarily serves eligible and/or low-income communities proposed by ComEd and reject the one proposed by EVgo (Staff Ex. 14.0 at 22-23).

(iv) Section 45(d)(4)

ComEd addresses the objective in Section 45(d)(4) in the BE Plan through the C&I and Public Sector EV Purchase Sub-program and the C&I and Public Sector EJ/R3 EV Charging Infrastructure sub-program. ComEd Ex. 1.01 at 52. These programs propose to support at least a 5% funding from BE Plan Budget for electrifying education and public transit medium-duty and heavy-duty vehicles located in or serving eligible communities. Based upon the above rationale, Staff recommends that the Commission find that the ComEd BE Plan is reasonably expected to achieve the objective set forth in Section 45(d)(4). Staff 15.0 at 4.

(v) Section 45(d)(5)

ComEd proposes to meet the objectives of Section 45(d)(5) through its Residential EV Charging Infrastructure Subprogram and C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program, which will distribute rebates for Residential and C&I EV chargers. ComEd Ex. 1.01 at 52. Staff states that the Commission should find that ComEd's proposed BE Plan meets the objective set forth in 20 ILCS 627/45(d)(5). Staff Ex. 3.0 at 6.

These programs will provide more information and incentives to customers, which will help ensure that the markets for charging equipment and networks remain competitive while also creating business opportunities for providers of charging equipment and charging networks. Additionally, sub-programs in ComEd's BE Plan incentivize make-ready infrastructure thereby reducing costs to customers. ComEd Ex. 1.01 at 52.

(vi) Section 45(d)(6)

The objective in Section 45(d)(6) was addressed in ComEd's BE Plan as modified by Staff's recommendation to support the Air Quality Mapping Pilot and the C&I and Public Sector EV Purchase sub-program. ComEd Ex. 1.01 at 53. Staff's proposed budget reflects the Company's original proposal, which directs a significant portion of funds under these sub-programs to medium and heavy-duty vehicle fleets and transit and school buses. ComEd 1.01 at 53. If given approval of the localized emission assessment recommendation below, Staff recommends that the Commission find that the ComEd BE Plan is reasonably expected to achieve the objective set forth in Section 45(d)(6). Staff Ex. 15.0 at 4.

The Commission should approve Staff's recommendation and direct ComEd to pursue an Air Quality Mapping ("AQM") pilot to conducting local emission assessments which will verify the estimates for eligible communities from Pollutant Tracking Metric #1, "Emission Reductions Supported by ComEd Programs," approved in Docket No. 22-0067 (Order at 212) and the BE Plan (ComEd Ex. 1.01 at 59).

Section 16-108.18 of the Act requires the utility to consider programs which

> Minimize emissions of greenhouse gases and other air pollutants that harm human health, particularly in environmental justice and equity investment eligible communities, through minimizing total emissions by accelerating electrification of transportation, buildings and industries where such electrification results in net reductions, across all fuels and over the life of electrification measures, of greenhouse gases and other pollutants, taking into consideration the fuel mix used to produce electricity at the relevant hour and the effect of accelerating electrification on electricity delivery services rates, supply prices and peak demand, provided the revenues the utility receives from accelerating electrification of transportation, buildings and industries exceed the costs.

220 ILCS 16.108.18(e)(3)(A).

Emissions reductions are based on estimates for eligible communities which may not accurately reflect local conditions. Staff testified that ComEd should either (1) use existing environmental impact measurements technology for local community assessment or (2) modify ComEd's proposed pilot program project entitled "Air Quality Mapping (AQM) Pilot," to help determine whether BE Plan activities had achieved the desired reduction of pollutants in eligible communities consistent with 20 ILCS 627/45(d)(6). Staff Ex. 4.0 at 9-11. ComEd removed the AQM pilot project from its list of proposed projects, which highlights the need for Commission action on this matter. ComEd Ex. 12.0 REV at 23. Recent research indicated that granular analysis smaller than the State or county area is required to avoid masking or understating the environmental impacts experienced by those communities due to existing or past sources of pollution. Moreover, estimated methods may not accurately reflect local conditions in eligible communities without further validation to corroborate the purported reductions. Staff Ex. 15.0 at 8-10.

Staff states that BE Pilot projects serve to inform the Company and stakeholders about how effectively BE programs achieve the requirements of the EVA, in this case, the requirements of Section 45(d)(6) – improving air quality in eligible communities. Regardless of whether the AQM pilot project remains part of ComEd's suite of BE pilot projects, there remains an obligation to validate the emission reductions estimates with local emission data either to ascertain the accuracy of the model used to develop the estimates or to make an accurate assessment of the emissions reduction based on empirical data. These localized emission assessments can then be used as a tool to improve future BE Plan outcomes consistent with 20 ILCS 627/45(d)(6). The Commission should approve the Staff's recommendation and direct ComEd to pursue an AQM pilot to obtain localized emission data because it more accurately reflects localized conditions in eligible communities.

ComEd argued that an AQM pilot program was not a good fit within its BE Plan. The purpose of the AQM pilot is to develop more accurate air quality technology to measure at a hyper-localized, granular level to understand the severity of air quality issues which impacts those living in eligible communities. Staff Cross Ex. 1.0 at 7. However, the issue is not the development of new air monitoring technology through the BE Pilot Program but rather how to best address the statutory language in the EVA "... including improving air quality in eligible communities who disproportionately suffer from emissions from the medium-duty and heavy-duty transportation sector[.]" 20 ILCS 627/45(d)(6). Estimated methods may not accurately reflect local conditions in eligible communities without further validation to corroborate the purported reductions. Staff Ex. 15.0 at 9-10. While it may be appropriate to initially refer to the estimates citing the reduction of 900,000 metric tons of carbon dioxide (ComEd IB at 4), it is improper to utilize these estimates over the long term without validation and verification through empirical localized data, to show whether improvement has occurred. If ComEd were permitted to rely on estimates for the long term, results may not be entirely accurate or representative of the air quality in those eligible communities. Thus, if the Commission agrees with Staff that establishing an accurate baseline of actual air quality within eligible communities is necessary to establish whether ComEd's BE Plan activities have "improv[ed the] air quality in eligible communities who disproportionately suffer from emission from the medium-duty and heavy-duty transportation sector," it should accept Staff's

recommendation and direct ComEd to utilize localized emissions data, as it more accurately reflects the actual conditions within eligible communities. Staff is not opposed to ComEd utilizing applicable localized emissions data obtained from independent third-party organizations to validate and verify its emission reduction estimates. However, consistent with the intent of the EVA, the Commission should direct ComEd to utilize localized emission data from eligible communities to demonstrate whether there is improvement in air quality as a result of BE Plan activities.

(vii) Section 45(d)(7)

Section 45(d)(7) requires ComEd's BE Plan "to support the efficient and cost-effective use of the electric grid in a manner that supports electric vehicle charging operations." 20 ILCS 627/45(d)(7). ComEd addresses these requirements through its School Bus Vehicle to Grid pilot and a Residential Optimized Charging pilot (ComEd 1.01 at 54), both of which Staff recommends the Commission adopt (see Section V.A.4). Assuming the Commission approves these pilots, Staff recommends the Commission find that the Company's BE Plan has met the specific objective set forth in Section 45(d)(7). Staff Ex. 5.0 at 4.

(viii) Section 45(d)(8)

Section 45(d)(8) requires the Commission to consider whether the investments and other expenditures are designed and reasonably expected to "provide resources to support private investment in charging equipment for uses in public and private charging applications, including residential, multi-family, fleet, transit, community, and corridor applications." 20 ILCS 627/45(d)(8). This objective was addressed in the BE Plan through the Residential EV Charging Infrastructure Sub-program and the C&I and Public Sector EJ/R3 EV Charging Infrastructure Sub-program. ComEd Ex. 1.01 at 54. Staff recommends that the Commission finds that the ComEd BE Plan is reasonably expected to achieve the objective set forth in Section 45(d)(8).

c. AG's Position

(i) Section 45(d)(1)

The AG asserts that ComEd's BE Plan places substantial upward pressure on rates and will not allow non-participants to financially benefit, thus violating Section 45(d)(1). *See* infra Section V.D.3. To rectify this problem, the AG requests that the Commission reduce the Company's total BE Plan spending to $28 million, as discussed in Section V.C.1.

d. ChargePoint's Position

(i) Section 45(d)(5)

ChargePoint strongly supports and appreciates that ComEd has designed its EV charging infrastructure programs to support site hosts' ability to choose the EV charging solution that works best for them. ChargePoint asserts that customer choice is the key program design feature that allows the competitive market dynamics that exist in the absence of a utility program to function within the utility program, which stimulates innovation and private investment. According to ChargePoint, parties generally agree that the design of ComEd's BE Plan programs meet the criterion in Section 45(d)(5).

(ii) Section 45(d)(8)

ChargePoint explains that the EVA requires the Commission to consider whether ComEd's BE Plan investments are designed and reasonably expected to (among other considerations): "provide resources to support private investment in charging equipment for uses in public and private charging applications, including residential, multi-family, fleet, transit, community, and corridor applications." 20 ILCS 627/45(d)(8). ChargePoint again asserts that, by restricting eligibility for the Make-Ready Infrastructure Rebate program, ComEd has only proposed to "provide resources to support private investment in charging equipment" to some customers and not to others. According to ChargePoint, while the EVA clearly emphasizes investments in eligible communities, there is no indication that the General Assembly intended ComEd to make infrastructure investments exclusively in eligible communities and public sector customers. By limiting eligibility and proposing a relatively small budget for the Make-Ready Infrastructure Rebate program, ChargePoint concludes that ComEd's proposals needlessly limit the resources that will be available to support private investment in charging equipment. ChargePoint recommends that the Commission should expand both eligibility and the budget for the Make-Ready Infrastructure Rebate program.

e. Commission Analysis and Conclusion

(i) Section 45(d)(1)

The Commission agrees with Staff that ComEd should conduct an analysis of the impact on nonparticipant ratepayers. ComEd argues that such an analysis is not required by the EVA. However, this analysis will help determine whether ComEd's BE Plans meet the objective of Section 45(d)(1). The Commission directs ComEd to include in its compliance filing an analysis to demonstrate whether the investments and other expenditures in its BE Plan are designed and reasonably expected to maximize total energy cost savings and rate reductions so that nonparticipants can benefit.

The BE Plan's budget is discussed in Section V.C.1.

(ii) Section 45(d)(2)

ComEd committed to include a Ridesharing program (or other pilot program aimed at providing EV access to low-income and EJ/R3 customers for whom car ownership is not an option), which alleviates one of Staff's concerns regarding meeting the objective in Section 45(d)(2). ComEd further states that it is open to meeting with Staff to discuss potential guidelines to ensure incentivized vehicles remain in ComEd's service territory. Staff requests that the Ridesharing program and results of ComEd's meetings with Staff regarding potential guidelines be included in the Company's compliance filing. The Commission agrees and ComEd is so directed. The Commission finds that ComEd has met the objectives set forth in Section 45(d)(2).

(iii) Section 45(d)3)

The programs that ComEd states go towards the objective of Section 45(d)(3) are the Residential EV Charging Infrastructure Sub-program ($5 million), the Residential BE Infrastructure Readiness Sub-program – Residential BE Infrastructure Rebate ($1 million) and the EJ/R3 Charging Make-ready Infrastructure Sub-Program ($20 million). With these programs, the Commission finds that ComEd's proposed BE Plan portfolio, even

as adjusted by the Commission, will meet or exceed the required 40% investment of make-ready infrastructure incentives to serve EJ/R3 and eligible communities.

The overall BE Plan budget is discussed in Section V.C.1. Section V.A.1 further addresses the Residential Program, and Section V.A.2 further addresses the EJ/R3 Charging Make-ready Infrastructure Sub-Program.

(iv) Section 45(d)4)

No party contests whether ComEd has met the objective in Section 45(d)(4). The Commission finds that ComEd has met this objective.

(v) Section 45(d)5)

No party contests whether ComEd has met the objective in Section 45(d)(5). The Commission finds that ComEd has met this objective.

(vi) Section 45(d)(6)

ComEd points to its C&I and Public Sector EV Purchase Sub-program and the Customer Education and Awareness Programs in stating that it has met the goals of Section 45(d)(6). Staff argues that ComEd should include an Air Quality Mapping pilot, which the Commission rejected in this first BE Plan (see Section V.A.4.). However, Staff does not appear to argue that ComEd fails to meet the objective of Section 45(d)(6) absent this pilot program. The Commission finds that ComEd has met the objective of Section 45(d)(6).

(vii) Section 45(d)(7)

No party contests whether ComEd has met the objective in Section 45(d)(7). The Commission finds that ComEd has met this objective

(viii) Section 45(d)(8)

ChargePoint argues that the eligibility requirements for ComEd's proposed C&I and Public Sector EJ/R3 Charging Make-Ready Infrastructure Sub-program limits resources that will be available to support private investment in charging equipment. This issue is addressed in Section V.A.2. The Commission further notes that it expanded eligibility requirements. The Commission finds that ComEd has met the objective of Section 45(d)(8).

3. Benefit-to-Cost Analysis Section 45(d)

a. ComEd's Position

The EVA requires that the Commission must determine the proposed BE Plan to be "cost-beneficial" based on a comparison of "the total cost of [BE] expenditures" with identified benefits associated with the BE Plan. 20 ILCS 627/45(d). ComEd states that it performed a BCA that is structured to align with the statutory language, and the BCA shows that ComEd's BE Plan is cost-beneficial.

ComEd states that its BE Plan produces net benefits in the amount of approximately $197 million. ComEd notes that the total costs of BE expenditures under the BE Plan is approximately $448 million, and the sum of "net present value of increased electricity costs … avoided by programs under the plan, the net present value of

reductions in other customer energy costs, net revenue from all electric charging in the service territory, and the societal value of reduced carbon emissions and surface-level pollutants, particularly in environmental justice communities," (20 ILCS 627/45(d)) is approximately $645 million. ComEd Ex. 13.0 REV at 4-7.

ComEd states that the benefit of "increased electricity costs…avoided by programs under the plan" is estimated be $3 million. *Id*. at 5. ComEd notes it based this estimate on the avoided energy, capacity, transmission, and distribution costs resulting from shifting or eliminating current electricity usage (e.g., a customer charging off-peak versus at times throughout the day). ComEd states this benefit will be realized as the BE Plan programs shift or eliminate sources of electricity usage in a way that avoids higher electricity costs.

ComEd estimates that the benefit of "reductions in other customer energy costs" to be valued at $509 million. ComEd notes it calculated this benefit as the avoided cost of the fuel associated with the non-electric technology that is replaced by the respective electric technology.

ComEd explains that it adopted a conservative assumption of $0 for the benefit of net revenue from all electric charging in ComEd's service territory. ComEd notes that such revenues are speculative at this point, which justifies ComEd's assumption.

ComEd estimates that the societal value of the reduced carbon emissions and surface level pollutants from its BE Plan will be $60 million and $73 million, respectively. ComEd notes that these estimates are based on governmental source estimates of the emission rates of carbon and surface level pollutants, and monetized values of harm resulting from those emissions.

ComEd estimates the incremental purchase cost for EV and non-EV electrification applications to cost $177 million. ComEd estimates the incremental maintenance cost for applicable electric technology to cause a net savings of $112 million because the maintenance cost of the applicable electric technology is generally expected to be lower than the comparable fossil-fuel based technology. ComEd estimates the costs for incremental charging, installation, and make-ready infrastructure associated with the BE Plan to be $123 million. ComEd estimates the increases in energy and capacity costs to be $52 million. ComEd estimates the increases in electric transmission and distribution costs to be $80 million. ComEd estimates the cost for ComEd's education and awareness efforts to be $26 million. ComEd estimates the cost for administrative and other program spending to be $102 million. And ComEd states that it assigned a net value of zero for the portion of the BE Plan budget for pilots and technical demonstrations because the BE Pilot Program's main purpose is to gain learning benefits that are not well suited to quantification.

ComEd states that it incorporated two of the four proposed adjustments to its BCA from Staff and the AG. ComEd notes its BCA assumes no vehicle-to-grid benefits are attributed to school buses that are not participating in ComEd's School Bus Vehicle to Grid Pilot. ComEd notes it adjusted its calculation approach used to estimate the effect of avoided surface pollutants.

ComEd argues that the Commission should reject Staff and AG's proposals to incorporate an adjustment for free ridership in the BCA. ComEd notes that ComEd's approach without a free ridership adjustment is consistent with approaches for other Commission-approved incentive programs. ComEd argues its approach not adjusting for free ridership is consistent with the goals of the EVA by recognizing every instance of adoption of the applicable technology provides societal benefits.

ComEd argues that Staff's proposed sensitivity analysis of BCA by assuming the maintenance cost savings for a school bus is equal to the estimated maintenance cost savings for a passenger vehicle. ComEd states that its school bus maintenance cost savings estimate is reasonable and that the effect of Staff's proposed sensitivity analysis results in an immaterial reduction in the total net benefit of the BE Plan.

ComEd contends its BCA is robust and complete, using the best available information and estimates at the time of analysis. ComEd notes that the EVA does not require ComEd to perform any sensitivity analyses of the BCA. ComEd points out that, notwithstanding the lack of a statutory requirement, ComEd presented additional sensitivity analyses that show that ComEd's BCA calculation is robust.

ComEd disagrees with Staff's recommendation that ComEd provide an additional BCA of each sub-program within its BE Plan. ComEd states that the EVA requires the Commission to find that the BE Plan as a whole is "cost-beneficial." ComEd points out that because there is an interdependency between the programs and sub-programs of within the BE Plan, attempting to develop separate BCAs for each program or sub-program could lead to misleading cost effectiveness assessments.

ComEd also disagrees Staff's assertion that the BCA is flawed because the rebate amounts may change, resulting in changes to the projected number of customers who would accept a rebate is irrelevant. ComEd argues that Staff's assertion is not relevant to showing that ComEd's proposed BE Plan is cost-beneficial because the assertion does not relate to the BCA that ComEd is required to present by statute, and it simply states an obvious truism.

b. Staff's Position

Staff asserts that the Commission should find that Staff's proposed budget (Staff Ex. 17.1) is cost-beneficial. Additionally, the Commission should order the Company to account for free ridership in its BE Plan using net-to-gross ("NTG") ratio of 80% until a different value is justified through evaluations of ComEd's or other similar programs or unless otherwise agreed to by stakeholders. The Commission should also order the Company to provide sub-program-level benefit-cost analyses for the components of its BE Plan and present it in its compliance filing and future BE Plan filings. Staff Ex. 14.0 at 33-34.

Staff provides an analysis of Staff's proposed budget showing that, using ComEd's BCA tool with modifications, it is cost-beneficial. Although ComEd asserts there are errors in this evaluation, the Company acknowledges Staff's proposed budget is still cost-beneficial when the errors are corrected. ComEd Ex. 13.0 REV at 14-15.

Staff's BCA analysis reflects the following assumptions and modifications:

- sub-program budgets are set to the amounts described in Staff's proposed budget;
- proportions of funds going to eligible communities for C&I and Public Sector rebates are set to the amounts described in Staff's proposed budget;
- incremental costs and benefits are scaled by 80% to reflect Staff's proposed NTG ratio;
- no V2G benefits from rebated buses are assumed;
- the analysis uses lower maintenance cost savings per mile ($0.04) than the one claimed in Blue Bird promotional materials used in ComEd's original analysis ($0.14).

Staff Ex. 14.0 at 33-34.

Staff raised a number of initial concerns with the BCA of ComEd's proposed BE Plan. While Staff takes no issue with ComEd's use of the total resource cost test, which includes most components that the statute specifies, the Company fails to base its calculation of costs and benefits on "net impacts." 20 ILCS 647/45(d). Staff's primary concern with ComEd's BCA is that it attributes 100% of emissions reductions and other EV-related benefits to ComEd's BE Plan. A proper benefit-cost analysis of a BE Plan should not account for benefits and costs that would have occurred absent the BE Plan. Staff Ex. 3.0 at 20-22.

One method of accounting for free ridership is through the use of an NTG ratio, also called an attribution factor. The NTG ratio is used to account for the fact that, even when an incentive is provided, not all incentivized behavior that occurs can be directly attributed to that incentive. For example, a NTG of 50% implies that 50% of recipients still would have made a purchase even if no incentive were offered.

The Company's BCA assumes a 100% NTG ratio, but there is ample reason to believe that 100% is not a reasonable NTG ratio for ComEd's BE Plan. A review of Massachusetts EV rebates found that 59% of recipients would have purchased EVs without rebates, while a study of federal tax credits found that 70% of recipients would have purchased EVs without the incentive. Staff Ex. 3.0 at 10. Staff thus recommended that the Company develop reasonable attribution assumptions that link the incentives provided by the Company to emissions reductions. Staff Ex. 3.0 at 21-22.

ComEd refused to adjust its BCA to implement any method of accounting for the fact that many people receiving benefits from its BE Plan would have purchased EVs even absent the incentives provided. The Company claims that it assigns value to every instance of EV adoption "associated with" a BE Plan rebate. Furthermore, ComEd claims that its programs provide incentives "regardless of the extent to which the incentive contributed to [the customer's] decision." ComEd Ex. 8.0 at 3; ComEd Ex. 13.0 REV at 8. Staff asserts that this description belies the exact issue that the Company refuses to solve by using a more reasonable NTG ratio. The BCA for a BE Plan should not include benefits and costs of every EV adoption associated with the BE Plan; it should only include benefits and costs of every EV adoption that results from the BE Plan. According to Staff, the Company appears to be aware of this distinction and acknowledged that "inclusion of emissions reductions that occur for reasons other than the BE Plan should be avoided." Staff Cross Ex. 1.0 at 13-14. As Staff has explained, there is no question

that EV adoption creates societal benefits. The question is the extent to which these benefits are attributable to actions taken by the Company as part of its BE Plan and thus how and to what extent they should be included in the BCA of the BE Plan. Staff Ex. 14.0 at 26-27.

Although it would be unreasonable to expect the Company to know with certainty whether any particular EV adoption was a result of the BE Plan, a NTG ratio acts functionally the same by discounting incremental costs and benefits by a reasonable proportion. Staff asserts that ComEd should use a NTG of less than 100% in its BCA to ensure that stakeholders and the Commission have a more realistic accounting of the costs and benefits associated with its Plan. While, as noted above, studies support an NTG of 59% to 70%, Staff proposes 80% as a reasonable compromise until ComEd has sufficient information to ascertain the actual NTG associated with its BE Plan.

Staff also expressed concerns with the failure of ComEd's BCA to account for the disproportionate effect of surface pollutants in EJ communities. Staff Ex. 3.0 at 22. ComEd's BCA accounted for this effect by using the United States Department of Energy's Alternative Fuel Life-Cycle Environmental and Economic Transportation ("AFLEET") tool's values for Cook County, IL. The reasoning given was that most of the EJ communities in ComEd's service territory are in Cook County. Staff Ex. 3.1 at 20. However, as Staff pointed out, this method assigns the same benefit to surface level pollutant reduction everywhere in ComEd's service territory, regardless of the actual level of pollution, and thus does not account for any disproportionate effects in EJ and R3 communities. To address this concern, Staff recommended use of relevant AFLEET values for each county in ComEd's service territory rather than assigning Cook County values to all counties, or some other similar method. Staff Ex. 3.0 at 22.

As discussed in Section V.D.1, above, ComEd's BCA fails to account for the impact on customer rates, as specified by the EVA (20 ILCS 627/45(d)). Specifically, Section 45(d) states: "The calculation of costs and benefits should be based on net impacts, *including the impact on customer rates*." 20 ILCS 647/45(d) (emphasis added). Although ComEd's BCA takes effects on ratepayers into account when assessing overall cost-effectiveness, the impact on ratepayers is not isolated and thus is not clear from the analysis presented. Staff Ex. 3.1 at 27. This calculation is important because some benefits to ratepayers, such as emissions reductions, will not have a direct effect on rates but the costs to implement the programs that achieve those reductions will. Staff Ex. 6.0 at 13. Given the size of ComEd's proposed BE Plan, these effects will not be insignificant. Staff Ex. 3.0 at 22. ComEd has not provided the analysis requested by Staff. The AG raised similar concerns about the lack of a secondary cost-effectiveness test to determine the impact on overall rates. AG Ex. 1.0 at 39.

Ameren's Ratepayer Impact Measure test in Docket Nos. 22-0431/22-0443 (Cons.), which is intended to separate out the effects on ratepayers (including non-participants), is an example of an analysis that would address Staff's concerns. Staff Ex. 6.0 at 14. Staff asserts that the Commission should require ComEd to provide such an analysis so that the true impact on ratepayers can be assessed.

Staff also took issue with the inclusion in ComEd's BCA of benefits of V2G for school buses other than those participating in ComEd's proposed pilot specifically

examining school bus V2G as well as the reliance on advertising material from Blue Bird Electric School Buses to estimate the maintenance costs reductions compared to ICE school buses. Staff Ex. 3.0 at 23. ComEd performed sensitivity analyses incorporating specific recommendations made by Staff (ComEd Ex. 8.0 at 6-8) and agreed to accept these adjustments to its BCA calculation in its surrebuttal (ComEd Ex. 13.0 REV at 3-4.) Specifically, the Company adopted Staff's recommended approach for accounting for the disproportionate effect of surface pollutants on EJ communities and the exclusion of V2G benefits for electric school buses not participating in ComEd's proposed V2G pilot.

Staff recommends that ComEd provide sub-program-level BCAs. Staff points out that sub-program-level BCAs are useful both to Staff and to stakeholders who seek to understand which sub-programs are not cost-effective and how other sub-programs balance these out, as well as which programs provide benefits that ComEd has deemed intangible. The costs of one sub-program may be offset by the benefits of another. However, as the Company modifies various programs in response to Staff and Intervenor recommendations, it is essential that the parties and the Commission are aware of how the parts combine to create the whole. Staff Ex. 3.0 at 23-24. ComEd did not provide any BCAs at the sub-program level and claimed that this is not necessary. ComEd argued it is not necessary because the statute requires the BE Plan to be cost-beneficial at the BE Plan level rather than at the program or sub-program level. ComEd Ex. 8.0 at 9-12; ComEd Ex. 13.0 REV at 11-12. While only the BE Plan as a whole is required to be cost-beneficial, the same is true of the utilities' EE plans and ComEd has always provided sub-program-level BCAs for its EE plans. Staff asserts that ComEd should do the same for its BE Plans.

While ComEd claims that providing such analyses "could lead to misleading cost effectiveness assessments and conclusions" (ComEd Ex. 13.0 REV at 12), Staff believes that providing additional information will allow the Commission and stakeholders to more accurately assess whether the interdependencies between programs claimed by ComEd are reasonable.

c. AG's Position

The AG requests that the Commission reduce ComEd's total BE Plan budget because the Company's surrebuttal proposal will place large upward pressure on rates and creates no financial benefits for non-participants. As explained by the AG, the Commission must determine that the BE Plan is cost-beneficial and that analysis must "be based on net impacts, including the impact on customer rates." 20 ILCS 627/45(d). The AG states that this section—when combined with Section 45(d)(1) which explicitly states that in approving the BE Plan the Commission must consider whether the plan is reasonably expected to "maximize total energy cost savings and rate reductions so that nonparticipants can benefit" — demonstrate that the cost-benefit analysis should include an analysis concerning customer rates and a conclusion that a utility's BE Plan will produce bill savings. 20 ILCS 627/45(d)(1).

The AG asserts that ComEd's BCA did not consider the effect on customer rates or the impact of the BE Plan on non-participants, as required by the EVA under Sections 45(d) and 45(d)(1). Instead, ComEd's BCA which it included in its surrebuttal testimony compared net benefits to net costs and concluded that the BE Plan would provide a total

net benefit of $197 million based on $448 million in costs and $645 million in net benefits. *See* ComEd Ex. 13.0 REV at 4-7. As shown in ComEd's analysis, the largest benefit ($509 million of the $645 million found by ComEd) is avoided fuel (gasoline/diesel) costs, which are benefits that accrue solely to program participants purchasing an EV. *Id*. at 5.

To remedy the issue of ComEd not considering the impact of the BE Plan on customer rates and non-participants, the AG conducted a Ratepayer Impact Measure ("RIM") test as a secondary cost-effectiveness test to calculate the impact of the BE Plan on non-participants. The AG's witnesses calculated the incremental net revenues that ComEd would likely receive from sales due to the Company's BE Plan and compared those figures to the BE Plan's costs to determine whether the BE Plan will generate more revenue than the Company spends on programs, thereby reducing rates for all customers. AG Ex. 1.0R at 39-40.

The AG's witnesses showed, however, that the costs of ComEd's BE Plan far outstrip the net revenues likely to be generated by the BE Plan over the lifetime of the EV adoption attributable to the BE Plan. As a result, ComEd's proposed plan puts upward pressure on rates for all consumers under the AG's analysis. *Id*. at 41. Further, the data shows that the BE Plan's costs exceed net revenues from 2026 to 2029 even when considering the net revenue stemming from all EV adoption projected in the ComEd territory, not just those EVs likely to be adopted because of ComEd's BE Plan. *Id*. Thus, ComEd's BE Plan puts upward pressure on rates in select years even when considering all EV charging revenue from the Company's entire service territory.

The AG also explains that the analysis provides a generous net revenue calculation because the analysis assumes that there is no free ridership (i.e., people who participate in BE Plan programs and purchase an EV, but who would have purchased the vehicle without the incentive included in the program). *Id*. at 45. The AG maintains that, in reality, free ridership is much higher and thus the AG's calculation of net revenue is almost certainly overstated.

In response, the Company rejected the AG's usage of an NTG ratio that is less than 100% in the calculation of its primary BCA. The Company states that usage of 100% NTG ratios (i.e., an assumption that there is no free ridership in ComEd's programs) is appropriate because "[t]his approach recognizes that every instance of adoption of the applicable technology provides societal value (e.g., avoided carbon emissions and other pollutants, system benefits, etc.) consistent with the goals of the EVA." ComEd IB at 50.

The AG states that the Commission should reject the Company's argument and order ComEd to use accurate NTG ratios that consider actual free ridership levels in all RIM analyses to determine the impact of the Company's programs on customer rates and non-participants.

d. CJCP's Position

Staff witness King, in his rebuttal testimony, criticizes ComEd's proposal because "while [ComEd witness] Vogt does describe where in the BCA customer rates are considered, the cost-benefit analysis does not separately identify effects on ratepayers...the Commission should direct ComEd to provide the RIM results or results

of a similar test that separates effects on ratepayers for each of its programs and [BE] Plan as a whole." Staff Ex. 14.0 at 31.

CJCP state that this is contrary to the EVA, which is clear that a primary function of the statute is to achieve the widespread adoption of electric vehicles, 20 ILCS 627/45(a), and that this widespread adoption should be targeted to confer various benefits upon Illinois—some of which would be expected to accrue outside the utility sector ("[w]idespread adoption of electric vehicles should stimulate innovation, competition, and increased choices in charging equipment and networks and should also attract private capital investments and create high-quality jobs in Illinois." 20 ILCS 627/45(a)(10)). CJCP point out that the provision that guides the Commission's review of BE Plans, Section 45(d) provides that approval should turn at least in part on whether the plan in question is in the public interest and whether it is cost-beneficial, and provides further that "[t]he plan shall be determined to be cost-beneficial if the total cost of beneficial electrification expenditures is less than the net present value of increased electricity costs (defined as marginal avoided energy, avoided capacity, and avoided transmission and distribution system costs) avoided by programs under the plan, the net present value of reductions in other customer energy costs, net revenue from all electric charging in the service territory, and the societal value of reduced carbon emissions and surface-level pollutants, particularly in environmental justice communities. Per CJCP, the calculation of costs and benefits should be based on net impacts, including the impact on customer rates." 20 ILCS 627/45(d). CJCP state this instruction to the Commission communicates unequivocally that the General Assembly was well aware that a given BE Plan would be comprised of multiple programs, and that the cost-benefit analysis that would inform whether the BE Plan was to be approved was to be performed at the level of the plan as a whole, and not at the level of the particular program. Logically, state CJCP, this implies an appreciation of the fact that a BE Plan is a portfolio of programs, and an expectation that some individual programs may not be cost-beneficial by themselves provided that the portfolio in its entirety is cost-beneficial. CJCP also state the statute is also clear that the impact on customer rates is part of this plan-level analysis, not a separate exercise that would be appropriate to undertake at the program level instead.

Per CJCP, nothing in the statute suggests that every single programmatic component — including those components expected to yield economic development benefits to the state as a whole — must, by itself (in addition to yielding the intended benefits, which might be expected to accrue outside the electric sector, as in the case of the economic development benefits contemplated in Section 45(a)(10)), also yield benefits to all non-participating ratepayers within ComEd's service territory by exerting downward pressure on rates paid by ComEd electric utility customers. To the contrary, state CJCP, the statute as a whole evinces an intention of leveraging transportation electrification to achieve societal goals outside the electric utility sector, and expressly provides a mechanism for permitting individual programs that might not, by themselves, be cost-beneficial to be approved as part of a portfolio of programs that in aggregate are cost-beneficial and promote the statewide public interest. Given this statutory framework, CJCP assert Mr. King's proposal is unnecessary for the Commission to grant approval of ComEd's BE Plan.

Staff criticizes the Company's benefit-cost calculations, among other things calling for the Company's assumed NTG to be lowered from 100% to 80%. In support of this recommendation, Staff points to testimony furnished by Staff and the AG. On close consideration, CJCP states those witnesses have failed to demonstrate that the free ridership studies they have cited are relevant points of comparison vis-à-vis ComEd's BE Plan, nor have they made a complete argument for how such studies should inform net-to-gross calculations; as such, this recommendation should be disregarded.

Staff asserts that its primary concern with ComEd's BCA is that "it attributes 100% of emission reductions and other EV-related benefits to ComEd's BE Plan. A proper benefit-cost analysis of a BE Plan should not account for benefits and costs that would have occurred absent the Plan." Staff IB at 103-104. Staff points to a similar assertion made by the AG, saying that the "AG also takes issue with ComEd's assumption that 100% of participant EV adoption occurs solely due to ratepayer subsidies provided through its BE Plan, noting that other states have seen high levels of free ridership, leading them to conclude that the benefits in the BCA are likely overstated." Staff IB at 104. However, CJCP point out that neither Staff nor the AG has offered persuasive evidence that the benefits included in ComEd's BCA should be discounted, and if so by how much.

Specifically, in rebuttal testimony AG witnesses Borden and Lane state that "the benefits within the [BCA] are likely overstated because the Company does not account for any free ridership and assumes all electrification adoption is the direct result of the incentives it proposes to offer." AG Ex. 2.0 at 17. CJCP state that while it is true, as a logical matter, it would make sense to adjust electrification benefits arising from a utility BE program downward by discounting electrification that would have occurred without such programs (if that amount could be ascertained) — the phenomenon that the AG refers to as "free ridership," AG Ex. 1.0 REV at 17 — it would make just as much sense to adjust benefits upward to recognize electrification that occurs as an indirect result of the program. CJCP point out that such indirect or second-order benefits could include, for example, EV purchases that are entirely independent of the programs but are inspired by the program-funded investments (which might include, e.g., additional EV acquisitions by program participants beyond what the programs entailed, or EV acquisitions by non-program-participants based on their own observations of the emerging market). However, CJCP go on to say that without any specific examination of the likely total effects of ComEd's proposed programs, it is not possible to guess which of these effects would predominate, but Staff assumes, without evidence examining the full range of programmatic effects, that a downward adjustment would be appropriate.

Unfortunately, CJCP state, the testimony on which Staff relied in its Initial Brief did not examine the full range of benefits; instead, it focused solely on the risk that some amount of program funds might be paid to EV purchasers who would have purchased EVs without program assistance. Specifically, Staff witness King, in direct testimony, described the only two studies cited in Staff's brief to estimate the extent of free ridership. Staff Ex. 3.0 at 10. CJCP state that it is of central importance is the fact that that both cited studies concern subsidies for the purchase of residential EVs — a type of subsidy that was only ever a small part of ComEd's proposal, and that has now been entirely dropped from ComEd's proposal as a consequence of Staff's Combined Motion and the

Interim Order. As such, CJCP aver those studies no longer have any relevance to any part of ComEd's proposal. Because the cited studies concern programs that are in no way comparable to ComEd's proposal, CJCP state the assertion that the cited studies "support an NTG of 59% to 70%" (Staff IB at 105) is false and even misleading; as such, using that range as an anchor for any sort of "compromise" of, e.g., 80%, would be inappropriate.

CJCP points out that the evidence offered by the AG is similarly problematic, in part because it relies largely on the same studies. Ultimately, CJPC state neither Staff nor the AG has furnished any evidence that free ridership would be likely to exist at all in the case of ComEd's proposed BE Plan, nor has either made any attempt to determine whether the hypothetical need to discount benefits based on such free ridership would, if it exists, predominate over the need to include additional benefits that result from private actors' decisions that are inspired by, but not funded by, the Company's programs. As such, CJCP contend that Staff and the AG's arguments that the benefits be discounted at this stage should be given no weight.

e. WeaveGrid's Position

WeaveGrid notes that the EVA prescribes an approach for determining whether the BE Plan is cost-beneficial, and each version of the BE Plan has shown significant net benefits. WeaveGrid respectfully disagrees with the position taken by Staff and the AG that the BCA should include free ridership in the calculations. WeaveGrid explains that there is precedent in Illinois for not incorporating free ridership in a BCA, including the Renewable Portfolio Standard and the Distributed Generation Rebate program. WeaveGrid points out that the policy that underpins the BE Plan is also different than EE programs. WeaveGrid further explains that such programs are focused on achieving cumulative persistent energy savings, and that the EVA does not require NTG or free ridership adjustments be applied to the BE Plan. WeaveGrid recommends that the Commission should approve ComEd's BCA.

f. Commission Analysis and Conclusion

The Commission is persuaded by Staff and the AG that ComEd should include sub-program-level BCAs for the components of its BE Plan and present it in its compliance filing and future BE Plan filings. While the BE Plan need only be cost-beneficial as a whole, BCAs on a sub-program level will aid the Commission, Staff, and stakeholders in determining which sub-programs are not cost-effective and how other sub-programs may balance those out. ComEd's analysis should include an analysis concerning customer rates such as a RIM or similar test. This will also further the objective of Section 45(d) of the EVA.

The Commission further agrees with Staff that use of a 100% NTG ratio is unrealistic. The Commission finds that there is no compelling evidence in the record to fully support any of the proposed NTG ratios. The Commission expects that the Company will work with Staff and Intervenors to ensure that for the next iteration of the BE Plan better information will be provided. Moreover, the Commission adopts the AG's proposal that NTG ratio studies should be provided for the next BE Plan. For this BE Plan, however, the Commission adopts an 80% NTG ratio.

It appears that Staff's other concerns, other than the budget that is discussed in Section V.C.1 of this Order, were already addressed by ComEd.

4. Consideration of the Staff Workshop Report Recommendations Section 45(d)

a. ComEd's Position

ComEd states that the EVA requires that its BE Plan "shall take into consideration recommendations from the workshop report." 20 ILCS 627/45(d). ComEd points out that its BE Plan reflects the three clear themes that emerged from the workshops. ComEd asserts that its BE Plan emphasizes equity by ensuring that all customers in the service area will benefit and by providing an opportunity to improve air quality in communities that suffer disproportionately from pollution. ComEd notes that through its BE Plan, the BE landscape will be kickstarted with a multi-pronged, all of the above deployment strategy across a wide range of electric vehicle types and BE applications. ComEd notes that its BE Plan is designed to overcome the many barriers that could limit, or hamper BE adoption.

b. Commission Analysis and Conclusion

No party contests this issue. The Commission finds that ComEd appropriately considered the recommendations from the workshop report. The Commission concludes that ComEd's BE Plan satisfies the workshop requirements of Section 45(d) of the EVA.

5. Workforce Equity Section 45(h)

a. ComEd's Position

ComEd states that the EVA requires ComEd to demonstrate, as part of its BE Plan, "efforts to increase the use of contractors and [EV] charging station installers that meet multiple workforce equity actions…[and] establish reporting procedures for vendors that ensure compliance with [45(h)], but are structured to avoid, where possible, placing an undue administrative burden on vendors." 20 ILCS 627/45(h). ComEd argues that its BE Plan satisfies this requirement.

ComEd points out that it has a longstanding commitment to supplier diversity. ComEd notes it also has experience in supporting and expanding the use of diverse local contractors, subcontractors, and suppliers in the design and execution of large, multi-year plans. ComEd states that it will leverage its Energy Efficiency Service Provider ("EESP") Network as a model when implementing its BE Plan to increase the use of EV charging station installers and contractors that meet multiple workforce equity actions. ComEd further states it will develop reporting procedures for vendors that ensure compliance with Section 45(h) by developing reporting procedures similar to those utilized for the EESP Network.

Staff proposes that the Commission direct ComEd to reflect in its compliance BE Plan the detailed recommendations for the workforce equity section. ComEd agreed to insert into the BE Plan additional detail on workforce equity, and ComEd will provide Staff and other parties an opportunity to review the compliance BE Plan prior to the filing in the final version with the Commission. ComEd Ex. 11.0 REV at 10.

b. Staff's Position

Staff states that the Commission should direct ComEd to reflect in its compliance BE Plan the detailed recommendations for the workforce equity section.

Staff explains that ComEd's initial BE Plan provided limited information regarding its Workforce Equity. Staff Ex. 10.0 at 4. In response to Staff data requests, ComEd agreed to incorporate greater detail regarding its supplier diversity processes. ComEd Ex. 6.0 at 17. As such, Staff recommends the Commission accept the Company's proposal for the workforce equity section of its BE Plan. Staff Ex. 21.0.

c. Commission Analysis and Conclusion

The Commission finds that the BE Plan demonstrates ComEd's efforts to increase the use of contractors and EV charging station installers that meet multiple workforce equity and its actions establish reporting procedures for vendors to ensure compliance with 20 ILCS 627/45(h). The Commission directs ComEd to include in its compliance BE Plan additional detail on workforce equity.

E. IDC Waiver

1. ComEd's Position

ComEd is requesting two waivers from the Commission. The first is a waiver of the Commission's IDC rules, set forth in 83 Ill. Adm. Code 452.280(e). ComEd states that the EVA requires that BE programs "shall provide for incentives such that customers are induced to use electricity at times of low overall system usage or at times when generation from renewable energy sources is high." 20 ILCS 627/45(b). ComEd notes that in order to provide such incentives, ComEd's BE Plan requires that residential customers who receive EV infrastructure rebates must elect one of several time-variant pricing options and remain in that pricing pan for at least three years. ComEd argues that a waiver of Section 452.280(e) is necessary so that ComEd can condition the receipt of the EV infrastructure rebate on enrollment in one of these pricing options for a period of three years.

ComEd also requests a waiver of Section 452.270 for ComEd's proposal, to the extent it constitutes "tying," to require customers who participate in the Residential Optimized Charging pilot to take service under one of two ComEd rates, either Rate RES or Rate BESH. ComEd notes that if a customer wants to participate in the Residential Optimized Charging pilot, then the customer must switch to Rate BES or Rate BESH. ComEd argues that, to the extent this constitutes "tying", ComEd should receive a waiver of Section 452.270 because such a waiver is necessary to implement the General Assembly's directive in the EVA.

ComEd opposes Staff's recommendation that the Commission deny ComEd's request for waiver. Staff claims that despite several modifications, ComEd's proposal still results in some customers being enrolled onto Rate BESH without their affirmative consent. Instead, Staff recommends that ComEd allow the customer to select from one of several options that incentivize charging during off-peak times prior to receiving a rebate. Staff also asserts that the waiver of IDC rules allows "ComEd to further encroach into the competitive retail market" and its assurances that the educational/marketing materials regarding the Residential EV Charging Infrastructure rebate will be

competitively neutral further negate the need for waiver. Staff IB at 113. ComEd is not encroaching on the retail market, as is made clear by its proposal to offer BE Plan incentives to taking service from ARES. ComEd's proposals related to time-variant rates are offered in response to the language of the EVA, which provides that BE programs include "incentives for electrification and associated infrastructure tied to using electricity at off-peak times." 20 ILCS 627/45(b)(5).

ComEd is also proposing an additional option for customers to receive a Residential Charging Infrastructure Rebate if they also participate in the Residential Optimized Charging pilot. But, in order to participate in the Residential Optimized Charging pilot, a customer must take service under one of two ComEd rates, either Rate BES or Rate BESH. ComEd Ex. 14.0 REV at 24. To the extent this constitutes "tying," ComEd also requests a waiver of 83 Ill. Admin, Code Section 452.270. ComEd Ex. 14.0 REV. at 24.

ICEA opposes ComEd's requirement for customers participating in the Residential Optimized Charging pilot to take service under one of two ComEd rates, either Rate BES or Rate BESH. ICEA asserts there is no statutory basis for ComEd to require a customer to take ComEd supply in order to receive benefits under the Residential Optimized Charging pilot. ComEd explained that it is completely optional for the customer to participate in the pilot program and make the corresponding rate switch. Moreover, ComEd notes that the requirement is appropriate in connection with the pilot nature of the program, and that the Commission has approved a similar requirement limiting eligibility for a pilot program to customers taking supply from ComEd in connection with ComEd's Rate Residential Time-of-Use Pilot Program ("Rate RTOUPP").

2. Staff's Position

Staff states that the Commission should deny ComEd's request for a waiver of the Commission's IDC rules set forth in 83 Ill. Adm. Code 452. Staff Ex. 9.0 at 3.

Staff explains that ComEd seeks a waiver of the Commission's IDC rules "out of an abundance of caution to avoid any potential issues" when enrolling recipients of its Residential EV Charging Infrastructure Sub-program rebate onto the Company's Rate BESH as the Company proposed to do in its BE Plan. ComEd Ex. 4.0 at 15. Staff raised concerns that "ComEd's waiver request creates a barrier to competition by forcing residential customers who receive the EV infrastructure rebate to enroll with ComEd's supply offering for at least three years." Staff Ex. 9.0 at 5. As a result, customers enrolled with an ARES for their electric supply are prohibited from qualifying for the EV Charging Infrastructure Sub-program rebate, which is the exact scenario the IDC rules are meant to prevent.

In its rebuttal testimony, ComEd modified its proposal to allow residential customers receiving the EV Charging Infrastructure Sub-program rebate to enroll onto an ARES offered time variant rate. ComEd Ex. 10.0 at 24. However, under its modified proposal, ComEd would initially place all recipients of the rebate onto Rate BESH and the customers could then decide to stay on Rate BESH or switch to an ARES time variant rate. As a result, "ComEd would still seek an IDC waiver, although perhaps more limited in scope. Rate BESH would then become the default rate for customers receiving the residential charging infrastructure rebate, rather than necessarily the requirement."

ComEd Ex. 9.0 at 18 (emphasis original). Subsequently, ComEd further modified its proposal stating that "[a]s long as a warrant is in place indicating that the customer is being supplied by the [A]RES on a time-variant rate, ComEd supports allowing the customer to remain on the [A]RES time-variant rate without moving to Rate BESH." Staff Ex. 20.1 at 1. Despite ComEd's modifications, its current proposal would still result in some customers being enrolled onto Rate BESH without the customer's affirmative consent and with little to no understanding of how the rate works or the impact Rate BESH would have on their electric bill. In Staff's opinion, while the modifications are an improvement they do not go far enough.

ComEd testified that "a waiver is warranted for the EV infrastructure programs to achieve the General Assembly's goals of minimizing system costs arising from electrification." ComEd Ex. 4.0 at 15. However, Staff asserts that the Company can accomplish these goals without a waiver of the IDC rules and without forcing customers onto a supply rate they did not select. In surrebuttal testimony, ComEd stated that "the failure of a customer to select one of [the] additional options could constitute ComEd "tying" Rate BESH to the EV Charging Infrastructure rebate program," which can be avoided by having the customer choose one of the eligible options as a condition of approval for the rebate. ComEd Ex. 14.0 REV at 23. As recommended in the BE Workshops Staff Report and by Staff, ComEd should offer different options to customers that incentivize charging during off-peak times and allow the customer to select one of the eligible options prior to receiving or being approved for the rebate. Additionally, a waiver of the IDC rules allows ComEd to further encroach into the competitive retail market and contravenes the Commission's mandate to promote retail competition.

In its surrebuttal testimony, ComEd agreed to "ensure that activities under the Customer Awareness and Education Program will be competitively neutral." ComEd Ex. 12.0 REV at 21. Further, the Company agreed to share education and marketing materials "with Staff and interested stakeholders before utilizing those materials." Staff Cross Ex. 1.0 at 50. Specifically, ComEd states that they are "generally open to sharing marketing materials for [the Residential EV Charging Infrastructure] Sub-program, as they are first developed, with [Office of Retail Market Development], [ICEA], and the parties participating in the instant docket." Staff Cross Ex. 1.0 at 51. These assurances that the educational and marketing materials regarding the Residential EV Charging Infrastructure Sub-program rebate will be competitively neutral and shared with Staff prior to being used, further negate the need for a waiver of the IDC rules.

Additionally, ComEd seeks a waiver of Section 452.70, a request which the Company first raised in surrebuttal testimony so that Staff and other interested parties were denied any opportunity to respond, in order to make ComEd's Rate BES and Rate BESH the two sole options for customers participating in the Residential Optimized Charging pilot. ComEd Ex. 14.0 at 23. However, Staff asserts that ComEd failed, both in surrebuttal testimony and in its Initial Brief, to provide any justification for this request. ComEd proposes to allow customers participating in the Residential Optimized Charging pilot to be enrolled in Rate BES, which is the Company's default rate. Therefore, there is no reason - and ComEd does not provide any explanation why customers receiving supply from an ARES should be prohibited from participating in the Residential Optimized Charging pilot. ICEA agrees with Staff and further states in its Initial Brief that "there is

no statutory basis for ComEd to require a customer to take ComEd supply in order to receive benefits under the Residential Optimized Charging pilot." ICEA IB at 11.

Because a waiver of IDC rules is not necessary and could negatively impact the competitive retail market, the Commission should deny ComEd's request for a waiver of the Commission's IDC Rules set forth in 83 Ill. Adm. Code 452.280(e). Staff Ex. 9.0 at 3.

3. ICEA's Position

According to ICEA, the IDC rules protect customers and market participants from anti-competitive behavior by utilities. ICEA posits that those prohibitions range from utility advertising in support of their rates (such as supply rates) that compete with third-party products and services — as opposed to monopoly services such as delivery rates — to a prohibition on engaging in "tying" as defined under state or federal antitrust law. *See e.g.*, 83 Ill. Adm. Code 452.240 (prohibiting certain marketing), 452.270 (prohibiting "tying"). ICEA represents that it does not generally support waivers of the prohibition on marketing, the Commission has in fact waived marketing rules in many cases (*see, e.g.,* Docket Nos. 18-1772, 18-1725/-1824 (Cons.)). To the knowledge of ICEA, the prohibition on tying — which is specifically defined related to actions prohibited under state or federal antitrust law — has not been waived to date. While ICEA states that it has identified multiple requests (some more specific than others) from ComEd for IDC waivers during the course of the BE Plan litigation, in its Initial Brief ICEA concluded that there was only one pending request for an IDC waiver. ICEA argues that ComEd's surviving IDC waiver request is specifically a request to engage in tying. ICEA argue that the Commission should either adopt ICEA's position to render this request moot or, in the alternative, reject ComEd's waiver request to engage in tying.

According to ICEA, ComEd's request for a waiver to engage in tying (83 Ill. Adm. Code 452.270) was first raised in ComEd's surrebuttal. ICEA offers that, as explained by ComEd witness Fruehe, as of its surrebuttal testimony ComEd intended to provide three rate options for residential customers participating in the EV Charging Infrastructure Sub-program. ICEA summarizes that under ComEd's surrebuttal testimony, a customer may elect ARES service, provided that the ARES service is time-variant and the ARES provides a warrant to ComEd or a residential customer may elect Rate BESH, ComEd's hourly supply tariff. *See* ComEd Ex. 15.0 at 16. Third, ICEA contends that a residential customer may participate in the Residential Optimized Charging pilot. *Id*. at 16.

According to ICEA, by far the simplest approach for the Commission to take is to direct ComEd to require ComEd to allow a customer to take supply from any source — not just ComEd Rate BES or Rate BESH — to participate in the Residential Optimized Charging pilot. ICEA contends that ComEd's proposed restriction appears to serve no purpose, and ICEA was unable to locate any testimony supporting the restriction. ICEA explains that ComEd's justifications were exclusive to time-variant rates — not ComEd BESH specifically — and were further undermined by ComEd shifting to allow participation of Rate BES customers.

ICEA counters that if, however, the Commission does not require ComEd to allow a customer on any supply rate (including ARES-offered products and services) to participate in the Residential Optimized Charging pilot, the Commission should reject ComEd's waiver request. ICEA argues that it is unclear that the Commission could —

even if it wanted to — provide a shield against litigation in the court system under state or federal law that ComEd is engaging in illegal tying. ICEA notes that unlike ComEd's monopoly distribution franchise, which is enshrined in the Act, there is no statutory basis for ComEd to require a customer to take ComEd supply in order to receive benefits under the Residential Optimized Charging pilot.

ICEA argues that Section 3 of the Illinois Antitrust Act provides in relevant part that:

> (4) Lease or make a sale or contract for sale of goods, wares, merchandise, machinery, supplies, or other commodities, or services (including master antenna television service), whether patented or unpatented, for use, consumption, enjoyment, or resale, or fix a price charged thereof, or discount from, or rebate upon, such price, on the condition, agreement, or understanding that the lessee or purchaser thereof shall not use or deal in the goods, wares, merchandise, machinery, supplies, or other commodity or service (including cable television service or cable television relay service), of a competitor or competitors of the lessor or seller, where the effect of such lease, sale or contract for such sale or such condition, agreement, or understanding may be to substantially lessen competition or tend to create a monopoly in any line of commerce;

740 ILCS 10/3(4). ICEA points to the statement by the Illinois Supreme Court that, "One violation set forth in this section is commonly referred to as a tying arrangement whereby a party agrees to sell or lease an item (the tying item) only on the condition that the purchaser or lessee also purchase a different item (the tied item)." *People ex rel. Scott v. Schwulst Bldg. Ctr., Inc*., 89 Ill. 2d 365, 370 (1982). ICEA further points out that the Illinois Supreme Court determined that "the Illinois legislature intended that tying arrangements be dealt with harshly" and violations are on a per se basis and not evaluated through the lens of reasonableness. *See id.* at 376-377.

ICEA concedes that the Illinois Antitrust Act does, of course, recognize the Commission's role in overseeing monopoly services (including some offered by ComEd). According to ICEA, the Illinois Antitrust Act thus carves out an exception for: "the activities of any public utility, . . . to the extent that such activities are *subject to a clearly articulated and affirmatively expressed State policy to replace competition with regulation*, where the conduct to be exempted is actively supervised by the State itself." 740 ILCS 10/5(3) (emphasis added). ICEA argues that there is no "clearly articulated and affirmatively expressed State policy" to require residential customers utilizing the Residential Optimized Charging pilot to only use ComEd rates.

Thus, ICEA concludes, even if the Commission decides that restricting the Residential Optimized Charging pilot to just ComEd rates is not "tying," it is not clear the Commission will be able to protect ComEd from costs of defending the program in court. ICEA argues that those costs will either be borne by ComEd or ratepayers — neither of which are justified when (at least to ICEA's review) there is no indication of why a customer must be on ComEd supply service in order to participate.

ICEA concludes that the Commission should direct ComEd to allow residential customers on ARES supply products and services to participate in the Residential Optimized Charging pilot and reject the waiver request as moot. However, continues ICEA, if the Commission declines to do so, the Commission should deny ComEd's waiver request.

ICEA highlights that Staff is strongly opposed ComEd's waiver of IDC rules to allow ComEd to switch customers to Rate BESH without affirmative customer direction if the customer did not select an ARES TOU supply product or the Residential Optimized Charging pilot prior to or concurrent with enrollment in the Residential EV Charging Infrastructure Sub-program. ICEA underscores its particular agreement with Staff that an IDC waiver for forcibly switching a customer to Rate BESH at the beginning of the three-year period "can be avoided by having the customer choose one of the eligible options as a condition of approval for the rebate." Staff IB at 113. ICEA argues that given that ComEd has not specified when it would make the switch, how it would communicate with the customer, and why ComEd cannot simply wait for the customer to make their own election, Staff's arguments demonstrate that ComEd did not sufficiently support its proposed IDC waiver. ICEA concedes that it does not speak for Staff, but ICEA does note that it does not appear be inconsistent with Staff's arguments presented in Initial Briefs for the Commission to consider allowing ComEd a limited waiver to switch customers to Rate BESH who are no longer on an ARES TOU supply product or the Residential Optimized Charging pilot during the three-year period.

ICEA points out the silence of CJCP on an IDC waiver for CJCP's proposed bundled delivery and supply TOU rate. *See* CJCP IB at 45 (not addressing the IDC waiver section). ICEA highlights that CJCP did not recommend an IDC waiver for its proposed bundled delivery and supply TOU rate, nor did it explain why it believes none is necessary. According to ICEA, while the Commission should not grant such a waiver even if CJCP or another party did request it, the failure to request an IDC waiver to bundle a delivery and supply rate is fatal under Section 452.270 because connecting the delivery rate to a ComEd supply rate meets the black letter definition of "tying" ICEA set out in its Initial Brief.

4. Commission Analysis and Conclusion

ComEd has agreed, and the Commission concurs and therefore directs ComEd, to share education and marketing materials, and that they be competitively neutral. The Commission has rejected ComEd's requirement that participants in the Residential Optimized Charging pilot take supply through Rate BES or Rate BESH (*see* Section V.A.4.). Accordingly, any waiver of IDC rules is premature or not necessary. ComEd's request for a waiver of IDC rules is denied.

VI. RECOVERY OF BE PLAN COSTS

A. ComEd's Cost Recovery Proposal

1. Rider BE

a. ComEd's Position

ComEd asserts that the Commission should approve ComEd's proposed Rider BE to recover its actual, Commission-approved BE Plan costs. ComEd states that a rider is

necessary and appropriate because ComEd has no control over whether, or to what extent, customers will claim incentives under the BE Plan Programs. ComEd notes that the Commission and Illinois courts have consistently found that rider mechanisms are appropriate and approved under circumstances where a utility is faced with unexpected, volatile, or fluctuating expenses.

ComEd notes that it modified its original Rider BE proposal to incorporate several of Staff's suggestions made during this proceeding. ComEd points out it agreed that costs to be recovered under Rider BE would not include incentive compensation expenses that are based on net income. ComEd also notes it agreed to perform an internal audit and file an annual report, along with testimony in support of reconciliation calculation. ComEd explains that Rider BE provides a cost recovery mechanism that ensures customers pay for only those costs ComEd actually incurs in connection with the BE Plan. ComEd notes the Commission would review the Rider BE costs in an annual reconciliation proceeding. ComEd states the Commission would examine and approve the costs to be included in Rider BE for recovery, including carrying costs.

ComEd disagrees with Staff and IIEC's suggestion that the Commission is prohibited from approving Rider BE because it would constitute single-issue ratemaking. However, both Staff and IIEC acknowledge that the prohibition against single issue rate-making does not require the rejection of all riders. The Commission unquestionably has the authority to approve riders in appropriate situations. *See People ex rel. Madigan v. Ill. Commerce Comm'n*, 2015 IL 116005, ¶ 24 (citing *City of Chi. v. Ill. Commerce Comm'n*, 13 Ill. 2d 607, 614 (1958)); *Citizens Util. Bd. v. Ill. Commerce Comm'n*, 166 Ill. 2d 111 (1995) ("The prohibition against single-issue ratemaking … does not circumscribe the Commission's ability to approve direct recovery of unique costs through a rider when circumstances warrant such treatment.").

ComEd also disagrees with Staff and IIEC's assertion that that there must be a "showing of exceptional circumstances" for the rider to be approved. Staff IB at 117; IIEC IB at 6. In fact, the Illinois Supreme Court has stated that "[t]he reference to 'exceptional circumstances' in Commonwealth Edison has no tether to our case law, and even that court frankly recognized that 'the Commission has the power to authorize a rider in a proper case and such authorization will not be reversed absent an abuse of discretion." *People ex rel. Madigan v. Ill. Commerce Comm'n*, 2015 IL 116005, ¶ 25 (citing *Commonwealth Edison Co. v. Ill. Commerce Comm'n*, 405 Ill. App. 3d 389, 411 (2010)).

ComEd disputes Staff, the AG, and IIEC's assertion that BE Plan costs are not appropriately recovered in a rider because such costs are not sufficiently outside of ComEd's control or adequately volatile. The parties state that ComEd controls the development and implementation of the programs, but it means only that ComEd can make funds available to customers. Customers are in control of whether they individually claim incentives, and the point in time at which they choose to do so. ComEd Ex. 10.0 at 25; ComEd Ex. 14.0 REV. at 15. ComEd agrees with Staff that ComEd's annual reports will provide information about customer uptake, but at the point in time when the report is produced the costs will already be incurred, so the annual report will not mitigate volatility in BE Plan costs.

ComEd also disputes the AG's assertion that budget flexibility and/or the reconciliation process will make up for any volatility from fluctuating customer adoption of incentives. Both mechanisms are reactive – neither will remove the unpredictability and volatility of customer uptake. For example, the budget flexibility feature of the plan is intended to help ComEd respond to the volatility and unpredictability of customer uptake – it does not eliminate the volatility. The same is true for the reconciliation mechanism (under either Rider BE, or a MYRP).

ComEd opposes Staff's suggestion that the costs of implementing the BE Plan would be more appropriately reviewed in multi-year plan reconciliations, rather than in separate reconciliation pursuant to Rider BE. ComEd notes only incentive and administrative costs will be included in Rider BE. ComEd argues that such costs are more appropriately recovered in a rider and separating the Commission's review of those costs provides a more detailed and transparent review of the BE Plan costs.

ComEd argues that Rider BE will not result in increased regulatory costs as Staff suggests. Rather, ComEd argues there will be regulatory costs regardless of which proceeding is used to evaluate ComEd's BE cost recovery– whether those costs are added to the regulatory costs of the MYRP or stand alone in a BE reconciliation proceeding. ComEd maintains that a separate docketed proceeding for addressing BE costs exclusively provides several regulatory benefits compared to requiring BE costs to be recovered through the MYRP. Requiring BE costs to be recovered through the MYRP would only add to the significant number of potential issues about which all parties must ultimately decide whether to litigate or not. "In contrast, a separate docketed proceeding addressing BE costs exclusively has several regulatory benefits as well, including a singular focus on one set of costs, without being weighed down by other litigation." ComEd Ex. 14.0 REV. at 21.

ComEd opposes the IIEC and Staff assertion that Rider BE would interfere with the operation of ComEd's MYRP by reducing the accuracy of ComEd's revenue requirements in the MYRP. However, Rider BE will accurately recover the actual value of relevant costs, as will ComEd's MYRP. The fact that different costs are recovered via different mechanisms will not diminish the accuracy of either mechanism. ComEd clarified that, if assuming the EV Charging Delivery classes are approved, the costs of ComEd-provided EV make-ready infrastructure will be included in ComEd's base delivery rates (i.e., these costs will be reviewed in rate cases and related reconciliation proceedings) and will not be recovered in Rider BE. But the costs of incentives and rebates, including costs of administering the programs, will be included in Rider BE. ComEd Ex. 14.0 REV 16.

Finally, ComEd disagrees with the AG's contention that, since Ameren withdrew its proposal for a rider related to its BE plan, the Commission should disregard ComEd's proposal. IIEC also notes that no other utility in Illinois is proposing to recover BE costs through a rider or on a cents per kWh basis. But Ameren's strategic decisions do not bind ComEd.

IIEC and Walmart oppose ComEd's plan to recover BE Plan costs through a volumetric charge for all customers, including demand-metered customers. Walmart and IIEC advance an alternative proposal that ComEd recover BE Plan costs from demand-

metered customers on a per-kW basis. Walmart Init. Br. at 6-7; IIEC Init. Br. at 9. ComEd continues to believe that a separate rider is the most appropriate mechanism for recovery of its BE Plan costs, but ComEd also recognizes "the potential for cross subsidization with[in] the demand-based classes and does not oppose Walmart's and IIEC's proposal to recover Rider BE costs on a kW basis for such customers, if the Commission were to direct it." ComEd Ex. 15.0 REV at 26. Staff similarly does not oppose this proposal, but requests that the Commission direct ComEd to detail, in a compliance filing, the manner in which it plans to implement Walmart's proposal.

b. Staff's Position

The Commission should reject ComEd's proposal to recover its BE Plan costs through a new rider, Rider BE. The Company's proposal for Rider BE should be rejected because Rider BE is not necessary, could lead to unreasonable rates, and will lead to increased regulatory costs. Staff Ex. 7.0 at 3. The Commission should also reject ComEd's proposal to establish regulatory assets, in which the Company plans to place 83% of its BE Plan costs or $83 million annually. Staff Ex. 7.0 at 3. The Commission should reject the Company's proposal for regulatory asset treatment because it provides the Company an incentive to have larger budgets, could lead to unreasonable rates, and will lead to increased regulatory costs. Staff Ex. 7.0 at 3.

ComEd proposes to recover all costs related to the BE Plan through Rider BE. Staff Ex. 7.0 at 5; Staff Cross Ex. 1.0 at 26. Rider BE would encompass the following:

(1) Operations and Maintenance ("O&M") costs placed in regulatory assets. There would also be carrying charges on the unamortized balances of the regulatory assets and amortization expense related to the regulatory assets;

(2) O&M costs that are not in the regulatory assets. There would also be carrying charges related to the O&M costs that are not in the regulatory assets; and

(3) capital assets which are Company-owned utility plant. These capital assets would earn a return, and there would be depreciation expense related to the capital assets.

The Company proposes to create one regulatory asset for each year of its BE Plan period, so in its initial BE Plan, the Company would create three regulatory assets, one each in 2023, 2024, and 2025. Staff Ex. 7.0 at 5. The regulatory assets will consist of incurred O&M costs associated with three of the five programs that ComEd proposes in its BE Plan: the Residential Program, the C&I and Public Sector Program, and the BE Pilot Program.

The O&M costs recovered outside of the regulatory assets will consist of incurred costs associated with the remaining two programs that ComEd proposes in its BE Plan: the Customer Education and Awareness Program and Portfolio costs. Staff Ex. 7.0 at 5.

The capital assets are for Company-owned Information Technology ("IT") assets. Staff Cross Ex. 1.0 at 26.

ComEd proposes to amortize each regulatory asset over 10 years (ComEd Ex. 4.0 at 14) and to depreciate the IT assets over five years. Staff Cross 1.0 at 26. ComEd also proposes to recover the carrying charges of the unamortized balance of the regulatory assets, the undepreciated balance of the IT assets, and its O&M costs that are not in the regulatory assets at the Company's weighted average cost of capital ("WACC"). ComEd Ex. 4.0 at 13. The O&M costs that are not in the regulatory assets will incur carrying charges because ComEd has designed Rider BE such that there is a two-year lag between when the Company incurs the costs and when the Company recovers them. ComEd Ex. 4.0 at 13.

Staff argues that the Company's proposal for Rider BE should be rejected because Rider BE is not necessary, and it could lead to unreasonable rates and will lead to increased regulatory costs. Staff Ex. 7.0 at 3. Of the other parties in this proceeding who specifically addressed Rider BE in their testimonies, all support Staff's position: Walmart is "generally supportive of recovering costs through base rates rather than riders" (Walmart Ex. 2.0 at 10), and IIEC also testified that it supported Staff's position (IIEC Ex. 1.0, Section II).

In Staff's opinion, Rider BE is not necessary to enable the Company to recover its prudent and reasonable BE Plan costs because it can recover these costs through other, currently approved mechanisms. Staff Ex. 7.0 at 7-8. The Company can recover its 2023 BE Plan costs through base rates set pursuant to Section 16-108.5 ("formula rates") and trued up through Rider Delivery Service Pricing Reconciliation ("DSPR"), ComEd's transition tariff pursuant to Section 16-108.25. This tariff serves as a transition for the Company from its current base rates that have been set under formula rates to its new MYRP. Rider DSPR has a reconciliation component that will allow the Company to recover its 2023 prudent and reasonable actual costs, including BE Plan costs, along with interest on any rate adjustments. Rider DSPR's reconciliation component is similar to the reconciliation component under formula rates, which governs how the Company is currently recovering its costs through base rates.

Staff states that the Company can recover its actual prudent and reasonable BE Plan costs incurred after 2023 through base rates through a MYRP. The Company filed a petition for approval of a MYRP on January 17, 2023. *See Commonwealth Edison Co*., Docket No. 23-0055, Pet. (Jan. 17, 2023). The MYRP is a comprehensive plan, pursuant to which ComEd seeks to increase customer rates by almost $1.5 billion over four years; ComEd argues that recovery of its revenue requirements is necessary to execute "[its] Grid Plan successfully." Docket No. 23-0055 Pet. at 2. The Grid Plan includes BE as one of its crucial considerations and, in fact, it is so integral to ComEd's Grid Plan that details of the Plan are included in Appendix D.6 to the Grid Plan. *See* Docket No. 23-0055, ComEd Ex. 5.01 at 125, 664-672. In light of this, the Company should not be permitted to recover an additional sum of up to $100 million annually through a separate rider. Instead, the Commission should direct the Company to include the costs of the BE Plan in the MYRP, consistent with the Company's inclusion of the BE Plan in its Grid Plan.

Under the MYRP paradigm, the Company will begin cost recovery of its BE Plan costs in 2024, which is one year earlier than under its proposed Rider BE, pursuant to which the Company proposes to delay imposing the rider surcharge until 2025. A MYRP, like Rider DSPR and rate setting under formula rates, has a reconciliation component that

will allow the Company to recover its actual costs, including its BE Plan costs, on an annual basis. Given these other, currently approved mechanisms for cost recovery, it is not necessary for the Company to recover BE Plan costs through its new, proposed Rider BE. Staff also has several concerns with cost recovery through Rider BE, which will be addressed below.

WeaveGrid supports ComEd's general cost recovery proposal, noting that "…no customers will be charged until 2025 [for 2023 costs]." WeaveGrid IB at 22. To clarify, Staff explains that ComEd has intentionally designed Rider BE so that there is a two-year lag between when the Company incurs the costs and when the Company would like to bill those costs to ratepayers. The Company proposes to reward itself and its shareholders for this self-imposed lag by seeking recovery of carrying charges on the O&M costs, with the carrying charges calculated using its WACC. ComEd Ex. 4.0 at 13. The WACC represents a return to shareholders in exchange for the shareholders providing invested capital or money for the Company to make investments in utility plant. However, O&M costs are not invested capital; they are expenses and are generally recovered as they are incurred and do not have associated carrying charges. In other words, even though ratepayers will not begin paying for 2023 BE plan costs until 2025, ratepayers will nonetheless be compelled to pay more through carrying charges, while shareholders earn a return on O&M costs, despite the fact those costs are not capital that they provided to the Company. In contrast, if costs are recovered through base rates through a MYRP instead of through Rider BE, costs would be reflected in rates one year earlier than under Rider BE. O&M costs would also be correctly recovered when incurred, and shareholders would not earn a return on these O&M costs, which is the proper, lawful outcome.

ChargePoint also supports ComEd's general cost recovery proposal, noting that "ComEd should be assured that it will recover all reasonable costs it incurs to implement the BE Plan…including its carrying costs." ChargePoint IB at 22. This argument ignores the fact that the Company can recover its actual reasonable and prudent costs through MYRP base rates. A separate rider for cost recovery is not necessary.

Staff states that isolating BE Plan costs to be recovered through Rider BE would constitute single-issue ratemaking, which is generally disallowed. "[B]ecause a rider, by nature, is a method of single-issue ratemaking, it is not allowed absent a showing of exceptional circumstances." *Commonwealth Edison Co. v. Ill. Commerce Comm'n*, 405 Ill. App. 3d, 389, 411, (2010); Staff Ex. 7.0 at 8-10. Single-issue ratemaking is a departure from the traditional ratemaking process, which involves developing rates through a balanced review of expenses, revenues, rate base investment, and the cost of capital in the aggregate. Instead, Rider BE would isolate BE costs from the Company's overall revenue requirement, in which potential changes in one or more expense or revenue items could be offset by increases or decreases in other such items. *See Bus. Prof'l People for the Pub. Interest v. Ill. Commerce Comm'n*, 146 Ill. 2d 175, 244-45 (1991)

The isolation of BE Plan costs from the other components of the overall revenue requirement could lead to unreasonable customer rates. For example, if the Company files a general rate case, the Company would recover increased BE costs through Rider BE without having to wait for the resolution of a new rate case. Individual components of operating expense like BE costs which have increased over time might be fully recovered

through Rider BE but other components of operating expense that have decreased over time and not recovered through a surcharge will be over-recovered by the Company through base rates. If Rider BE were approved and as long as the Company has the option to file a general rate case, the risk of the Commission setting rates without considering all components of the revenue requirement in the aggregate would continue to exist.

While single-issue ratemaking is a concern under the MYRP paradigm because the Company retains the option to file a general rate case in the future, it is also a concern for other reasons. The MYRP has an annual adjustment component that allows the Company to recover its actual costs but only to an extent; under Section 16-108.18(f)(6)(A), if the Company's actual expenses for years 2024-2027 are higher than its estimated expenses for those years, the Company is allowed to recover the difference only up to 105% of the approved revenue requirement for that year. Because the approved revenue requirement will serve as the basis for determining the allowed adjustment, it is critical that the approved revenue requirement be accurate. If Rider BE is approved, the approved revenue requirement under an MYRP may not be accurate. Additionally, recouping the BE Plan costs through a rider could essentially enable the Company to avoid the limit on cost recovery, which would serve to undermine the benefits and cost containment incentives of the MYRP, a central tenet of P.A. 102-0662. The resultant differing treatment of BE Plan costs versus the Company's other costs is further evidence that the rider is single-issue ratemaking.

Because of the risk of single-issue ratemaking, Staff states, riders should be limited to unique situations generally outside the normal utility company's day-to-day operations and/or include costs that are nonrecurring, unpredictable, or beyond the utility company's ability to control. Staff Ex. 7.0 at 12. The Commission should approve a rider only if "(1) the cost is imposed upon the utility by an external circumstance over which the utility has no control and (2) the cost does not affect the utility's revenue requirement. In other words, a rider is appropriate only if the utility cannot influence the cost and the expense is a passthrough item that does not change other expenses or increase income." *Commonwealth Edison Co. v. Ill. Commerce Comm'n*, 405 Ill. App. 3d 389, 414 (2010).

Staff states that the Company has not demonstrated that its BE Plan costs are a result of unusual circumstances, nor has it demonstrated that it has no control over these costs. On the contrary, the Company has control over the development, implementation, evaluation, and other costs of the BE Plan programs. While there is some uncertainty surrounding the final, approved level of spending given the timing of when BE Plans are approved and when the MYRP is filed (Staff Ex. 18.0 at 16) the Company has total control over how much it spends on implementation of its BE Plan. The Company developed budgets based on its many years working on electrification efforts within the transportation sector. ComEd Ex. 1.0 at 6. The Company also plans to review data from its vendors who have been selected to help implement its BE Plan regarding both spending to date and projected spending on at least a monthly basis. Staff Cross Ex. 1.0 at 29. This data will inform the Company about customer uptake in its BE programs and allow the Company to take appropriate actions to increase participation, control costs, and if the Commission grants it, the ability to shift its budget in response to this information. Thus, the Company's costs are not so unpredictable or out of the Company's

control that they necessitate recovery through a rider. In fact, the Company's BE costs are no more unpredictable than other grid plan costs the Company is seeking to recover through its MYRP.

The General Assembly intended the BE Plan to inform the MYIGP, which in turn informs the MYRP, based on references in the MYIGP statutory language in Section 16-105.17 regarding both the BE Plan and the MYRP. The Company should include its best estimate of BE Plan costs needed to achieve the statutory objectives and requirements for the years covered by the MYRP in its MYRP. When the Commission's final Order related to this BE Plan docket comes out in March 2023 (which covers BE Plan years 2023-2025), and if the Commission approves a significantly different BE Plan budget than the estimates the Company included in the MYRP for years 2023-2025, the Company will have ample opportunity to revise its MYRP budget to reflect those differences. When the Commission issues the final Order related to the Company's second BE Plan in March 2025 (which covers BE Plan years 2026–2028), and in the event the Commission deems a significantly different budget than the estimated costs the Commission ultimately approved for years 2026–2027 in the MYRP filed in January 2023, the Company could seek modification of the MYRP in its second BE Plan proceeding in order to align the MYRP costs for those years with what was approved in its second BE Plan docket. Alternatively, the Company could ask, in the MYRP docket, that the final Commission Order in that docket include direction that the budget for 2026 and 2027 be updated, through a compliance filing, with the actual costs approved in the BE Plan dockets; Staff supports this alternative. Neither of these alternatives requires a new filing or a new docket and therefore would not result in significant regulatory costs. Staff Ex. 18.0 at 16-17.

Additionally, Staff argues cost recovery of BE Plan costs through Rider BE would result in higher regulatory costs than if those costs were recovered through base rates in a MYRP. Staff Ex. 18.0 at 18. Both Rider BE and a MYRP have a reconciliation component to them, both of which necessitates a reconciliation proceeding. If Rider BE is approved, all parties, including Staff, ComEd, and Intervenors (at least those with sufficient resources to participate in both Rider BE and MYRP reconciliation proceedings), will need to participate in two separate proceedings, which increases costs for all parties. Intervenors, who may not have extensive resources, may need to review MYRP reconciliations and may not have the resources to also review the Rider BE reconciliations; this may diminish the level of scrutiny in the sense that fewer parties are reviewing whether the expenses incurred were reasonable and prudently incurred. Considering all of the costs, including BE costs, in one docket would result in lower regulatory costs.

Including BE Plan costs in the MYRP would also decrease the risk of multiple cost recovery, which is a significant concern because ComEd does not seek to recover specific, discrete costs through Rider BE but instead all BE Plan costs, some of which have similar descriptions as other costs for ComEd's electricity operations in other areas. For example, ComEd's BE costs include costs for "marketing activities" (ComEd Ex. 2.0 at 34) and "labor…legal services, financial, and customer support/experience activities…" (ComEd Ex. 2.0 at 40), which are costs that occur in other areas of ComEd's operations. This risk is simply unnecessary, given that the MYRP provides a route to recoup costs

that is less expensive and more efficient than a Rider. Similar to Rider BE, the MYRP also has a true-up component that would allow the Company the opportunity to recover its actual BE Plan costs. This true-up component would further mitigate any possibility of BE cost under- or over-recovery.

The Company made four arguments in support of its proposed Rider BE. One, its BE costs are inherently volatile, uncertain, or unpredictable. ComEd Ex. 5.0 at 18; ComEd Ex. 10.0 at 25. Two, "…base rates contain the costs related to distribution services…ComEd believes costs related to other incentives are more appropriately recovered through a rider." ComEd Ex. 10.0 at 25. Third, the Company argued that "separating the Commission's review of [BE costs] from its review of all ComEd's other costs of providing delivery service will enable a more detailed and transparent review of BE Plan costs." ComEd Ex. 14.0 REV at 16. Finally, ComEd stated that "…as shown in [ComEd witness Newhouse's] direct testimony, ComEd has numerous existing riders in Illinois that have been approved by the Commission. These riders recover similar costs as Rider BE and should be approved… ." ComEd Ex. 14.0 REV at 22. Staff addresses each of the Company's arguments below.

Contrary to the Company's argument, Staff asserts that ComEd's BE costs are not inherently volatile, uncertain, or unpredictable. Staff Ex. 7.0 at 6. There are several reasons for this conclusion. First, ComEd already has experience with electrification efforts within the transportation sector. According to ComEd, the Company has "been working on electrification efforts within the transportation sector for many years" (ComEd Ex. 1.0 at 6) so the Company has familiarity with the associated costs.

Second, ComEd has already determined budgets for certain programs "based on a preliminary assessment of the costs to support their corresponding sub-programs…" (ComEd Ex. 2.0 at 6) which belies the argument that costs are not ascertainable or predictable.

Third, the Company has control over the development, implementation, evaluation, and other costs of the BE Plan programs and will be tracking the progress of these programs. ComEd described the content for the Company's BE Plan annual report, which will include general information on its progress related to implementation and execution of each of the BE Plan programs. ComEd Ex. 1.0 at 30-34. The report will also include updates on certain metrics, such as the total number of sub-program applications received, and the rebates distributed. Collected and reviewed on a regular basis, this data will continuously inform the Company about customer uptake in its programs and sub-programs, allowing the Company to take appropriate actions to increase participation and/or control costs, if necessary. The Company has confirmed that it will review data from its vendors who have been selected to help implement its BE Plan regarding both spending to date and projected spending on at least a monthly basis. Staff Cross Ex. 1.0 at 29.

Lastly, ComEd has requested the Commission grant it budget flexibility, which Staff supports subject to certain conditions. Assuming the Commission grants budget flexibility, ComEd will be able to shift funding across its approved programs and sub-programs and across BE Plan years, thereby giving the Company even greater control

over its BE Plan costs and decreasing what uncertainty exists about the cost of BE Plan implementation.

The Company also argued that "…base rates contain the costs related to distribution services…ComEd believes costs related to other incentives [in the BE Plan] are more appropriately recovered through a rider," (ComEd Ex. 10.0 at 25) and that "…the costs of ComEd-provided EV make-ready infrastructure will be included in ComEd's base delivery rates…and will not be recovered in Rider BE. The costs included in Rider BE are the costs of incentives and administrative costs…those costs [are] more appropriately recovered in a rider…[.]" ComEd Ex. 14.0 REV at 16. However, the Company failed to explain how BE Plan costs are different from the costs related to distribution services recovered through base rates and why BE Plan costs should be recovered through a new rider.

ComEd stated that base rates contain the costs related to distribution services, such as the costs of ComEd-provided EV make-ready infrastructure. ComEd Ex. 10.0 at 25. Further, ComEd acknowledged, "[n]o component of ComEd's BE Plan would be appropriately functionalized as transmission and/or generation assets." Staff Ex. 18.2 at 48. The Company did not suggest its BE costs should be considered something other than distribution costs. Since BE Plan costs are not transmission and/or generation costs, they must be costs for distribution services, which should be recovered through base rates, because "…base rates contain the costs related to distribution services…[.]" ComEd Ex. 10.0 at 25.

The Company also argued that "separating the Commission's review of [BE Plan costs] from its review of all ComEd's other costs of providing delivery service will enable a more detailed and transparent review of BE Plan costs." ComEd Ex. 14.0 REV at 16 (emphasis added). ComEd agreed to provide an annual BE Plan report (ComEd Ex. 11.0 REV, Section V) that will provide for transparency into the BE Plan costs, and further, the reconciliation process for the MYRP can allow for a detailed and transparent review of BE Plan costs and do so in the context of the Company's overall operations. As explained earlier, it is possible that some Intervenors may not have sufficient resources to participate in both a MYRP proceeding and a Rider BE proceeding and may choose to participate in only the MYRP proceeding, so there is a risk that there may be fewer parties assessing the reasonableness and prudence of costs to be recovered if Rider BE is approved.

In addition, the Company currently provides education and undertakes activities that support EV adoption and/or the development of EV infrastructure, and the costs of these activities are recovered through ComEd's base delivery service rates and not through a rider. Staff Ex. 18.2 at 49. That these costs, currently recovered through base rates, would be excluded from the total revenue requirements in the MYRP docket and instead recouped through a new rider, underscores the argument that the costs associated with the BE Plan are not unique.

Finally, the Company argued that "…as shown in [ComEd witness Newhouse's] direct testimony, ComEd has numerous existing riders in Illinois that have been approved by the Commission. These riders recover similar costs as Rider BE and should be approved… ." ComEd Ex. 14.0 REV at 22. Based on Staff's review of Mr. Newhouse's

direct testimony (ComEd Ex. 4.0 at 7), with one exception, the listed riders are explicitly authorized by statute. The EVA does not explicitly authorize the recovery of BE Plan costs through a rider. Staff Ex. 7.0 at 13. Absent that authorization, Staff opines the Commission must determine that a rider is necessary, and Rider BE is not.

In conclusion, Staff states the Commission should reject Rider BE. If the Commission rejects Rider BE, as it should, the BE Plan costs will be recovered through base rates in ComEd's MYRP, but the rate design and cost assignment to ComEd's customer classes will be determined through ComEd's next rate design proceeding. Under Section 16-105.5(a), the Company has the option to defer the rate design component of its MYRP, and under Section 16-105.5(b), if the Company decides to defer the rate design component to a later proceeding, the MYRP filing shall be consistent with the rate design and cost allocation across customer classes that is currently in place. Therefore, fixed costs, such as BE Plan costs, or costs that do not vary with customers' energy usage will be recovered through demand charges for demand-metered customers. ComEd has elected to defer the rate design component of the MYRP, so this rate design and cost allocation will remain in place until the Company's next rate design proceeding.

If the Commission approves Rider BE in some form despite Staff's objections, Staff recommends that the Commission make the following modifications to Rider BE (Staff Ex. 7.0 at 13-14):

First, the Commission should order the Company to modify its tariff language to reflect the exclusion of certain costs from recovery, subject to the limitations outlined in Section 16-108.18. If the Commission were to reject the Company's proposed Rider BE, the Company's BE costs would be recovered through a MYRP pursuant to Section 16-108.18. If Rider BE is approved, the costs to be recovered should be subject to the same limitations outlined in Section 16-108.18, including the disallowance of incentive compensation expense that is based on net income. ComEd agreed with this modification (ComEd Ex. 14.0 REV at 22) but had not updated its proposed tariff language to reflect this change.

Second, the Commission should direct the Company to identify specific costs to be recovered through Rider BE. In ComEd Exhibit 15.02, the Company identified the costs to be recovered through Rider BE only in broad terms, as the costs associated with the BE programs. Requesting that all expenditures related to the BE Plan, rather than specific, discrete costs, be recovered through Rider BE increases the risk that BE Plan costs will be recovered multiple times through both the rider and other approved cost recovery mechanisms. ComEd indicated its intent to "develop a unique set of Project IDs to identify costs related to the BE Plan" (Staff Ex. 18.2 at 47); however, ComEd has not indicated any preventive controls to ensure the accuracy of these cost assignments to project IDs. As such, once the cost categories are determined in this proceeding, the Company should identify specific costs to be recovered through Rider BE and accordingly update the tariff language, if Rider BE is approved.

Third, the Company should perform an annual internal audit, after the completion of each plan year, of its costs and subsequent recovery of costs pursuant to the rider.

The Company agreed with this modification (ComEd Ex. 10.0 at 25-26) and updated the tariff language to reflect this commitment. ComEd Ex. 15.02.

Fourth, the Commission should order the Company to prepare an annual report summarizing the results of the annual internal audit and prepare testimony concerning its reconciliation filing, explaining the costs, revenues, and when applicable, reconciliation adjustments. This report and testimony should be submitted to the Commission with the Company's petition to initiate a proceeding to review the costs incurred in the prior BE Plan year by April 1. The Company agreed with this modification (ComEd Ex. 10.0 at 25-26), but the updated tariff language (ComEd Ex. 15.02) did not reference the preparation of testimony explaining the costs, revenues, and when applicable, reconciliation adjustments to accompany the Company's reconciliation filing. The Commission should direct the Company to update its tariff language to include testimony to be filed with the annual internal audit report. This will help ensure that the filing is complete and accurate and identify a Company witness who can respond to questions from Staff.

Fifth, if the Commission approves some form of Rider BE, the Commission should adopt Staff's recommendation to apply a modified WACC as described in detail in Staff's testimony (Staff Ex. 8.0; Staff Ex. 19.0) and later.

Finally, both IIEC and Walmart support Staff's recommendation to reject ComEd's proposed Rider BE. However, if Rider BE is approved, IIEC and Walmart propose to recover BE Plan costs from demand-metered customers through a demand or $/kW charge. The Company agreed. Staff recommends that the Commission direct ComEd to detail how it would implement this proposal in its compliance filing.

c. AG's Position

The AG requests that the Commission reject ComEd's proposal to recover incentive and administrative costs associated with its BE Plan through a proposed Rider BE. Instead, the AG maintains that the Company should collect these costs through delivery base rates. The AG explains that ComEd proposes a split approach to recovering the costs of its BE Plan spending. First, ComEd plans to recover the costs of its programs that provide make-ready infrastructure through its base delivery rates, which will ultimately be included in the Company's upcoming MYRP filing. ComEd Ex. 14.0 REV at 16. Second, the Company seeks to recover its costs to provide incentives and its administrative costs through Rider BE. *Id*. at 16. The AG and Staff both request that the Commission deny Rider BE and the AG echoes the concerns of Staff witness Poon who stated that the Company's rider proposal could lead to unreasonable customer rates by failing to consider all BE Plan costs together and would generate increased regulatory costs. The AG also notes that ComEd's costs were not unpredictable and that there was little risk that the Company would under-recover its costs because of the reconciliation process included in the MYRP.

The AG asserts that the Commission should reject ComEd's arguments on this issue, deny ComEd cost-recovery under Rider BE, and direct the Company to recover all its BE Plan spending though base rates for three reasons. As to ComEd's first argument, the AG asserts that ComEd's costs are not unpredictable and thus are not the type of costs traditionally afforded rider treatment. ComEd will have control over administrative costs, investment decisions, and plan implementation. These programs, designed and

implemented by the Company, do not qualify as imposing unexpected, volatile, or fluctuating expenses beyond the utility's control and thus are dissimilar from projects for which courts have approved rider treatment. *See, e.g., People ex rel. Madigan v. Ill. Commerce Comm'n*, 2011 IL App (1st) 100654, ¶¶32-42.

Further, even if ComEd's costs were uncertain, the AG explains that ComEd has requested budget flexibility to deal with any uncertainty that may arise. ComEd states that it will retain flexibility to adjust the dollar value of rebates if it appears that a larger or smaller rebate would more effectively spur adoption. Thus, the AG notes that if program participation is low for one program and high in another, ComEd can take the funds it would receive through base rates to fund the BE Plan and shift money between programs to fund programs in line with their popularity and even adjust the dollar value of the rebates to incent participation.

The AG also argues that ComEd's volatility argument fails because the MYRP, through which the Company would recover its BE Plan costs if the Commission rejects Rider BE, already provides for a reconciliation mechanism which will allow ComEd to recover its actual BE Plan costs. 220 ILCS 5/16-108.18(f)(6)(A)(2). This means that ComEd will have the opportunity to true-up all its BE Plan costs as part of its total cost of service, so long as these excess costs do not result in the Company exceeding 105% of its total delivery service revenue requirement. 220 ILCS 5/16-108.18(f)(6)(A)(i). As a result, ComEd does not need a rider to guard against the possibility of under recovering its BE Plan costs in a given year if participation is higher than expected because the MYRP reconciliation already provides for the recovery of these costs.

Next, the AG maintains that ComEd is incorrect that a review of BE Plan costs in its own proceeding will allow for a more detailed and transparent review of the Company's costs. The AG states that, in reality, review of BE Plan costs in a separate proceeding will make it exceedingly difficult to track all the Company's BE Plan costs and prevent duplication. Approving Rider BE would result in ComEd's Rider BE Plan incentive and administrative expenses being reviewed in one reconciliation proceeding while ComEd's make-ready expenses are reviewed in a separate proceeding. As Staff witness Poon stated, this could lead to a situation where these BE Plan costs are approved "without considering that they may be offset by changes in other items of the [Company's delivery] revenue requirement." Staff Ex. 7.0 at 8. The AG explains that historic Commission practice under the prohibition against single-issue ratemaking has been to review all utility costs at the same time in the context of a rate case because "[o]ftentimes a change in one item of the revenue formula is offset by a corresponding change in another component of the formula." *See Bus. & Prof'l People for the Pub. Interest v. Ill. Com. Comm'n*, 146 Ill. 2d 175, 244 (1991). The AG adds that the risk of an inaccurate delivery revenue requirement and unreasonable rates is particularly acute in this case given that ComEd proposes to recover administrative expenses through Rider BE. The Company will also recover its administrative expenses through base delivery rates as O&M expenses. Thus, the AG explains that if O&M costs that are included in delivery base rates also facilitate the execution of ComEd's BE Plan, there is a risk of double recovery if those costs are not deducted from ComEd's recovery of BE Plan administrative expenses through Rider BE.

The AG further argues that ComEd's assertion that there will be regulatory costs regardless of whether the Company approves Rider BE or requires ComEd to collect its BE Plan costs through delivery base rates fails because parties have limited resources to engage in multiple proceedings. In response to arguments advanced by Staff that two separate cost-recovery mechanisms with two different reconciliations for BE Plan costs will create added regulatory costs, ComEd asserts that its proposal will not create increased regulatory costs because "[r]equiring BE costs to be recovered through the [MYRP] would only add to the significant number of potential issues about which all parties must ultimately decide whether to litigate or not" in that proceeding. ComEd IB at 59–60. The AG argues that this argument, however, fails to consider that parties like the AG and Staff would need to allocate expert witnesses and attorney time to two entirely separate reconciliation proceedings, rather than allocating resources to a single rate case. The creation of yet another reconciliation proceeding increases regulatory costs, and potentially diminishes the level of scrutiny that stakeholders can commit with limited resources. By comparison, a single reconciliation proceeding for the MYRP would not increase regulatory costs and allows parties to review all ComEd's BE Plan costs in the aggregate. In a single proceeding, parties could also examine the interaction between changes in other components of the Company's revenue requirement and ComEd's BE Plan costs and revenues.

The AG also supports two arguments offered by Staff which assert that the Commission should reject Rider BE. First, Staff explained that the Company is already recovering some of the costs that it proposes to recover through Rider BE through delivery base rates. Second, Staff notes that Ameren does not propose to recover its costs through Rider BE and thus the Commission would be creating two different cost-recovery mechanisms by approving Rider BE. As explained by the AG, Ameren withdrew its proposal to recover BE Plan costs through a rider in Docket Nos. 22-0431 and 22-0443 (cons.) and now proposes to recover its BE Plan costs through delivery base rates.

Thus, the AG requests that the Commission reject ComEd's Rider BE because it could lead to duplication, unreasonable customer rates, increased regulatory costs, and will require the Commission and other intervenors to commit resources to two entirely separate but overlapping reconciliation proceedings. Further, the AG maintains that the uncertainty cited by the Company can be addressed by its proposed budget flexibility tools to move funds collected through delivery base rates from one program to another to match program participation.

d. Walmart's Position

Walmart does not oppose the recommendations of Staff and IIEC that the Commission reject Rider BE in its entirety and instead require the Company to recover BE Plan costs through base rates or an MYRP. Walmart Ex. 2.0 at 9-10.

Walmart and IIEC additionally oppose the Company's proposal to recover costs from demand-metered customers on a cents per kWh charge and instead argue that such costs should be recovered from these customers on a demand, or per kW basis. Walmart Ex. 1.0 REV at 12-13; IIEC Ex. 1.0 at 2-3. In addition to the lack of legislative mandate for the Company's proposal, recovering the fixed costs of the BE Plan on an energy basis

would result in improper cost shifting as between high and low-load factor customers. Walmart Ex. 1.0 REV at 13.

To address this concern, IIEC put forward a proposal by which ComEd could allocate costs to customers classes, facilitating cost recovery on a demand basis for demand-metered customers. IIEC Exhibit 1.0 at 14-17. In surrebuttal testimony, the Company agreed with Walmart that ComEd's volumetric cost recovery proposal creates the "potential for cross-subsidization with the demand-based classes." ComEd Ex. 15.0 at 25-26. Accordingly, ComEd agreed to adopt the proposal put forward by Walmart and IIEC to recover costs from demand-metered customers on a per kW basis. Walmart Cross Ex. 1.0. By agreeing to the cost recovery proposal put forward by Walmart and IIEC, ComEd amended its BE Plan proposal on cost recovery.

e. ChargePoint's Position

ChargePoint supports ComEd's cost recovery proposal. ChargePoint asserts that ComEd should be assured that it will recover all reasonable costs it incurs to implement the BE Plan as approved by the Commission, including its carrying costs. ChargePoint also supports ComEd's proposal to use a regulatory asset to recover the costs of the BE Plan, which it states will allow customers to pay for the cost of the BE Plan over time.

f. IIEC's Position

IIEC opposes the recovery of BE Plan costs through a rider, and on the basis of a cents per kWh charge. *See* IIEC Ex. 1.0 at 2-3. IIEC asserts that the use of a rider to recover particular utility costs should only be approved under certain conditions, which have not been met in this case. First, the costs recovered under the rider should be volatile and unpredictable. *See* IIEC Ex. 1.0 at 4. However, according to IIEC, this condition has not been met for the four substantial reasons identified by Staff witness Poon (Staff Ex. 7.0 at 6-7) and summarized by IIEC witness Stephens (IIEC Ex. 1.0 at 4).

IIEC says the second criterion necessary for costs to be recovered through a rider is that the costs be outside the utility's control. IIEC notes Illinois courts have indicated that a ". . . rider is only appropriate only if the utility cannot influence the cost. . ..". *See, Commonwealth Edison Co. v. Ill. Commerce Comm'n*, 405 Ill. App. 3d 389, 414. IIEC asserts that the costs in question here are within ComEd's control or can be influenced by ComEd. *See* Staff Ex. 7.0 at 6-7; Staff Ex. 18.0 at 16; IIEC Ex. 1.0 at 5.

IIEC indicates that the third criterion for costs to be recovered through a rider, is that they be sufficiently material so as to require more frequent rate cases absent rider recovery. IIEC Ex. 1.0 at 4. According to IIEC witness Stephens, this is not the case here. *Id*. at 5. ComEd has not shown that it will need to file more frequent rate cases. *Id*. at 5-6. Indeed, as acknowledged by Staff witness Poon, BE Plan costs incurred in 2023 can be recovered with the reconciliation, under current formula rate transition tariffs. IIEC Ex. 1.0 at 5. IIEC also notes that if ComEd files a MYRP in January 2023, the BE Plan costs will not require more frequent rate cases.

IIEC asserts that ComEd has not met a single one of the identified criterion for rider recovery, let alone all three. IIEC argues that in addition to failing to meet any of the necessary rider criteria, Rider BE should be rejected because it constitutes single-issue ratemaking in that it does not allow examination of all utility costs at the same time. IIEC

Ex. 1.0 at 6. IIEC points out that Staff witness Poon has identified the single-issue ratemaking aspect of Rider BE indicating that such riders only consider the costs of one component of the revenue requirement of the utility isolated from other components, which can lead to inaccurate revenue requirements and to unreasonable customer rates. IIEC Ex. 1.0 at 6 (citing Staff Ex. 7.0 at 8-9).

It is IIEC's position that if Rider BE is rejected, as Staff and IIEC recommend, then the Commission will have the opportunity to evaluate and assign known costs to the various ComEd rate classes in the context of a rate case or MYRP and make this determination based on cost causation. IIEC affirms that ComEd's proposal within Rider BE is to charge the same costs to all nonresidential customer classes, even though their usage characteristics, use of the delivery system, and perhaps more importantly, use of EV incentives and charging facilities, will vary across the thirteen proposed non-residential delivery classes. IIEC notes ComEd currently has eleven existing nonresidential delivery classes and proposes two more. *See* ComEd Ex. 5.02 at 2-3, ComEd Ex. 5.05 at 2.

IIEC contends that the BE Plan costs should be allocated between nonresidential customer classes to the maximum extent feasible, preferably separately to all classes, for charges that customers pay to best reflect costs. The largest elements of the BE Plan are anticipated to be the EV rebates and EV charging equipment. ComEd should be able to estimate the rebate cost by class and sector. ComEd should be able to estimate other lesser costs as well. IIEC Ex. 1.0 at 14. IIEC argues that a single charge for all nonresidential customers would not be granular enough to protect against inter-class subsidies across the numerous nonresidential classes which are disparate in size and use. IIEC suggests that if BE Plan dollars are going to be spent on particular customers, sectors, or classes, it would be reasonable to recover the costs in proportion to the dollars expended on behalf of each customer's sector or class. IIEC Ex. 1.0 at 15-16. Specifically, IIEC asserts that ComEd should allocate BE Plan costs reasonably across the classes responsible for them, regardless of whether or not it preferred to do so. *Id*. IIEC notes that Staff witness Sanders suggested in his rebuttal testimony that the Commission should consider that costs recovered from customers for the ComEd BE Plan should reflect costs that those customers are responsible for. Staff Ex. 17.0 at 40-41.

IIEC stresses that, as indicated by Mr. Stephens, a large industry may use hundreds of millions of kWh of energy for their operations each year, and not use a single kWh having anything to do with EVs or the facilities needed to charge them. IIEC points out that large industrial plants may have no more electric charging facilities than a small commercial business, or even a residential customer, or possibly none at all; but ComEd's recovery method fails to acknowledge any disparity. IIEC notes that on the contrary, ComEd's recovery method would require these industrial companies pay the same rate as small commercial customers, albeit at an exponentially higher cost because of unrelated kilowatt-hour usage. IIEC contends that industrial customers will unfairly support (or subsidize) these programs to a much larger degree than smaller customers, especially those customers actually receiving the direct benefits of the BE spending. IIEC Ex. 1.0 at 11. IIEC posits that given the expected diversity of usage of electrification incentives and facilities among the eleven existing, as well as the two proposed non-

residential classes, a single rate simply cannot result in cost-based charges IIEC concludes that whether or not Rider BE is approved, costs should be assigned separately and there should be separate charges for each of the rate classes or as many groups as possible.

IIEC stresses that whether or not Rider BE is approved, the cost recovery should not be through a cents per kWh charge, as originally proposed by ComEd. ComEd had proposed that Rider BE costs be recovered pursuant to a single uniform cents per kWh charge to all residential customers and a separate, single, uniform cents per kWh charge to all non-residential customers. IIEC Ex. 1.0 at 8-9; ComEd Ex. 5.06 at 5.

IIEC notes that Walmart also opposed the use of a volumetric charge for recovery of BE costs from all customers, including demand metered customers. Walmart Ex. 1.0 at 11-14. IIEC supports and agrees with Walmart. IIEC explains that the cost of BE programs does not vary in any way with the unrelated energy usage of customers, whether industrial, commercial, or residential. Electricity used in the process of making steel, for example, has nothing to do with ComEd's spending on EV charging or other BE Plan costs. IIEC Ex. 1.0 at 11-12.

IIEC points out that collection on an energy basis violates the basic ratemaking tenet, as well as Illinois law, that rates should be allocated to those customers who cause the costs to be incurred. 220 ILCS 5/1-102(d)(iii). IIEC argues that inasmuch as neither the EVA nor any other aspect of P.A. 102-0662 requires the costs to be recovered on an equal cents per kWh basis, the Commission should reject that approach in favor of a cost-based approach.

IIEC emphasizes that ComEd, in its surrebuttal testimony, indicates that it recognized the potential for cross-subsidization under its proposal to collect fixed BE Plan costs on a volumetric basis, as argued by Walmart and IIEC. ComEd Ex. 15.0 at 25-26. IIEC suggests that ComEd is no longer opposed the Walmart and IIEC recommendation to collect BE costs on a kW basis, for those classes with demand meters, if the Commission so directed. *Id*. IIEC argues this recovery method should apply whether BE costs are recovered through Rider BE or through base rates, whereby the costs can be recovered on the same basis as distribution facilities charges, which is on a per kW basis for all of the nonresidential classes but the smallest (Watt-Hour Delivery Class). *See*, ILL. C. C. No. 10, 6th Revised Sheet No. 61.

g. Commission Analysis and Conclusion

The Commission has broad discretion whether to approve a rider. *See e.g., People ex. rel. Madigan v. Ill. Commerce Comm'n*, 2015 IL 116005 ¶ 25, 25 N.E.3d 587, 596 (Jan. 2015). Exercising that discretion here, the Commission finds that ComEd has not sufficiently demonstrated that Rider BE is necessary to the recovery of BE Plan costs. Among other considerations, the Commission finds that ComEd has not sufficiently demonstrated that the BE Plan costs are a result of unusual circumstances, nor that they are difficult to control. The Commission agrees with Staff and Intervenors that recovery through Rider BE would result in higher regulatory costs than if those costs were recovered in base rates. Further, Rider BE is unnecessary, could lead to unreasonable customer rates, and provides a disincentive for ComEd to manage and control costs.

ComEd's proposed Rider BE is denied and ComEd should recover costs through base rates in its MYRP.

On exceptions, ComEd raises new facts and argument regarding recovery of BE Plan costs through the MYRP. ComEd's objections are untimely. Staff outlines in direct testimony how ComEd can recover BE Plan costs through the MYRP, through base rates prior to approval of the MYRP, and trued up via Rider DSPR. Staff Ex. 7.0 at 7-8. To the extent ComEd incurs BE Plan costs prior to approval of its MYRP presently pending in Docket Nos. 22-0486/23-0055 (cons.), ComEd can recover those costs through base rates or the DSPR. To the extent ComEd's second BE Plan proceeding, to be filed in approximately March 2025, were to result in new costs for BE Plan-related programs, the Commission authorizes the Company to seek to amend its MYRP to incorporate any changes approved in that second BE Plan proceeding.

The Commission notes that CJCP address the issues of Rider BE and the regulatory asset for the first time in Brief on Exceptions. CJCP's arguments largely reflect arguments made by ComEd that the Commission has considered and rejected.

2. Regulatory Asset

a. ComEd's Position

ComEd states that utilizing a regulatory asset to amortize certain BE Plan costs is reasonable and mitigates the up-front bill impact of the BE Plan on customers without compromising the scope and breadth of BE Plan activities. ComEd argues that recovering appropriate BE Plan costs through a regulatory asset allows for a more effective and immediate utility investment at a much lower initial impact upon customer rates and bills, and ensures that costs are aligned with benefits. ComEd notes that the rate impact of the $100 million investment will be smaller up front because the majority of the BE Plan costs will be included in the regulatory asset, so annual bill impacts of the BE Plan will be spread over the ten-year amortization period.

ComEd disagrees with Staff and AG's opposition to the use of a regulatory asset. ComEd states that a regulatory asset mitigates the upfront impact of the BE Plan on customer rates. ComEd argues that regulatory asset treatment enables asset purchase incentive costs to be spread over the entire useful life of the assets, which aligns costs with benefits. ComEd points out that regulatory asset treatment also mitigates possible volatility in customer bills. ComEd notes that a regulatory asset will result in a better match between bill impacts and customer benefits.

ComEd refutes Staff's suggestion that a regulatory asset might encourage ComEd to spend more than its approved BE Plan budget. ComEd points out that this concern is unfounded because ComEd's BE Plan costs will be regularly reviewed by the Commission for prudence and reasonableness in reconciliation proceedings.

Staff claims that ComEd's evidence incorrectly conflated customer benefits and costs with ComEd's benefits and costs, pointing out that the regulatory asset would include costs of incentives, rather than company-owned capital assets. Similarly, the AG argues that the BE Plan costs ComEd proposed to include in the regulatory asset were more like postage and insurance costs and should be treated as short-term expenses because ComEd will not own the assets purchased by customers. ComEd asserts that

a regulatory asset will result in a better match between customer bill impacts and customer benefits, because spreading the recovery of these costs out across the useful life of the asset (e.g. the EVs or customer-owned equipment purchased with a BE Plan incentive) matches the costs that customers bear each year with the benefit they experience in that year. ComEd Ex. 9.0 at 11.

ComEd states that that the Commission should approve the structure of the regulatory asset as proposed by ComEd. ComEd notes it chose to include the costs of the Residential Program, C&I and Public Sector Program, and BE Pilot Program in the regulatory asset because the programs are specifically designed to incentivize adoption of assets with long useful lives. ComEd also notes that Portfolio and Customer Education and Awareness Program costs are better suited to remain as O&M costs or capital costs because these costs will not directly translate into assets with long expected useful lifespans.

ComEd states that the optimal period over which the regulatory asset should be amortized is ten years. ComEd points out that the BE Plan targets numerous kinds of BE technologies with various expected useful lifespans. ComEd explains that transportation BE technology, such as EVs, can reasonably be expected to last up to twelve years. But ComEd notes that non-transportation BE technology may have shorter expected useful lifespans. ComEd argues that an amortization period should be set at ten years because of the various expected useful lifespans.

ComEd refutes Staff's recommendation that the regulatory assets be used only for accounting purposes, and that the prudence and reasonableness of the costs included in the regulatory asset be evaluated in future rate proceedings. ComEd states that all BE Plan costs are already subject to a prudence and reasonableness review by the Commission, including those in a regulatory asset, and the prudence and reasonableness review will occur in future Rider BE reconciliations.

ComEd also declines Staff's recommendation to limit the costs placed in the regulatory asset to rebates and exclude administrative expenses. ComEd argues that significantly limiting which costs are included in the regulatory asset will lead to significant, up-front bill impacts for customers, and misalignment between the costs and benefits of the BE Plan. ComEd argues it is reasonable to provide regulatory asset treatment of the administrative expenses to smooth out annual bill impacts because administrative costs will correlate with and will be incurred irregularly like costs of the incentives themselves.

Both Staff and the AG raise concerns about the carrying costs associated with the regulatory asset. ComEd responds that while it is true that carrying costs increase the actual dollar amount paid by customers over time, when a proper rate of return is used, the total cost, adjusted for the time-value of money is the same. *See* ComEd Ex. 9.0 at 12-13. When Staff and the AG emphasize the dollar amounts of anticipated carrying costs over time, they ask the Commission to ignore the time-value of money and assume that one dollar today is the same as one dollar ten years from now, when clearly it is not.

b. Staff's Position

Staff explains that a regulatory asset consists of costs incurred in a given year that would normally be recorded as expenses in that year. With a regulatory asset, these

costs are instead recorded as an asset and then recovered over a multiple year period with the unrecovered portion receiving a return, rather than the costs being recovered as they are incurred. Staff Ex. 7.0 at 14-15. Staff states that the Commission should reject ComEd's request for regulatory asset treatment. Staff Ex. 7.0 at 3; Staff Ex. 18.0 at 4.

First, Staff states, the Company incorrectly conflates customer benefits and customer costs with the Company's benefits and the Company's costs. Staff Ex. 18.0 at 6-7. It is the customers, not ComEd, who may or may not purchase and own assets like EVs and EV charging infrastructure. For the customers who purchase these assets, the assets will benefit the customers, not the Company, over the useful lives of the individual assets purchased. In contrast, payments that customers make to the Company for utility service represent revenues to the Company. This revenue that the Company collects is intended to cover the Company's cost of providing service, which includes a return on Company-owned capital assets, not on customer-owned capital assets.

The costs that the Company is proposing to place into regulatory assets are not Company-owned capital assets. Staff Ex. 18.0 at 7. Rather, these costs ($83 million annually) consist primarily of financial assistance to the Company's customers. This financial assistance is a current cost to the Company and therefore should be matched to the Company's current revenue. If the cost of this financial assistance is instead spread out over time, the Company's current revenue will be matched to only a portion of its current expenses, and this resulting mismatch may lead to unreasonable rates. Furthermore, any financial assistance that the Company provides to customers is not a long-term asset that is expected to yield long-term benefits to the Company, rebates and administrative costs are not Company-owned utility plant upon which the Company is entitled to earn a rate of return. Rather, they are treated as O&M costs and recovered from ratepayers as expenses, at such time as the Company incurs them. While these costs should be recovered, these costs should not be added to the Company's rate base and allowed to earn a return. Under regulatory asset treatment, these costs would be placed in a regulatory asset and earn a return just as if they were plant.

Second, Staff explains, because regulatory assets result in deferred costs that are recovered over time so the initial impact to bills is less noticeable, regulatory assets could encourage larger budgets. In fact, the Company is requesting regulatory asset treatment in this docket so it can mitigate the impact of its proposed $100 million annual budget on ratepayers. ComEd Ex. 4.0 at 8. ComEd's argument that regulatory assets will allow the Company to smooth the impact of BE Plan spending addresses a problem that ComEd created. Staff Ex. 7.0 at 17-18. Because ComEd proposes such a large budget, it proposes to recoup the majority of its BE Plan costs through regulatory assets to minimize the initial impact to bills. However, the Company could minimize the overall impact to bills simply by spending less money. ComEd claims that a smaller budget would "delay and minimize the advancement of the State's BE goals" (ComEd Ex. 9.0, 13), but there is no evidence that the more money the Company spends, the quicker it can achieve the State's BE goals. Indeed, given the lack of data to support many of the programs ComEd proposes for its first BE Plan, this is not a realistic assumption. Staff agrees that electrifying transportation is crucial to addressing Illinois' heavily polluting transportation sector; but it is also vitally important to effectuate these goals while minimizing the overall

expense to ratepayers. Staff Ex. 18.0 at 10. To that end, Staff proposed an alternative budget in Staff Exhibit 17.1. Staff urges the Commission to approve its alternative budget.

Furthermore, while the initial bill impact under regulatory asset treatment may be smaller than without it, over time the bill impact from regulatory asset treatment will be greater due to carrying charges incurred on the unamortized balances of the regulatory assets and due to increased regulatory costs. Staff Ex. 18.0 at 8-9. By Staff's estimate, ratepayers would pay about $96.5 million just in carrying charges over a 12-year period as a result of the regulatory assets the Company is proposing to establish in each of the three years of just its first BE Plan. Staff Ex. 18.0 at 9. These costs will be compounded in future years if the Company proposes and receives Commission authorization for regulatory asset treatment in future BE Plan filings but would be avoided if regulatory asset treatment is not allowed. ComEd did not directly address the fact that a regulatory asset would result in higher costs for customers over the long term but stated that "when regulatory asset recovery is compared to recovery of costs as expenses, the difference in total cost is the time value of money…[i]f the financing costs match the time value of money, the total costs are the same." ComEd Ex. 9.0 at 12-13. Again, this statement conflates the Company's preferences with those of its customers. While the Company may be indifferent to recovering its BE Plan costs immediately as O&M costs versus recovering those costs over ten years under regulatory asset treatment, the Company cannot make the same statement about the impact on its customers. On the contrary, customers pay more over time under regulatory asset treatment. Staff Exs. 18.1; 7.0 at 19; 7.1 at 4-5.

Staff states that regulatory assets also increase overall regulatory costs because regulatory assets require additional time and resources for the Company to track and monitor over the period of deferral. They also require Staff, the Commission, and Intervenors to review the appropriateness of the incurred costs that have been allocated to the regulatory assets and to review all the calculations associated with them through a docketed proceeding. Consequently, this further increases costs to ratepayers. If regulatory asset treatment is approved, all these increased costs would be passed on to ratepayers. ComEd argued that "Staff witness Poon ignores the substantial increase in customer benefits that creation of a regulatory asset would allow" (ComEd Ex. 14.0 REV at 13), but ComEd failed to identify the "substantial increase" in customer benefits. In fact, any benefit to ratepayers through lower rates would be short-lived, as customers have to pay the carrying costs for the first regulatory asset year after year; these costs will compound as another regulatory asset, with associated carrying charges, is created each subsequent year.

Finally, the Company argued that regulatory asset "treatment helps better balance the priorities of the State of Illinois with the other investments ComEd makes to benefit [its] customers," (ComEd Ex. 14.0 REV, at 12) but did not explain why. There is nothing in the record establishing what the "priorities of the State of Illinois" are, what the "other investments ComEd makes to benefit [its] customers" are, or why these are currently unbalanced. The EVA unambiguously contemplates amongst other things "methods of minimizing ratepayer impacts ..." but permitting the Company to receive regulatory asset treatment on BE Plan costs would exacerbate ratepayer impacts, rather than minimizing them. 20 ILCS 627/45(d)(v).

Staff notes that WeaveGrid supports ComEd's proposal for regulatory asset treatment for the rebates offered in ComEd's BE Plan and provided examples of utilities in several states that received authorization to treat rebates offered in their BE programs as regulatory assets. WeaveGrid Ex. 1.0 at 24. In Staff's opinion, the Commission should reject WeaveGrid's recommendation that rebates should be treated as regulatory assets simply because it is done in other states with different statutes and different regulatory structures. While there could be value in reviewing other utilities' docketed BE proceedings, decisions of other Commissions should not be a consideration in this proceeding because there are differences in regulatory environments, statutory requirements, customers, and service territories between utilities in other states and ComEd. However, if the Commission approves regulatory asset treatment despite Staff's strong opposition, only the cost of rebates and not administrative costs should be placed into regulatory assets.

Staff also notes ChargePoint supports ComEd's proposal to use regulatory assets to recover the majority of its BE Plan costs, noting that regulatory assets "…will allow customers to pay for the cost of the BE Plan over time." ChargePoint IB at 22. This assertion is without merit, according to Staff. Customers will pay for the cost of the BE Plan over time regardless of whether regulatory asset treatment is approved because there will be other iterations of the BE Plan, and the costs of those BE Plans will be recovered from customers. The difference is that if regulatory asset treatment is approved, ratepayers will be responsible for paying more over time than if this treatment were rejected as Staff recommends.

The Commission should also reject ComEd's proposal to establish regulatory assets because of the risk of single-issue ratemaking. Staff Ex. 7.0 at 15-16. Similar to the Company's proposal to recover all BE Plan costs through Rider BE, its proposal to establish regulatory assets involves considering BE Plan costs in isolation from the other components of the Company's revenue requirement rather than in the aggregate. A regulatory asset removes an expense from current operating results and then sets it aside for future ratemaking recovery. Deferring and amortizing an operating expense, which the Company proposes to do here by creating regulatory assets, causes revenue and expenses to become improperly matched because one year's expenses would be netted against a different year's revenue. This improper matching of expenses and revenue distorts the revenue requirement and can lead to unreasonable rates. An MYRP filing can mitigate the risk of single-issue ratemaking because it allows the Company to recover actual costs. However, even though the Company intends to file a MYRP in January 2023, the Company is not obligated to continue filing MYRPs in the future because it always has the option to file a general rate case later. As long as the Company has the option to file a general rate case, the risk of the Commission setting rates without considering all components of the revenue requirement in the aggregate will exist. Furthermore, the MYRP has an annual adjustment component that allows the Company to recover its actual costs but only to an extent; under Section 16-108.18(f)(6)(A), if the Company's actual expenses for years 2024-2027 are higher than its estimated expenses for those years, the Company is allowed to recover the difference only up to 105% of the approved revenue requirement for that year. Because the approved revenue requirement will serve as the basis for determining the allowed adjustment, it is critical that the

approved revenue requirement be accurate. An inaccurate revenue requirement could lead to unreasonable rates.

Because of the risk of single-issue ratemaking, the creation of regulatory assets should be limited to scenarios in which the costs are unusual or non-recurring, and the costs are incurred as a result of unexpected or unforeseen events. Staff Ex. 7.0 at 15. Staff opines that the Company has not demonstrated that its BE Plan costs are so different from its other operating costs that they warrant special treatment.

If the Commission approves regulatory asset treatment despite Staff's strong opposition to such treatment, the Commission should approve it with the following clarifications and modifications (Staff Ex. 7.0 at 20-21; Staff Ex. 18.0, Section III B):

First, regulatory asset treatment should be granted for this initial BE Plan period only. Language in the final Order should state that if the Company desires regulatory asset treatment in future BE Plans, it should re-request this treatment in its future BE Plan filings for Commission consideration. Therefore, regulatory asset treatment for the initial BE Plan period would apply to the creation of regulatory assets in years 2023 – 2025 only. Limiting regulatory asset treatment to the initial BE Plan period will also limit the total carrying charges to be recovered from ratepayers over time. Staff Ex. 18.0 at 13. The Company generally agreed with this clarification. ComEd Ex. 9.0 at 14.

Second, the final Order should state that the approval of the regulatory assets is for accounting purposes only; the approval in this docket does not preclude the Commission, Staff, and/or Intervenors from reviewing the calculations, including but not limited to the consideration of amortization periods, the calculations of carrying charges and amortization expense, and the prudence and reasonableness of costs that are being aggregated in the regulatory assets, in any future rate or reconciliation proceeding. As discussed earlier, the Commission should reject Rider BE. Therefore, if the Commission grants regulatory asset treatment and rejects Rider BE, the regulatory assets would be reviewed later in a MYRP and in annual performance evaluation proceedings, which includes an annual adjustment or reconciliation between the actual revenue requirement and the approved revenue requirement or in a traditional rate case, if the Company chooses to file one later. Staff Ex. 18.0 at 13. The Company continued to claim that the costs in the regulatory assets should be reviewed in Rider BE reconciliation proceedings but did not oppose this clarification. ComEd Ex. 9.0 at 14.

Third, include language in the final Order to limit the deferred costs in the regulatory assets to incentives that customers use to purchase and own the BE technologies that the Company's BE Plan is focused on deploying. If the Commission approves regulatory asset treatment, which it should not, only the deferred rebate costs, and not administrative costs, should be placed in regulatory assets, consistent with the Company's reasoning about which O&M costs should be included in and which should be excluded from regulatory assets. Staff Ex. 7.0 at 21. If the Commission grants the Company regulatory asset treatment, the administrative costs within the $83 million that the Company proposes to defer as regulatory assets should be treated as O&M costs not to be amortized as regulatory assets, consistent with the Company's proposed treatment of Portfolio costs. If both regulatory asset treatment and Rider BE are approved, the Commission should order the Company to revise its Rider BE tariff language to reflect

that costs to be placed in the regulatory assets are limited to rebates and not any administrative expenses. The Company disagreed with this modification but did not explain why its administrative costs that it is proposing to place in regulatory assets should be given treatment different from its Portfolio (administrative) costs that it is proposing not to place in regulatory assets. ComEd Ex. 14.0 REV at 15.

c. AG's Position

The AG requests that the Commission reject ComEd's proposal to include $83 million of its $100 million annual BE Plan budget in a regulatory asset because the proposal would significantly increase the amount of money ratepayers will pay for the BE Plan.

First, the AG maintains that while regulatory asset treatment may produce cost-savings and smoother rate increases in the near-term by spreading out costs over a ten-year amortization period, ComEd's proposal results in customers paying significantly more to cover the costs of the BE Plans over the lifetime of the plans, especially if the Company is allowed to stack regulatory assets on top of one another for each BE Plan. As described by the AG's witnesses, shareholders would receive, and ratepayers would pay, an additional $81 million for the exact same BE Plan programs if the Company was allowed to create a regulatory asset — the difference between $300 million if regulatory asset treatment is denied and $381 million if regulatory asset treatment is allowed. AG Ex. 1.0R at 57. The entirety of the excess $81 million is return paid to investors on plan spending that ComEd would otherwise not be entitled to receive. The AG maintains that this excess cost violates the various portions of the EVA which call on the Company to design BE Plans that minimize rate impacts such as Section 45(d)(v) which states that the BE Plans should seek to minimize the rate impact experienced by low-income ratepayers in the pursuit of facilitating the expansion of EV charging. 20 ILCS 627/45(d)(v).

The AG explains that customers are only neutral to the deferral of costs created by a regulatory asset over a ten-year period if their incomes increase commensurate with ComEd's rate of return over the lifetime of the regulatory asset. However, this is extremely unlikely to be the case. The Company's proposed WACC for its regulatory asset is 5.72% over the next ten years. For customers to pay less in adjusted dollars for the BE Plan costs under ComEd's regulatory asset proposal, their incomes must increase commensurate with the WACC rate of return. As described by the AG's witnesses, this is highly unlikely to occur over the course of the next ten years. AG Ex. 2.0 at 28. Further, the AG's witnesses stated that the most vulnerable ratepayers are at elevated risk of paying significantly more under ComEd's proposal given that "low-income, unemployed, and elderly residents are even less likely to see sufficiently high wage or other income increases for the next ten years to be theoretically neutral to ComEd's regulatory asset treatment." *Id*. at 28 (footnotes omitted). Thus, to the AG, the Company's proposal will result in customers paying significantly more for the BE Plans and will specifically burden vulnerable ratepayers who are less likely to experience increases in their incomes to cover the additional cost of capital associated with the regulatory asset.

In addition, the AG explains that regulatory asset treatment would result in BE Plan costs increasing greatly over time if the Commission approved regulatory assets for the

Company's next rate case. The EVA calls for a BE Plan every three years and, as a result, the cost to consumers to pay for these plans can be expected to grow as each year's expenses accumulate over multiple plan cycles. The AG's witnesses presented a figure showing how regulatory assets stack on top of another over multiple plan cycles and drive up the charges paid by consumers. The AG states that not only does regulatory asset treatment result in customers paying more for BE Plans over the lifetime of the regulatory asset when compared to expensing the costs as O&M, but the Company's proposal would also result in ratepayers paying more in future years for BE Plan costs than they would pay if the costs were immediately expensed.

Second, the AG maintains that the Commission should also reject ComEd's second argument that regulatory asset treatment enables incentive costs to be spread over the entire useful life of the assets that are incentivized, which aligns costs with benefits. The AG states that ComEd's argument attempts to analogize ComEd's incentive expenses to investments it makes in utility-owned plant with a depreciable life, on which the Commission generally allows a return. The AG asserts, however, that the Company's rebates are much more similar to costs which have traditionally been expensed and that have not generated a return. As explained by the AG's witnesses, recurring expenses that do not extend the life of utility plant are not classified as new capital investments and are traditionally treated as expenses under standard ratemaking practices, with the costs recovered from ratepayers in the year expended without a return. AG Ex. 2.0 at 26-27. The AG states that the Company's proposed refunds are similar to traditional expenses such as postage or insurance costs in that they are short-term expenses where the costs are immediately paid and under which the utility obtains no additional plant. The AG states that the fact that the rebates will facilitate third-party purchases of materials with a long useful life does nothing to offset these traditional accounting principles because the purchases are not utility plant and ComEd does not own the materials associated with the rebates.

The AG adds that the Company's costs are also unlike others that the Commission has traditionally approved for regulatory asset treatment because the Act has not explicitly granted the utilities the right to receive regulatory asset treatment in this case. The AG notes that the Act specifically grants regulatory asset treatment for EE Plan costs and the costs to provide rebates to customers electing to install distributed generation, even though these programs provide benefits to individual customers without creating utility ownership of plant. 220 ILCS 5/8-103B(m)(e). Similarly, Section 16-107.6(h) of the Act, which governs the cost-recovery related to the provision of rebates for the installation and operation of distributed generation, states that "[t]he utility shall defer the full amount of its costs [to provide rebates approved under Section 16-107.6(d)] as a regulatory asset. The total costs deferred as a regulatory asset shall be amortized over a 15-year period." 220 ILCS 5/16-107.6(h). The AG notes that there is no language in the EVA permitting ComEd to recover its BE Plan costs pursuant to a regulatory asset. The AG concludes that, in the absence of statutory authorization, the Commission should not approve regulatory asset treatment for ComEd's BE Plan costs.

d. IIEC's Position

It is IIEC's position that ComEd should be allowed to recover its prudent and reasonable operating expenses, but it should not be allowed to earn a return on those

expenses, including expenses associated with BE. IIEC agrees with the Staff and the AG that ComEd's proposal for regulatory asset treatment of BE Plan costs should be rejected.

IIEC observes that in support of its request to create a regulatory asset, ComEd suggests that the BE Plan costs will deliver long-term benefits to ComEd customers. However, IIEC reasons that whether or not the expense provides long-term benefits is not a standard for earning a return. IIEC reasons that, for example, diligent distribution line maintenance also provides "long-term benefits" but whether benefits accrue does not make it a capital investment that warrants the return. IIEC does not believe that compliance with the BE requirement in the EVA, 20 ILCS 627/45 should be allowed to become a new profit center for ComEd.

IIEC points out that under ComEd's proposal, a majority of BE Plan costs would be included in the regulatory assets ComEd proposes to create, while the annual bill impact of same will be spread over the 10-year amortization period. IIEC notes ComEd's statement, "[f]or example, if a $100 million investment can be placed in a regulatory asset and amortized over a ten-year period, rather than expensed in a single year, the rate impact of that $100 million investment will be smaller upfront." ComEd Ex. 4.0 at 10. IIEC says that while it is true that ComEd's illustration shows the rate impact may be smaller up front, IIEC points out it also shows that customers will end up paying more, because of the return ComEd seeks on the regulatory asset for these expenses. According to IIEC, it is noteworthy that ComEd did not show the total cost paid by customers over time in its comparison of customer rate impacts associated with the regulatory asset treatment in Figure 1 of its Initial Brief. ComEd IB at 62. When the costs are totaled for both residential and C&I customers, the charges are greater in the "with Regulatory Asset" rows in Figure 1. According to IIEC, the rows in ComEd's Figure 1 sum to $1.28 with the regulatory asset and $1.17 without the regulatory asset, for residential, and $5.64 with the regulatory asset and $5.07 without the regulatory asset, for C&I. IIEC observes that Staff and the AG have indicated customers could pay an additional $81 million (AG) or $96.5 million (Staff) for ComEd's BE Plan if a regulatory asset is created. *See*, AG IB at 59; Staff IB at 132.

IIEC notes that in response to Staff's position that a regulatory asset might encourage ComEd to spend more than its approved BE Plan budget, ComEd claims that Staff's position was unfounded because its BE Plan costs, including those proposed for regulatory asset treatment will be regularly reviewed by the Commission in reconciliation proceedings. IIEC points out that ComEd expects the Commission to believe that it would not be encouraged to spend more when offered the opportunity for a return. According to IIEC, this defies common business sense.

IIEC supports the position and reasoning of Staff and the AG that the ComEd proposal to create a regulatory asset should be rejected.

e. WeaveGrid's Position

WeaveGrid recommends that ComEd be allowed to treat certain BE Plan costs as regulatory assets. Allowing ComEd to amortize certain BE expenses can better position the BE Plan to support widespread transportation electrification while also helping minimize the near-term bill impacts. WeaveGrid further explains that regulatory asset treatment aligns the timelines of accumulated costs with the benefits of electrification.

WeaveGrid notes that other state commissions have approved regulatory asset treatment for electrification programs, and that Illinois has approved regulatory asset treatment for energy efficiency programs where the benefits similarly accrue over time.

f. Commission Analysis and Conclusion

Upon consideration of the parties' arguments, the Commission does not agree with ComEd that regulatory asset treatment of certain BE Plan costs is reasonable. While regulatory asset treatment will mitigate the upfront costs to customers, it significantly increases the costs customers pay over time.

ComEd claims that the carrying costs of the regulatory asset will not result in unreasonable rates because, with a proper rate of return, the total cost adjusted for the time-value of money is the same. ComEd argues that one dollar today is not the same as ten years from now. The Commission understands the time value of money, but the problem with ComEd's argument is that it assumes customers' incomes will increase commensurate with ComEd's rate of return, which, as the AG points out, is unlikely to happen.

Additionally, while BE Plan costs will provide long-term benefits to customers, this does not mean that it is appropriate or reasonable for ComEd to earn a rate of return on those costs. The Commission agrees with Staff and the AG that the BE Plan incentive expenses are more analogous to costs that have been traditionally expensed and do not earn a rate of return. BE Plan incentives, such as rebates, allow third-parties to purchase materials with a long useful life but this does not equate with ComEd's treatment of these materials as akin to utility plant because ComEd does not own the materials associated with the incentives.

ComEd's proposal for regulatory asset treatment of certain BE Plan costs is denied.

3. Rate of Return Applied to Rider BE Cost Recovery

a. ComEd's Position

ComEd contends that its WACC should apply to all BE Plan expenses including the proposed regulatory asset, O&M, and capital expenses. ComEd notes that its WACC represents ComEd's cost of the capital used to fund the costs during the amortization period. ComEd argues that it is appropriate for the regulatory asset to include ComEd's carrying costs calculated using its WACC to ensure that ComEd recovers all its actual costs associated with the implementation and operation of the BE Plan. ComEd asserts that it is also reasonable for ComEd to recover its WACC for O&M and capital expenses incurred under the BE Plan because such expenses incur carrying costs during the intervening years between incurring and recovery.

ComEd argues that Staff and Walmart's alternative rate of return proposals should be rejected. ComEd points out that Staff and Walmart's recommendations do not reflect ComEd's costs of financing. ComEd argues that Staff and Walmart are mistaken by assuming ComEd will finance the BE Plan using only debt. With regard to Staff's proposal, ComEd points out Staff's proposal would apply an artificially lowered, arbitrary rate of return to the regulatory asset rather than the true cost of how ComEd finances the operations of its business. ComEd asserts that it will finance the BE Plan using both debt

and equity. ComEd notes the WACC reflects the combined, weighted average cost of funds (both debt and equity) used to finance the total operations of the utility.

ComEd disagrees with Staff's suggestion that a lower ROE is justified because Rider BE eliminates risks applicable to rate base assets. ComEd points out that regardless of which cost recovery method applies (Rider BE, Rider DSPR, or MYRP), each method incorporates a reconciliation mechanism and a prudency test prior to recovery. ComEd states that the WACC applied in all three methods would be subject to Commission approval.

ComEd also disagrees with Staff's suggestion that cases where the Commission authorized a time-horizon and adjusted ROE for rider assets for costs that were incurred pursuant to a legislative mandate, support a lower ROE for the BE Rider. ComEd notes that each of the cases Staff cites either involve utilities that do not have annually reconciled rates or were decided before the Energy Infrastructure Modernization Act ("EIMA") was passed.

ComEd points out it is undertaking the BE Plan in response to a legislative mandate. ComEd argues it would be inappropriate to apply a lesser financing rate (as proposed by Staff and Walmart) to any independent component of ComEd's utility operations, especially when ComEd finances all its investments in the same way using both debt and equity.

If, however, the Commission accepts Staff's proposal to treat the regulatory asset as funded entirely, or largely using debt, that debt must be removed from ComEd's overall capital structure. As ComEd witness Newhouse explained, if specific debt is deemed to finance BE costs, it cannot also be used to finance other components of ComEd's business. ComEd Ex. 14.0 REV at 19.

b. Staff's Position

For each BE cost recovery component, Staff argues for the application of a modified WACC in which the cost of equity is reduced to reflect the respective recovery period and lower risk associated with Rider BE. Staff Ex. 8.0 at 2; Staff Ex. 19.0 at 1.

The Company's proposal incorrectly implies that the risk inherent in the recovery of BE costs equals the risk of the Company's electric delivery services assets. Unlike the Company's electric delivery services rates for which the utility could earn more or less than the Commission-approved, fair return on investment, the Company proposes that the BE Plan costs will be recovered through a rider that will provide dollar-for-dollar recovery of the actual costs incurred. Thus, there will be no risk of costs exceeding the amount to be recovered. In addition, Rider BE includes an annual reconciliation that would further ensure timely recovery of approved BE costs. That "true-up" reduces the risk associated with the BE expenditures relative to cost recovery through traditional rates. Therefore, the recovery of costs through Rider BE requires a lower rate of return than rate base assets. However, BE Plan costs will not be without risk, as they will be subject to a prudence review before they can be recovered, so the BE cost recovery components warrant a higher return than the effectively riskless U.S. Treasury bond yield. Thus, Staff recommends adjusting the WACC authorized in the Company's most recent

rate case by substituting a cost of common equity between that authorized for rate base assets and the yield on U.S. Treasury bonds. Staff Ex. 8.0 at 2-4, 6.

In addition to a recovery risk adjustment, Staff explains that the cost of common equity included in the Company's authorized WACC also needs to be adjusted to reflect the shorter duration of investment for the BE cost recovery components relative to rate base. The Company's authorized rate of return on rate base reflects the investor-required rate of return on equity into perpetuity. In contrast, the Company's proposal would amortize the regulatory asset over 10 years, recover the O&M costs in two years, and amortize the capitalized costs over five years. All else equal, assets with different time horizons have different required rates of return. Therefore, for the BE Plan regulatory assets, Staff recommends reducing the Company's cost of equity by the spread between 10-year and 30-year high quality corporate bonds, to account for the time horizon difference between rate base assets and the BE cost recovery period. For example, the recent spread between 10-year and 30-year high quality corporate bonds yields is 18 basis points. Therefore, the 10-year recovery period for the Regulatory Asset alone would reduce the Company's cost of equity from the 7.36% authorized in Docket No. 21-0367 to 7.18%. Similarly, because the BE Plan O&M costs will be recovered on a 2-year lag, Staff recommends reducing the Company's cost of equity applicable to O&M by the spread between 2-year and 30-year high quality corporate bonds. The recent spread between 2-year and 30-year high quality corporate bonds yields is 86 basis points. Therefore, the 2-year recovery period of O&M costs alone would reduce the Company's cost of equity from 7.36% to 6.50%. Likewise, Staff recommends reducing the Company's cost of equity applicable to capital costs by the spread between 5-year and 30-year high quality corporate bonds. The recent spread between 5-year and 30-year high quality corporate bonds yields is 68 basis points. Therefore, the 5-year recovery period of capital costs alone would reduce the Company's cost of equity from 7.36% to 6.68%. Staff Ex. 8.0 at 5; Staff Ex. 19.0 at 3.

To combine both the time horizon adjustment and the recovery risk adjustment, Staff recommends ComEd's costs of common equity for Rider BE equal the midpoint between the Company's time horizon-adjusted, Commission-authorized cost of common equity and the current interest rate for U.S. Treasury bonds of the same term. Specifically, Staff's return recommendation for the Regulatory Asset includes an ROE component that equals the midpoint between the 10-year U.S. Treasury debt rate and the Company's authorized ROE, as adjusted to reflect a 10-year maturity instead of a perpetuity. The recent 10-year U.S. Treasury bond rate was 3.45%. Thus, the midpoint between that and the 7.18% horizon-adjusted cost of common equity would produce a 5.32% cost of common equity for the BE Plan regulatory asset.

Similarly, Staff's return recommendation for O&M costs includes an ROE component that equals the midpoint between the 2-year U.S. Treasury debt rate and the Company's authorized ROE, as adjusted to reflect a 2-year maturity instead of a perpetuity. The recent 2-year U.S. Treasury bond rate was 3.87%. The midpoint between that and the 6.50% horizon-adjusted cost of common equity would produce a 5.19% cost of common equity for BE Plan O&M costs. Likewise, Staff's return recommendation for Capitalized Costs includes an ROE component that equals the midpoint between the 5-year U.S. Treasury debt rate and the Company's authorized ROE, as adjusted to reflect

a 5-year maturity instead of a perpetuity. The recent 5-year U.S. Treasury bond rate was 3.66%. The midpoint between that and the 6.68% horizon-adjusted ROE would produce a 5.17% ROE for the BE Plan Capitalized Costs. Staff Ex. 19.0 at 3.

Regarding the cost of debt included in Staff's modified WACC proposal, Staff explains that estimating the Company's marginal cost of debt for the BE cost recovery components would be theoretically superior to using the embedded cost of long-term debt applicable to rate base but doing so would be much more complicated and would not materially affect its recommendation. Thus, for simplification purposes, Staff uses the Company's authorized cost of debt as a proxy to estimate the marginal cost of debt included in the WACC for Rider BE. Staff Ex. 8.0 at 8; Staff Ex. 19.0 at 4-5.

Staff's recommendation is to combine the adjusted cost of common equity with the cost of debt and the component weighting authorized in the Company's last rate case. The process Staff proposes to estimate the rates of return for Rider BE costs is premised on an approach that the Commission has found appropriate for adjusting the authorized ROE for rate base assets downward to reflect the shorter maturity and the lower relative risk of cost recovery via a rider mechanism. Staff Ex. 19.0 at 6. Staff recommends that the Commission adopt Staff's recommended approach if it approves Rider BE.

The Company's argument suggests that its overall cost of capital (i.e., the WACC) determines the required rate of return on new assets it acquires. Staff states that the opposite is true. The weighted average of the required rates of return of the individual assets the Company owns determines its WACC. *See Central Ill. Light Co. d/b/a/ AmerenCILCO*, Docket No. 08-0619, Order at 32 (Aug. 19, 2009); Staff Ex. 19.0 at 5-6. The currently authorized WACC does not reflect the lower cost of financing BE costs, which have not yet been incurred. Since BE cost recovery is not reflected in the WACC that was authorized in the Company's last rate case, the application of the authorized WACC, as the Company proposes, would overstate the Company's overall financing costs. By seeking cost recovery through Rider BE, the Company seeks to separate Rider BE assets from rate base assets. Therefore, a distinct cost of capital must be applied to Rider BE assets. Staff Ex. 19.0 at 5.

Despite ComEd's claim, Staff did not suggest ComEd would rely exclusively or in large part on debt financing; tellingly, ComEd provides no citation to any evidence in support of this statement. In fact, Staff's proposal not only clearly includes both debt and equity but does so in the same proportions approved by the Commission in ComEd's last rate proceeding. Staff recommended "a modified [weighted average cost of capital], including both debt and equity, be applied," and testified that Staff's calculation was derived by combining the "[adjusted] cost of common equity with the cost of debt and the component weighting authorized in the Company's last rate case." Staff Ex. 8.0 at 7; Staff Ex. 19.0 at 2, 4.

Relying on this misrepresentation of Staff's position, the Company argues that a portion of the debt assigned to each cost category must be removed from the capital structure supporting rate base. ComEd Ex. 9.0 at 16; ComEd 14.0 REV at 17, 19. The Company assumes that the debt identified in Staff's proposal represents a portion of the same debt supporting ComEd's rate base. Staff explains that this not the case. Staff did not argue that the same debt financing rate base would also finance BE costs. Rather,

Staff used the Company's authorized cost of debt as a proxy to estimate the marginal cost of debt financing BE costs. Staff Ex. 8.0 at 8; Staff Ex. 19.0 at 4-5.

ComEd also asserts that rider recovery does not reduce risks applicable to rate base assets, and a lower return should not be applied to costs recovered through Rider BE, if approved. ComEd Ex. 14.0 REV at 18. The Company argues that if Rider BE is not approved, the costs that ComEd currently proposes to recover in Rider BE would instead be recovered in ComEd's delivery services rates, through ComEd's Rider DSPR or the MYRP to be filed in January 2023, both of which incorporate a reconciliation mechanism and require a prudency test to ensure recovery. This argument is misguided for multiple reasons. First, the reference to Rider DSPR is irrelevant. Staff's recommendation focuses on setting the proper rate of return if Rider BE is approved rather than the return that is foregone if Rider BE is rejected. Indeed, if Rider BE is rejected, none of these arguments matter, as there will be no need to set a return for Rider BE. If Rider BE is approved, however, it will be implemented after the ROE for the MYRP is established through a fully-litigated rate proceeding in 2023. Therefore, the Commission will have no need to use the ROE for Rider DSPR, which does not represent a market-based investor-required ROE but is a legal construct determined by formula. Second, the Company ignores the fact that, unlike cost recovery through the MYRP, cost recovery through Rider BE reflects shorter time horizons of 2, 5, and 10 years and will provide dollar-for-dollar recovery of the actual costs incurred. In contrast, the Company's authorized rate of return on rate base in the MYRP will reflect an investor-required rate of return on equity into perpetuity, and the recovery of actual costs in the MYRP reconciliation above 105% of the estimated costs will be disallowed. Staff Ex. 8.0 at 5; 220 ILCS 5/16-108.18(f)(6). These factors make cost recovery through the MYRP riskier than cost recovery through Rider BE. Third, the Company ignores that, instead of filing an MYRP, the Company could file a traditional rate case in any year. Cost recovery through a traditional rate case would be riskier still, as Mr. Newhouse acknowledges, noting there would be no annual reconciliation. ComEd Ex. 14.0 REV at 19. The foregoing notwithstanding, if the Commission concludes there is no difference in the appropriate WACC under the different recovery options, that only further supports Staff's conclusion that Rider BE is unnecessary. Staff Ex. 7.0 at 7-8.

The Company also argues that it would be inappropriate to apply a return other than the WACC to BE cost recovery because ComEd is undertaking the BE Plan in response to a legislative mandate. ComEd Ex. 9.0 at 17. However, Staff argues that this is irrelevant. The Commission authorized a time-horizon, risk-adjusted ROE for rider assets calculated in a manner similar to Staff's proposal in this proceeding for another ComEd program enacted in response to a legislative mandate. *See Commonwealth Edison Company*, Docket No. 10-0138, Order at 44 (Dec. 15, 2010).

For all the foregoing reasons, Staff concludes that the Commission should reject the Company's return proposal and adopt Staff's recommendation to apply a modified WACC that includes a time- and risk-adjusted cost of equity.

c. Walmart's Position

Walmart opposes the Company's proposal to earn its WACC, which includes an equity component, on O&M costs. Walmart Ex. 1.0 REV at 10. The need for a carrying

charge for O&M is because ComEd has proposed to recover its O&M on a two-year lagging basis. ComEd Ex. 4.0 at 13. Nothing prevents ComEd from contemporaneously recovering its O&M costs. Walmart Ex. 2.0 at 4. Moreover, if such costs were contemporaneously recovered, there would be no basis to even request a carrying charge. Thus, to the extent the Commission authorized a carrying charge, Walmart argued that it should be limited to the Company's cost of debt. *Id*.

d. Commission Analysis and Conclusion

The Commission rejects ComEd's proposed Rider BE and therefore makes no finding regarding the rate of return that should be applied.

B. Customer Bill and Rate Impact

1. ComEd's Position

ComEd states that it designed the BE Plan to limit customer bill impacts associated with implementation of the statutorily required BE Plan while still achieving the goals of the EVA. ComEd notes that the BE Plan has an estimated bill impact for a typical residential customer of up to 18 cents per month using the regulatory asset.

ComEd disagrees with Staff's attempts to impose more onerous requirements on ComEd's efforts to mitigate customer bill impacts. ComEd points out that its BE Plan was specifically designed to ensure the impact on customer bills or rates would be reasonable, considering the policy goals the BE Plan meets and the benefits it delivers. Staff argues that ComEd must at least conduct an analysis of the impact of the BE Plan on "nonparticipant ratepayers." ComEd notes that there is no such requirement under the EVA. ComEd argues that its BE Plan satisfies the EVA requirement that a BE Plan be "designed and reasonably expected to," among other things, "maximize total energy cost savings and rate reductions so that nonparticipants can benefit." 20 ILCS 627/45(d)(1). ComEd points out that Staff does not propose a method to conduct such an analysis. ComEd argues it is not clear how one might identify "non-participant ratepayers," and distinguish them from participants.

2. Staff's Position

As explained in detail in Section V.D.1. and Section V.D.3., ComEd failed to provide the analyses required by statute and the Commission should direct ComEd to prepare an analysis that considers economic costs and benefits and isolates ratepayer impacts.

3. Commission Analysis and Conclusion

As noted in Section V.D.3, the Commission agrees with Staff. ComEd is directed to prepare an analysis that considers economic costs and benefits and isolates ratepayer impacts.

VII. RATES AND RATE CLASSES

A. ComEd's Proposals

1. Separate EV Charging Delivery Classes

a. ComEd's Position

ComEd proposes two new, optional, nonresidential EV Charging Delivery Classes. ComEd states that the new delivery classes are intended to support the goals of the EVA by reducing the upfront cost barriers associated with the installation of infrastructure to support new EV Charging stations. ComEd points out the new delivery classes will encourage EV uptake because the classes potentially reduce the cost per charge when providing participating customers the option to pay distribution facilities costs on a volumetric basis. ComEd notes the new EV Charging Delivery Classes will encourage further EV uptake by allowing participating customers flexibility to pay based on kW or kWh.

ComEd states that it will use the charges associated with the Small Load (0-100 kW) Delivery Service Class and the Medium Load (100-400 kW) Delivery Service Class as proxies for the L2 EV Charging Delivery Class and EV Fast Charging Delivery Class, respectively. ComEd notes it has very limited kWh and kW usage data for customers operating EV charging stations as the market is still emerging and L2 charging stations are not typically separately metered. ComEd states it will develop delivery service charges that are based on the usage characteristics of each class after ComEd determines it has sufficient data on the load profiles of the new classes to establish their coincident peak and non-coincident peak kW demands to allocate costs.

ComEd recognizes there is a level of uncertainty associated with the new EV Charging Classes. ComEd Points out that the burden of this uncertainty would be placed upon other customers who do not charge EV if the EV Charging Delivery Classes are eliminated. ComEd argues that this uncertainty could potentially cause the non-EV charging customers to subsidize EV charging customers. ComEd notes that the distinction between EV charging customers' usage and the usage of other customers are expected to cause more pronounced cross-subsidization as EV charging demand grows.

ComEd recognizes the potential for subsidization in its own EV Charging Delivery Class proposal. ComEd points out that its proposed EV Charging Delivery Classes will effectively provide security and stability of established rates because the rates for the new classes will be based upon ComEd's existing C&I classes. ComEd notes that once it has sufficient data, ComEd will propose new charges based upon the actual loads and costs associated with the EV charging customers in a future Rate Design Investigation proceeding.

ComEd explains that the EV Charging Delivery Classes are offered within the BE Plan and pursuant to pre-existing authority under Act. ComEd states that the new delivery classes' costs will only be recovered from customers participating in the classes. ComEd states it plans to recover the costs of make-ready infrastructure from customers that choose to have ComEd install them with a separate monthly line item.

Staff recommends the Commission reject the two rate classes, but if the Commission does approve them, then it should: "1) approve NRDC's sliding scale

approach for the demand charge alternative, with Staff's proposed modifications; and 2) approve the AG's proposed reporting metrics." Staff IB at 2. CJCP propose that demand charges be created on a sliding scale that is based on customer load factor. CJCP IB at 46-47, 49. ComEd sees merit in the CJCP's approach if the Commission rejects the ComEd EV Charging Classes and the Watt-Hour Class alternative, but there appears to be consensus around the Watt-Hour Class alternative.

b. Staff's Position

The Commission should reject ComEd's two proposed EV Charging Delivery Classes along with all proposed modifications proposed by Intervenors and instead approve ComEd's alternative proposal to allow EV charging customers to participate in the Watt Hour Delivery Class, as discussed in more detail below. If the Commission approves ComEd's EV Charging Delivery Classes, the Commission should: (1) approve CJCP's sliding scale approach for the demand charge alternative, with Staff's proposed modifications; and (2) approve the AG's proposed reporting metrics. Staff Ex. 17.0 at 3.

Staff does not support the creation of new rate classes outside of a general rate design case with a supporting cost-of-service study. Staff Ex. 17.0 at 16. Staff understands ComEd will file a petition seeking approval of a revenue neutral rate design no later than May 2024; any new rate classes should be considered in that proceeding. In addition, although Staff requested to review the proposed tariffs for the proposed rate classes, the Company declined to provide them, arguing the EV Charging Delivery Classes are delivery service rate classes which are only meant to complement the BE Plan. ComEd Ex. 10.0 at 6. Many intervenors echoed Staff's concerns about the way ComEd is proposing these new classes and raised concerns about risks to resetting rates once ComEd collects sufficient data, and the lack of clarity around how much data is enough and how long it will take to collect said data. Staff Ex. 17.0 at 5-17.

c. CJCP's Position

Section 45(d)(iii) and (iv) of the EVA state, respectively, that BE Plans must consider "optional commercial tariffs to traditional demand-based rate structures to facilitate charging for light duty, heavy duty, and fleet [EVs]," 20 ILCS 627/45(d)(iii), and "financial and other challenges to [EV] usage in low-income communities, and strategies for overcoming those challenges, particularly in communities and for people for whom car ownership is not an option." 20 ILCS 627/45(d)(iv). CJCP note that ComEd proposes the creation of separate EV Charging Delivery Classes for nonresidential customers with separately metered EV charging load – an EV L2 Charging Delivery Class and an EV Fast Charging Delivery Class. ComEd would recover the costs of customer-side make-ready facilities through a monthly line item charge on customer bills. Customers in one of the delivery classes would have the option to have distribution charges billed on a kW or kWh basis. NRDC Ex. 1.0 REV at 20-21.

As CJCP witness Nelson testified, insufficient data exists to warrant adding separate EV charging delivery classes at this time. ComEd stated in its Initial Brief, "Currently, ComEd has very limited kWh and kW usage data for customers operating EV charging stations as the market is still emerging and [L2] charging stations are not typically separately metered." ComEd IB at 71. "ComEd is also aware that there could be some level of subsidization in its own EV Charging Delivery Class proposal…."

ComEd IB at 72. Mr. Nelson stated that EV load has not been shown to be significantly different from other C&I load. He suggested that load profile data should be gathered and if it demonstrates a justification for a separate class in the future, then it should be established at that time. CJCP contend that this approach is preferable to ComEd's approach, which entails gathering sufficient date and then "propos[ing] new charges based upon the actual loads and costs associated with the EV charging customers…." ComEd IB at 72.

While the rationale for the charging classes is that, at least in part, it is important "to separate the costs related to these cost causers from those caused by other types of customers," ComEd Ex. 10.0 at 13, CJCP aver there is no clear evidence that these sort of cost shifts will actually occur, or that these optional rate classes will avoid such shifts. It is curious, CJCP contend, that on the one hand ComEd dismisses Clean Jobs Coalition Parties' proposal that demand charges be based on a sliding scale based on customer load factor, stating that "in the current environment, where data is more limited, a sliding scale approach runs the risk of setting the demand charges either too low, or too high, each resulting in cross-subsidies within the class." ComEd Ex. 10.0 at 13. On the other hand, Clean Jobs Coalition Parties continue, when it comes to its own proposals, ComEd fails to acknowledge comparable data deficits, even where they clearly appear to exist – and the creation of those separate delivery classes is a class in point. Clean Jobs Coalition Parties assert that those delivery classes present a clear risk of 'cross-subsidies within the class,' and when asked about what data they have concerning the cross-subsidy risk, ComEd's responses suggest that they possess no such data and have performed no analyses that would give rise to such data. Indeed, according to Clean Jobs Coalition Parties, ComEd's discovery responses suggest that they possess no such data and have performed no analyses that would give rise to such data. EDF Ex. 1.4 at 2. As such, Clean Jobs Coalition Parties encourage the ongoing tracking of this metric with this proposal – rather than just evaluating resulting data at the ten-year mark, as the Company proposes. ComEd Ex. 15.0 at 10.

Another problem with ComEd's proposed new delivery classes, Clean Jobs Coalition Parties contend, is that the proposal omits important considerations that may affect how smoothly many vehicles are integrated into the grid in the most cost-effective way. As CJCP point out, ComEd continues to separate the L2 and DCFCs into separate classes, stating that the Company is "initially proposing that [L2] delivery charges be based upon the Small Load Delivery Service Class (0-100 kW) and that DCFC delivery charges be based upon the Medium Load Delivery Service Class (101-400 kW)." ComEd Ex. 15.0 at 4. Clean Jobs Coalition Parties contend this distinction is arbitrary and does not recognize the realities of fleet diversity, given that some fleets within the small load delivery class may need DCFCs and some fleets within the medium load delivery class may have more vehicles but may require L2 chargers only. In addition, to Clean Jobs Coalition Parties, if the intention with these delivery classes is to reduce upfront cost barriers, the fact that these classes are "paired with ComEd's proposal for separately metering nonresidential EV charging stations," ComEd Ex. 15.0 at 7, seems at odds with that intention. As Clean Jobs Coalition Parties add, submetering (discussed in Section V.B.2) can be an effective and less costly alternative to requiring a separate meter, making ComEd's continued refusal to consider it as part of a program purportedly designed to address upfront cost barriers hard to understand.

Yet another problem with ComEd's proposed new delivery classes, according to CJCP, is that for the per kWh option, ComEd proposes to base their distribution charge on a flat volumetric rate. As Clean Jobs Coalition Parties witness Nelson explained, demand charges for C&I customers should not be eliminated entirely; some distribution facilities are driven by a customer's demand and their costs should be collected through demand charges. He explained that with no demand charge component, EV customers with high peak demand would have no incentive to manage their demand, likely leading to under-collection of distribution costs from them. Additionally, as Mr. Nelson stated, converting demand charges entirely to flat energy charges creates little incentive for EV customers to manage their charging load, including limiting peak demand and avoiding charging during high-cost periods. NRDC Ex. 1.0 at 23. He pointed out that this does not provide sufficient incentive to ensure that charging coincides with low-cost times and times of high renewable energy availability.

CJCP witness MacDougall testified that vehicles like trucks and buses, "as batteries on wheels...have tremendous promise as a resource; in the aggregate, they represent flexible demand that can be deployed on various time scales to maximize reliance on renewable generation and reduce the need for system capacity." EDF Ex. 1.0 REV at 7. However, she continued, if given an insufficient price signal to adequately manage that demand, those critically important services will amount to a missed opportunity, potentially creating significant—but avoidable—costs across the system which ratepayers will have to bear.

If the Commission were to adopt ComEd's proposed new EV Charging Delivery Classes, CJCP propose that the Commission reject the per kWh energy charge option and instead require a new sliding scale demand charge alternative where the demand charge depends on the customer's load factor. NRDC Ex. 1.0 REV at 25-26.

CJCP note that ComEd initially dismissed their proposal that demand charges be based on a sliding scale, but ComEd failed to acknowledge comparable data deficits for the Company's proposed separate delivery classes, which present a clear risk of cross-subsidies within the class. According to Clean Jobs Coalition Parties, ComEd provided no data or analyses concerning cross-subsidy risk. *See* EDF Ex. 1.4. CJCP note that in his surrebuttal testimony, however, ComEd witness Fruehe found merit in the sliding scale demand charge approach of Mr. Nelson. ComEd Ex. 15.0 at 11.

d. Electrify America's Position

Electrify America opposes ComEd's proposal for separate EV Charging Delivery Classes for five key reasons.

First, it is premature to establish new EV Charging Delivery Classes. Electrify America states ComEd has provided no evidence supporting the need to create EV charging-specific rate classes at this time, including EV charging load profiles, any new analysis of EV charging class customers or data on what costs nonresidential EV charging customers place on the distribution system (in Illinois or in other states). Electrify America Ex. 2.0 at 11-12; *see also* ComEd Ex. 15.0 at 4; ComEd Ex. 5.0 at 13. Electrify America asserts new EV charging delivery classes should be considered only when there is sufficient data regarding customer load profiles to indicate whether separate classes are justified and that at least ten years of data is needed to inform ComEd, the

Commission, ratepayers, and other stakeholders as to whether a separate delivery class is needed for EV charging loads. Electrify America Ex. 2.0 at 12-14. The collection and use of actual customer data and the documentation of established load patterns must be available to investigate whether a new class is warranted and to provide stakeholders with sufficient information to remove uncertainty over what that new class may look like. Electrify America Ex. 2.0 at 12-13.

Second, states Electrify America, the new EV Delivery Classes could result in future rate shock. Electrify America's witness Bride points out that given the uncertainty surrounding EV load patterns, a rate reset under the new classes could result in a rate shock rendering some EV charging stations uneconomical and drive EVSPs away from investing in ComEd territory. *Id*.

Third, ComEd's proposed solution to rate shock, introducing a rate limiter or phase-in approach, would simply defer the worst impacts of a chaotic rate reset within the new delivery classes. *Id*. at 23. Electrify America contends that deferring rate shock or spreading out its impacts over time will not adequately resolve the risks and disincentives rate shock presents to nonresidential EV customers.

Forth, Electrify America states that requiring customers who elect to utilize make-ready facilities to remain in the proposed new rate classes may permanently deter participation. Electrify America Ex. 1.0 REV at 13.

Fifth, Electrify America states that ComEd's comparison of its proposal for new EV delivery classes to other distinct classes that have been established historically – the Railroad Delivery Class and the General Lighting Delivery Class – is improper. The establishment of those classes is distinguishable because (1) unlike nonresidential EV charging customers, the railroad class and the lighting class have long histories of load data that demonstrate load patterns that "are dissimilar to those of other customers with comparable total demand," and (2) the comparison is inappropriate is due to the physical setup for railroad and lighting customers. Electrify America Ex. 2.0 at 11-12.

Electrify America witness Bride testified that the Commission should consider the Bonbright principles of stability and simplicity in setting an initial rate design. Electrify America Ex. 2.0 at 10. It is important to start simply, and as the nonresidential EV charging customer cohort is better understood with more data, the rates can be adjusted as needed. *Id*.

Electrify America responds to the CJCP's recommendation that the Commission direct ComEd "to adopt a demand charge alternative that includes a sliding scale based on the customer's load factor," (CJCP IB at 49) with similar concerns stating it does not address or overcome the risks and barriers associated with proposed standalone EV delivery classes. Electrify America states the sliding-scale proposal presumes approval of ComEd's EV Charging Delivery Class proposal and would subject to the same issues EA and other intervenors have identified related to prematurity and rate shock.

e. ChargePoint's Position

ChargePoint expresses appreciation for the intent behind ComEd's proposed EV Charging Delivery Classes, which it states were designed for the purpose of allowing customers to install make-ready infrastructure and pay for it over time and to offer EV

charging customers volumetric ($/kWh) rates instead of demand-based ($/kW) rates. However, ChargePoint argues that creating separate rate classes is neither necessary nor justified to achieve these outcomes, as demonstrated by ComEd's alternative proposals to allow EV charging customers to take service on the Watt-Hour Delivery Class and to provide any non-standard make-ready infrastructure to customers through Rider NS.

While ChargePoint supports developing new rate options for EV charging, it argues that it is premature to establish separate rate classes for EV charging at this time. Specifically, ChargePoint supports ComEd's proposal to install make-ready infrastructure and allow customers to pay for it over time and ComEd's proposal to offer EV charging customers volumetric ($/kWh) rates instead of demand-based ($/kW) rates, but asserts that neither of these proposals require or justify the creation of separate rate classes. By proposing to create separate rate classes, ChargePoint alleges, ComEd's proposal presumes, without any evidence, that the cost of serving EV charging customers will be different from other customers in the small and medium delivery classes. ChargePoint witness Deal explained that ComEd's proposal puts the proverbial cart before the horse. New rate classes are typically developed when a utility has load data demonstrating that a certain group of customers are sufficiently distinct from other customers to warrant a new rate class to limit intraclass subsidies. ComEd has not presented any such data in this proceeding, according to ChargePoint. ChargePoint urges the Commission to not allow ComEd to create new rate classes based merely on ComEd's assumption that the costs EV charging customers cause are meaningfully different from other commercial customers.

Moreover, ChargePoint asserts that ComEd's proposal to directly assign make-ready costs to individual customers through the EV Charging Delivery Classes instead of providing make-ready incentives to all non-residential customers, while better than nothing, is a major missed opportunity. According to ChargePoint, ComEd would support substantially more EV charger deployment if the Commission directs ComEd to expand the budget and eligibility of the nonresidential Make-Ready Infrastructure Rebate program.

ChargePoint also responds to ComEd's argument in its Initial Brief that "eliminating the EV Charging Delivery Classes would, in effect, place the burden of this uncertainty upon other customers who do not charge EVs, and this could potentially cause the non-EV charging customers to subsidize EV charging customers." ComEd IB at 71 (emphasis in original). ChargePoint claims that this argument is pure speculation, as new rate classes should be based on actual data and not ComEd's expectations of what the data will show. Moreover, argues ChargePoint, the load profiles of different types of EV charging customers are far from uniform. ChargePoint witness Deal explains that the load profiles of workplace L2 chargers, fleet L2 chargers, DCFCs along travel corridors at fueling centers, and DCFCs in shopping centers will all be very different from one another as a result of their different use cases. According to ChargePoint, such heterogeneity makes EV charging customers a better fit for the existing commercial rate classes, which apply to a wide variety of customers, than new rate classes. ChargePoint asserts that ComEd does not appear to have considered the diversity of EV charging loads in its proposal. Rather, alleges ChargePoint, ComEd assumes that EV charging

customers will have load profiles that are all similar to one another and all different from other commercial customers. ChargePoint concludes that there is simply no data or evidence in the record that support ComEd's assumption.

ChargePoint recommends that the Commission reject ComEd's proposed EV Charging Delivery Classes and approve ComEd's alternative proposals.

f. Tesla's Position

Tesla supports Staff's recommendation that the Commission should reject ComEd's two proposed EV Charging classes and instead approve ComEd's alternative proposal to allow non-residential customers whose primary purpose is to provide EV charging services to be eligible to take delivery service under the Watthour Delivery Service Class.

g. EVgo's Position

EVgo contends that ComEd's proposal to create two new EV Charging Delivery Classes is premature and should be rejected. EVgo points out that the proposal lacks evidentiary support and that any creation of a distinct rate class or EV-specific customer charges should be based on a cost-of-service analysis. In addition, EVgo argues that the EV Charging Delivery Class proposal does not comply with the requirements of the EVA. In any event, approval of ComEd's EV Charging Delivery Class proposal is not necessary because ComEd has proposed an alternative tariff for EV charging customers that multiple parties consider to be superior and in compliance with the EVA.

h. Commission Analysis and Conclusion

The Commission finds that it is more appropriate for ComEd to propose creation of new rate classes in a general rate design investigation proceeding with accompanying cost-of-service studies. The Commission echoes Intervenors' concerns regarding the lack of data on the proposed new delivery classes and finds that adopting EV delivery classes at this time is premature. ComEd''s proposal to establish new EV Charging Delivery Classes is denied.

2. Watt-Hour Delivery Class

a. ComEd's Position

ComEd proposes, as an alternative to the establishment of the EV Charging Delivery Classes, that nonresidential EV Charging customers be permitted to join ComEd's pre-existing Watt-Hour Delivery Class for a period of at least ten years. ComEd notes this alternative proposal will enable EV Charging Customers to elect to take delivery service under a class that recovers distribution facilities costs based upon a volumetric $/kWh charge. ComEd argues that this proposal will result in a lower distribution charge for customers with high demand and low usage as compared to the charge they would have received in a class that bases the charge on a $/kW basis.

Notably, there is significant support for the Watt-Hour Delivery Class proposal from many parties. These parties emphasize that the benefit of the Watt-Hour Delivery Class is it provides nonresidential EV charging customers with an alternative to demand-based rates while avoiding many of the concerns raised about the EV Charging Delivery Classes proposal. Several parties recommend that it be implemented no later than six months

from the date of the final order. ComEd opposes this specific timeline and is committed to implementing the change by June 2024.

b. Staff's Position

Staff recommends that the Commission approve ComEd's alternative proposal to allow EV charging customers to participate in the Watt Hour Delivery Class, and direct ComEd to implement the tariff no later than six months after the Commission's final Order in this proceeding.

In response to many parties' objections to the creation of new rate classes, ComEd presented an alternative proposal to allow nonresidential EV charging customers to take service under their Watt-Hour Delivery Class. ComEd Ex. 15.0 at 10. This solution encompasses the demand charge alternative that many parties support, and that the statute requires, and also contains a component to address make-ready infrastructure. This alternative proposal gives ComEd the opportunity to service these customers in an existing rate class and collect the needed data to fully develop EV Charging Delivery Classes. ComEd proposes customers will be eligible for service in the Watt-Hour Delivery Class during the first half of 2024. ComEd Ex. 15.0 at 13. However, given that these customers are being added to an existing rate class, Staff finds this implementation timeframe unreasonably long. Further, this proposal serves to address Section 45(d)(iii) of the EVA, concerning optional tariffs 20 ILCS 627/45(d)(iii), so the extended implementation timeline conflicts with the spirit of the statute. Staff recommends the Commission directs ComEd to prioritize the implementation of the update to their tariff and customer information systems and allow customers to begin taking service no later than six months after the Commission's final Order in this proceeding.

c. CJCP's Position

Clean Jobs Coalition Parties assert that, while participating in the existing Watt-Hour Delivery Class may be helpful for certain C&I customers, this proposal appears to suffer from the same deficiency -- the volumetric charge does not appear to be time-based, resulting in a failure to harness the potential for EVs to help integrate more renewable energy and enable a more efficient use of the system. Clean Jobs Coalition Parties continue to recommend that ComEd alter its distribution charges in order to better reflect grid conditions — by utilizing a time-based rate.

d. Electrify America's Position

Electrify America supports adoption of ComEd's alternative Watt-Hour Delivery Class proposal. Electrify America notes this proposal has widespread support among participants in this proceeding and addresses many of the concerns raised by the EV Charging Delivery Class Proposal. In support of the Watt-Hour Delivery Class proposal Electrify America observes the Watt-Hour Delivery Class proposal: (1) allows EV charging customers to remain eligible for the rate class of a minimum of 10 years; (2) lets ComEd gather data regarding EV charging customer behavior from utility meter data without customer involvement and evaluate that data to further develop rate structures; (3) addresses the demand charge barrier; and (4) allows EV charging customers to join an existing delivery class, providing greater stability to customers and mitigating the rate shock that may result from the new delivery class proposal. Electrify America witness

Bride explained, given that the Watt-Hour Delivery Class is an existing rate with approximately 87,377 customers and 383,359 kWh in annual load, "the risk of a chaotic reset of the rate once EV charging station billing determinants are assessed is greatly reduced." Electrify America Ex. 2.0 at 4. The volumetric delivery charges in the class remove the demand charge barrier faced by EV charging stations and the ten-year eligibility timeframe "provides much needed certainty for EV Charging station developers planning investments." *Id*. The Watt-Hour Delivery Class proposal also follows Bonbright principles by allowing for simplicity and stability in an initial rate design. *Id*. As EV charging load becomes a larger percentage of the delivery class, the rate will adjust incrementally to reflect the revised costs of service. Electrify America Ex. 2.0 at 4.

Electrify America further supports positions presented by Staff and other Intervenors that the Commission should direct ComEd to implement its Watt-Hour Delivery Class proposal within six months of the Commission's final order in this proceeding to help maximize its beneficial impact towards meeting Illinois transportation electrification objectives. Electrify America asserts that six months provides ComEd a reasonable time-period for administrative implementation while supporting the EVA's goals for widespread electrification in Illinois by 2030 and its requirement to provide optional alternatives to demand-based rates. It further asserts that because this proposal relates to an existing delivery class, efficient implementation should be possible.

e. ChargePoint's Position

ChargePoint expresses appreciation both that ComEd offered in surrebuttal an alternative proposal to its EV Charging Delivery Classes and that there is widespread support among the parties for this alternative proposal. According to ChargePoint, the first part of ComEd's alternative proposal is to allow EV charging customers to take service on its existing Watt-Hour Delivery Class, which is a volumetric delivery rate without a demand charge. ChargePoint asserts that this proposed solution retains one of the key benefits of the EV Charging Delivery Classes proposal – the volumetric rates – without the downsides of creating new rate classes before ComEd has data to support the need for new rate classes. ChargePoint also states that taking service on the Watt-Hour Delivery Class rates will allow site hosts to avoid the impact of demand charges on EV charging station installations with low-load factors, which will encourage EV charger deployment. ChargePoint recommends that the Commission approve ComEd's proposed changes to the Watt-Hour Delivery Class, which appear in ComEd Ex. 15.01, to allow site hosts to qualify for this class.

ChargePoint agrees with Staff, Electrify America, EVgo, and Tesla that ComEd's proposed implementation timeline of 2024 is not reasonable and that the Commission should direct ComEd to begin allowing EV charging customers to take service on the Watt-Hour Delivery Class within six months of the Commission's final order. ChargePoint recognizes that ComEd has numerous implementation deadlines but argues that, given the importance of ensuring that ComEd has an optional volumetric rate available for EV charging customers, it is reasonable to require ComEd to implement these tariff changes within six months.

f. Tesla's Position

Tesla supports Staff's recommendation that the Commission approve ComEd's alternative proposal to allow EV charging customers to participate in the Watt-Hour Delivery Service Class. Tesla further states that it strongly supports Staff's recommendation that the Commission direct ComEd to implement the revised tariff no later than six months after the Commission's final Order in this proceeding.

g. EVgo's Position

EVgo urges Commission approval of ComEd's proposal to modify its existing Watt-Hour Delivery Class to make the delivery class available to EV charging customers. Modifying the Watt-Hour tariff as ComEd proposes would allow EV charging customers to elect to take delivery service under a class that recovers distribution facilities costs based upon a volumetric $/kWh charge, rather than a demand charge ($/kW) basis. EVgo notes that this proposal addresses precisely the rate design barrier that the EVA directs BE Plans to address, and EVgo supports its approval but urges rapid implementation. EVgo observes that ComEd typically receives approximately 90 days to implement tariff changes, as acknowledged by ComEd, and EVgo requests that ComEd's implementation of the Watt-Hour tariff changes be no different. EVgo states that six months is nearly double the amount of time that ComEd typically receives for implementing tariff changes. EVgo believes that requiring a six-month deadline for customer enrollment under the modified Watt-Hour tariff would provide a critical backstop so that EV charging customers have certainty to begin taking service under this tariff, which is consistent with the statutory requirement that ComEd's BE Plan include an optional commercial tariff to facilitate EV charging. Thus, EVgo requests that the Commission direct ComEd to implement the Watt-Hour tariff changes as soon as practicable, and at least no later than six months from the date of the Commission's issuance of a final Order in this proceeding.

h. Commission Analysis and Conclusion

The Commission rejects ComEd's new EV Charging Delivery Classes (see Section VII.A.1) and finds ComEd's alternative proposal to modify the existing Watt- Hour Delivery Class acceptable and it is approved. ComEd's alternative proposal includes a demand charge alternative and contains a component to address make-ready infrastructure. However, the Commission agrees with Staff, EVgo, Electrify America, ChargePoint, and Tesla that ComEd's proposed implementation timeline of June 2024 is unreasonably long. Accordingly, the Commission directs ComEd to prioritize modification of its Watt-Hour Delivery Class and begin enrolling EV charging customers on the modified Watt-Hour Delivery Class tariff no later than six months from the date of issuance of this Order.

B. Make-Ready Infrastructure

1. Rider NS

a. ComEd's Position

ComEd notes that Rider NS is the financial mechanism used to collect the costs associated with nonstandard customer requests or requirements. ComEd states that if the Commission approves the Watt-Hour Delivery Class proposal, then ComEd proposes to provide make-ready infrastructure as nonstandard and recover the costs directly from through Rider NS, as an alternative to providing make-ready services as standard for the

proposed EV Charging Delivery Service Class. ComEd points out that Rider NS would apply to service dedicated to EV charging as a service that is different from a typical ComEd customer.

ComEd notes that, under Rider NS, ComEd would work with customers on a case-by-case basis to determine the infrastructure facilities needed for EV Charging and to determine dollar amounts due from a customer. ComEd states that ComEd representatives would design the EV charging infrastructure facilities for the customer, then the customer approves the Rider NS charges, and ComEd would construct the infrastructure facilities. ComEd notes that the make-ready infrastructure will be recovered through individual customer-specific charges.

Electrify America notes that ComEd agreed to a waiver of nonstandard facilities charges for second points of service dedicated to EV charging for customers participating in the Watt-Hour Delivery Class or the EV Delivery Classes. Electrify America agrees with Tesla and ChargePoint that this waiver should apply to all nonresidential EV charging customers regardless of the delivery class in which they take service. ComEd opposes this recommendation. If ComEd were to allow this waiver to apply to all nonresidential EV charging customers regardless of class, then non-EV customers would unjustifiably bear the associated costs. ComEd Ex. 10 at 14.

Finally, the CTA asserts that ComEd facilities serving bus charging stations should be standard service and not subject to Rider NS. Thus, CTA claims that "Rider NS should not impose additional fees on the CTA for the make-ready infrastructure because the new standard service is for the statutory make-ready infrastructure to serve charging stations at the CTA [g]arages." CTA IB at 19. ComEd opposes this recommendation and believes that the CTA's interpretation of "make-ready infrastructure" is too broad and opposes any modification of Rider NS to reflect that interpretation.

b. Staff's Position

The Commission should reject CTA's recommendation that the Commission modify ComEd's Rider NS to clarify that the rider does not apply to services and facilities that are defined in the EVA as make-ready infrastructure.

ComEd argues that "Rider NS is the financial mechanism used to collect the costs associated with nonstandard customer requests or requirements, for example, larger or different services or facilities than those considered standard. Nonstandard facilities are installed, owned, and maintained by ComEd at the customer's expense." ComEd IB at 75. Staff understands that, under ComEd's nonstandard practice, ComEd installs, owns, and maintains facilities that ComEd provides to customers. This being the case, CTA has the option of providing and owning the customer side of the make-ready infrastructure while still participating in ComEd's proposed EV delivery class. Under this scenario, ComEd would not need to install, own, and maintain the customer side of the make-ready infrastructure. Staff Ex. 16.0 at 24.

c. Electrify America's Position

Electrify America supports ComEd's agreement to waive nonstandard facilities charges for second points of service dedicated to EV charging customers participating in the Watt-Hour Delivery Class under the Watt-Hour proposal or in one of the new delivery

classes under the new EV Delivery Classes proposal. It further supports recommendations by Tesla and ChargePoint that this waiver for a second point of service should apply regardless of which delivery class a nonresidential EV charging customer is taking service under. Electrify America Ex. 2.0 at 14-15. Electrify America contends that ComEd has provided no support for its position that Tesla and ChargePoint's recommendation will result in non-EV customers unjustifiably bearing associated costs. *See* ComEd Ex. 10 at 14. Electrify America argues that expanding the waiver of nonstandard facilities charges will support the development of nonresidential EV charging infrastructure by allowing EVSPs to select rates that best meet their needs without the constraints of added costs for nonstandard facilities.

d. CTA/City's Position

ComEd's Rider NS applies to "non-standard services and facilities" that are beyond what is required to provide "standard electric service" to a customer. CTA/City argue that standard electric service for the CTA garages should include the lines and equipment that will be used for charging electric buses. At present, the CTA garages are served via two separate lines with a total demand at each garage of about 1 MW. The demand is projected by the CTA to increase to up to 20 MW per garage when the bus electrification process is complete. Thus, "standard service" becomes the electric service required for a CTA garage that maintains, provides the make-ready infrastructure for, and charges about 300 buses. As a result, the CTA concludes that Rider NS should not impose additional fees on the CTA for the make-ready infrastructure because the new standard service is for EVA-defined make-ready infrastructure to serve charging stations at the CTA garages. The CTA proposed that ComEd should pay for such "make-ready infrastructure." The CTA proposes language changes to Rider NS consistent with its proposal.

ComEd argues that the language of the EVA should not be read broadly and "cannot make such a significant exception for only one of its customers." ComEd RB at 105. In recognition of ComEd's criticism, the CTA's proposed language for Rider NS language was modified in the CTA/City language for Proposed Order to clarify that it is not solely for the CTA but would apply to any municipal corporation organized under the Metropolitan Transit Authority Act as well as any other governmental entity providing charging of electric transit buses.

e. ChargePoint's Position

ChargePoint explains that in conjunction with its alternative proposal to allow EV charging station site hosts to take service on the Watt-Hour Delivery Class, ComEd also proposed to "provide make-ready facilities as nonstandard and recover the costs directly from customers choosing ComEd-provided make-ready facilities through Rider NS … ." ChargePoint further explains that, in response to a discovery request from ChargePoint, ComEd provided more details on the differences between its original EV Charging Delivery Classes and its alternative proposal to provide make-ready infrastructure through Rider NS. In that response, states ChargePoint, ComEd explained that under the EV Charging Delivery Classes proposal, a customer receiving make-ready from ComEd would pay a monthly line item on their bill "based upon the class average cost for the facilities required for that customer's site" but that these "[i]ndividual charges could vary

over time as charges are based on the revenue requirements associated with the make-ready facilities." Although several parties (including ChargePoint) initially compared ComEd's Delivery Classes to an on-bill financing mechanism, ChargePoint notes that these additional details reveal that under the EV Charging Delivery Classes proposal and unlike on-bill financing programs, customers would not be paying for the actual cost of the make-ready infrastructure installed on their property and that the charges they pay could change over time.

ChargePoint further notes that, by contrast, ComEd explained that under its alternative Rider NS proposal, customers that receive make-ready from ComEd would pay a monthly line item "based upon the specific costs for the facilities required for that customer's site" and that these charges would not change unless the customer required additional or different facilities. In other words, ChargePoint explains, though customers may be required to pay some upfront costs under the Rider NS proposal, customers would pay for the actual costs of the make-ready infrastructure deployed on their property rather than a "class average" cost.

ChargePoint expresses appreciation to ComEd for providing these additional details, which ChargePoint asserts demonstrate that the alternative Rider NS proposal is far preferable to the EV Charging Delivery Classes from a customer perspective because (1) a customer would pay for the actual cost of make-ready infrastructure deployed on its property and (2) the charges a customer pays for make-ready infrastructure would not change over time. According to ChargePoint, the predictability and stability of the Rider NS proposal would encourage more participation and more EV charger deployment than ComEd's EV Charging Delivery Classes proposal.

ChargePoint also agrees with Tesla that the Commission should approve ComEd's proposal to provide second points of service for existing customers dedicated to EV charging should receive service in accordance with standard new service connection rules. ChargePoint asserts that, as there was some confusion in the record about how such second points of service dedicated to EV charging would be treated for existing customers, the Commission should make this an explicit directive in its final Order.

ChargePoint recommends that the Commission approve ComEd's alternative Rider NS proposal and reject its proposed EV Charging Delivery Classes proposal. ChargePoint reiterates, however, that expanding the eligibility and budget for the nonresidential Make-Ready Infrastructure Rebate program as ChargePoint recommends is a much more effective way to encourage EV charger deployment than requiring customers to pay for make-ready costs over time through Rider NS. ChargePoint supports the alternative Rider NS proposal but views it as a second-best option that customers might choose if the Make-Ready Infrastructure Rebate program runs out of funds.

f. Commission Analysis and Conclusion

Because the Commission approves ComEd's Watt-Hour Delivery Class, the Commission further approves of ComEd's proposal to use Rider NS for cost recovery of make-ready facilities. Under Rider NS, customers would pay for the actual costs of the make-ready infrastructure and the charges would not change over time, thus promoting stability and predictability. The Commission notes that ComEd agreed to provide second

points of service dedicated to EV charging for existing customers participating in the Watt-Hour Delivery Class to receive service in accordance with standard new service connection rules rather than under Rider NS. According to ComEd, this will be conditioned on the customer electing to take service under the Watt-Hour Delivery Class for at least one year.

Electrify America and ChargePoint recommend that the waiver of nonstandard facilities charges should apply to all nonresidential EV charging customers regardless of the delivery class in which they take service. ComEd argues that this proposal "does not follow cost causation principles and would likely cause non-EV charging customers to unjustifiably bear costs caused by EV charging customers." ComEd. Ex. 10.0 at 14. To avoid potential class cross-subsidization, the Commission rejects the proposal to apply the waiver to all nonresidential EV charging customers regardless of the delivery class.

The Commission also rejects CTA/City's interpretation of make-ready infrastructure and declines to modify Rider NS based on this interpretation.

2. Rider DE

a. ComEd's Position

ComEd states that it established Rider DE to reduce the risk that other customers would have to cover the costs of the construction of facilities for a particular customer by requiring that customer to provide a deposit. ComEd notes that Rider DE requires the customer to provide a deposit based on the cost of the extension work and then refunds that deposit to the customer based on the customer's actual annual usage. ComEd points out that Rider DE governs ComEd's line extension policy and will not change substantially as a result of the addition of the proposed new EV charging classes. ComEd further notes that infrastructure construction from the distribution system up to the customer's property will be considered standard and will be subject to the terms of the Rider DE, if applicable.

ComEd disagrees with CTA's proposed modification of Rider DE to cover the full costs of an extension or upgrade by ComEd of its distribution facilities to any premises providing charging services to public transit buses. ComEd argues that the deposit requirement in Rider DE is necessary to reduce the risk that other customers would pay for large distribution system extensions. ComEd also points out that it is very likely that a customer that uses Rider DE will eventually have their deposit refunded, assuming their estimated demands were reasonably accurate, and the customer continues to operate as planned.

b. Staff's Position

The Commission should reject CTA's recommendation that the Commission modify ComEd's Rider DE to eliminate the deposit requirement for make-ready infrastructure. It appears to Staff that Rider DE was established to ensure that the construction of facilities for a particular customer would ultimately result in additional revenue from that customer, reducing the risk that other customers would have to cover the costs of the extension. Rider DE requires CTA to make a deposit to secure ComEd's provision of standard facilities to support CTA's EV charging stations. ComEd claims Rider DE enables customers to recoup their deposits over time as the load develops. The Commission should reject the CTA's recommendation because it would allow CTA to shift

its financial responsibilities to other ComEd customers. Staff Ex. 16.0 at 24. Such an outcome is contrary to principles of cost-causation. *See* 220 ILCS 5/1-102(d)(iii) (costs should be paid by those who incur them).

c. CTA/City's Position

For make-ready infrastructure installed by ComEd, the Company wants the CTA to pay a deposit to ComEd for the work under Rider DE, that is the work and equipment ComEd would install on the ComEd side of the meter for make-ready infrastructure. CTA/City oppose this request. Based on current estimates for the work to be done, the required deposit payable to ComEd would be over $27 million across CTA's garages. Because the infrastructure being added is to enable charging of CTA's electric fleet, a goal that is provided for in the EVA, CTA/City argue that the Commission should modify Rider DE to eliminate the deposit requirement for make-ready infrastructure.

Paying a deposit to ComEd to guarantee later payment would deprive the CTA of access to millions of dollars it could otherwise use to actually acquire electric buses or otherwise enable electrification of its fleet. *See* CTA Ex. 4.0 at 4.

ComEd argues that the deposit requirement may be met by providing a letter of credit, and the cost still must be paid by the CTA. CTA/City reply that requiring the CTA to pay for a letter of credit does not provide any working capital to ComEd, but rather takes working capital away from the CTA that could otherwise be used for the electrification of its system. CTA/City argue that the deposit requirement should be eliminated and proposes tariff language consistent with its position.

d. Commission Analysis and Conclusion

Rider DE's deposit requirement reduces the risk that other customers would have to cover the costs of the construction of facilities for a particular customer. The Commission notes that, according to ComEd, customers are likely to have their deposit refunded assuming their estimated demands were reasonably accurate. CTA/City's recommendation to modify Rider DE is rejected.

C. Hourly Pricing and Time of Use

1. Residential Customers

a. ComEd's Position

ComEd notes that it currently offers two time-variant supply rates to residential customers. First, ComEd offers Rate BESH, which is an hourly pricing supply rate. Second, ComEd offers Rate RTOUPP, which is a pilot TOU supply rate. The pilot's duration is four years, ending in June 2024, and it is limited to a maximum participation of 1900 customers. Both Rate RTOUPP and Rate BESH apply only to the supply portion of customers' bills as the distribution-related costs are not charged to residential customers on a time-variant basis.

In response to feedback from the parties, ComEd explains that it modified its original proposal in which residential customers who received an incentive under the BE Plan would initially be placed on Rate BESH. Under ComEd's revised proposal, during the three years after receipt of the Residential Charging Infrastructure Rebate, each residential customer may choose to remain on Rate BESH or choose to take service

pursuant to either (i) Rate BESH; (ii) an approved ARES TOU rate (or potential future ComEd TOU rate if approved by the Commission); or (iii) Rate Optimization pilot. If a customer is served by an ARES under a time-varying rate, and receives a rebate, ComEd will allow that customer to continue to take supply under the ARES rate and will not switch the customer to Rate BESH. ComEd notes that customers will also be provided a third option to satisfy the rebate requirements in that they may elect to participate in ComEd's proposed Rate Optimization pilot. ComEd modified its original proposal in which residential customers who received an incentive under the BE Plan would be initially placed on Rate BESH, in response to feedback from the parties.

The AG also recommends that the Commission exempt low-income customers from any requirement to participate in a TOU rate as a condition of receiving an incentive. The AG asserts that Rate BESH supply prices can be volatile, which could introduce rate and bill shock if customers are unable to shift load in certain hours. CJCP agree with the AG on this point, noting that real-time pricing under Rate BESH is not appropriate for all residential customers and a simple TOU rate applicable to entire house usage (including supply, transmission, and distribution) should apply. ICEA is opposed to new TOU supply rates but supports utilities offering TOU delivery rates as long as those delivery rates are available without regard to supplier.

ComEd does not oppose developing a TOU distribution rate in its upcoming rate design investigation and agrees that an appropriately structured TOU could promote off-peak charging that maximizes the efficiency of the grid.

b. Staff's Position

Staff concludes ComEd's BE Plan minimally addresses 20 ILCS 627/45(d)(ii). Staff recommends the Commission direct ComEd to develop and propose a TOU distribution rate consistent with Section 45(d)(ii) in its next rate design investigation case to incent residential and small commercial customers to charge their EVs at times beneficial to the grid. Staff Ex. 6.0 at 5. The Company appears open to this recommendation, as it has modified its original proposal for customers receiving a charging infrastructure rebate to allow those customers to take service under a potential future ComEd distribution TOU rate, not offered on a limited, pilot basis, if and when such a rate is approved by the Commission. In addition, Staff states, the Commission should direct ComEd to consider the following in the development of such TOU rate: (1) that any TOU rate developed contains differences between peak and off peak that are significant enough to encourage customers to shift usage without deterring customers from signing up for the rate, (2) the rate's on-peak and off-peak periods should coincide with the distribution system on-peak and off-peak periods, and (3) the Company's rate proposal should include an incentive for EV owners (i.e., monthly/annual bill credits) to go on the rate, but the rate should not be available exclusively to EV owners. Staff Ex. 6.0 at 6.

Staff acknowledges that the Company incorporated Rate BESH into its BE Plan as a way to use TOU rates and help address this requirement, but Section 45(d)(ii) directs ComEd to include TOU rates that are beneficial for EV users and for all customers. Staff *Id*. at 5. Rate BESH is an electric supply rate option and will primarily benefit those who elect to get their service from ComEd. Having a TOU distribution rate, as Staff has recommended, will allow customers to choose their supplier while creating an easy-to-

follow price structure that encourages off-peak electric consumption, and adds a potential cost saving rate option for customers with varying levels of financials and access to technology. *Id*. The AG recommends ComEd develop a distribution TOU rate for residential customers. Staff's recommendation is aligned with the AG's recommendation, and the addition of small C&I customers only adds more options to an additional rate class. Staff Ex. 17.0 at 32.

In its Initial Brief, the AG argues for the first time that the "Commission should exempt low-income customers from the requirement to take service under a TOU rate to participate in the Residential EV Charging Infrastructure Subprogram." AG IB at 66. Proposing this exemption so late in the litigation process deprives the parties of the ability to thoroughly evaluate the proposal and robs the Commission of additional information needed to fully consider the exception; moreover, it is not clear that the AG's suggestion is supported by the record evidence. In part, the EVA states that all BE "programs shall provide for incentives such that customers are induced to use electricity at times of low overall system usage or at times when generation from renewable energy sources is high." 20 ILCS 627/45(b). While the AG is correct that "[t]he [EVA] also does not require that all program participants take service under a TOU rate[,]" Staff opines that exempting low-income customers from the requirement might well strain the grid. AG IB at 68. Whether any of the time variant rate options are appropriate for low-income customers should be determined by each individual customer, based on how the customer uses electricity. Staff understands that not all customers would benefit from a time variant rate, which is one of the reasons why the Commission should direct ComEd to provide customers with different options that incentivize customers to charge their EVs during off-peak times.

The Commission should reject CJCP's proposal that ComEd offer "a simple TOU rate, applicable to [the customer's] entire whole-house usage and that includes supply, transmission and distribution." CJCP IB at 51. Throughout this docket and in their Initial Briefs, Staff and ICEA have raised policy concerns and legal challenges that prohibit ComEd from offering a TOU rate that would include distribution, transmission, and supply costs or individual TOU rates for transmission and supply costs. CJCP fail to recognize that Illinois is a restructured state and does not address the policy concerns and legal challenges raised by Staff and ICEA. Allowing ComEd to offer a TOU rate that includes supply cost, whether bundled or individual, will create legal challenges for the Company and goes against the Commission's mandate to promote retail competition. For these reasons and those raised by ICEA, the Commission should reject CJCP's recommendation that ComEd offer a TOU rate that includes distribution, transmission, and supply costs.

c. AG's Position

The AG requests that the Commission exempt low-income customers from any requirement to participate in a TOU rate as a condition of receiving a utility incentive.

The AG requests that the Commission should exempt low-income customers from the requirement to take service under a Commission-approved or ARES-offered TOU rate to participate in the Residential EV Charging Infrastructure Sub-program because these customers are least able to absorb the charges that would stem from using electricity

during non-preferred periods. The AG also notes that their concern that low-income ratepayers will pay more is not a speculative risk. The AG explains that ComEd currently operates a TOU rate pilot program through its Rate RTOUPP, a rate which gives residential customers three different supply price windows with higher prices during peak hours. As described by the AG's witnesses, ComEd's compliance filing from spring 2022 showed that of the 102 low-income customers in the pilot, "six have saved $258.53 cumulatively overall and 96 have lost a cumulative $6,709.01" since June 2020. AG Ex 1.0R 46. Thus, low-income customers have lost a substantial amount of money by participating in RTOUPP. To protect vulnerable customers from possible losses and increased charges, the AG states that the Commission should not require low-income customers to enroll in a TOU rate.

The AG states that the wild price swings and unlikely savings resulting from ComEd's TOU supply rates create too large of a risk that low-income customers will not realize cost-savings through their participation and that they will pay more, not less, for electricity service if forced to switch from default supply service to a TOU rate. The AG maintains that this result would frustrate Section 45(d)(v) of the EVA, which states that the BE Plans should seek to minimize the rate impact experienced by low-income ratepayers in the pursuit of facilitating the expansion of electric vehicle charging. 20 ILCS 627/45(d)(v).

Finally, the AG argues that the EVA does not require that all program participants take service under a TOU rate. The AG maintains that Section 45(d)(ii) imagines that the Company will create a TOU distribution-only incentive through its BE Plan and does not require the Commission to place all customers receiving an incentive under the BE Plans on a supply TOU rate.

The AG requests that the Commission direct ComEd in its next rate design investigation to develop and propose a TOU distribution-only rate for residential customers and small commercial customers. The AG explains that, in its current suite of rates, ComEd does not offer a TOU rate that charges customers based on the amount of stress their demand places on the Company's distribution system. Instead, ComEd offers two supply TOU rates — Rate BESH and Rate RTOUPP — which measure changes in supply prices across the PJM territory. The AG argues that the EVA clearly imagines that ComEd would develop TOU rates to promote off-peak charging that maximizes efficient use of the grid. For example, Section 45(d)(ii) of the EVA requires the Company, as part of its BE Plan, to develop TOU rates that "allow electric vehicle charging to respond to local system conditions, manage critical peak periods, serve as a demand response or peak resource, and maximize renewable energy use and integration into the grid." 20 ILCS 627/45(d)(ii). Similarly, Section 45(d)(7) states that the Commission must consider in its evaluation of the Company's BE Plan whether its programs are reasonably expected to "support the efficient and cost-effective use of the electric grid in a manner that supports electric vehicle charging operations." 20 ILCS 627/45(d)(7). Efficient usage of ComEd's grid will unlock savings for customers by limiting the Company's need to invest money in distribution system improvements to handle greater peak load.

The AG explains, however, that ComEd's current distribution and supply rates do not satisfy this statutory requirement because the Company lacks a TOU rate that measures the times when distribution circuits experience peak load and instead has TOU

rates based on supply prices throughout PJM's ComEd zone that do not track distribution system congestion. As explained by the AG's witnesses in regard to Rate BESH, ComEd provided no evidence in this proceeding to demonstrate that the rate provides a consistent price signal to shift load off-peak relative to distribution system peak hours. AG Ex. 1.0R at 49.

d. CJCP's Position

The EVA requires the BE Plan to specifically address BE programs that include TOU rates and "their benefit for electric vehicle users and for all customers…." 20 ILCS 627/45(d)(ii).

Clean Jobs Coalition Parties note that, as modified, ComEd proposes to require residential customers receiving charging infrastructure rebates to choose as an electricity supply rate: (i) ComEd Rate BESH; (ii) an approved ARES TOU rate (or potential future ComEd TOU rate); or (iii) ComEd's Rate Optimization pilot. Clean Jobs Coalition Parties witness Nelson explained why real-time pricing under Rate BESH is not appropriate for all residential customers. While Rate BESH should remain an available option, he points out that most EV drivers do not have access to the advanced energy management systems required in order to optimize charging around the dynamic price signals under Rate BESH. NRDC Ex. 1.0 REV at 14. In addition to real-time pricing that changes by the hour, Mr. Nelson recommends that residential customers should have available a simple TOU rate, applicable to their entire whole-house usage and that includes supply, transmission and distribution. As he explained, a simple, well-designed TOU rate can provide effective price signals to cause customers to shift charging to low-cost periods without the complexity and price volatility of real-time pricing. Mr. Nelson pointed out that under such a TOU rate, customers can set their EVs and chargers to begin charging at the same specific daily time instead of having to try to track and respond to changing hourly prices. Another advantage, as Mr. Nelson pointed out, a TOU rate also will protect customers from exposure to exceptionally high prices caused by emergency events that could occur under a real-time pricing rate. NRDC Ex. 1.0 REV at 15. He recommended that a TOU rate should be the default rate for residential EV customers who participate in the rebate program as well as EV-owning customers who do not receive the rebates. He pointed to yet another advantage - that having the TOU rate applicable to the customer's entire electricity usage also eliminates the need for a separate EV charging meter. NRDC Ex. 1.0 REV at 16-17.

In response to Mr. Nelson's proposals, the Company claimed that a whole-house TOU rate may not be practical due to adjustments resulting from the differences between the monthly rate charged to customers and the cost of energy procured in the hourly market. ComEd Ex. 10.0 at 21-23. Nonetheless, as Clean Jobs Coalition Parties note, the Company stated it would consider developing a TOU rate applicable to both generation and distribution in its upcoming (likely 2024) rate design investigation. Mr. Nelson asserted that a whole-house TOU rate would not only give participating customers a chance to lower their costs, but also would, by encouraging beneficial charging behavior, lower system costs to the benefit of all customers. Clean Jobs Coalition Parties contend that Mr. Nelson's proposed pricing periods are straightforward and actionable, with customers able to program their EVs and chargers to charge at the same time every day. NRDC Ex. 3.0 at 3. Clean Jobs Coalition Parties note that AG witnesses (which the

the AG backs off from advocating in briefing) also proposed that the Commission require ComEd to "design and file TOU rate options for the generation and distribution cost components for its rate that accurately reflect peak times and provide appropriate cost signals to customers to allow for grid beneficial charging." AG Ex. 1.0R at 53-54.

e. ICEA's Position

ICEA states that it adamantly opposes introduction of new TOU supply rates by ComEd. However, according to ICEA, its position is irrelevant because ComEd's opposition is sufficient for total rejection.

ICEA notes that ComEd does not propose a new nonresidential supply or delivery rate in the present docket. According to ICEA, Section 16-103(e) of the Act provides in relevant part that "The Commission shall not require an electric utility to offer any tariffed service other than the services required by this Section." 220 ILCS 5/16-103(e). ICEA contends that while Section 16-103(b) does require the utility to offer real-time pricing (as ComEd does with Rate BESH), nowhere in Section 16-103(e) is any other type of time-variant rate—much less a combined supply and delivery rate—required. Thus, ICEA deduces, the Commission cannot force ComEd to provide any time-variant rate other than real-time pricing under Section 16-103(b) against ComEd's will. As a result, ICEA concludes that ComEd's failure to propose a TOU supply rate is dispositive.

ICEA notes that nothing in Section 45(d)(ii) of the EVA supersedes or provides an independent obligation in addition to Section 16-103(e). ICEA posits that Section 45(d)(ii) merely requires that the BE Plan "specifically address" the "development and implementation of . . . [TOU] rates and their benefit for [EVs]" — there is no separate authority or mandate for additional time-variant rates. ICEA notes that ComEd does specifically address Rate BESH several times in the BE Plan and ComEd proposed several modifications to reference ARES-offered time-variant products and services.

While ICEA notes it is opposed to new TOU supply rates, ICEA counters that it has consistently supported utilities offering TOU delivery rates — as long as those delivery rates are available without regard to supplier.

ICEA observes that no party (ICEA included) other than CJCP appears to support a new combined supply and distribution TOU rate proposed by CJCP. According to ICEA, the AG initially supported a combined supply and distribution TOU rate in early testimony, but now support a distribution-only TOU rate. ICEA expresses appreciation that the AG agrees with Staff that a combined supply and delivery TOU rate would "interfere with the supply market for ARES." AG IB at 70. ICEA strongly agrees with Staff's underlying arguments that CJCP's proposal would undermine a nascent ARES residential TOU market that could greatly increase supply options if allowed to develop.

ICEA notes that CJCP similarly does not address Section 16-103(e), which provides that "The Commission shall not require an electric utility to offer any tariffed service other than the services required by this Section." 220 ILCS 5/16-103(e). ICEA further notes that Section 45(d)(ii) only requires ComEd to "specifically address" development and implementation of TOU rates — which it does with existing Rate BESH and Rate RTOUPP, as well as plans for a future delivery TOU rate to be proposed in the revenue-neutral rate design investigation.

ICEA juxtaposes Section 45(d)(ii) of the EVA with, for instance, Section 16-107 of the Act that requires ComEd to offer a real-time pricing supply rate states that "Each electric utility shall file, on or before May 1, 1998, a tariff or tariffs" to support real-time pricing. 220 ILCS 5/16-107(a). ICEA argues that Section 45(d)(ii) does not mandate filing of any tariff or tariffs. ICEA observes that, while rare, statutes outside of the Act use parallel language to Section 16-107 to require filing of specific tariffs. *See, e.g.,* 20 ILCS 3855/1-75(c-5)(9)(A) (requiring tariff as part of coal-to-solar program). ICEA argues that if the General Assembly had intended to supersede Section 16-103(e), it has demonstrated it knows how to direct filing of specific tariffs if it so chooses. ICEA claims that when read in the context of other statues, it is clear the Section 45(d)(ii) of the Electric Vehicle Act does not require utilities to issue new tariffs and supersede the limitations of Section 16-103(e).

According to ICEA, CJCP similarly does not explain why it benefits customers to impair the nascent competitive retail market — CJCP neither disputed nor addressed ICEA witness Wright's testimony that ARES do not offer many residential TOU supply products today due to barriers but that those barriers are not present for residential EV customers. *See, e.g.*, ICEA Ex. 1.0. ICEA observes that CJCP similarly did not dispute or even engage the testimony of ICEA witness Stewart regarding his company's interest in serving residential EV customers with TOU rates.

f. LVEJO's Position

LVEJO notes that the AG expresses concern about the possible impacts of TOU rates on low-income customers based on data from ComEd's current TOU Rate Pilot Program. The AG encourages ComEd to exempt low-income customers from the requirement to take service under a TOU rate to participate in the Residential EV Charging Infrastructure Subprogram. LVEJO also finds this data disconcerting. Low-income customers have less resources to be able to absorb large fluctuations in their utility bills, such as the data suggests TOU Rates can cause. While LVEJO does not support or object to the AG's proposal, it does believe there needs to be more information gathered about the potential impacts of TOU rates on low-income customers. LVEJO states that, if ComEd does not adopt the AG's proposed exemption, the Commission should require ComEd to perform more studies about issues of TOU rates for low-income customers, how to better equip these same customers to avoid them, as well as implement program changes based on these studies' outcomes. LVEJO states that this information could also help inform the design of relevant materials for the Customer Education and Awareness Program.

g. Commission Analysis and Conclusion

The Commission approves ComEd's proposal to require residential customers who receive a Residential Charging Infrastructure Rebate to take service under either (i) Rate BESH; (ii) an approved ARES TOU rate (or potential future ComEd TOU rate); or (iii) Rate Optimization pilot. In its Initial Brief, the AG raises a new proposal that low-income customers be exempt from having to take service under a TOU rate because they may pay more, not less, for electricity service if forced to switch from default supply service to a TOU rate. While this could be a concern, the Commission agrees with LVEJO that more information is needed about the potential impacts of TOU rates on low-income

customers. The AG's proposal is denied. The Commission directs ComEd to work with Staff and stakeholders to gather more information on the impacts of TOU rates for low-income customers.

ComEd, Staff, the AG, and ICEA either support or do not oppose requiring ComEd to develop and propose a TOU distribution rate in its next rate design investigation proceeding. The Commission finds this proposal reasonable, and it is adopted. In addition, the Commission adopts Staff's recommendation and directs ComEd to consider the following in the development of such TOU rate: (1) that any TOU rate developed contains differences between peak and off peak that are significant enough to encourage customers to shift usage without deterring customers from signing up for the rate; (2) the rate's on-peak and off-peak periods should coincide with the distribution system on-peak and off-peak periods; and (3) the Company's rate proposal should include an incentive for EV owners (i.e., monthly/annual bill credits) to go on the rate, but the rate should not be available exclusively to EV owners.

The Commission does not adopt CJCP's proposed whole-house delivery and supply TOU rate. The Commission is a creature of statute and is limited to its authority provided in the statute. Section 16-103(e) contains a plain limitation on the Commission's authority to order new rates other than as required in Section 16-103(e). The Commission disagrees with CJCP that Section 45(d)(ii) contains any new authority for the Commission, and it does not supersede Section 16-103(e).

2. Commercial and Industrial Customers

a. ComEd's Position

ComEd states that ComEd's existing C&I customer rate structure is ideal for those customers who can charge their EVs overnight. ComEd argues that the Rate BESH and time-variant delivery charges will generally result in a rate structure that is likely to be extremely attractive to customers able to charge EVs overnight. ComEd states that, with exception of customers in Watt-Hour Delivery Class, C&I Customers are not charged for delivery costs associated with demand that occurs after 6 pm (off-peak). ComEd notes it will continue to offer Rate BESH for supply to C&I customers.

CJCP propose that ComEd offer a simple TOU rate that included transmission and supply charges for C&I customers. Electrify America and the ICEA both oppose the development of a TOU rate for C&I customers. ComEd continues to believe that its current offerings to C&I customers, which are time-variant, are sufficient to encourage off-peak charging while also providing flexible options for customers.

b. Staff's Position

The Commission should reject CJCP's proposal that "ComEd offer a simple TOU rate option that includes transmission and supply charges" for the Commercial and Industrial ("C&I") customers. CJCP IB at 53. CJCP not only fail to recognize that Illinois is a restructured state, but also ignore the competitive declaration that applies to "retail customers with peak demands of 400 kilowatts and above." 220 ILCS 5/16-113(e). As a result, C&I customers are required to purchase their electric supply from an ARES or through a utility tariff that the Commission has declared to be competitive (i.e., ComEd's Rate BESH). 220 ILCS 5/16-113(a). CJCP claim that "C&I customers that do not take

service under Rate BESH and choose to take service under a distribution rate with no time-variant component, may have little to no incentive to manage their charging", but provide no evidence to support this conclusion. CJCP IB at 53. Further, ICEA notes that "the market for non-residential customers is far more developed" and CJCP provide "no justification for utility intrusion into the competitive retail market." ICEA IB at 14. CJCP's proposal will create legal challenges for the Company, goes against the Commission's mandate to promote retail competition, and ignores the competitive declaration in place for C&I customers. For these reasons and those raised by ICEA, the Commission should reject CJCP's recommendation that ComEd offer a TOU rate that includes transmission and supply costs. Staff IB at 32.

c. CJCP's Position

In addition to proposing the two new delivery classes for nonresidential EV customers, CJCP note that ComEd highlights that its Rate BESH for Company-furnished electricity supply is applicable in certain circumstances. Although some C&I customers are good candidates to manage more complex price signals, CJCP assert that real-time pricing may not be appropriate for all C&I customers. In order to ensure sufficient optionality to reflect the wide variety of customers in the C&I space, CJCP witness Nelson recommended that, for C&I customers, ComEd offer a simple TOU rate option that includes transmission and supply charges. He asserted that the design, including the price differentials and time periods, should be similar to the recommended residential TOU rate. NRDC Ex. 1.0 REV at 23. Mr. Nelson suggested that, to help overcome concerns over competition, for larger C&I customers, rate offerings that would accomplish the objectives of a bundled TOU rate option could be developed "through third-party partnerships or through verified connections created by [ComEd] with third-party partners." NRDC Ex. 3.0 at 7.

CJCP assert that the policy and legal challenges by Staff and ICEA to a TOU Rate option are unavailing. Clean Jobs Coalition Parties acknowledge that Staff opposes a TOU rate that includes distribution, transmission, and supply costs on the basis that it conflicts with Illinois' policy of promoting competition. CJCP note that ICEA also opposes the TOU rate option, from a legal and policy standpoint. As Clean Jobs Coalition Parties point out, ICEA argues that Section 16-103(e) of the Act prevents the Commission from requiring ComEd to adopt such a TOU rate, quoting Section 16-103(e), which, as ICEA notes provides that "[t]he Commission shall not require an electric utility to offer any tariffed service other than the services required by this Section." ICEA IB at 13. ICEA argues that ComEd's opposition to the TOU rate option proposed by the Clean Jobs Coalition Parties is dispositive. Clean Jobs Coalition Parties argue, however, that ICEA reads too much into Section 16-103(e). They assert that statutes other than the Act grant authority and impose requirements on the Commission and public utilities. The question, according to CJCP, is how to read these statutes together. They assert it is noteworthy that the Illinois Power Agency Act, for example, includes a provision that states, "[n]othing in this Act infringes upon the authority granted to the [Illinois Commerce] Commission." 20 ILCS 3855/1-22. By contrast, as CJCP point out, no provision addressing the impact on the overall contours of the Commission's authority appears in the EVA. Consequently, according to Clean Jobs Coalition Parties, the absence of any such provision supports the conclusion that the EVA can and does grant additional authority to the Commission

to adopt a rate structure that furthers the goals of the EVA, even if the utility itself did not propose that particular rate structure.

CJCP argue that the EVA, as amended by P.A. 102-0662, provides such additional statutory authority to the Commission concerning ComEd's tariffs. CJCP contend this is evident from the language the legislature used in several parts of the EVA amendments. The best indicator of legislative intent—the primary objective of statutory interpretation—is the plain meaning of the language actually used. *E.g., People v. Leib*, 2022 IL 126645, ¶ 28; *Skaperdas v. County Casualty Ins. Co*., 2015 IL 117021, ¶15, 28 N.E.3d 747, 751-752. As Clean Jobs Coalition Parties assert, it is instructive to review the language utilized in certain relevant portions of the EVA. CJCP point to Section 45(c) of the amended EVA, for example, which directs the stakeholder workshop process to consider benefits of and barriers to EV adoption, including "benefits to the distribution system from [EV] usage, the avoidance and reduction in capacity costs from optimized charging and off-peak charging, energy price and cost reductions." 20 ILCS 627/45(c)(2)-(4). Clean Jobs Coalition Parties point out that the first item in this list expressly pertains to the utility distribution system, while the latter two concern electric capacity and supply pricing. Thus, according to Clean Jobs Coalition Parties, the legislature not only knowingly referenced the "distribution system," they did so in the same sentence in which they referenced and expressed interest in avoiding and lowering (non-distribution-related) capacity costs and energy prices and costs. Clean Jobs Coalition Parties reason that this statutory language provides strong evidence that, when the legislature did not include a distribution system reference or qualification, it was intentional. For supporting legal authority, Clean Jobs Coalition Parties pointed out that, as the Illinois Supreme Court has stated, "'[i]f a statutory provision is unambiguous, we must apply it straightforwardly, without reading in exceptions, limitations, or qualifications.'" *Save Our Ill. Land v. Ill. Commerce Comm'n*, 2022 IL App (4th) 210008, as modified upon denial of rehearing (2022), ¶ 49, quoting *People ex rel. Webb v. Wortham*, 2018 IL App (2d) 170445, ¶ 31. Similarly, Clean Jobs Coalition Parties point out, the Court stated in *Skaperdas*, "Courts may not depart from the plain language of a statute by reading into it exceptions, conditions, or limitations that the legislature did not express." 28 N.E.3d at 752. To apply a "distribution" qualifier to certain portions of the EVA's provisions that do not include the term "distribution," including the provisions referenced above in this paragraph and others noted hereinbelow, would, in CJCP's view, violate a basic tenet of statutory construction by reading into the provision in question a "limitation," i.e., applicable only to "distribution," that the legislature did not express.

Continuing, Clean Jobs Coalition Parties note that the definition of BE programs in Section 45(b) includes program examples that demonstrate a legislative intent to include programs affecting energy supply, and not just distribution. Clean Jobs Coalition Parties believe it is telling that none of the mentions regarding energy are qualified just to include distribution. Examining the statutory language, Clean Jobs Coalition Parties note that the term "optimized charging programs" is defined to mean programs that allow EV owners to "set their vehicles to be charged based on the electric system's (not "electric distribution system's") current demand, retail or wholesale market rates, incentives, the carbon or other pollution intensity of the electric generation mix, the provision of grid services, efficient use of the electric grid, or the availability of clean energy generation." 20 ILCS 627/45(b). As Clean Jobs Coalition Parties point out, the foregoing program list contains

both programs that are specific to the utility's distribution system, or grid, and programs that clearly refer to energy demand and supply. To Clean Jobs Coalition Parties, it is significant that the definition of this term adds, "Optimized programs may be operated by utilities as well as third parties." The TOU rate option described by the Clean Jobs Coalition Parties witness Nelson, they contend, fits and is consistent with this statutory provision, as a program "operated by utilities."

Next, CJCP further review EVA Section 45(d), which requires the Commission, in reviewing a utility BE Plan, to consider whether utility investments and expenditures are designed to "maximize total energy cost savings and rate reductions so that nonparticipants can benefit." 20 ILCS 627/45(d)(1). Again, as Clean Jobs Coalition Parties assert, this is evidence that the legislature intended utility programs, including rates and tariffs, to take into account and affect "total energy" savings and reductions, not just those pertaining to the distribution system and distribution rates. Clean Jobs Coalition Parties argue that language used in the Section 45(d)(i-x) factors provide yet further evidence that the legislature intended energy supply-related programs and tariffs to be included. As CJCP point out, Section 45(d)(ii) does not, for example, refer to TOU distribution rates. CJCP note that this subsection continues its energy supply focus through using the terms "manage critical peak periods, serve as a demand response or peak resource, and maximize renewable energy use." CJCP RB at 46.

To further buttress their position, CJCP note that EVA Section 45(e) states that proceedings under the section are to proceed according to the rules contained in Article IX of the Act, which governs public utility rate proceedings. It is a fundamental and customary procedure, as Clean Jobs Coalition Parties assert, that when a public utility files a rate case or other tariff that includes a proposed rate, the Commission will often approve rates that are different than what the utility proposed. Here, as they characterize it, Clean Jobs Coalition Parties are requesting the Commission to approve their proposal to have ComEd adopt TOU rate options, consistent with its Article IX rate-setting authority, which will further the aims of the EVA.

CJCP also note that ICEA cites and relies on Section 452.270 of the Commission's regulations to support its argument that a TOU rate option may not be considered. The cited regulation states, "[a]n Integrated Distribution Company shall not tie, as defined by state and federal anti-trust laws, the provision of any tariffed service to the taking of any other product or service offered or provided by the IDC." 83 Ill. Adm. Code 452.270. Clean Jobs Coalition Parties contend that ICEA's attempt to fit the TOU rate option into this administrative provision is off base. Regulation is a substitute for competition, they point out, a way to prevent natural monopolies from earning monopoly profits. Clean Jobs Coalition Parties assert that ICEA again reads too much into this regulatory provision. CJCP point out that any bundled utility offering in a sense involves a tying arrangement — energy, transmission and distribution are bundled, or tied together, in the bundled offering. But Clean Jobs Coalition Parties contend that is not illegal tying, and not what the administrative regulation is intended to prohibit. They argue that the opinion ICEA cited in support of its argument is inapposite. Clean Jobs Coalition Parties point out that in that case, *People ex rel. Scott v. Schwulst Bldg. Ctr., Inc*., 89 Ill.2d 367, 432 N.E.2d 855 (1982), the owners of single-family building lots who also were in the business of selling certain building materials were alleged to condition the purchase of a building lot

upon the purchase of a package of building materials. The AG sued under the Illinois Antitrust Act. As Clean Jobs Coalition Parties note, the owners and the transactions involved were in the private sector. CJCP point out that the Illinois Antitrust Act, recognizing the distinction between parties in the private sector and regulated utilities, includes a provision exempting regulated public utility activities, such that, as Clean Jobs Coalition Parties reason, such activities may not be construed to be illegal. 740 ILCS 10/5. CJCP argue that the case has no applicability here.

Clean Jobs Coalition Parties believe that ICEA's position would have deleterious effects on the developing EV market. CJCP point out that, from a policy standpoint, in addition to restrictions on customer choice, as ICEA acknowledges, ARES-offered time-variant supply products and services are not widely available for residential customers currently. *See* ICEA Ex. 1.0 at 4. As ICEA admits, the reason for so few ARES-offered time-variant products and services is that there are barriers, particularly regulatory hurdles to obtaining the necessary interval meter data to initially price products and "real-time" data to administer certain products and services. *See* ICEA Ex. 1.0 at 4-5; ICEA Ex. 2.0 at 6-7. ICEA claims such barriers are far lower for residential customers with EVs, meaning residential customers with EVs are a desirable market for ARES seeking to offer time-variant supply products and services. *See* ICEA Ex. 1.0 at 5-6; ICEA Ex. 2.0 at 7-8. Clean Jobs Coalition Parties assert that, while ICEA witness Wright claims EVs to be a desirable market, he offered no supporting evidence that his ARES association members will be able to serve it. According to Clean Jobs Coalition Parties, Mr. Wright's characterization of residential EV owners being a "desirable market" is an empty one, devoid of any evidence, and in fact contrary to evidence of ARES' actual experience to date.

d. ICEA's Position

ICEA notes that similar to residential customers, ICEA once again supports a delivery-only TOU rate being offered by ComEd. In addition, ICEA notes that while the residential market for ARES time-variant supply products and services is "nascent," the market for non-residential customers is far more developed. ICEA further notes that in addition to ICEA's discussion of legal barriers and that ARES do offer TOU supply products to non-residential customers, Electrify America stated that TOU "rates are unnecessary for commercial EV charging customers, who are already subject to strong price signals through ComEd's Rate BESH." Electrify America IB at 12. While ICEA observes that ARES TOU products will often also provide strong price signals, pursuant to Section 16-107 all non-residential customers have the option of ComEd Rate BESH.

e. Electrify America's Position

Electrify America supports ComEd's conclusion that existing Rate BESH, which provides an hourly price, already provides a strong price signal to commercial EV charging sites taking service under Rate BESH and, accordingly, a separate price signal is not needed. Electrify America states that Rate BESH provides a strong price signal on a daily and seasonal basis. Electrify America Ex. 1.0 REV at 24-25 (explaining how Rate BESH offers price signals within energy prices and through the use of "Capacity Tags" that are used along with capacity market prices to determine monthly capacity charges). Electrify America witness Bride also points out that many DCFC station operators are

incentivized to take service under Rate BESH noting that "[m]any DCFC charging station operators rely on default energy supply pricing options due to the reluctance of competitive energy suppliers to serve DCFC loads at attractive terms." Electrify America Ex. 1.0 REV at 25.

Electrify America also contends that impediments exist that may limit the effectiveness of TOU rates for public DCFC stations and that adoption of such rates may confuse customers of public DCFC stations and is premature given the developing nature of the EV industry and EV adoption. Electrify America asserts TOU rate adoption for public DCFC charging may not achieve Section 45(d)(ii)'s goal of incentivizing charging during off peaks hours in a way that benefits electric vehicle users and all customers, stating there is no indication TOU rates for public DCFC stations will incentivize off peak charging or that they will benefit electric vehicle users or C&I customers. EV users expect fair and predictable pricing and expect to be able to charge as quickly as possible. Accordingly, public DCFC station operators are reluctant to pass through elevated costs from price signals and public DCFC stations may have difficulty adjusting load to reduce demand charges. Electrify America Ex. 1.0 REV at 26. Additionally, EV users often utilize public DCFC chargers in order to complete their journeys, resulting in TOU rates having little impact on when such drivers might utilize a public charging station. *Id*.

In connection with Staff and AG's request that the Commission direct ComEd to develop a distribution TOU rate for residential and small commercial customers as part of its next rate design, Electrify America notes that continued impediments may exist to a distribution TOU providing helpful price signals for public DCFC stations. Accordingly, it asserts that mandatory TOU pricing should not be introduced within the Watt-Hour Delivery Class during the ten-year eligibility period for public DCFC to participate in that class. Electrify America contends that for a TOU rate to allow for the continued EVA goals of development of EV infrastructure in Illinois, participation in the rate must be optional. It further requests that if the Commission adopts Staff and AG's proposal that the Commission's direction to ComEd be limited to investigating whether a TOU rate is appropriate prior to inclusion in a rate design and include a process for stakeholder participation and input in that process.

f. Commission Analysis and Conclusion

As with residential customers, CJCP propose that ComEd offer a TOU rate that includes transmission and supply charges for C&I customers. The Commission denies this proposal for the same reasons. Moreover, as ICEA points out, the market for nonresidential customers is more developed, which provides less justification for any intrusion by ComEd into this competitive retail market beyond Rate BESH.

Staff and the AG propose that ComEd develop a TOU distribution rate for its next rate design investigation proceeding for residential and small commercial customers. As previously determined in Section VII.C.1, this proposal is approved. Whether or not the TOU rate as proposed in the future rate design investigation proceeding is appropriate and should be adopted will be determined in that proceeding. However, the Commission directs ComEd to work with Staff and stakeholders in the development of the new proposed distribution TOU rate.

VIII. INDEPENDENT EVALUATION

A. ComEd's Position

Several parties suggest that ComEd engage an independent third-party evaluation, measurement, and verification ("EM&V") contractor. An independent impact evaluation of the BE Plan programs would not be appropriate – not only did the General Assembly not require one, but the purpose of the BE Plan is to advance electrification in ComEd's service territory, which will necessarily encourage new load through the Plan programs, the expansion of EV charging infrastructure, and additional EVs on the road. "Although ComEd's BE Plan is designed to influence the timing and profile of that new load, the load itself will not exist prior to the establishment of the BE Plan." ComEd Ex. 6.0 at 26.

However, ComEd notes that there may be value in conducting an independent evaluation of BE Plan programs that focuses on process, particularly if the anticipated level of demand does not materialize for any BE Plan programs and/or sub-programs. Likewise, ComEd contends, it could provide insight into how portfolio and/or program design may need to be adjusted in future BE Plans. As part of a process evaluation, ComEd claims it will evaluate whether incentive programs being offered as a condition of receiving a rebate are successful in encouraging customers to shift their electricity usage and charge their EVs during off-peak times. ComEd claims it has also committed to including additional data in its annual report, which will begin April 1, 2024, and will provide visibility into charging patterns after one year of the BE Plan. "If the Commission directs ComEd to conduct such an evaluation, ComEd is open to Staff's recommended evaluator independence protocols, including the requirement that the draft evaluation plans be shared with interested stakeholders for feedback." ComEd Ex. 12.0 REV. at 26-27.

Both Staff and the AG continue to recommend that the Commission order NTG surveys to provide an examination of whether ComEd's BE Plan programs are successfully encouraging customers to shift their electricity usage and EV charging to off-peak hours. Both parties assert that NTG surveys are critical for determining the impact of the BE Plan on non-participants. ComEd continues to respectfully disagree with this recommendation. The focus and emphasis of the BE Plan is to encourage BE in the State of Illinois through incentivizing increased utilization of EVs and other BE measures. Unlike traditional EE programs where analysis of free ridership is necessary for the evaluation of the utility's programs, here, many of the benefits of the BE Plan are indirect, dispersed, and hard to adequately quantify.

B. Staff's Position

Staff states that the Commission should direct an independent evaluation take place for ComEd's BE Plan and that the results from the first evaluation and ComEd's responses to recommendations be reported no later than the April 1, 2026 Annual Report for ComEd's BE Plan. Staff Ex. 12.0 at 5-6. The Commission should direct that, after the first evaluation, the independent evaluation be repeated to provide at a minimum updated evaluation results in the annual report on a three-year cadence. According to Staff, the Commission should not arbitrarily limit the evaluation to a "process-only" evaluation. The Commission should direct ComEd to include, in the independent evaluation, an analysis

to determine whether the incentive programs being offered as a condition of receiving the rebate are successful in encouraging customers to shift their electricity usage and charge their EVs during off-peak times to avoid straining the electric grid. Finally, the Commission should impose independence protocols on the independent evaluator comparable to those that it has adopted in other independent evaluation contexts, which include an opportunity for stakeholder input on both the draft evaluation plans and evaluation reports. Specifically, the Commission should include the following language in its final Order in this proceeding:

> ComEd shall engage an independent evaluator and shall implement the following evaluator independence protocols to ensure that evaluator independence is maintained in the evaluation of ComEd's BE Plan:
>
> 1. Any contract between ComEd and the independent evaluator shall provide that:
>
>   a. The Commission has the right to direct ComEd to terminate the contract if the Commission determines the evaluators were not acting independently.
>
>   b. The evaluators must act independently from ComEd and be able to independently evaluate ComEd's Beneficial Electrification Plan.
>
>   c. All data used in the evaluations must be made available to the Commission or Commission Staff upon request.
>
>   d. With the exception of communications related solely to contractual or other administrative issues, all written communications between the independent evaluator and ComEd (or contractor acting on ComEd's behalf) and/or Commission Staff shall be copied to ComEd and Commission Staff.
>
>   e. With the exception of any phone, webinar, or in-person meetings related solely to contractual or other administrative issues, ComEd and Commission Staff will be made aware of, and invited to, all meetings between the independent evaluator and ComEd (or contractor acting on ComEd's behalf) and/or Commission Staff.
>
> 2. ComEd shall submit the finalized but not yet executed contract with the independent evaluator to the Commission by letter to the Executive Director. Commission Staff will submit a report to the Commission containing its assessment of the contract and/or scope of work and describing its recommendations for Commission action, if any. In addition, ComEd will submit any fully executed contract and scope of work with the independent evaluator as a compliance filing in ICC Docket Nos. 22-0432/22-0442 (Consol.) within fourteen (14) days of execution. Such compliance filing will be treated as public information, subject to redactions approved by the Commission of provisions deemed confidential.
>
> 3. Draft evaluation plans shall be shared with interested stakeholders for feedback.

4. Draft evaluation reports shall be shared with interested stakeholders for feedback.
5. ComEd shall file all final evaluation reports in ICC Docket Nos. 22-0432/22-0442 (Consol.) within fourteen (14) days of receipt.
6. ComEd shall provide its response to evaluator recommendations in its annual report.

Staff Ex. 12.0 at 6-7.

Staff testified that it is a best practice to have independent evaluations of ratepayer-funded programs to ensure the programs continue to be modified in a manner that benefits the ratepayers funding such programs, and that such modifications serve to help achieve statutory objectives. Staff Ex. 1.0 at 13. ComEd proposes a variety of new programs within its BE Plan that it has no experience implementing. While presumably ComEd will hire qualified vendors that have the necessary experience to successfully implement the proposed BE programs, it is a good idea to have an independent evaluation performed of those programs to ensure such programs are modified in a manner that best serves the Company's ratepayers and achieves the statutory objectives and requirements of the EVA. *Id*.

ComEd conceded that there may be value in conducting an independent evaluation of programs but indicated ComEd is only open to a focused independent process-only evaluation, explicitly excluding "an impact evaluation, which checks metrics and performs [NTG] research." ComEd Ex. 12.0 REV at 26. Staff states that the Commission should reject ComEd's proposed limitation on the independent evaluation. As an initial matter, Staff notes that it is not always 100% clear whether a particular evaluation is "process-only" versus "impact-only" and for efficiency evaluations often cover both aspects. To arbitrarily limit the independent evaluation to "process-only" will only serve to create unneeded arguments among the parties during the evaluation plan development process as to whether a particular evaluation proposal is truly "process-only." Staff's proposed independence protocols include a collaborative evaluation plan development process and details related to the scope of the independent evaluation can be worked out with the evaluator, ComEd, and other stakeholders as part of that process. Staff Ex. 12.0 at 4. While it may be possible to identify some components of ComEd's BE Plan to be evaluated at this stage, it is possible issues may arise during the implementation of the BE Plan that may warrant an evaluation focus on those issues as well, and ComEd, the evaluator, and stakeholders should not be arbitrarily limited by a "process-only" requirement. Staff and ComEd agree "that the analysis proposed by . . . Staff witness Capellan could be considered a process evaluation, not an impact evaluation." Staff Cross Ex. 1.0 at 52. Thus, to the extent the Commission adopts the Company's proposal to limit independent evaluation to process only evaluations, which it should not, that determination would not preclude the evaluator from performing the evaluation recommended by Staff witness Capellan.

Additionally, the Commission should not prohibit the independent evaluation from assessing NTG as ComEd recommends. Both the AG and Staff have expressed concerns about ComEd's unrealistic 100% NTG assumption used in its BE Plan. Staff cited evaluations from around the country of vehicle rebates programs with very high free

ridership. Staff Ex. 3.0 at 10. ComEd's BE Plan includes vehicle rebates in its C&I and Public Sector EV Purchase Sub-Program. While Staff testified that NTG surveys for every single program may not be a good use of evaluation resources, the vehicle rebate programs contained in the ComEd BE Plan are actually prime candidates for such NTG research to be performed based on the evaluation evidence from other states. Staff Ex. 12.0 at 4. Having such research performed on the programs can help to inform future program modifications to help reduce free ridership and provide greater net benefits for ratepayers. Accordingly, the Commission should not limit the scope of the independent evaluation and should instead let Staff, the AG, the evaluator, ComEd, and other stakeholders work out those details as part of the collaborative evaluation plan development process Staff recommends the Commission adopt.

With respect to evaluator independence protocols, Staff testified that independence protocols for other independent evaluators in Illinois have provided value, in that they help to ensure the evaluators seriously consider input and feedback from entities other than just the utility as they perform their evaluations of the utility's programs. Staff Ex. 1.0 at 15. In addition, Staff testified that such protocols add credibility to the evaluations. *Id*. For these reasons, Staff recommends the Commission adopt evaluator independence protocols for the independent evaluators of the Company's BE Plan as set forth above, so stakeholders can provide meaningful feedback on the evaluation plan, and so the results of the evaluation are useful to the Commission when it evaluates future BE Plan Update filings. ComEd indicated that it is open to Staff's recommended evaluator independence protocols, including the requirement that draft evaluation plans be shared with interested stakeholders for feedback. ComEd Ex. 12.0 REV at 26-27. Accordingly, the Commission should adopt these evaluator independence protocols. ComEd also confirmed in its Initial Brief that it is open to Staff's recommended evaluator independence protocols. This issue is also uncontested.

The Commission should direct an independent evaluation be conducted that includes a more complex and detailed analysis regarding the Residential EV Charging Infrastructure Sub-Program Rebate to determine whether the incentive programs being offered as a condition of receiving the rebate are successful in encouraging customers to shift their electricity usage and charge their EVs during off-peak times to avoid straining the electric grid. Staff Ex. 9.0 at 10-11.

Despite agreeing to an independent evaluation, ComEd originally disagreed "that there should be any evaluation done to assess whether the BE Programs or the EV Charging Delivery Class are successful in encouraging customers to shift their electricity usage." ComEd Ex. 11.0 REV at 23. ComEd argued that "the BE Plan is designed to encourage new load from EVs to charge off peak, and as such there will not be prior load data for an independent evaluator to use to determine whether said load has shifted." *Id*. Staff disagreed and opined that the Company's concerns are premature. Moreover, Staff testified that "[t]here are already customers who own and charge EVs without receiving an incentive to charge during off-peak times, so the evaluator can examine the changes in behavior between those customers and EV owners who enroll in one of the incentive programs." Staff Ex. 20.0 at 20-21. Staff believes "[i]t would be better to hear from the independent evaluator what evaluation methodology options are available to perform

such an analysis and address [ComEd]'s concerns, rather than simply writing off that such an evaluation will be unlikely to provide meaningful insight." *Id*.

The Company has modified its proposal and agrees with Staff. In ComEd's Initial Brief, the Company states it "will evaluate whether incentive programs being offered as a condition of receiving a rebate are successful in encouraging customers to shift their electricity usage and charge their EVs during off-peak times." ComEd IB at 80. As a result, the Commission should direct ComEd to include an analysis to determine whether the incentive programs being offered as a condition of receiving the rebate are successful in encouraging customers to shift their electricity usage and charge their EVs during off-peak times to avoid straining the electric grid. Staff Ex. 20.0 at 4. This issue is uncontested and Staff's recommendation should be adopted.

C. AG's Position

The AG requests that the Commission order an independent evaluation that includes the development of NTG evaluations to determine the levels of free ridership by program and to incorporate in the evaluation Staff's requested analysis of whether the BE Plan programs are shifting electricity usage and EV charging to off-peak times. The AG explains that the AG and Staff requested in their testimony and briefing that the Company obtain an independent evaluation of its BE Plan. Specifically, the AG requests that, at minimum, the evaluation include the development of NTG evaluations to determine the levels of free ridership by program. AG Ex. 1.0R at 62. Staff requested that the Company submit the results of its first evaluation by no later than April 1, 2026, and every three years thereafter, and that the evaluation include a detailed analysis determining whether the incentive programs included in the BE Plan are successfully encouraging customers to shift their electricity usage and EV charging to off-peak hours. Staff Ex. 12.0 at 2-4; Staff Ex. 20.0 at 21.

In response, ComEd committed to conducting an evaluation every three years, but rejected the AG's recommendation to include in the evaluation NTG surveys and proposed that an independent evaluation include only "process evaluations," rather than "impact evaluations." ComEd IB at 80–81. As explained by ComEd witness Borggren, a process-only evaluation would exclude evaluation of NTG ratios and would only focus on how portfolio and/or program design may be adjusted in future BE Plans. ComEd Ex. 12.0 REV at 26. The Company did not directly comment on Staff's request to incorporate in the evaluation Staff's requested analysis of whether the BE Plan programs are shifting electricity usage and EV charging to off-peak times.

The AG asserts that the Commission should reject ComEd's request to include only process evaluations in its independent evaluations and should instead order that independent evaluations include the development of NTG evaluations to determine the levels of free ridership by program. The AG explains that an independent evaluation that includes NTG evaluations to determine the levels of free ridership by program is necessary for the Commission, the utility, and the parties to evaluate the effectiveness of tens of millions of dollars of incentives and program costs. NTG surveys allow parties to identify and quantify free ridership rates by program and are a key input in a RIM analysis as they factor into the calculation of net revenues caused by BE Plan spending. *See* supra Section V.D.3. Parties will not be able to effectively conduct accurate RIM analyses

in the future if the Commission does not order a determination of NTG ratios in the independent evaluation.

D. WeaveGrid's Position

WeaveGrid explains that the EVA does not require an independent evaluation of the BE Plan to be conducted. However, WeaveGrid concurs with the arguments of Staff, the AG, and ComEd that there would be benefits for some independent evaluation of the BE Plan. WeaveGrid notes that such an independent evaluation should focus on process improvements for the BE Plan.

E. Commission Analysis and Conclusion

ComEd does not generally oppose an independent evaluation or Staff's recommended evaluator independence protocols, including the requirement that the draft evaluation plans be shared with interested stakeholders. The Commission directs ComEd to perform an independent evaluation for ComEd's BE Plan and include those results and any responses to the evaluation's recommendations no later than the April 1, 2026 Annual Report for ComEd's BE Plan. After the first evaluation, the independent evaluation shall be repeated to provide at a minimum updated evaluation results in the annual report on a three-year cadence. ComEd agreed to many of Staff's recommendations should the Commission approve an independent evaluation, and those are hereby adopted. However, ComEd still objects to the any requirement that the independent evaluation include NTG surveys. As noted in Section V.D.3., the Commission finds that NTG surveys will aid in determining whether ComEd's BE Plan is cost-beneficial. Accordingly, the Commission requires that ComEd's independent evaluation include NTG surveys. The Commission also directs ComEd to include, in the independent evaluation, an analysis to determine whether the incentive programs being offered as a condition of receiving the rebate are successful in encouraging customers to shift their electricity usage and charge their EVs during off-peak times to avoid straining the electric grid. Finally, ComEd is directed to engage an independent evaluator and shall implement the following evaluator independence protocols to ensure that evaluator independence is maintained in the evaluation of ComEd's BE Plan:

1. Any contract between ComEd and the independent evaluator shall provide that:
    a. The Commission has the right to direct ComEd to terminate the contract if the Commission determines the evaluators were not acting independently.
    b. The evaluators must act independently from ComEd and be able to independently evaluate ComEd's Beneficial Electrification Plan.
    c. All data used in the evaluations must be made available to the Commission or Commission Staff upon request.
    d. With the exception of communications related solely to contractual or other administrative issues, all written communications between the independent evaluator and ComEd (or contractor acting on ComEd's behalf) and/or

Commission Staff shall be copied to ComEd and Commission Staff.

e. With the exception of any phone, webinar, or in-person meetings related solely to contractual or other administrative issues, ComEd and Commission Staff will be made aware of, and invited to, all meetings between the independent evaluator and ComEd (or contractor acting on ComEd's behalf) and/or Commission Staff.

2. ComEd shall submit the finalized but not yet executed contract with the independent evaluator to the Commission by letter to the Executive Director. Commission Staff will submit a report to the Commission containing its assessment of the contract and/or scope of work and describing its recommendations for Commission action, if any. In addition, ComEd will submit any fully executed contract and scope of work with the independent evaluator as a compliance filing in ICC Docket Nos. 22-0432/22-0442 (Consol.) within fourteen (14) days of execution. Such compliance filing will be treated as public information, subject to redactions approved by the Commission of provisions deemed confidential.

3. Draft evaluation plans shall be shared with interested stakeholders for feedback.

4. Draft evaluation reports shall be shared with interested stakeholders for feedback.

5. ComEd shall file all final evaluation reports in ICC Docket Nos. 22-0432/22-0442 (Consol.) within fourteen (14) days of receipt.

6. ComEd shall provide its response to evaluator recommendations in its annual report.

IX. ANNUAL REPORTINIG

A. ComEd's Position

ComEd notes that it initially proposed annual reporting for the BE Plan to include general information on its progress related to the implementation and execution of each of the BE Plan programs and sub-programs. However, ComEd states that it has agreed with various parties, including Staff, to add a section in the compliance filing BE Plan on the annual report, which will include procedural details regarding when it will be filed, how it will be filed, and what information will be included in it. ComEd notes that it has also committed to including in the report the following information:

- A summary of the implementation, operation, and administration of the BE Plan as requested by Staff witness Jenkins.

- Aggregate information on the demographics of program and procurement applicants and beneficiaries, consistent with the direct testimony of ComEd witness Washington.

- General information related to the implementation and execution of each of the BE Plan Programs and sub-programs as listed in ComEd witness Washington's direct testimony.

- Information regarding ComEd's outreach and education efforts, particularly to eligible communities, as requested by Staff witness King.

- Information regarding "the availability and reliability of EVSE systems and EV charging stations" incentivized through ComEd's BE Plan, if ComEd requires recipients of incentives to report annual reliability information, as requested by Staff witness Balogun. ComEd Ex. 6.0 at 24, quoting Staff Ex. 5.0 at 3.

- A high-level budget summary and any changes to the budget, as requested by Staff witness Poon.

- kWh data for charging incentivized through the Residential EV Charging Infrastructure Sub-program, to the extent that data is available, and usage data for customers opting into the EV Charging Delivery Classes, to the extent that data is available, as requested by Staff witness Capellan and AG witnesses Borden and Lane.

- The estimated reduction in air emissions resulting from the BE Plan, as requested by AG witnesses Borden and Lane.

- The effectiveness of shifting load through the optimized charging pilot, to the extent possible, as requested by WeaveGrid witness Bell.

- Aggregate information regarding the number of charging sites, stations, ports, and types of charging stations incentivized for the sub-program incentivizing EV charging infrastructure.

- Anonymized and aggregate load profiles by charging use case if there are enough projects incentivized through the C&I and Public Sector EV Charging Infrastructure Make-ready sub-program. If this data is reported in other contexts, ComEd will cite to such data.

- ComEd also plans to report annually on the BE Pilot Program, including details on each specific pilot focus area, in the Annual Report.

- ComEd intends to include a high-level summary comparison of budget and actual costs for each program and sub-program in the annual report.

- ComEd also commits to explaining any changes to the budget in its annual report.

Finally, ComEd states that it agrees to complete the first annual report by April 1, 2024, which will provide stakeholders with preliminary information on the implementation of the current BE Plan in advance of the second BE Plan filing.

Several parties proposed that the annual report include information regarding the reliability of charging stations and equipment. ComEd argues that this proposal should not be adopted. First, it argues, much of the requested information is not available to ComEd, and several parties in this docket noted how onerous those reporting requirements would be for them. If these reporting requirements are implemented, ComEd contends, then charging station providers will have to track multiple different reporting requirements within a single state for their chargers, which makes it unnecessarily complicated to operate in Illinois and goes against the purpose of BE programs. Second, ComEd espouses charging station operators are incentivized to run their EV charging stations efficiently and effectively as their business models depend on that. Finally, ComEd argues that it would not be appropriate for it to play a supervisory role in these relationships with the charging station providers.

CJCP continue to recommend that ComEd provide data concerning interconnection timelines, including the average interconnection time for sites. ComEd opposes this recommendation as it does not differentiate between an EV station and any other new load in its service connection process. ComEd Ex. 11.0 REV. at 22.

B. Staff's Position

ComEd, the AG, WeaveGrid, and Staff all agree on the information that should be included in the annual report, with the exception of the Annual Reliability Report Requirements. Specifically, ComEd states that "[s]everal parties proposed that the Annual Report include information regarding the reliability of charging stations and equipment. This proposal should not be adopted." ComEd IB at 83. Staff interprets ComEd's statement to mean that ComEd might be the only stakeholder in this proceeding that is arguing against Staff's assertion that reliability standards will ensure a high degree of certainty to EV owners/public that the public chargers will be available and functioning when needed. Staff recommends that the Commission direct ComEd to modify its BE Plan to require annual reliability reports about the public charging stations that qualified and received incentives in its BE Plan. Staff IB at 25. Staff believes that this information will allow Staff, the Commission, and the public to know the state and the reliability of the public EV charging stations that qualified for and for which owner and operators received incentives under ComEd's BE Plan.

C. AG's Position

The AG states that ComEd did not agree to provide the entirety of the data requested by the AG, but in the interest of minimizing the contested issues in this proceeding, it requests that the Commission approve ComEd's annual reporting.

D. CJCP's Position

CJCP state that in order for a program to be successful – and to successfully inform future iterations of the BE plan – it is imperative that data be collected consistently and that data collected be of sufficient quantity and type to successfully inform those future iterations.

One data reporting category recommended by CJCP witness MacDougall, and rejected by ComEd, is data concerning interconnection timelines, including average interconnection time for sites, the number of rejected interconnection applications, and a summary of common reasons for rejected applications. CJCP contends that long interconnection timelines for charging infrastructure and rejected interconnection applications that force applicants to revise and resubmit their applications can be a significant burden for charging station developers and a source of significant delays in bringing new charging infrastructure online. Indeed, states CJCP, given that interconnection can take months, and in some cases years, a utility's failure to understand the extent to which interconnection can be a barrier to EV adoption – or to have a plan to mitigate that barrier with careful planning – might result in consumer hesitancy to adopt electric vehicles, ultimately stunting the vehicle market.

Despite this reality, ComEd rejected Dr. MacDougall's recommendation to include such interconnection data in its annual report, stating only that "ComEd has an obligation to serve all customers and does not differentiate between an EV station and any other new load in its new service connection process." ComEd Ex. 11.0 REV at 22. CJCP states this position demonstrates a failure to recognize the specific needs of EV charging customers — namely, that their significant capacity needs can arise in a comparatively short period of time, which gives rise to a unique mismatch between customers' needs and ordinary utility interconnection processes and makes utilities' timely attention to interconnection challenges critically important.

Per CJCP, Section 45(d)(8) of the EVA specifically requires the Commission to consider "whether the [utility] investments and other expenditures are designed and reasonably expected to… provide resources to support private investment in charging equipment…." 20 ILCS 627/45(d)(8). CJCP believe ComEd should be on notice that interconnection timelines are something that creates problems for charging customers everywhere else; minimal EV adoption in ComEd's service territory may have kept this issue from surfacing previously, but in light of the EVA it is only a matter of time before it does. As such, CJCP aver this Commission cannot reasonably find that a BE Plan that entirely ignores this issue can be "reasonably expected to…provide resources to support private investment" by would-be charging customers in the ComEd service territory. CJCP IB at 56.

Electrify America argues that the Commission should reject any "burdensome and unnecessary EVSP reporting requirements," and that it is "outside of the Commission's jurisdiction to impose reporting requirements upon EV charging station operators." Electrify America IB at 3, 35. Weave Grid similarly argues that neither ComEd nor EVSPs should be "obligated to report on data that would be expensive and difficult to obtain or otherwise not required by the [EVA]." Weave Grid IB at 24.

However, CJCP continue to point out that consistent collection and reporting of data is essential for ensuring that ComEd's BE Plan is meeting its goals and effectively deploying ratepayer funds, and for informing improvements to future iterations of the BE Plan. According to CJCP, where charging station operators are receiving ratepayer funds through the BE Plan, it is plainly within the Commission's power to direct ComEd to attach conditions to the receipt of those funds, including data reporting conditions. Further, CJCP state the fact that the EVA only specifically names a handful of data reporting categories does not change the Commission's ability to require additional categories, as the EVA lists the topics to be addressed in the BE Plan "at a minimum," 20 ILCS 627/45(d), making the list a floor, not a ceiling. Given the fact such reporting requirements are well within the Commission's and ComEd's authority as part of the BE Plan, and the value of such reporting for current and future BE Plans, CJCP states the Commission should reject the recommendations of Electrify America and WeaveGrid and require ComEd to adopt robust data reporting requirements as part of its BE Plan.

Finally, Staff recommends that the Commission should reject CJCP's recommendation that ComEd conduct a market potential study, distribution grid impact studies, and load research reports. Staff IB at 51-52. Clean Jobs Coalition Parties' recommendation is based on the need for data on the pace of transportation electrification and the impact this transition is having on ComEd's distribution grid as a whole and in specific areas. Staff argues that taking the recommended actions "would increase BE Plan costs" and is "more appropriate in the [MYIGP] Plan proceedings…." Staff IB at 51-52. Given Illinois' ambitious transportation electrification goals as outlined in the EVA, 20 ILCS 627/45(a), and the likely need for additional distribution grid investment to serve this new load, EDF Ex. 1.0 REV at 9, CJCP state it is important that ComEd and the Commission have an accurate picture of the pace of EV deployment and any resulting grid impacts, which the recommended market potential study, distribution grid impact studies, and load research reports would provide. Therefore, CJCP aver it is appropriate that the Commission direct ComEd to complete this work as part of its BE Plan.

E. WeaveGrid's Position

WeaveGrid supports ComEd's proposed annual reporting process. Specifically, WeaveGrid notes that ComEd incorporated stakeholder recommendations in its proposed annual public reporting process, including the recommendation of Staff to track and report kWh delivered to different categories of residential customers and highlighting program outcomes, as well as the AG's recommendation to share information related to rate options. WeaveGrid states its support for ComEd's annual report process outlined in ComEd Ex. 11.0.

F. Commission Analysis and Conclusion

ComEd has committed to many expanded reporting requirements requested by the parties. The Commission directs ComEd to describe in its compliance BE Plan the annual report process and all the information the Company committed to provide. Some reporting requirements remain contested.

The Commission finds CJCP's proposal that ComEd implement reporting requirements for average interconnection time for sites, the number of rejected interconnection applications, and a summary of common reasons for rejected applications

reasonable, and it is adopted. Collection and reporting of such data will help the Commission determine if ComEd's BE Plan is meeting its goals and effectively deploying ratepayer funds, and for informing improvements to future iterations of the BE Plan.

The Commission rejects CJCP's recommendation that ComEd conduct a market potential study, distribution grid impact studies, and load research reports as this is more appropriately addressed in the MYIGP Plan proceedings. *See* Section V.B.2.

With respect to Staff's proposed uptime reporting, the Commission adopts Staff's proposed uptime standard and reporting requirements.

The Commission further observes that the approved programs provide a unique, early opportunity to acquire information regarding community-specific customer electrification capabilities and needs as well as any localized distribution grid barriers to beneficial electrification. The Commission directs ComEd to capture and report any such information, finding that it can inform future electrification programs and MYIGP infrastructure investments. Among other information, ComEd is specifically directed to report on the number of applications, by customer class, received under Rider NS related to beneficial electrification and EV charging as well as the number of such applications that were withdrawn and successfully completed. ComEd shall also collect and report detailed information on the number, value and time frame of the deposits required under Rider DE related to the EV charging infrastructure and beneficial electrification.

X. FUTURE BE PLANS AND COMPLIANCE FILING

Staff and ComEd agree that the Commission should adopt in its final Order in this proceeding the following language detailing the stakeholder collaboration process leading up to the BE Plan Update filings (Staff Ex. 12.0 at 11-12; ComEd Ex. 11.0 REV at 25-26):

> ComEd is directed to continue to review and consider stakeholder feedback from the MYIGP process related to the BE Plan and it should incorporate that stakeholder feedback as appropriate in the BE Plan Update to be filed by July 1, 2024.
>
> In addition, in early April of 2024 ComEd is directed to meet with Staff and interested stakeholders, particularly those that have intervened in this docket, walk through the information in the annual report, discuss stakeholder feedback from the MYIGP process, answer questions, and share thoughts on changes or additions the Company is considering to the BE Plan for the July 1, 2024 BE Plan Update filing, including its ideas for subprogram-level budgets. ComEd will solicit input from stakeholders on the Company's suggested BE Plan changes and additions, including subprogram-level budgets, as well as any new ideas from stakeholders. ComEd will hold follow-up meetings with stakeholders in an attempt to resolve issues leading up to the BE Plan Update filing. ComEd is directed to meaningfully consider stakeholder feedback and work collaboratively with stakeholders in advance of the BE

Plan Update filing to reduce the number of contested issues in the docket.

ComEd will repeat this process for the July 1, 2027 BE Plan Update filing and subsequent update filings unless modified by the Commission.

Staff and ComEd also agree that the Commission should adopt the following compliance filing process (Staff Ex. 12.0 at 13-14; ComEd Ex. 11.0 REV at 24):

(a) ComEd will share a draft compliance BE Plan with Staff and Intervenors no later than five weeks following the Commission's final Order.

(b) Staff and Intervenors will provide ComEd comments, if any, on the draft compliance BE Plan regarding whether the draft compliance BE Plan accurately reflects the Commission's final order within two weeks following the receipt of the draft compliance BE Plan.

(c) ComEd will file a compliance BE Plan in this proceeding no later than four weeks following the date it shares its draft compliance BE Plan with Staff and Intervenors.

The Commission adopts the stakeholder collaboration process and the compliance filing process as agreed by ComEd and Staff.

XI. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having considered the entire record herein and being fully advised in the premises, is of the opinion and finds that:

(1) Commonwealth Edison Company is an Illinois corporation engaged in the sale and distribution of electricity in the State of Illinois and, as such, is a public utility within the meaning of Section 3-105 of the Act;

(2) the Commission has jurisdiction over Commonwealth Edison Company and the subject matter of this proceeding;

(3) the facts and conclusions reached in this Order are supported by the record and are hereby adopted as findings of fact and conclusions of law;

(4) Commonwealth Edison Company's proposed BE Plan as modified herein is reasonable and meets the statutory requirements and policy goals of the EVA;

(5) Commonwealth Edison Company should implement the additional reporting requirements as adopted herein;

(6) Commonwealth Edison Company will share a draft compliance BE Plan with Staff and Intervenors no later than five weeks following the Commission's final Order; Staff and Intervenors will provide Commonwealth Edison Company comments, if any, on the draft compliance BE Plan regarding whether the draft compliance BE Plan accurately reflects the Commission's final order within two weeks following the receipt of the draft compliance BE Plan;

(7) Commonwealth Edison Company will file a compliance BE Plan in this proceeding no later than four weeks following the date it shares its draft compliance BE Plan with Staff and Intervenors; and

(8) Commonwealth Edison Company's proposed BE Plan as modified herein is cost-beneficial and in the public interest.

IT IS THEREFORE ORDERED by the Commission that Commonwealth Edison Company shall implement the BE Plan as approved by this Order.

IT IS FURTHER ORDERED that Commonwealth Edison Company is directed to implement the additional reporting requirements as adopted herein.

IT IS FURTHER ORDERED that Commonwealth Edison Company will share a draft compliance BE Plan with Staff and Intervenors no later than five weeks following the Commission's final Order; Staff and Intervenors will provide Commonwealth Edison Company comments, if any, on the draft compliance BE Plan regarding whether the draft compliance BE Plan accurately reflects the Commission's final order within two weeks following the receipt of the draft compliance BE Plan.

IT IS FURTHER ORDERED that Commonwealth Edison Company will file a compliance BE Plan in this proceeding no later than four weeks following the date it shares its draft compliance BE Plan with Staff and Intervenors.

IT IS FURTHER ORDERED that Commonwealth Edison Company shall file tariff revisions necessary to implement the BE Plan as discussed in this Order.

IT IS FURTHER ORDERED that any motions, petitions, objections, or other matters in this proceeding that remain outstanding are hereby disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that pursuant to Section 10-113(a) of the Public Utilities Act and 83 Ill. Adm. Code 200.880, any application for rehearing shall be filed within 30 days after service of the Order on the party.

IT IS FURTHER ORDERED that, subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By Order of the Commission this 23rd day of March, 2023.

(SIGNED) CARRIE ZALEWSKI

Chairman

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 17-05 November 30, 2017

Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, Pursuant to G.L. c. 164, § 94 and 220 CMR 5.00 et seq., for Approval of General Increases in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Mechanism.

ORDER ESTABLISHING EVERSOURCE'S REVENUE REQUIREMENT

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I. INTRODUCTION

On January 17, 2017, NSTAR Electric Company ("NSTAR Electric")[1] and Western Massachusetts Electric Company ("WMECo"), each doing business as Eversource Energy (collectively, "Eversource" or "Companies") filed a petition with the Department of Public Utilities ("Department") seeking approval of increases in base distribution rates for electric service pursuant to G.L. c. 164, § 94 ("Section 94"), as well as other proposals. NSTAR Electric's last base distribution rate proceeding was in 2005. Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company, NSTAR Gas Company, D.T.E. 05-85 (2005). WMECo's last base distribution rate proceeding was in 2010. Western Massachusetts Electric Company, D.P.U. 10-70 (2011).

At the time of the initial filing in this matter, NSTAR Electric and WMECo existed as individual, wholly owned subsidiaries of Eversource Energy (Exh. ES-GMBC-1, at 24). However, the subsidiaries were operated on a fully consolidated basis, with two geographic areas designated as "Eversource East" (NSTAR Electric's service area) and "Eversource West" (WMECo's service area) (Exh. ES-GMBC-1, at 24). The service area designated as Eversource East encompasses the City of Boston and surrounding communities, extending west to Sudbury, Framingham, and Hopkinton, as well as communities in southeastern Massachusetts extending from Marshfield, south through Plymouth, Cape Cod, and Martha's Vineyard, and west through New Bedford and Dartmouth (Exh. ES-GMBC-1, at 24). Within

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[1] NSTAR Electric is comprised of three operating units – Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company (Exh. ES-RDP-1, at 5). See also BEC Energy/Commonwealth Energy Systems, D.T.E. 99-19 (1999).

this geographic area, NSTAR Electric serves approximately 1.2 million residential and commercial and industrial ("C&I") customers in approximately 80 communities, covering approximately 1,700 square miles (Exh. ES-GMBC-1, at 24-25).

The service area designated as Eversource West encompasses the City of Springfield and surrounding communities, extending west to the New York border and north to Greenfield and the Vermont border (Exh. ES-GMBC-1, at 25). Within this geographic area, WMECo serves approximately 209,000 residential and C&I customers in approximately 59 communities in western Massachusetts, covering approximately 1,500 square miles (Exh. ES-GMBC-1, at 25).

In the instant case, Eversource seeks to increase NSTAR Electric's rates to generate $56.1 million in additional revenues, an approximate 6.6 percent increase over current total operating revenues (Exh. ES-DPH-2 (East), Sch. DPH-1 (Rev. 4)).[2] Eversource seeks to increase WMECo's rates to generate $34.7 million in additional revenues, an approximate 25.4 percent increase over current operating revenues (Exh. ES-DPH-2 (West), Sch. DPH-1 (Rev. 4)).[3] The cost of service component of the Companies' filing is based on a test year of July 1, 2015 through June 30, 2016 (Exhs. ES-CAH-1, at 8; ES-DPH-1, at 8).

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[2] In its initial filing, Eversource sought to increase NSTAR Electric's rates to generate $60.2 million, a seven percent increase over current operating revenues (Exh. ES-DPH-2 (East), Sch. DPH-1). Eversource revised the proposed increase during the course of this proceeding.

[3] In its initial filing, Eversource sought to increase WMECo's rates to generate $35.7 million, a 27 percent increase over current operating revenues (Exh. ES-DPH-2 (West), Sch. DPH-1). Eversource revised the proposed increase during the course of this proceeding.

The Companies' requested rate increase includes the recovery of merger-related costs and, for WMECo, exogenous costs associated with a settlement approved by the Department in NSTAR/Northeast Utilities Merger, D.P.U. 10-170 (2012) and discussed below in additional sections of this Order. The Companies also request approval, pursuant G.L. c. 164, § 96 ("Section 96"), to complete the corporate consolidation of NSTAR Electric and WMECo. Further, NSTAR Electric proposes, pursuant to Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50-A (2008), to implement a rate mechanism to decouple its electric revenues from its sales.

The Companies also propose to implement a performance-based ratemaking ("PBR") mechanism that would allow each company to adjust its distribution rates on an annual basis through the application of a revenue-cap formula. Within the PBR mechanism, the Companies propose to undertake $400 million in incremental capital investments over the next five years on projects the Companies state are designed to integrate distributed energy resources and improve service reliability, including projects to develop electric vehicle infrastructure and electric-storage capabilities. The Companies also propose to implement a credit/debit card payment system that will allow customers to pay their bills electronically without a transaction fee. Further, the Companies propose to make certain changes to their existing storm fund mechanisms, vegetation management programs, and methods used to recover property taxes.

Finally, the Companies' initial filing included a number of rate design proposals, including the elimination of separate rates for NSTAR Electric's three operating units (i.e., Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company) and the establishment of one rate for each rate class; the consolidation and alignment of NSTAR Electric's and WMECo's general service rate classes; the consolidation of a number of reconciling mechanism rates; the introduction of a new optional time-of-use rate (rate G-5) for certain small general service (rate G-1) customers; and the implementation of a monthly minimum reliability contribution ("MMRC") rate for new customers seeking to install distributed generation. In their initial filing, the Companies did not propose to consolidate the distribution rates of NSTAR Electric and WMECo. On June 1, 2017, the Companies filed a revised rate design proposal that contained several key differences from the Companies' initial filing. In particular, the Companies now propose to: (1) consolidate the revenue requirements of NSTAR Electric and WMECo for rates effective January 1, 2018 and January 1, 2019; (2) maintain existing rate classes, using legacy cost allocation studies, for rates effective January 1, 2018; (3) consolidate rate classes and rates for NSTAR Electric's and WMECo's residential customers effective January 1, 2019; (4) retain rate class WR in 2019; and (5) modify the proposed transmission revenue allocation and rate design, the low-income discount, and certain components of the MMRC rate.

The Department docketed this matter as D.P.U. 17-05 and suspended the effective date of the proposed rate increases to investigate the propriety of the Companies' request. The Companies have requested that any new rates approved in this proceeding be

implemented in two phases, with the first phase to take effect on January 1, 2018, and the second phase to take effect on January 1, 2019.

II. PROCEDURAL HISTORY

On January 25, 2017, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a notice of intervention pursuant to G.L. c. 12, § 11E (a). The following entities were granted full party intervenor status: (1) Acadia Center; (2) Associated Industries of Massachusetts ("AIM"); (3) the City of Cambridge; (4) the towns of Aquinnah, Barnstable, Bourne, Brewster, Chatham, Chilmark, Dennis, Edgartown, Eastham, Falmouth, Harwich, Mashpee, Oak Bluffs, Orleans, Provincetown, Sandwich, Tisbury, Truro, West Tisbury, Wellfleet, and Yarmouth, as well as Barnstable County and Dukes County, acting together as the Cape Light Compact (collectively, "Cape Light Compact"); (5) Conservation Law Foundation ("CLF"); (6) Department of Energy Resources ("DOER"); (7) the Federal Executive Agencies ("FEA"); (8) Low-Income Weatherization and Fuel Assistance Program Network and the Massachusetts Energy Directors Association ("Low Income Network"); (9) Northeast Clean Energy Council ("NECEC"); (10) Retail Energy Supply Association ("RESA"); (11) The Energy Consortium ("TEC"); (12) University of Massachusetts ("UMass"); and (13) Western Massachusetts Industrial Group ("WMIG").

The following entities were granted limited intervenor status: (1) the Town of Barnstable; (2) Cape and Vineyard Electric Cooperative ("CVEC"); (3) ChargePoint, Inc. ("ChargePoint"); (4) Choice Energy, LLC ("Choice Energy"); (5) Direct Energy Business,

LLC, Direct Energy Business Marketing, LLC, Direct Energy Services, LLC, and Direct Energy Solar, LLC (collectively, as "Direct Energy"); (6) the Energy Consumers Alliance of New England, Inc., d/b/a Massachusetts Energy Consumers Alliance ("Mass. Energy") and the Sierra Club; (7) the City of Newton and the Towns of Arlington, Lexington, Natick and Weston ("Municipalities"); (8) PowerOptions, Inc. ("PowerOptions"); (9) Sunrun, Inc. ("Sunrun") and the Energy Freedom Coalition of America, LLC ("EFCA"); and (10) Vote Solar.[4] Finally, the following entities were granted limited participant status: (1) The Berkshire Gas Company; (2) Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid; (3) the Massachusetts Water Resources Authority; (4) Microgrid Resources Coalition; (5) the Union of Concerned Scientists; and (6) Wal-Mart Stores East, LP.

Pursuant to notice duly issued on January 30, 2017, the Department held ten public hearings in the Companies' service areas: (1) in Natick on March 22, 2017; (2) in Boston on March 23, 2017; (3) in Cambridge on March 30, 2017; (4) in Barnstable on April 3, 2017; (5) in New Bedford on April 5, 2017; (6) in Plymouth on April 6, 2017; (7) in Pittsfield on April 10, 2017; (8) in Springfield on April 12, 2017; (9) in Tisbury on April 24, 2017; and (10) in Greenfield on April 26, 2017. The Department also received written comments from numerous public officials and NSTAR Electric and WMECo ratepayers.

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[4] Regarding intervention and limited intervention, see D.P.U. 17-05, Hearing Officer Ruling on Petitions for Intervention at 6-8 (July 17, 2017); D.P.U. 17-05, Hearing Officer Ruling on Petitions for Intervention at 5-9 (March 13, 2017).

On June 9, 2017, the Department issued an Interlocutory Order that allowed for additional public hearings, discovery, and testimony addressing the investigation of the Companies' revised rate design proposal. D.P.U. 17-05, Interlocutory Order at 13-14 (June 9, 2017) ("Interlocutory Order"). Pursuant to the Interlocutory Order, the Department will issue a separate Order to address rate design issues. Interlocutory Order at 14.[5]

Pursuant to notice duly issued on June 23, 2017, the Department held three additional public hearings in the Companies' service area to receive comment on the revised rate design proposal: (1) in Boston on July 26, 2017; (2) in Pittsfield on August 1, 2017; and (3) in Barnstable on August 2, 2017. The Department also received additional written comments from public officials and NSTAR Electric and WMECo ratepayers.

The Department held 15 days of evidentiary hearings from June 7, 2017, through June 29, 2017, to address the non-rate design issues raised in the Companies' initial filing. The Department held four days of evidentiary hearings from September 11, 2017 through September 14, 2017, to address all aspects of the Companies' initial and revised rate design proposals.

In support of the Companies' filings, the following witnesses, all of whom are employed by Eversource Energy Service Company ("ESC"), have provided testimony: (1) Craig Hallstrom, President, Regional Electric Operations for Massachusetts and

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[5] Based on the revenue requirements approved in this Order, the Department directs the Companies to provide updated allocated cost of service studies and bill impacts in the same format as set forth in responses to Record Requests DPU-49 and DPU-50. This update will be provided for illustrative purposes only. The Companies shall make this filing within five (5) business days of this Order.

Connecticut; (2) Penelope M. Conner, Chief Customer Officer and Senior Vice President; (3) Douglas P. Horton, Director, Revenue Requirement – Massachusetts; (4) Paul R. Renaud, Vice President of Engineering-Massachusetts; (5) Jennifer A. Schilling, Director of Strategy and Performance; (6) Samuel G. Eaton, Project Director, Electric Vehicle Charging and Energy Storage; (7) Sasha Lazor, Director, Compensation; (8) Michael P. Synan, Director, Benefits Strategy; (9) Vera L. Admore-Sakyi, Director, Vegetation Management; (10) Leanne M. Landry, Director, Budget and Investment Planning; (11) Edward A. Davis, Director of Rates; (12) Richard D. Chin, Manager of Rates; (13) Jessica Cain, Vice President of Customer Operations; and (14) Karen Hodge, Manager of Load Settlement and Analysis. In addition, the following outside consultants provided testimony on behalf of the Companies: (1) Mark E. Meitzen, Ph.D, Vice President, Christensen Associates; (2) Dennis L. Weisman, Professor Emeritus of Economics, Kansas State University; (3) Carl G. Degen, President, Christensen Associates; (4) Robert B. Hevert, Partner, ScottMadden, Inc.; (5) John J. Spanos, Senior Vice President, Gannett Fleming Valuation and Rate Consultants LLC; (6) James D. Simpson, Senior Vice President, Concentric Energy Advisors; (7) David A. Heintz, Vice President, Concentric Energy Advisors; and (8) Melissa F. Bartos, Assistant Vice President, Concentric Energy Advisors.

The Attorney General sponsored the testimony of the following witnesses: (1) David Dismukes, Ph.D., Consulting Economist, Acadian Consulting Group; (2) J. Randall Woolridge, Ph.D., Professor of Finance, Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration at the University

Park Campus of the Pennsylvania State University; (3) David Effron, Consultant, Berkshire Consulting Services; (4) Donna Ramas, Principal, Ramas Regulatory Consulting, LLC; (5) Gregory L. Booth, P.E., President, PowerServices, Inc., UtilityEngineering, Inc., and Booth, PLLC; (6) Scott J. Rubin, independent consultant; and (7) William W. Dunkel, Principal, William Dunkel and Associates.

Acadia Center sponsored the testimony of: (1) Abigail Anthony, Ph.D., former Director, Grid Modernization Initiative, Rhode Island; and (2) Mark LeBel, Staff Attorney, Acadia Center. The Town of Barnstable sponsored the testimony of: (1) Douglas N. Riley, Esq.; and (2) Daniel Wolf, Chief Executive Officer, Cape Air. The City of Cambridge sponsored the testimony of Stephen J. Lenkauskas, City Electrician.

CVEC sponsored the testimony of: (1) Paul Gromer, president, Peregrine Energy Group; (2) Jennifer Rand, Town Administrator, West Tisbury; and (3) Carol A. Woodbury, Superintendent of Schools, Dennis-Yarmouth Regional School District. Cape Light Compact sponsored the testimony of: (1) Paul L. Chernick, president, Resource Insight, Inc.; (2) Kevin F. Galligan, president, Galligan Energy Consulting, Inc.; (3) Karl R. Rábago, Executive Director, Pace Energy and Climate Center at the Elisabeth Haub School of Law; and (4) Jonathan F. Wallach, Vice President, Resource Insight, Inc.

ChargePoint sponsored the testimony of Michael K. Waters, Director, Utility Solutions (East), ChargePoint. CLF, Mass. Energy, and the Sierra Club jointly sponsored the testimony of Douglas B. Jester, Partner, 5 Lakes Energy LLC. FEA sponsored the testimony of: (1) Michael P. Gorman, Managing Principal, Brubaker & Associates, Inc.;

and (2) Amada M. Alderson, Senior Consultant, Brubaker & Associates, Inc. The Municipalities sponsored the testimony of: (1) William H. Ferguson, Energy Program Manager, City of Newton; (2) Mark Sandeen, Managing Director, RePower Partners LLC; (3) Jillian Wilson-Martin, Sustainability Coordinator, Town of Natick; and (4) Donna VanderClock, Town Manager, Town of Weston.

RESA sponsored the testimony of Frank Lacey, independent consultant. Sunrun and EFCA jointly sponsored the testimony of: (1) Tim Woolf, Vice President, Synapse Energy Economics; (2) Melissa Whited, Senior Associate, Synapse Energy Economics; and (3) David J. Garrett, Managing Member, Resolve Utility Consulting, PLLC. TEC sponsored the testimony of James D. Bride, Principal, Energy Tariff Experts, LLC.

UMass sponsored the testimony of: (1) Raymond Jackson, Director, Physical Plant Division, UMass; (2) Michael McGerigle, Deputy Director, Facilities, UMass; and (3) Richard Silkman, Ph.D., Chief Executive Officer, Competitive Energy Services, LLC. Finally, Vote Solar sponsored the testimony of: (1) Ronald J. Binz, public policy consultant; and (2) Nathan Phelps, Program Manager, Distributed Generation Regulatory Policy, Vote Solar.

Following the June 2017 evidentiary hearings, the following parties filed initial and reply briefs: (1) Eversource; (2) Acadia Center; (3) the Attorney General; (4) Cape Light Compact; (5) ChargePoint; (6) Choice Energy; (7) DOER; (8) FEA; (9) Low Income Network; (10) Mass. Energy and the Sierra Club; (11) NECEC; (12) RESA; (13) Sunrun and

EFCA; (14) Vote Solar; and (15) WMIG and TEC. The following parties filed only initial briefs: (1) AIM; (2) CLF; and (3) UMass.

Following the September 2017 rate design-related hearings, the following parties filed initial and reply briefs related to rate design issues: (1) Eversource; (2) Acadia Center; (3) Attorney General; (4) Cape Light Compact; (5) City of Cambridge; (6) CVEC; (7) DOER; (8) FEA; (9) Low Income Network; (10) Municipalities; (11) NECEC; (12) Sunrun and EFCA; (13) TEC; (14) Town of Barnstable; (15) UMass; (16) Vote Solar; and (17) WMIG.

The evidentiary record includes responses to 242 sets of information requests issued to the Companies, intervenors, and limited intervenors and responses to 111 record requests.

III. VERIFICATION OF NSTAR ELECTRIC'S ANNUAL RETURNS AND DISTRIBUTION RATE BASE ASSETS

A. Introduction

Pursuant to a settlement between the Companies, DOER, and NSTAR Gas Company ("NSTAR Gas") ("DOER Settlement") approved in D.P.U. 10-170 (see also Sections V.A and VIII.M below),[6] NSTAR Electric was required to file with the Department an independent study that included: (1) an examination and verification of the annual returns to the Department for the four-year period ending December 31 of the test-year period; and (2) verification of the assets contained in NSTAR Electric's distribution rate base as of the test year end, developed through a systematic review as described in the National Association of Regulatory Commissioners ("NARUC") Rate Case and Audit Manual (DOER Settlement

[6] Pursuant to 220 CMR 1.10(3), the Department incorporates by reference the DOER Settlement filed and approved in D.P.U. 10-170-B.

at Art. 3.3 & n.1). In its decision approving the DOER Settlement, the Department directed NSTAR Electric to submit the required information by April 15, 2015, or 60 days prior to the filing of its next base rate case, whichever occurred first. D.P.U. 10-170-B at 3, 66.

Pursuant to the DOER Settlement, the examination and verification of NSTAR Electric's annual returns and the verification of the company's distribution rate base assets was to be conducted by an independent accounting firm identified through a competitive bid process conducted by NSTAR Electric in consultation with the Attorney General and DOER (DOER Settlement at Art. 3.3). More specifically, the Attorney General and DOER were to select the independent accounting firm, subject to the consent of NSTAR Electric (DOER Settlement at Art. 3.3). The costs of the independent study would not be eligible for rate recovery (DOER Settlement at Art. 3.3).

With respect to the examination and verification of NSTAR Electric's annual returns, the selected independent accounting firm was tasked to verify the mathematical accuracy of the returns; verify that the operating costs reported in the annual returns reconcile to NSTAR Electric's financial statements, including, but not limited to, the company's audited income statement and balance sheet; and confirm that the annual returns were rendered in accordance with regulatory accounting standards and requirements, as applicable (DOER Settlement at Art. 3.3).

Regarding the verification of NSTAR Electric's distribution rate base assets, the systematic review was to include a comprehensive listing of assets, and include a verification of assets in plant-in service, plant held for future use, construction work in progress,

gains/losses from property sales, and acquisition adjustments/goodwill (DOER Settlement at Art. 3.3 n.1).

Finally, as part of its decision in D.P.U. 10-170, the Department directed NSTAR Electric to provide the following additional information, traceable to the annual returns, for calendar years 2012 through 2015:[7] (1) total operations and maintenance ("O&M") expense; (2) depreciation and amortization; (3) taxes other than income taxes; (4) income taxes; (5) total plant in service; (6) rate of return; and (7) total operating revenues by rate component. D.P.U. 10-170-B at 23, 66.[8]

Following a competitive bid process, Ernst & Young, LLP ("Ernst & Young") was selected to perform the independent accounting study of NSTAR's Electric's annual returns and distribution rate base assets (Exh. ES-DPH-1, at 8, 11-12). On April 15, 2015, NSTAR Electric submitted the verification of its annual returns performed by Ernst & Young for calendar years 2010 through 2014 (Exhs. ES-DPH-1, at 10; ES-DPH-4, Sch. DPH-2, at 56-60). On October 30, 2015, following extensions granted by the Department, NSTAR Electric submitted: (1) the rate base examination performed by Ernst & Young as of December 31, 2014; and (2) information regarding the aforementioned seven categories of

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[7] As part of its decision in D.P.U. 10-170, the Department approved a base rate freeze applicable to the distribution rates of NSTAR Electric, NSTAR Gas, and WMECo, so that base rates in effect on January 1, 2012, remained in place until January 1, 2016. D.P.U. 10-170-B at 18-19, 107.

[8] For purposes of this additional information, the Department directed NSTAR Electric to provide the information separately for each of its component companies: Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company. D.P.U. 10-170-B at 66 n.67.

financial information for calendar years 2012 through 2015 (Exhs. ES-DPH-1, at 10; ES-DPH-4, Sch. DPH-2, at 5-27, 76-79). On November 15, 2016, NSTAR Electric submitted Ernst & Young's verification of the company's 2015 annual return (Exhs. ES-DPH-1, at 11; ES-DPH-4, Sch. DPH-2, at 66-70). The same day, NSTAR Electric submitted the rate base examination performed by Ernst & Young updated through June 30, 2016, the end of the test year in this case, and information regarding the seven categories of financial information, also updated through June 30, 2016 (Exhs. ES-DPH-1, at 11; ES-DPH-4, Sch. DPH-2, at 34-49, 81-82).

B. Positions of the Parties

On brief, the Companies summarize the scope and results of Ernst & Young's work and, in particular, note that the verification of the assets in NSTAR Electric's distribution rate base supports the company's rate base computation used to develop its cost of service (Companies Brief at 152-156). Thus, the Companies assert that Ernst & Young's examination of NSTAR Electric's rate base assets provides an independent verification that the company's computed rate base is accurate and appropriate to use in computing NSTAR Electric's revenue requirement (Companies Brief at 156). No other party addressed the independent accounting study of NSTAR Electric's annual returns and distribution rate base assets.

C. Analysis and Findings

1. Retention of Ernst & Young

As noted above, the examination and verification of NSTAR Electric's annual returns and the verification of the company's distribution rate base assets was to be conducted by an independent accounting firm identified through a competitive bid process conducted by NSTAR Electric in consultation with the Attorney General and DOER (DOER Settlement at Art. 3.3). The record shows that NSTAR Electric developed a request for proposals ("RFP") in consultation with DOER and the Attorney General, and the RFP was issued to five national accounting firms (Exh. ES-DPH-1, at 11). NSTAR Electric subsequently received two qualifying bids in response to the RFP (Exh. ES-DPH-1, at 11). NSTAR Electric, DOER, and the Attorney General agreed to retain Ernst & Young (Exh. ES-DPH-1, at 11). Based on the foregoing, the Department finds that NSTAR Electric complied with the requirements of the DOER Settlement by working with the Attorney General and DOER and selecting Ernst & Young through a competitive bidding process (Exh. ES-DPH-1, at 11-12). Further, we note that the Companies have not included for recovery in this proceeding any expenses associated with Ernest & Young's scope of work.

2. Examination and Verification of NSTAR Electric's Annual Returns

With respect to the examination and verification of NSTAR Electric's annual returns, the record shows that Ernst & Young analyzed NSTAR Electric's annual returns and Federal Energy Regulatory Commission ("FERC") Form 1 filings for the years ending December 31, 2010 through December 31, 2015 (Exh. ES-DPH-4, Sch. DPH-2, at 56-60, 66-70). More specifically, for each of the foregoing years, Ernst & Young agreed the balance sheets and

income statements found in NSTAR Electric's FERC Form 1 filings with those found in the company's general ledger (Exh. ES-DPH-4, Sch. DPH-2, at 59, 69). Next, Ernst & Young traced NSTAR Electric's general ledger back to the audited financial statements for each subject year, and considered any differences or reclassifications from the audited financial statements to the FERC Form 1 filings (Exh. ES-DPH-4, Sch. DPH-2, at 59, 69). In addition, Ernst & Young confirmed the mathematical accuracy and internal consistency of the FERC Form 1 filings (Exh. ES-DPH-4, Sch. DPH-2, at 59, 69).

For each of the subject years, Ernst & Young also analyzed the calculations of NSTAR Electric's return on equity (or "ROE") as they appeared in the FERC Form 1 filings (Exh. ES-DPH-4, Sch. DPH-2, at 59, 69). More specifically, Ernst & Young agreed the revenue and expense items contained within the return calculation to the corresponding FERC Form 1 income statement (Exh. ES-DPH-4, Sch. DPH-2, at 59, 69). Next, Ernst & Young agreed the asset and equity items contained within the return calculation to the corresponding FERC Form 1 balance sheet (Exh. ES-DPH-4, Sch. DPH-2, at 59, 69). In addition, Ernst & Young recalculated applicable allocation factors, average balances, and the ROE percentage (Exh. ES-DPH-4, Sch. DPH-2, at 59, 69).

As a standard for guidance in analyzing NSTAR Electric's annual ROE calculation, Ernst & Young used the Department's April 3, 2003, letter to gas and electric distribution companies, which sets forth the manner in which an electric distribution company's ROE should be calculated (Exh. ES-DPH-4, Sch. DPH-2, at 59, 69; see also Department Letter Re: Annual Returns (April 3, 2003)). Ernst & Young determined that NSTAR Electric's

calculation of total common equity was not fully consistent with the Department's guidelines, as NSTAR Electric neglected to make a necessary adjustment in deriving total proprietary capital (Exh. ES-DPH-4, Sch. DPH-2, at 59-60, 69-70). However, Ernst & Young noted that the effect of such an adjustment was modest, with "minimal effect on the average rate of return" for the 2010-2015 period (Exh. ES-DPH-4, Sch. DPH-2, at 59-60, 69-70).[9]

Based on the foregoing, the Department finds that the scope of work performed by Ernst & Young was sufficient to verify the mathematical accuracy of NSTAR Electric's annual returns and to verify that the operating costs reported in the annual returns reconcile to NSTAR Electric's financial statements. Further, Ernst & Young's examination was sufficient to confirm whether the annual returns were rendered in accordance with regulatory accounting standards and requirements. The Department also accepts Ernst & Young's corrections to NSTAR Electric's earned ROE calculations for proprietary capital, and further note that these corrections have a negligible effect on NSTAR Electric's earned ROE as reported to the Department (Exh. ES-DPH-4, Sch. DPH-2, at 60). Accordingly, the Department concludes that Ernst & Young's examination and verification of NSTAR Electric's annual returns complies with the requirements set forth in the DOER Settlement (DOER Settlement at Art. 3.3). The Department directs the Companies, going forward, to

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[9] Specifically, the average ROE reported on the FERC Form 1 for the years 2010 through 2015 is 11.39 percent, while the average ROE for the same period taking into account the adjustment associated with total proprietary capital is 11.41 percent (see Exh. ES-DPH-4, Sch. DPH-2, at 60, 70). Ernst & Young notes that it did not consider the impact, if any, of verification of NSTAR Electric's rate base assets on the annual return analysis or ROE calculation (Exh. ES-DPH-4, Sch. DPH-2, at 60, 70).

revise their calculation of total utility common equity in a manner consistent with the Department's April 3, 2003, letter.

3. Verification of the Assets in NSTAR Electric's Distribution Rate Base

As noted above, Ernst & Young also was retained to verify the assets in NSTAR Electric's distribution test year end rate base (DOER Settlement at Art. 3.3). The record shows that Ernst & Young conducted a comprehensive review of NSTAR's Electric's plant in service, which included physically observing assets; comparing and corroborating accounting records and asset operating systems; testing sample work orders to confirm accurate and timely updating of accounting and operating systems and appropriate recording of assets; identifying "unusual items" that required further investigation; applying general analytics to the reasonableness of unit costs of various assets over time; and validating the cost of general plant by analyzing the related work orders and agreeing the work order amounts to the balances in the accounting records (Exh. ES-DPH-4, Sch. DPH-2, at 10-21, 39-43). Ernst & Young also confirmed, through review and analysis of supporting documentation, the accuracy of other items in NSTAR Electric's distribution rate base, including plant held for future use, gains and losses, accumulated depreciation, and accumulated deferred income taxes (Exh. ES-DPH-4, Sch. DPH-2, at 7, 21-25, 36, 44-46). The record shows that Ernst & Young conducted this systematic review in a manner consistent with the NARUC audit manual (Exh. ES-DPH-4, Sch. DPU-2, at 9, 38).

Based on its examination, Ernst & Young identified small discrepancies in quantities and types of assets, but no errors that would materially affect the assets in NSTAR Electric's

distribution rate base (Exh. ES-DPH-4, Sch. DPH-2, at 7, 25, 36, 47). Ernst & Young attributed the discrepancies to the early vintage of many of the assets and the different methodology for maintaining records between NSTAR Electric's accounting and operating systems (Exh. ES-DPH-4, Sch. DPH-2, at 7, 25).

Ernst & Young made a number of recommended adjustments to costs to correct for the aforementioned discrepancies. In particular, Ernst & Young recommended that: (1) certain assets should be retired totaling $11,301,550 (see Exhs. ES-DPH-4, Sch. DPH-2, at 7, 13, 16; ES-DPH-3 (East), WPs DPH-28, at 3, DPH-29); (2) certain assets should be reclassified between accounts totaling $6,651,075 (Exhs. ES-DPH-4, Sch. DPH-2, at 20, 27, 36, 40; ES-DPH-3 (East), WP DPH-28, at 3); and (3) certain assets should be removed from plant in service totaling $418,733 (see Exhs. ES-DPH-4, Sch. DPH-2, at 2, 36-37, 40; ES-DPH-3 (East), WP DPH-28, at 3). The record shows that the Companies incorporated these corrections into NSTAR Electric's plant in service and depreciation and amortization reserve accordingly (Exhs. ES-DPH-1, at 14; ES-DPH-3 (East), WPs DPH-28, at 3, DPH-29).

Based on the foregoing, the Department finds that Ernst & Young conducted a systematic review of the assets in NSTAR Electric's test year end distribution rate base, which included a comprehensive listing of assets, and a verification of assets in plant in service, plant held for future use, construction work in progress, gains/losses from property sales, and acquisition adjustments/goodwill, in a manner consistent with the NARUC audit manual. Accordingly, the Department concludes that Ernst & Young's verification of the

assets in NSTAR Electric's distribution rate base complies with the requirements set forth in the DOER Settlement (DOER Settlement at Art. 3.3).

4. Other Information

Pursuant to the Department's Order approving the DOER Settlement, NSTAR Electric provided the following information for 2012 through the end of the test year in this case: (1) total O&M expense; (2) depreciation and amortization; (3) taxes other than income taxes; (4) income taxes; (5) total plant in service; (6) rate of return; and (7) total operating revenues by rate component (Exh. ES-DPH-4, Sch. DPH-2, at 76-79, 81-82). See also D.P.U. 10-170-B at 66. Further, for each category, NSTAR Electric provided the applicable reference in the FERC Form 1 (Exh. ES-DPH-4, Sch. DPH-2, at 76, 81). The Department has reviewed this information, and we find that NSTAR Electric has substantially complied with the directives set forth in D.P.U. 10-170-B.[10]

IV. COMPANIES' USE OF A SPLIT TEST YEAR

A. Introduction

The cost of service component of the Companies' filing is based on a test year of July 1, 2015, through June 30, 2016, a non-calendar or "split" test year (Exhs. ES-CAH-1,

[10] In its approval of the DOER Settlement, the Department directed NSTAR Electric to provide this information separately for each of its three component companies (i.e., Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company). D.P.U. 10-170-B at 66 n.67. In response, NSTAR Electric noted that it had ceased separate tracking and reporting for its legacy operating companies as of January 1, 2007 (Exh. ES-DPH-4, Sch. DPH-2, at 76). In view of the unavailability of legacy company-specific data and the fact that NSTAR Electric began operations as a single corporate entity effective January 1, 2007, the Department accepts this information in the format provided.

at 8; ES-DPH-1, at 8).[11] Non-calendar test years have, on occasion, been accepted by the Department. See, e.g., Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 15-155, at 21-22 (2016); Plymouth Water Company, D.P.U. 14-120, at 16 (2015); Milford Water Company, D.P.U. 12-86, at 1 (2013). However, the Department has expressed its strong preference for a calendar year test year and has noted that any company that seeks to rely on a split test year faces a high burden to demonstrate as a threshold matter that its proposed test year is reviewable and reliable and represents a full accounting of the company's operations for the period. D.P.U. 14-120, at 16 & n.11.

In support of its split test year filing, the Companies retained the accounting firm of Deloitte & Touche LLP ("Deloitte & Touche") to review the Companies' operations and verify the accuracy of its non-calendar year test year financial data (Exhs. ES-DPH-1, at 9, 15; ES-DPH-4, Sch. DPH-3; Tr. 4, at 794). Deloitte & Touche issued a report of its findings, which the Companies submitted as part of the initial filing in this case (Exh. ES-DPH-4, Sch. DPH-3). Further, the Companies provided account level detail at the six-digit FERC account level, along with a mapping to the balances as reported on the Companies' respective FERC Form 1, and an explanation of adjustments, if any (Exh. ES-DPH-4, Schs. DPH-4 (East), (West)). In addition, the Companies provided documentation showing historical account data of expense and revenue activity for the years

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[11] A test year that spans two calendar years, as opposed to a test year based on a calendar year, is often referred to as a "split" test year. NSTAR Gas Company, D.P.U. 14-150, at 45 n.26 (2015); Plymouth Water Company, D.P.U. 14-120, at 12, 16 (2015). A test year, whether a calendar test year or a "split" test year, comprises a period of twelve consecutive calendar months.

2015 and 2016, as well as the split test year ending June 30, 2016 (Exhs. ES-DPH-1, at 17; AG-51-4 & Atts.).

B. Positions of the Parties

On brief, Eversource summarizes the scope and results of Deloitte & Touche's work and argues that the Companies have satisfied the Department's requirements for reliance on a split test year (Companies Brief at 156-158). No other party addressed the Companies' use of a split test year.

C. Analysis and Findings

1. Introduction

It is well-established Department precedent that base rate filings are based on an historic test year, adjusted for known and measurable changes. NSTAR Gas Company, D.P.U. 14-150, at 45 (2015); D.P.U. 07-50-A at 52-53; Massachusetts Electric Company, D.P.U. 18204, at 4 (1975); see also Massachusetts Electric Company v. Department of Public Utilities, 383 Mass. 675, 680 (1981). In establishing rates pursuant to Section 94, the Department examines a test year on the basis that the revenue, expense, and rate base figures during that period, adjusted for known and measurable changes, provide the most reasonable representation of a distribution company's present financial situation, and fairly represent its cost to provide service. D.P.U. 14-120, at 9; see Ashfield Water Company, D.P.U. 1438/1595, at 3 (1984).

The selection of the test year is largely a matter of a distribution company's choice, subject to Department review and approval. Fitchburg Gas and Electric Light Company, D.P.U. 15-80/D.P.U. 15-81, at 145-146 (2016), citing D.P.U. 07-50-A at 51; Boston Edison

Company, D.P.U. 1720, Interlocutory Order at 7-11 (January 17, 1984). The Department requires that the historic test year represent a twelve-month period that does not overlap with the test year used in a previous rate case unless there are extraordinary circumstances that render a previous Order confiscatory. D.P.U. 14-150, at 45, n.26; Massachusetts Electric Company, D.P.U. 19257, at 12 (1977). The test year is generally the most recent twelve-month period for which financial information exists. D.P.U. 14-150, at 45 n.26; Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 24, cert. denied, 439 U.S. 921 (1978).

As noted above, the Department has expressed strong preference for a test year cost of service based on a calendar year as opposed to a split test year. D.P.U. 14-120, at 12, 16; see also D.P.U. 14-150, at 45, n.26. Although the Department has, on occasion, accepted a non-calendar test year, see D.P.U. 15-155, at 21-22; D.P.U. 14-120, at 10, 16; D.P.U. 12-86, at 1, we also have recognized that there are significant complications associated with the use of a split test year that can call into question the use of such data to establish rates. D.P.U. 14-120, at 10; see AT&T Communications of New England, Inc., D.P.U. 90-133-A at 5-6 (1991). For example, test year amounts associated with a split test year will not tie back to amounts included in the Annual Returns submitted to the Department, which are prepared on a calendar-year basis. D.P.U. 15-155, at 14-15; D.P.U. 14-120, at 11. The use of a split test year also limits the Department's ability to review year-to-year changes in expense levels. D.P.U. 15-155, at 15; D.P.U. 14-120, at 11. This limitation is of significant concern to the Department because reliance on a split test

year may create an improper incentive for utilities to book expenses into a certain time period for purposes of creating an inflated test year expense. D.P.U. 15-155, at 15; D.P.U. 14-120, at 11. Another complication associated with use of a split test year involves year-end accounting for accrued revenues and expenses which, if not properly recognized in the rate setting process, may result in distorted measurement of net operations. D.P.U. 15-155, at 15; D.P.U. 14-120, at 11; see The Berkshire Gas Company, D.P.U. 1490, at 35-37 (1983).

It also is well established that the burden is with a company to satisfy the Department that the company's proposal will result in just and reasonable rates. D.P.U. 15-155, at 15; D.P.U. 14-120, at 11-12; Boston Gas Company, D.T.E. 03-40, at 52, n.31 (2003), citing The Berkshire Gas Company, D.T.E. 01-56-A at 16 (2002); New England Gas Company, D.P.U. 10-114, at 22 (2011); Boston Gas Company, D.P.U. 93-60, at 212 (1993); Blackstone Gas Company, D.P.U. 19579, at 2-3 (1978).[12] Therefore, given the importance of the concerns discussed above and their significance for ratepayers, the Department affirms its very clear preference to use an historic calendar year test year to establish rates. D.P.U. 15-155, at 15; D.P.U. 14-120, at 11-12.

The Department has noted that any decision to rely on a non-calendar test year will carry with it a high burden for a company to demonstrate that its proposed rates are just and reasonable. D.P.U. 15-155, at 15-16; D.P.U. 14-120, at 12. Specifically, any company that

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[12] That the burden of proof is always with those who take the affirmative in pleading is a long-held tenet in Massachusetts jurisprudence. Phelps v. Hartwell, 1 Mass. 71, 73 (1804).

seeks to rely on a split test year, as a threshold matter, must demonstrate by clear and convincing evidence that its proposed test year is reviewable and reliable and represents a full accounting of the company's operations for the period. D.P.U. 15-155, at 16; D.P.U. 14-120, at 16; see D.P.U. 19579, at 2-4; Cape Cod Gas Company/Lowell Gas Company, D.P.U. 18571/18572, at 4-14 (1976). Further, at a minimum, a company that proposes to use a split test year must be prepared to make a threshold showing:

(1) how its test year account balances tie back to the account balances as reported in the Annual Returns;

(2) that the amounts have been properly audited (or, in the case of a small water company that is not a subsidiary of a publicly traded entity, otherwise verified) and are available for review;

(3) that a meaningful year-to-year review of changes in expense levels and revenues is possible, such that the Department can determine whether the company's test year expenses and revenues are representative of its ongoing costs and revenues, are reasonable in amount, and account for any seasonal variability; and

(4) that the company has properly recognized accruals booked to reserve accounts, including any end of period reconciliations of those account balances.

D.P.U. 15-155, at 16; D.P.U. 14-120, at 16 n.11.

2. Analysis and Findings

The record shows that Eversource retained Deloitte & Touche to verify that: (1) data contained in the FERC Form 1 and Form 3-Q information prepared for the split test year was from the books and records of the Companies; (2) data included in the computation of the revenue requirement reconciles to the FERC Form 1 and Form 3-Q data, as appropriate; and (3) amounts included in Eversource's calculations of revenue requirements agree to other amounts within the Companies' filing as appropriate (Exhs. ES-DPH-1, at 9; ES-DPH-4,

Sch. DPU-3). As noted above, the Companies also provided internal account data in support of its use of a split test year (Exhs. ES-DPH-1, at 17; ES-DPH-4, Schs. DPH-4 (East), (West); AG-51-4 & Atts.).

Based on our review of the Deloitte & Touche report and the account level detail provided by the Companies, we find that it is possible to tie the Companies' test year account balances back to the account balances as reported in the annual returns. See D.P.U. 14-120, at 16 n.11. Further, while the Deloitte & Touch report does not represent an audit or an unqualified opinion letter, we find that Deloitte & Touche's examination provides an independent and extensive review of the Companies' test year cost of service data that is sufficient to make the D.P.U. 14-120 threshold showing. See D.P.U. 15-155, at 18.[13] Given the scope of Deloitte & Touche's examination, as set forth in the report, the review was comparable to the scope of a typical financial audit.

In addition, we conclude that the aforementioned information, when reviewed in conjunction with the annual return verification conducted by Ernst & Young (as discussed above) and the historical account data provided by the Companies, allows for a meaningful review of year-to-year changes in expense levels in order to determine whether the Companies' test year expenses and revenues are representative of their ongoing costs and revenues, are reasonable in amount, and account for any seasonal variability. See D.P.U. 14-120, at 16 n.11.

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[13] We note that Deloitte & Touche performs regular annual audits of the Companies' financial statements (Tr. 4, at 796).

Finally, we find that the Companies have demonstrated that they properly recognized accruals booked to reserve accounts, including any end of period reconciliations of those account balances. See D.P.U. 14-120, at 16 n.11. In particular, the Companies incorporated several adjustments to test year data in order to ensure the proper recognition of expenses in the test year (Exhs. ES-DPH-1, at 18; ES-DPH-2 (East), Sch. DPH-6, at 4 (Rev. 2); ES-DPH-2 (West), Sch. DPH-6, at 4 (Rev. 1)).

3. Conclusion

Based on the above considerations, the Department finds that Eversource has satisfied the split test year threshold requirements set forth in D.P.U. 14-120 and has demonstrated that its financial data is reviewable and reliable and represents a full accounting of the Companies' operations for the test year period. D.P.U. 14-120, at 16; see D.P.U. 19579, at 2-4; D.P.U. 18571/18572, at 4-14.[14] Therefore, we conclude that there is sufficient reviewable and reliable information in the record to evaluate Eversource's filing based on a test year for the twelve months ending June 30, 2016. While we accept Deloitte & Touche's report for purposes of determining the accuracy and reviewability of the financial information submitted by the Companies in this case, we do not accept the report as a proxy for establishing the appropriate cost of service in this case. The Department will evaluate the reasonableness of costs and appropriate ratemaking treatment in the specific sections of this Order that follow.

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[14] Further, we note that Eversource has not included for recovery in this case the costs associated with Deloitte & Touche's retention for purposes of supporting the Companies' use of a split test year.

Finally, we emphasize that our findings here are limited to the specific facts and circumstances of this case and in no way change the Department's clear preference for companies to use a calendar year test year as the norm. D.P.U. 15-155, at 22; D.P.U. 14-120, at 16. We reiterate that any company that seeks to rely on a split test year must, at a minimum threshold level, make a prima facie showing by clear and convincing evidence that its proposed test year is reviewable and reliable and represents a full accounting of the company's operations for the period. D.P.U. 15-155, at 22; D.P.U. 14-120, at 16; see D.P.U. 19579, at 2-4; D.P.U. 18571/18572, at 4-14. Failure to make such a robust showing will result in dismissal of the company's rate proceeding.

V. CORPORATE CONSOLIDATION

A. Introduction

In D.P.U. 10-170, NSTAR Gas and NSTAR Electric, along with their parent holding company NSTAR, and WMECo, along with its parent holding company Northeast Utilities (collectively "joint petitioners") sought approval from the Department to merge NSTAR and Northeast Utilities into a consolidated organization.[15] On February 15, 2012, the joint petitioners, the Attorney General, and DOER submitted a proposed settlement ("Merger Settlement") to the Department. That same day, the joint petitioners and DOER submitted to the Department a separate proposed settlement, the DOER Settlement (see Section III.A above).[16] On April 4, 2012, the Department approved both the Merger Settlement and the

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15 The merger was reviewed by the Department pursuant to Section 96.

16 Pursuant to 220 CMR 1.10(3), the Department incorporates by reference the Merger Settlement filed and approved in D.P.U. 10-170-B.

DOER Settlement and, consequently, the joint petitioners' proposed merger. D.P.U. 10-170-B at 107-108. In the Order approving the settlements, the Department approved a rate freeze applicable to Eversource's base distribution rates until January 1, 2016. D.P.U. 10-170-B at 36, 39-41.

While the Department's approval of the Merger Settlement allowed for the merger of NSTAR and Northeast Utilities, neither the Merger Settlement itself nor the Department's approval of the Settlement constituted approval of the merger or consolidation of the separate operating companies (i.e., NSTAR Electric, NSTAR Gas, and WMECo). D.P.U. 10-170-B at 103. These companies remain legally and functionally separate and subject independently to the Department's jurisdiction under G.L. c. 164, § 1. D.P.U. 10-170-B at 103. The Companies now seek to legally consolidate WMECo with and into NSTAR Electric,[17] with NSTAR Electric as the surviving entity (Exhs. DPU-20-1; AG-30-7, at 49-50).[18]

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[17] Upon obtaining Department's approval, the Companies will execute a merger agreement to accomplish the corporate reorganization (Exh. DPU-20-1, at 2-3).

[18] On July 6, 2016, the Companies filed a petition with the Department for an advisory ruling that the provisions of Section 96(d) made it unnecessary to seek Department approval of the consolidation of NSTAR Electric and WMECo into a single legal entity. NSTAR Electric Company/Western Massachusetts Electric Company, D.P.U. 16-108, at 1 (2017). The Department determined that the enactment of Section 96(d) did not eliminate the need for the Companies to seek approval of such a merger, because: (1) the Merger Settlement predated the enactment of Section 96(d); and (2) the terms of the Merger Settlement demonstrated the intent of the settling parties in that proceeding to require review and approval by the Department of the merger of NSTAR Electric and WMECo under Section 96. D.P.U. 16-108, at 14-21. The Department concluded that the proposed consolidation of NSTAR Electric and WMECo would require Department review and approval on the merits pursuant to Section 96, and that such a proposal could be submitted as part of Eversource's then-anticipated rate case filing. D.P.U. 16-108, at 20.

B. Description of the Proposed Merger

As a result of the Merger Settlement, NSTAR Electric and WMECo are fully integrated from a management and operational perspective (Exh. ES-CAH-1, at 7). The Companies have consolidated day-to-day field operations, capital-investment planning, including electric field operations, electric system operations, resource planning, and emergency response planning for NSTAR and WMECo (Exh. ES-CAH-1, at 39-41). The Companies' Proposed Merger represents a legal consolidation of two affiliates of a single holding company, and would require no operational changes (Exhs. ES-CAH-1, at 39; DPU-20-1).

As a result of the Proposed Merger, WMECo's outstanding common stock would be converted into that of NSTAR Electric using an exchange rate of 0.00023007 shares of NSTAR Electric common stock per share of WMECo common stock, whereupon WMECo will cease to exist (Exhs. DPU-20-1; AG-30-7, Att. at 49-51).[19] NSTAR Electric would then, as the surviving entity, acquire all of WMECo's state and FERC-jurisdictional facilities, contracts, and assets, including assets dedicated to providing utility service, as well as associated obligations (Exhs. DPU-20-1; AG-30-7, at 7-8, 50). The consolidated entity would provide electric service to approximately 1.4 million customers in Boston and 139 cities and towns in eastern and western Massachusetts, covering a collective area of approximately 3,200 square miles (Exh. DPU-20-1). The Companies anticipate that, pending

[19] As discussed further below, because WMECo currently has 434,653 shares of common stock outstanding, the stock exchange will result in these shares being converted into 100 shares of NSTAR Electric common stock (see Exh. AG-30-7, Att. at 49).

approval by the Department, the corporate consolidation would be effective January 1, 2018, coinciding with the effective date of new rates resulting from this proceeding (Exh. ES-CAH-1, at 8).

On March 2, 2017, the Companies received authorization from FERC for NSTAR Electric's acquisition of WMECo's jurisdictional facilities (Exhs. ES-DPH-1, at 4; DPU-20-1(e)). As part of a separate request, also on March 2, 2017, the Companies obtained FERC approval, pursuant to Section 203(a)(1)(B) of the Federal Power Act, for an internal corporate reorganization (Exh. DPU-20-1, at 2). The Companies also sought FERC approval of NSTAR Electric's assumption of WMECo's short-term debt obligations; however, this request remains pending (Exh. DPU-20-1, at 2).

C. Section 96 Considerations

1. Standard of Review

Section 96 sets forth the Department's authority to review and approve mergers, consolidations, and acquisitions and, as a condition for approval, requires the Department to find that the proposed transaction is "consistent with the public interest." Section 96 is the lineal descendent of St. 1908, c. 529, § 2, and these core words of the standard, "consistent with the public interest," date from that century-old enactment. In the past, the Department has construed the Section 96 standard of consistency with the public interest as requiring a balancing of the costs and benefits attendant on any proposed merger or acquisition, stating that the core of the consistency standard is "avoidance of harm to the public." Boston Edison Company, D.P.U. 850, at 5-8 (1983). Thus, the Department has historically interpreted the merger standard as a "no net harm" test, meaning that a proposed merger or

acquisition is allowed to go forward upon a finding by the Department that the public interest would be at least as well served by approval of a proposal as by its denial. NEES/EUA Merger, D.T.E. 99-47, at 16 (2000); BECo/ComEnergy Acquisition, D.T.E. 99-19, at 10 (1999); Eastern/Colonial Acquisition, D.T.E. 98-128, at 5 (1999); NIPSCO/Bay State Acquisition, D.T.E. 98-31, at 9 (1998); Eastern/Essex Acquisition, D.T.E. 98-27, at 8; D.P.U. 850, at 5-8.

In D.P.U. 10-170, the Department modified the Section 96 standard from a "no net harm" test to a "net benefits" test. D.P.U. 10-170, Interlocutory Order on Standard of Review at 21 (March 10, 2011). Accordingly, to satisfy the statutory requirement that a transaction is "consistent with the public interest," petitioners must demonstrate that the benefits of a consolidation, merger, or acquisition outweigh the costs. D.P.U. 10-170, Interlocutory Order on Standard of Review at 21-22, 27. To determine whether petitioners have satisfactorily met this burden, the Department continues to consider the special factors surrounding an individual proposal. D.P.U. 10-170, Interlocutory Order on Standard of Review at 26-27.

The Department has held that various factors may be considered in determining whether a proposed merger or acquisition is consistent with the public interest pursuant to Section 96. Traditionally, the Department has considered the following factors: (1) effect on rates; (2) effect on the quality of service; (3) resulting net savings; (4) effect on competition; (5) financial integrity of the post-merger entity; (6) fairness of the distribution of resulting benefits between shareholders and ratepayers; (7) societal costs; (8) effect on economic

development; and (9) alternatives to the merger or acquisition. Guidelines and Standards for Mergers and Acquisitions, D.P.U. 93-167-A at 7-9 (1994) ("Mergers and Acquisitions"). The Department has held that this list of factors is illustrative and not "exhaustive," and the Department may consider other factors, or a subset of these factors, when evaluating a Section 96 proposal. D.T.E. 99-47, at 17-18; D.T.E. 99-19, at 11-12; D.T.E. 98-128, at 6. No one factor is controlling.

As amended in 2008, Section 96 expressly requires the Department to consider, at a minimum, the following four factors: (1) proposed rate changes, if any; (2) long-term strategies that will assure a reliable, cost-effective energy delivery system; (3) any anticipated interruptions in service; and (4) other factors that may negatively impact customer service. The second factor, regarding long-term strategies, is the only one not previously addressed in the so-called "nine-factor test" established in Mergers and Acquisitions.[20]

Although Section 96 mandates that the Department consider the specific factors enunciated in the statute, the Department is not foreclosed from considering the nine factors, or a subset of those factors, established in Mergers and Acquisitions. Furthermore, depending upon the nature of the transaction, in determining whether the transaction is consistent with the public interest, the Department may consider additional factors not

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[20] The remaining statutory factors correspond to factors established in Mergers and Acquisitions. Specifically, the first factor in Section 96 is subsumed by the first factor established in Mergers and Acquisitions, the effect of the proposed transaction on rates. The third and fourth factors delineated in Section 96 correspond to the second factor established in Mergers and Acquisitions, the effect on the quality of service.

delineated in the statute or established in Mergers and Acquisitions. D.T.E. 99-47, at 17-18; D.T.E. 99-19, at 11-12; D.T.E 98-128, at 6.

The Department's determination as to whether the merger or acquisition meets the requirements of Section 96 must rest on a record that quantifies costs and benefits to the extent such quantification can be made. The Department also may undertake a more qualitative analysis of those aspects that are hard to measure. D.P.U. 10-170, Interlocutory Order on Standard of Review at 27; Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company/Canal Electric Company, D.T.E. 06-40, at 16-17 (2006); D.T.E. 99-47, at 18; Mergers and Acquisitions at 7. A Section 96 petition that expects to avoid an adverse result cannot rest on generalities, but must instead demonstrate benefits that outweigh the costs, including the cost of any acquisition premium sought. D.P.U. 10-170, Interlocutory Order on Standard of Review at 21-22, 27; D.T.E. 99-47, at 18; D.T.E. 99-19, at 12; D.T.E. 98-128, at 7; D.T.E. 98-31, at 11; D.T.E. 98-27, at 10; Mergers and Acquisitions at 7.

2. Positions of the Parties

a. Attorney General

While the Attorney General does not specifically object to the Proposed Merger, she notes her concern that the Department has not yet considered the associated rate effects of the Companies' proposal to consolidate various rates and rate classes for NSTAR and WMECo (Attorney General Brief at 211). She asserts that the Department should defer any decision on the Proposed Merger until it has heard all the evidence on the Companies' current rate design proposals and the rate effects on customers (Attorney General Brief at 211-212).

Further, the Attorney General argues that regardless of whether the Department approves the Proposed Merger, it should require Eversource to maintain separate financial accounting records and to file separate Annual Returns with the Department if and until all rate classes are merged (Attorney General Reply Brief at 100-101). According to the Attorney General, absent separate accounting records for each operating company, there will be no accounting data to support the rates and charges Eversource bills to customers in the two service territories (Attorney General Reply Brief at 100). Additionally, she contends that if the Department wanted to perform a cost of service for WMECo's customers, Eversource no longer would have the data available if separate financial accounting is eliminated, and the tracing back of base rate, transmission, transition, and basic service costs to the operating companies would be "impossible" (Attorney General Reply Brief at 100).

b. RESA

Although RESA asserts that it has no inherent problem supporting the concept of the proposed corporate consolidation of NSTAR Electric and WMECo and its efforts to enhance operational efficiencies, RESA opposes the Companies' rate class and rate consolidation proposals, which RESA claims is part of the corporate consolidation proposal (RESA Brief at 5; RESA Reply Brief at 3). Specifically, RESA maintains that Eversource's proposals for consolidation of rate classes and rates, as well as proposed changes to basic service procurement, could potentially have a negative impact on competition, and, as a result, are not in the public interest (RESA Reply Brief at 3).

c. Companies

Eversource argues that the Department should allow the corporate consolidation of NSTAR Electric and WMECo (Companies Brief at 159-160). According to the Companies, the Proposed Merger will eliminate the need to prepare and file separate Securities and Exchange Commission ("SEC") Forms 10K and 10Q for WMECo, as well as separate FERC Forms 1 and 3Q (Companies Brief at 159, citing Exh. ES-DPH-1, at 183-184). Further, Eversource contends that although the financial reporting systems and processes will be consolidated, such a consolidation will not prevent the Companies from maintaining separate rates for customers in the pre-merger service territories (Companies Brief at 159). Finally, the Companies note that they are not proposing to consolidate the revenue requirement calculation as part of the Proposed Merger, though they provided a consolidated revenue requirement for illustrative purposes (Companies Brief at 160).

3. Analysis and Findings

a. Section 96

i. Introduction

As noted above, Section 96 requires the Department to consider, at a minimum, four statutory factors in evaluating the Proposed Merger. The Department also may consider any of the additional factors set forth in the "nine-factor test" established in Mergers and Acquisitions. Further, depending upon the nature of the transaction, the Department may consider additional factors, not delineated in the statute or established in Mergers and Acquisitions. See D.T.E. 99-47, at 18; D.T.E. 99-19, at 12; D.T.E. 98-128, at 6.

The Department's analysis will focus on the following factors: (1) proposed rate changes at the time of the transaction, if any; (2) costs and resulting net savings of the merger; (3) long-term strategies that will assure a reliable, cost-effective energy delivery system; (4) effect on customer service, including interruptions in service; and (5) financial integrity of the post-acquisition entities. The Department considers these factors to encompass the four factors specified in Section 96, and deems these to be relevant here in light of the specific terms of the Proposed Merger.

ii. Effects on Rates

The first factor we consider in our Section 96 analysis is the proposed rate changes at the time of the transaction. The Attorney General and RESA argue that the Department must consider the effect of the Proposed Merger on customers' bills, and RESA specifically expresses concern with the effect of the Companies' proposed consolidation on competition (Attorney General Brief at 211-212; RESA Brief at 3-7; RESA Reply Brief at 3). In addition, the Attorney General argues that the Department should defer any decision on the Proposed Merger until it has heard all of the evidence on the Companies' current rate design proposals and the rate effects on customers (Attorney General Brief at 211-212).

The Department finds that the corporate consolidation of NSTAR Electric and WMECo will not, in itself, result in any changes to the rates, prices, charges, or terms and conditions applicable to NSTAR's or WMECo's customers, nor to the Department's ability to review current or future rate changes (Exhs. DPU-20-2; AG-30-7, Att. at 13-20). As such, the Department finds the effect on rates to be a neutral factor in our Section 96 analysis of

the Proposed Merger. Therefore, the Department finds it unnecessary to defer its decision on the Proposed Merger.

iii. Costs and Resulting Net Savings

In reviewing a proposed merger, one of the factors that the Department considers is the resulting net savings, if any. The Department has recognized that transaction costs may accompany a merger or acquisition, and that these costs may be recovered in rates provided that they meet the public interest standard of Section 96 as part of the general reckoning of costs and benefits under this statute. D.T.E. 99-47, at 36; D.T.E. 99-19, at 37; D.T.E. 98-27, at 52-53. In reviewing estimated merger savings, the "Department's review . . . must be based on whether the figures proposed by the [p]etitioners are reasonable estimates." D.T.E. 99-47, at 47, 50. Projections of future events are not subject to the same standards of measurement and evaluation that the Department uses in a rate case; rather, they can be judged in terms of whether they are substantiated by past experience, and supported by logical reasoning founded on solid theory. D.T.E. 99-47, at 50.

Most of the operational savings associated with the combination of NSTAR Electric and WMECo into one entity have already been achieved through the Merger Settlement. Specifically, during the test year the Companies experienced a cost savings attributable to the 2012 consolidation of $27.3 million for NSTAR and $4.5 million for WMECo (Exh. ES-DPH-4, Sch. DPH-10, at 56). Net of the proposed amortization expense, the Companies anticipate an annual savings as a result of the consolidation of approximately $25 million for NSTAR, and $4 million for WMECo (see Exhs. ES-DPH-1, at 156;

ES-DPH-3 (East), Sch. DPH-24, at 3 (Rev. 3); ES-DPH-3 (West), Sch. DPH-24, at 3 (Rev. 3); ES-DPH-4, Sch. DPH-10, at 56).

Eversource anticipates that its shareholders will incur a one-time cost of approximately $2 million to complete the Proposed Merger transaction, consisting of $1 million in legal costs and $1 million in vendor support costs associated with updates of financial reporting systems (Exh. DPU-20-8). The Companies expect modest additional savings from the Proposed Merger, arising from the consolidation of corporate accounts, reconciliations, audits, and regulatory filings (Exh. DPU-20-3; Tr. 5, at 1022-23). Specifically, the Companies expect ratepayers to see annual savings in the range of $500,000 to $1 million through increased administrative efficiency resulting from streamlining of corporate and regulatory processes, including reduced use of outside services, fees, and amortized rate case expense (Exh. DPU-20-8). Additionally, the Companies anticipate interest rate savings from an approximate 25 basis point reduction in WMECo's borrowing costs, saving up to $750,000 annually (Exh. DPU-20-8).

Although the Companies' expected savings of $500,000 to $1.75 million are relatively modest, the Department recognizes that they are nonetheless tangible, greater than the expected costs, and would accrue annually to ratepayers, while the merger-related costs will be a one-time cost borne by shareholders (Exhs. DPU-20-8; DPU-20-9). The Department concludes that Eversource has made a fair and reasonable demonstration of the costs and savings that would result from the Proposed Merger, and that over time the Proposed Merger would result in net savings for ratepayers (Exhs. DPU-20-8; DPU-20-9; DPU-52-2).

Accordingly, the Department finds that, based on an analysis of the savings and costs related to the Proposed Merger, as presented by the Companies, there would be an overall net benefit to ratepayers from approval of the Proposed Merger.

iv. Long-term strategies that will assure a reliable, cost-effective energy delivery system

The third factor that we consider in our Section 96 factor analysis is long-term strategies to provide a reliable, cost-effective energy delivery system. The Proposed Merger is not expected to have any impact in relation to system reliability and long-term energy delivery infrastructure, as the operational processes that support these outcomes already are fully consolidated as a result of the Merger Settlement (Exh. DPU-20-3). However, we note that activities and commitments that advance clean energy development and address climate change are important components of this Section 96 factor as well. D.P.U. 10-170-B at 76-77. Thus, we consider the effect of the Proposed Merger on clean energy development and climate change mitigation in the Commonwealth.

In D.P.U. 10-170-B, the Department found that the consolidation of NSTAR Electric and WMECo under a single holding company would facilitate the energy efficiency, solar, and Electric Vehicle ("EV") Pilot provisions of the Merger Settlement, and provide material benefits for the ratepayers of NSTAR Electric and WMECo in the form of energy efficiency, solar, and EV initiatives, as well as long-term renewables procurement, and public outreach concerning the Commonwealth's climate goals. D.P.U. 10-170-B at 80-83, 85-87, 90-96. We find no evidence that the legal consolidation of NSTAR Electric and WMECo in the instant proceeding would weaken the anticipated benefits recognized from the Merger

Settlement or serve to frustrate the Commonwealth's clean energy development or climate change goals.[21] Based on the above findings, the Department concludes that the Proposed Merger is consistent with the maintenance of a reliable, cost-effective energy delivery system.

v. Effects on Customer Service and Service Quality

As part of our Section 96 review, we next look at the potential impact of the Proposed Merger on quality of service, any anticipated interruptions of service, and any other factors that may adversely impact customer service. The Department recognizes the importance of maintaining service quality, particularly when the merger of entities and the resultant efforts to achieve cost savings can potentially lead to service quality degradation. D.P.U. 10-170-B at 73; Boston Gas Company/Essex Gas Company, D.P.U. 09-139, at 23 (2010).

The Companies demonstrated that changes in restoration practices and other measures following the merger of NSTAR and Northeast Utilities have already resulted in a reduction of almost 40 percent to WMECo's average duration of outages (Exh. ES-CAH-1, at 9). In addition, there has been a reduction of approximately 30 percent in WMECo's average frequency of outages (Exh. ES-CAH-1, at 9). The Companies fully anticipate that continued improvement will occur as system investment and grid modernization continue (Exh. ES-CAH-1, at 9). The Department is satisfied that the Proposed Merger would cause no detrimental changes to customers and would have no noticeable customer-facing effects

[21] As discussed in detail in Section X below, Eversource makes proposals in this proceeding to enable investment in technologies such as electric storage, electric vehicles, and other initiatives to improve the resiliency of the distribution system and further the Commonwealth's clean-energy goals.

(Exh. DPU-20-5). In addition, no interruptions in service are anticipated in relation to the Proposed Merger (Exh. DPU-20-4).

The Companies do not offer specific improvements to customer service and service quality based solely on the legal consolidation of NSTAR Electric with WMECo. Nevertheless, the performance benchmarks included in Eversource's existing service quality plans provide strong incentives to ensure that its ratepayers will be protected from service degradation following the Proposed Merger. Service Quality Standards for Electric Distribution Companies and Local Gas Distribution Companies, D.P.U. 16-SQ-10 through D.P.U. 16-SQ-14 (2016). Furthermore, the Department finds that Eversource will have the opportunity to improve its service quality to its ratepayers through increased administrative efficiencies and the adoption of combined best practices post-merger (Exh. DPU-20-8). Therefore, in analyzing the Proposed Merger's effect on customer service and service quality, the Department finds that the Proposed Merger will not result in any adverse impact on customer service or the quality and consistency of service to ratepayers and will instead support the continued improvements in service quality recognized following the merger of NSTAR and Northeast Utilities.

vi. Financial Integrity of the Post-Acquisition Entity

Finally, the Department considers the financial integrity of the post-acquisition company as a factor in our Section 96 analysis of the Proposed Merger. Mergers and Acquisitions at 8-9. Eversource states that the Proposed Merger will have no negative impact on the financial integrity of the surviving company, NSTAR Electric

(Exh. DPU-20-11). A review of NSTAR Electric's current financial and operating data, as represented by its annual returns to the Department and filings with both FERC and the SEC, demonstrates that it is a financially viable company (Exhs. AG-1-2, Att. (a) (Supp. 1); AG-1-2 (Supp. 2); AG-1-2, Att. (a) (Supp. 3); AG-1-2, Att. (b) (Supp. 3)). The Companies do not expect to significantly change NSTAR Electric's capital structure as a result of the Proposed Merger (Exh. DPU-20-11). Additionally, the Companies do not expect the consolidation to have an impact on NSTAR Electric's credit rating or borrowing costs following the consolidation (Exh. DPU-20-11). Furthermore, NSTAR Electric intends to assume the debt obligations of WMECo (Exh. DPU-20-8). The lower borrowing costs of NSTAR Electric, applied to WMECo's operations, will improve the financial integrity of NSTAR Electric as the surviving operation (Exh. DPU-20-8).

Moreover, NSTAR Electric's post-merger financial position is likely to be enhanced by the ability to reduce costs through the savings described above. As such, the Department finds no reason to expect that the Proposed Merger would compromise the financial integrity of NSTAR Electric as the surviving company. Accordingly, for all of these reasons, the Department finds that the merger would have a beneficial effect on NSTAR Electric's financial integrity.

vii. Conclusion

As described in detail above, the Department finds that the Proposed Merger will provide net savings to ratepayers, long term strategies that will assure a reliable, cost-effective energy delivery system, potential further improvements in customer service and

service quality, and increased financial integrity of NSTAR Electric as the surviving entity. Accordingly, the Department finds that the Companies have satisfied the statutory requirement that the Proposed Merger is "consistent with the public interest," by demonstrating that the benefits of the Proposed Merger outweigh the costs.

b. Financial Recordkeeping

As noted above, Eversource seeks to consolidate the financial recordkeeping of the Companies post-merger (Companies Brief at 159). The Attorney General requests that the Department require the Companies to retain separate financial accounting records and to file separate Annual Returns, if and until all rate classes are merged (Attorney General Reply Brief at 100-101).

Gas and electric companies engaged in the manufacture and sale or distribution of gas or electricity are required to keep their books and accounts in a form prescribed by the Department. G.L. c. 164, § 81; 220 CMR 50.00, 51.00, 52.00. The Department may require that a company maintain certain records and accounting practices. Fryer v. Department of Public Utilities, 373 N.E.2d 977, 374 Mass. 685 (1978). The Department has previously required merging companies that intend to maintain their existing rate structures to maintain separate financial records in order to allow for proper identification of costs between multiple service areas. Bay State Gas Company/Brockton-Taunton Gas Company, D.P.U. 18133, at 5 (1974).

In this instance, the Department finds that it is necessary for the consolidated company to maintain separate accounts for the former NSTAR Electric and WMECo entities

because these companies currently have separate rates, and may continue to maintain the same after this proceeding.[22] Moreover, despite the operational integration of the Companies, the potential for degradation in service quality-related activities still exist. D.P.U. 09-139, at 24. Therefore, the Department directs the Companies to maintain separate financial records and service quality data. As to the form of the separate financial records, Eversource may consider direct assignment or allocation through the use of subaccounts, when appropriate.

We now turn to the Attorney General's request that the Companies be required to file separate Annual Returns for what will be the former NSTAR Electric and WMECo. Companies are required to furnish a return annually to the Department, in a form prescribed by it. G.L. c. 164, § 83. The Department has not previously required companies to maintain separate annual returns by legacy service territories as a condition of a merger. Moreover, the Attorney General's proposal for separate Annual Returns was first raised in her reply brief. Consequently, there is an insufficient evidentiary record to determine whether the post-merger consolidated NSTAR Electric would be able to separate its financial

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[22] The Department has observed that the failure to maintain separate accounts will, over time, eliminate rate differentials between separate service areas by virtue of the lack of reliable cost data. D.P.U. 18133, at 5. Rate consolidation, if such is to be permitted in the future, should be based on substantial evidence, and not through default. In this regard, the Department will address any such issues in its subsequent Order addressing rate design issues.

data to the degree necessary to file separate Annual Returns, as the Attorney General proposes.[23]

As such, while the Department will require the Companies to keep separate financial records and service quality data for the legacy NSTAR Electric and WMECo, we decline to require the consolidated Companies to file separate Annual Returns. The Department will consider the consolidation of service quality reporting metrics in the context of the Companies' service quality filings.

D. Stock Transactions

1. Introduction

As of December 31, 2016, NSTAR Electric had 100 common shares outstanding with a par value of $1.00 per share, and WMECo had 434,653 common shares outstanding with a par value of $25 per share (Exhs. AG-1-2, Att. (a) at 150-151 (Supp. 3); AG-1-2, Att. (b) at 142-143 (Supp. 3)). In order to effect the Proposed Merger, the Companies propose to exchange all the common shares of WMECo for common shares of NSTAR Electric based on an exchange ratio of 0.00023007 shares of NSTAR Electric common stock for each share of WMECo common stock (Exh. AG-30-7, Att. at 50). Consequently, 434,653 aggregate common shares of WMECo will be converted into 100 shares of NSTAR Electric (see

[23] In the case of combination gas and electric utilities, the Department has not attempted to segregate capital structures between gas and electric operations. This is because the Department considers cash to be fungible, and thus has concluded that it is not appropriate or feasible to allocate the components of the utility's capital structure among various operating divisions. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 225 (2002); Fitchburg Gas and Electric Light Company, D.P.U. 1214-D at 4-5 (1985). These same inherent difficulties would arise with efforts to generate separate Annual Returns by service area.

Exh. AG-30-7, Att. at 49). WMECo's exchanged stock certificates will be cancelled automatically and cease to have any rights with respect to the surviving company (Exh. AG-30-7, Att. at 51).

2. Standard of Review

To approve the issuance of stock, bonds, coupon notes, or other types of long-term indebtedness by a gas or electric company, the Department must determine that the proposed issuance meets two tests.[24] First, the Department must assess whether the proposed issuance is reasonably necessary for the purpose for which such issuance of securities has been authorized. G.L. c. 164, § 14; Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 395 Mass. 836, 841-842 (1985) ("Fitchburg II"), citing Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 394 Mass. 671, 678 (1985) ("Fitchburg I"). The Supreme Judicial Court has found that, for the purposes of G.L. c. 164, § 14, reasonably necessary means "reasonably necessary for the accomplishment of some purpose having to do with the obligations of the company to the public and its ability to carry out those obligations with the greatest possible efficiency." Fitchburg II at 842, citing Lowell Gas Light Company v. Department of Public Utilities, 319 Mass. 46, 52 (1946) ("Lowell Gas"). In cases where no issue has been raised about the reasonableness of management decisions regarding the requested financing, the Department limits its G.L. c. 164, § 14, review to a determination of reasonableness of the company's proposed use of the proceeds of a securities issuance. Colonial Gas Company,

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[24] Long term refers to periods of more than one year from the date of issuance. G.L. c. 164, § 14.

D.P.U. 90-50, at 6-7 (1990); Canal Electric Company, et al., D.P.U. 84-152, at 20 (1985). The burden of proving that an issuance is reasonably necessary rests with the company proposing the issuance, and the Department's authority to review a proposed issuance is not limited to a perfunctory review. Fitchburg I at 678; Fitchburg II at 842; Lowell Gas at 52.

Second, the Department must determine whether the company meets the net plant test. Milford Water Company, D.P.U. 91-257, at 5 (1992); Edgartown Water Company, D.P.U. 90-274, at 5-7 (1990); Barnstable Water Company, D.P.U. 90-273, at 6-8 (1990); Colonial Gas Company, D.P.U. 84-96, at 5-8 (1984).[25] Regarding the net plant test, a company is required to present evidence that its net utility plant is equal to or in excess of its total capitalization. Aquarion Water Company of Massachusetts, D.P.U. 11-55, at 12, 28-29 (2011); D.P.U. 90-50, at 4-5. For purposes of this test, net utility plant is derived from utility plant in service less accumulated depreciation and excluding the following: (1) contributions in aid of construction; (2) construction work in progress; and (3) goodwill. D.P.U. 11-55, at 12, 28-29; Southern Union Company, D.T.E. 01-32, at 10-11 (2001); D.P.U. 84-96, at 5, 7-8. The Department's definition of total capitalization is, for purposes

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[25] The net plant test is derived from G.L. c. 164, § 16, which provides the Department with authority to protect against an impairment of capital. Childs v. Krey, 199 Mass. 352, 356 (1908). Thus, when the Department approves a securities issuance under G.L. c. 164, § 14, we require a demonstration that the fair structural value of the plant and land exceeds the company's outstanding stock and long-term debt. D.P.U. 84-96, at 5. When the value of such plant and land is less than the value of the company's outstanding stock and long-term debt, the Department may prescribe conditions and requirements to make good within a reasonable time the impairment of the capital stock. G.L. c. 164, § 16.

of this test, the sum of long-term debt, preferred stock, common stock, and premiums on common stock outstanding. D.P.U. 11-55, at 28-29; D.P.U. 84-96, at 5.[26]

Where issues concerning the prudence of a company's capital financing have not been raised or adjudicated in a proceeding, the Department's decision does not represent a determination that any specific project is economically beneficial to the company or to its customers. Boston Gas Company, D.P.U. 95-66, at 7 (1995). Further, the Department's approval of a securities issuance in a G.L. c. 164, § 14, proceeding may not in any way be construed as a ruling on the appropriate ratemaking treatment to be accorded any costs associated with the proposed financing. D.P.U. 95-66, at 7.

3. Analysis and Findings

a. Introduction

The Companies will enter into an agreement and plan of merger upon receiving Department approval of the Proposed Merger, including the issuance of common stock as necessary to exchange with WMECo (Exhs. DPU-20-1, at 1; AG-30-7, Att. at 49-51). As noted above, Department approval is required for any stock issuance by a gas, electric, or water company. G.L. c. 164, § 14. In addition, G.L. c. 164, § 16 is implicated in any petition brought under G.L. c. 164, § 14, and G.L. c. 164, § 99 is implicated in any petition brought under Section 96. Therefore, the Department will examine the proposed stock issuance pursuant to G.L. c. 164, §§ 14, 16, and 99.

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[26] For purposes of the net plant test, the Department excludes retained earnings from the calculation of total capitalization. D.P.U. 11-55, at 28 n.29; Southern Union Company, D.T.E. 04-36, at 9-10 (2004). In addition, premiums on common stock are treated as common stock. Western Massachusetts Electric Company, D.P.U. 09-50, at 16 (2010), citing D.T.E. 04-36, at 9 n.5.

b. Stock Issuance

The Proposed Merger requires the issuance of 100 common shares by NSTAR Electric as consideration in the transaction (Exh. AG-30-7, Att. at 49-51). The Companies represent that the purpose of the stock issuance by NSTAR Electric is to facilitate the merger of WMECo into NSTAR Electric (Exh. AG-30-7, Att. at 49-51). The Department has found that issuance of stock by an operating company for the purpose of exchanging for the stock of another operating company that is being acquired pursuant to Section 96 is a legitimate utility purpose as contemplated by G.L. c. 164, § 14. D.T.E. 06-40, at 22-23; D.T.E. 99-47, at 61; Brockton Edison Company/Fall River Electric Light Company, D.P.U. 19552, at 9. Therefore, the Department finds that the proposed stock issuance by NSTAR Electric is reasonably necessary to accomplish a legitimate purpose in meeting NSTAR Electric's service obligations in accordance with G.L. c. 164, § 14, and thus meets the first prong of the Department's two-prong standard.

With regard to the net plant test requirement of G.L. c. 164, § 16, as of December 31, 2016, NSTAR Electric had plant in service of $7,796,064,193, with an accumulated depreciation reserve of $ 2,256,001,075, for a net plant balance of $5,440,063,118 (Exh. AG-1-2, Att. at 28 (Supp. 3)). NSTAR Electric's total capitalization for purposes of the net plant test on that same date was $2,143,000,100, consisting of $100 in common stock, $43,000,000 in preferred stock, and $2,100,000,000 in long-term debt (Exh. AG-1-2, Att. (a) at 32 (Supp. 3)). NSTAR Electric subsequently issued $350,000,000 in long-term debt on May 6, 2017, and issued another $350,000,000 on

October 5, 2017 (Exh. DPU-31-6). NSTAR Electric Company, D.P.U. 16-189, Compliance Filing (October 13, 2017). A portion of the October 5 issuance will be used to refinance $400,000,000 in long-term debt that will mature on November 15, 2017 (Exhs. DPU-31-6; AG-1-2, Att. (a) at 154-155 (Supp. 3); AG-26). D.P.U. 16-189, Compliance Filing (October 13, 2017).

Additionally, as of December 31, 2016, WMECo had utility plant in service of $1,935,531,756, along with accumulated depreciation of $347,401,580, for an aggregate net plant of $1,588,130,176 (Exh. AG-1-2, Att. (b) at 26 (Supp. 3)).[27] In turn, WMECo's total capitalization for purposes of the net plant test on that same date was $579,771,476, consisting of $10,866,325 in common stock, $3,905,151 in premiums on common stock, and $565,000,000 in long-term debt (Exh. AG-1-2, Att. (a) at 30 (Supp. 3)). NSTAR Electric intends to reclassify WMECo's exchanged common stock and premiums as additional paid-in capital, thus eliminating these balances from consideration in the net plant test (Exh. AG-30-7, Att. at 141). As such, for purposes of the net plant test, NSTAR Electric's post-merger net plant would be $7,028,193,294, with a total capitalization of $3,008,000,200,[28] resulting in an excess of net utility plant over outstanding capital of $4,020,193,094. The Department finds that NSTAR Electric's current and post-merger plant investment is sufficient to support the proposed issuance of 100 shares of common stock.

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[27] This figure excludes construction work in progress, Account 107.

[28] $2,143,000,100 +700,000,000 - $400,000,000 + $565,000,000 + $100.

c. G.L. c. 164, § 99

General Laws chapter 164, § 99 ("Section 99") is the operative statute governing increases in capital stock to effect an acquisition and it states:

> The purchasing or consolidated company may, for the purposes authorized by [G.L. c. 164, §§ 96 and 97], increase its capital stock and issue bonds in the same manner and subject to the limitations provided in [G.L. c. 164, §§ 13, 14, 18, and 19]; and may, for the same purpose and subject to the same limitations and notwithstanding any special law applicable thereto, exchange its securities for those of the selling or merged company upon such terms as the [D]epartment approves; but the aggregate amount of the capital stock and the aggregate amount of the debt, respectively, of the consolidated companies shall not, by reason of such consolidation, be increased.

The Department has determined that, for purposes of Section 99, capital stock consists of common stock, preferred stock, and premiums on stock. D.P.U. 99-47, at 63-64; Boston Gas Company, D.P.U. 17138, at 7 (1971); Pittsfield Coal Gas Company, D.P.U. 10956 (1954).

The Companies must demonstrate that the aggregate amount of capital stock and debt for NSTAR Electric and WMECo will not increase as a result of the Proposed Merger. As noted above, NSTAR Electric's capital stock as of the date of the Proposed Merger will consist of $100 in common stock and $43,000,000 in preferred stock (Exh. AG-1-2, Att. (a) at 32 (Supp. 3)). WMECo's capital stock consists of $10,866,325 in common stock and $3,905,151 in premiums on common stock (Exh. AG-30-7, Att. at 148). Thus, the aggregate par and premiums of the Companies' capital stock is $57,771,576.

Using the stock exchange ratios proposed by the Companies, 100 shares of NSTAR Electric common stock would be issued in exchange for 434,653 shares of WMECo common

stock (see Exh. AG-30-7, Att. at 49). The Department has reviewed the proposed exchange ratios and post-merger capital stock balance, and finds that the aggregate amount of the Companies' capital stock will not increase as a result of the Proposed Merger. Moreover, because no new debt would be issued, the aggregate amount of the Companies' debt would not increase as a result of the Proposed Merger. Therefore, the Department finds that no further action is required under Section 99.

E. Confirmation of Franchises

1. Introduction

The Companies request that the Department confirm that NSTAR Electric, as the surviving corporation subsequent to the Proposed Merger, will retain all franchise rights and obligations that were previously held by WMECo and that further action, pursuant to G.L. c. 164, § 21, is not required to consummate the merger (Joint Petition at ¶ 28; Exhs. DPU-20-12; DPU-35-5). None of the parties commented on this issue.

2. Analysis and Findings

General Laws chapter 164, § 21, states: "[a] corporation subject to this chapter shall not, except as otherwise expressly provided, transfer its franchise, lease its works or contract with any person, association or corporation to carry on its works, without the authority of the general court" (emphasis added). Moreover, G.L. c. 164, § 98 states that "[t]he purchasing or consolidating company shall except as provided in [G.L. c. 164, § 97],[29] have and enjoy all the powers, rights, locations, licenses, privileges and franchises, and be subject to all the

[29] General Laws chapter 164, § 97 pertains to the acquisition of a water storage reservoir or hydroelectric plant by an electric company.

duties, liabilities and restrictions, of the company selling or merged as aforesaid, so far as they are applicable to the purchasing or consolidated company."

The Department has determined that approval of corporate mergers pursuant to Section 96 obviates the need for separate legislative approval under G.L. c. 164, § 21 for transfer of franchise rights. New England Gas Company et al., D.P.U. 13-07-B at 11-18 (2014); D.T.E. 99-47, at 65-66; Haverhill Gas Company, D.P.U. 1301, at 4 (1984). The Department has stated that an action properly approved under Section 96 would not require separate authorization of the General Court because the General Court itself authorized the Department to approve such a transaction. D.P.U. 13-07-B at 11-12; D.P.U. 1301, at 5.

The various franchise rights held by WMECo have been acquired from time to time by WMECo and its predecessors in interest since their inception through various actions, including special legislative acts, Department orders, grants of location, easements, and rights of way (Exh. DPU-20-12; Tr. 1, at 111-113). See, e.g., St. 2008, c. 273; St. 1962, c. 731; St. 1952, c. 113; St. 1910, c. 580; St. 1900, c. 42; Western Massachusetts Electric Company/Huntington Electric Light Company, D.P.U. 16972, at 7-8 (1971); Huntington Electric Company/Strathmore Paper Company, D.P.U. 13534, at 4 (1961); Lee Electric Company, D.P.U. 4020 (1930).[30] The Companies have not requested that the Department investigate or verify the current validity of any franchise right (Tr. 1, at 114). Further, no issues have been raised as to the validity of WMECo's franchise rights.

[30] The documentation supporting these franchise rights dates as far back as the late nineteenth century, and is maintained on a decentralized basis at WMECo's various service centers (Tr. 1, at 113-114).

On the effective day of the merger, NSTAR Electric will have and enjoy its own existing powers, rights, locations, privileges, and franchises and will be subject to all the associated duties, liabilities, and restrictions. In addition, NSTAR Electric will have and enjoy the powers, rights, locations, privileges, and franchises of WMECo and will be subject to all the associated duties, liabilities, and restrictions of WMECo. The Department finds that approval of the Proposed Merger pursuant to Section 96 obviates the need in this case for legislative approval under G.L. c. 164, § 21. D.P.U. 13-07-B at 17-18; D.T.E. 99-47, at 65-66; D.P.U. 1301, at 4. Accordingly, the Department hereby ratifies and confirms that all the franchise rights and obligations currently held by WMECo shall continue with NSTAR Electric after the consummation of the merger.

VI. REVENUES

A. Test Year Revenue Adjustments

1. Introduction

Eversource reported total test year operating revenues of $2,769,893,671 for NSTAR Electric and $479,998,869 for WMECo (Exhs. ES-DPH-2 (East), Sch. DPH-5, at 1 (Rev. 3); ES-DPH-2 (West), Sch. DPH-5, at 1 (Rev. 3)). Eversource proposes adjustments to the Companies' test year operating revenues: (1) to remove costs recovered through ratemaking mechanisms that operate outside of base; (2) to normalize the booked test year amounts for ratemaking purposes; and, (3) to account for known and measurable changes in O&M expense levels occurring after the end of the test year and through the midpoint of the rate year (Exh. ES-EPH-1, at 21). The proposed adjustments reduce total operating revenues to $854,286,489 for NSTAR Electric and $136,621,525 for WMECo (Exhs. ES-DPH-2 (East),

Sch. DPH-5 (Rev. 3); ES-DPH-2 (West), Sch. DPH-5 (Rev. 3)). The proposed adjustments are set forth in further detail below.

2. Companies Proposed Adjustments

a. Reclassification Adjustment and Normalizing Adjustments

Eversource proposes to reclassify $244,975 in special contract revenues from NSTAR Electric's Distribution Revenue category to its Other Revenue category (Exhs. ES-DPH-1, at 31; ES-DPH-2 (East), Sch. DPH-5, at 1 (Rev. 3)). Eversource states that this adjustment was made to recognize that special contract revenues are not part of the revenue requirement that is used to determine the revenue decoupling adjustments (Tr. 6, at 1184-1185). This adjustment has no net impact on total operating revenues (see Exh. ES-DPH-2 (East), Sch. DPH-5, at 1 (Rev. 3)).

Eversource also proposes normalization adjustments totaling $1,918,235,114 for NSTAR Electric and $343,813,492 for WMECo (Exhs. ES-DPH-2 (East), Sch. DPH-5 (Rev. 3); ES-DPH-2 (West), Sch. DPH-5 (Rev. 3); DPU-25-11; AG-19-9). These adjustments are intended to remove revenues that are reconciled and recovered outside of base distribution rates (e.g., through reconciling mechanisms) or to correct for discrepancies between calculated and booked revenues (Exhs. ES-DPH-1, at 31-32; AG-19-9, Att. at 1).

b. Pro Forma Adjustments

i. Introduction

Eversource proposes a number of pro forma adjustments totaling $2,627,932 for NSTAR Electric and $436,148 for WMECo (Exhs. ES-DPH-2 (East), Sch. DPH-5 (Rev. 3); ES-DPH-2 (West), Sch. DPH-5 (Rev. 3)). According to Eversource, these adjustments

account for purported known and measurable changes in the Companies' operating revenues. Each proposed adjustment is set forth separately below.

ii. NSTAR Electric's Rents from Electric Property

Eversource proposes to increase NSTAR Electric's revenues associated with its rents from electric property, which includes facilities leases and pole attachment revenues, by $1,363,355 (Exhs. ES-DPH-1, at 33-35; ES-DPH-2 (East), Sch. DPH-5 (Rev. 3); ES-DPH-3 (East), WP DPH-5, at 2). This overall adjustment is the result of proposed adjustments to the following rental agreements.

The first adjustment is associated with NSTAR Electric's pole attachment agreement with RCN Corporation ("RCN"). Under this agreement, RCN is obligated to pay NSTAR Electric a fee for attaching certain equipment to poles, including attachments to poles jointly owned by NSTAR Electric and Verizon (Exh. DPU-38-7, Att.). During the test year, Eversource booked $2,401,664 in revenues associated with the RCN agreement (Exh. ES-DPH-2 (East), WP DPH-5, at 2). According to the Companies, RCN notified Eversource that, starting January 1, 2016 (i.e., halfway through the test year), RCN entered into a pole attachment agreement with Verizon whereby RCN would pay Verizon half of the pole attachment revenues previously paid to Eversource (i.e., RCN would pay each pole owner the jointly owned rate for applicable pole attachments as opposed to the solely owned rate it had paid only to NSTAR Electric in 2015) (Exh. DPU-38-7; Tr. 15, at 3087). Eversource states that, going forward, NSTAR Electric's share of pole attachment revenues from RCN will be $1,824,336 (Exhs. ES-DPH-1, at 33; ES-DPH-3 (East), WP DPH-5, at 2

(Rev. 3)). Accordingly, Eversource proposes to decrease its test year revenues by $577,328 (Exhs. ES-DPH-1, at 33; ES-DPH-3 (East), WP DPH-5, at 2 (Rev. 3); Tr. 15, at 3087).

Second, Eversource anticipates rental revenues from NSTAR Gas for its share of the use of facilities in Plymouth, Somerville, and Hyde Park to decrease by $61,007 (Exhs. ES-DPH-1, at 33-34; ES-DPH-3 (East), WP DPH-5, at 2 (Rev. 3)). According to Eversource, this revenue decrease for NSTAR Electric reflects the most updated costs to be charged to NSTAR Gas (Exh. ES-DPH-1, at 33-34).

Third, Eversource proposes to increase its rental revenues for NSTAR Electric by $1,542,042 to reflect changes associated with its relocation of its New Bedford service center to a new facility in New Bedford (Exhs. ES-DPH-1, at 34; ES-LML-1, at 46; ES-DPH-3 (East), WP DPH-5, at 2 (Rev. 3); DPU-36-4, Att.).[31] Eversource states that a portion of the new facility will be rented to NSTAR Gas, which accounts for the increase in rental revenues (Exh. ES-DPH-1, at 34).

Next, Eversource proposes to increase NSTAR Electric's rental revenues by $82,424 to reflect lease revenues received from MembersPlus Credit Union and Herb Chambers Companies (Exhs. ES-DPH-1, at 34-35; ES-DPH-3 (East), WP DPH-5, at 2 (Rev. 3)). According to Eversource, this adjustment does not represent a change in test year levels; instead it is a normalizing adjustment to recognize these revenues in its account for Other Rent from Electric Property rather than as an offset to rent expense (Exhs. ES-DPH-1, at 35; ES-DPH-2 (East), Sch. DPH-18, at 2; ES-DPH-3 (East), WP DPH-5, at 2 (Rev. 3)).

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[31] The New Bedford service center project is addressed in Section VII.C below.

Finally, Eversource recently entered into a lease agreement with Beth Israel Hospital to rent a section of the Companies' facility in Westwood to the hospital (Exhs. DPU-8-3 & Atts. (Supp. 1)); Tr. 4, at 779-780; Tr. 6, at 1182-1184). Eversource states that this agreement will increase rental revenues by $377,224 for NSTAR Electric (Exhs. DPU-8-3 & Att. (b) (Supp. 1); ES-DPH-3 (East), WP DPH-5, at 2 (Rev. 3); Tr. 4, at 779-780; Tr. 6, at 1182-1184).

iii. NSTAR Electric's Other Electric Revenues

Eversource proposes to increase NSTAR Electric's Other Electric Revenues by $1,264,577 (Exhs. ES-DPH-3 (East), WP DPH-5, at 1 (Rev. 3); DPU-25-8, Att.). This adjustment comprises a proposed increase of $1,713,654 to account for adjustments related to restoration and other fees, and a proposed decrease of $449,077 associated with the expected cancellation of a transmission service agreement between NSTAR Electric and the Town of Belmont, Massachusetts Municipal Light Department ("Belmont Light") ("Belmont Service Agreement") (Exhs. ES-DPH-3 (East), WP DPH-5, at 1 (Rev. 3); DPU-25-6, at 1; DPU-25-8, Att.; DPU-25-9; AG-37-2).

With respect to fees, NSTAR Electric proposes increases in its returned check fee, account restoration fee (meter), and warrant fee (Exhs. ES-DPH-3 (East), WP DPH-5, at 1 (Rev. 3); DPU-25-8, Att.; DPU-25-9).[32] Further, Eversource proposes revenue adjustments for three additional fees – an account restoration fee (pole), an account restoration fee

[32] The warrant fee includes costs associated with preparation of paperwork, time at courthouses, police details, constables/sheriffs, locksmiths, and court fees (Exh. DPU-6-4, Att. (c)).

(manhole), and a sales tax abatement fee (Exhs. ES-DPH-3 (East), WP DPH-5, at 1 (Rev. 3); DPU-25-8, Att.; DPU-25-9).[33] Eversource's proposed fees are addressed in Section XVII.C below.

iv. WMECo's Restoration and Other Fees Revenues

Eversource proposes to increase WMECo's restoration and other fees revenues by $436,148 to account for adjustments related to restoration and other fees (Exh. ES-DPH-3 (West), WP DPH-5 (Rev. 3); AG-19-41, Att.). Specifically, Eversource proposes increases to WMECo's return check fee, account restoration fee (meter), warrant fee, and account restoration fee (manhole), and an adjustment to reflect a sales tax abatement fee (Exhs. ES-DPH-3 (West), WP DPH-5 (Rev. 3); AG-19-41, Att.). Eversource also proposes an adjustment to WMECo's Other Electric Revenue to reflect a decrease associated with the account restoration fee (pole) (Exhs. ES-DPH-3 (West), WP DPH-5 (Rev. 3); AG-19-41, Att.).[34] Eversource's proposed fees are addressed in Section XVII.C below.

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[33] The proposed increase of $1,713,654 to account for adjustments related to restoration and other fees is broken down as follows: (1) return check fee – $94,996; (2) account restoration fee (meter) – $1,344,954; (3) warrant fee – $138,804; (4) account restoration fee (pole) – $11,954; (5) account restoration fee (manhole) – $5,324; and (6) sales tax abatement fee – $117,622 (Exhs. ES-DPH-3 (West), WP DPH-5, at 1 (Rev. 3); AG-19-41, Att.).

[34] The proposed increase of $436,148 to account for adjustments related to restoration and other fees is broken down as follows: (1) return check fee – $24,583; (2) account restoration fee (meter) – $384,552; (3) warrant fee – $7,919; (4) account restoration fee (manhole) – $9,708; (5) sales tax abatement fee – $11,086; and (6) account restoration fee (pole) – ($1,700) (Exhs. ES-DPH-3 (East), WP DPH-5 (Rev. 3); DPU-25-8, Att.; DPU-25-9).

3. Positions of the Parties

a. Attorney General

The Attorney General argues that, consistent with Department precedent, the Companies' revenues should be adjusted to reflect the test year-end number of pole attachments multiplied by current pole attachment rates (Attorney General Brief at 199, citing Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 09-39, at 121 (2009); Massachusetts Electric Company, D.P.U. 95-40, at 79 (1995); Boston Edison Company, D.P.U. 85-266-A/85-271-A, at 117 (1986); D.P.U. 1720, at 85). Using this method, the Attorney General calculates the amount of pole attachment test year-end revenues to be included in the cost of service as $4,554,630 for NSTAR Electric and $810,302 for WMECo (Attorney General Brief at 199-200, citing Exh. AG-51-17; RR-AG-26).

Further, as described in Section XVII.C below, the Attorney General challenges several of Eversource's proposed fee increases. The Attorney General does not, however, offer any specific adjustments to revenues related to these challenges.

Finally, the Attorney General argues that the Companies should not be allowed to make a pro forma adjustment to eliminate $449,077 in revenues related to the Belmont Service Agreement (Attorney General Brief at 196; Attorney General Reply Brief at 50). According to the Attorney General, the proposed adjustment cannot be recognized as a known and measurable change because it has not occurred and the record does not support a finding that the contract will be terminated (Attorney General Brief at 196; Attorney General Reply Brief at 50-51). Further, the Attorney General contends that the Companies have failed to establish that termination of the Belmont Service Agreement is outside the normal

ebb and flow of revenue changes resulting from the addition and departure of customers (Attorney General Brief at 198).

b. Companies

The Companies argue that its proposed revenue adjustments are consistent with the Department's practices and should be accepted (Companies Brief at 172-175). With respect to pole attachments revenues, the Companies contend that the Attorney General's revenue adjustment calculations based on test year-end pole attachment counts and rates are erroneous because she transposed the rates assigned to jointly- and solely-owned poles, which inflated her calculation (Companies Brief at 507-508).[35] The Companies arguments concerning the reasonableness of the proposed increases to specific fees are summarized below in Section XVII.C.

Regarding the Belmont Service Agreement, the Companies argue that because Belmont Light completed the construction of a new substation and is taking steps to transfer its load to the new substation, it is "very unlikely" that Belmont Light will continue taking service under the Belmont Service Agreement (Companies Reply Brief at 144). Therefore, the Companies assert that the Department should allow the proposed adjustment to remove

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[35] According to the Companies, the test year-end pole attachment revenue calculations using the correct (i.e., non-transposed) rates for jointly and solely owned poles are $2,994,480 for NSTAR Electric and $439,623 for WMECo (Companies Brief at 507-508, citing Exhs. ES-DPH-3 (East), WP DPH-5, at 2; ES-DPH-2 (West), Sch. DPH-5, at 1; AG-51-17; AG-51-17 (Rev. 1); RR-AG-24). The Companies do not, however, propose to use these revenue calculations as the baseline for their proposed revenue adjustments.

revenues related to the Belmont Service Agreement (Companies Brief at 507; Companies Reply Brief at 144).

4. Analysis and Findings

a. Proposed Reclassification and Normalization Adjustments

The Department has reviewed the evidence supporting Eversource's proposed reclassification of NSTAR Electric's special contract revenues and the Companies' proposed normalization adjustments (Exhs. ES-DPH-1, at 31-32; ES-DPH-2 (East), Sch. DPH-5 (Rev. 3); ES-DPH-2 (West), Sch. DPH-5 (Rev. 3); AG-19-9 & Att.; DPU-25-11). We find that the aforementioned adjustments are consistent with Department practice and, therefore, are allowed.

b. Proposed Pro Forma Adjustments

i. NSTAR Electric's Rents from Electric Property

As noted above, Eversource proposes to increase NSTAR Electric's revenues associated with its rents from electric property by $1,363,355 (Exhs. ES-DPH-1, at 33-35; ES-DPH-2 (East), Sch. DPH-5 (Rev. 3); ES-DPH-3 (East), WP DPH-5, at 2 (Rev. 3)).

The Department has reviewed the evidence supporting the proposed adjustments relating to NSTAR Gas' share of the Plymouth, Somerville and Hyde Park facilities leases; the relocation of the New Bedford service center; the Members Plus Credit Union and Herb Chambers lease; and Beth Israel Hospital's lease of space at the Companies' Westwood facility (Exhs. ES-DPH-1, at 33-35; ES-DPH-3 (East), WP DPH-5, at 2 (Rev. 3); DPU-8-3 & Atts. (Supp. 1); DPU-36-4, Att.; Tr. 4, at 779-780; Tr. 6, at 1182-1184). We find that the aforementioned adjustments are known and measurable. Therefore, the Department

allows the proposed adjustments to the Companies' revenues in the amount of $1,940,683 related to the leases identified above.

With respect to pole attachments revenues, the Companies propose to decrease test year revenues by $577,328 to reflect a change in pole attachment revenues from RCN (Exhs. ES-DPH-1, at 33; ES-DPH-3 (East), WP DPH-5, at 2 (Rev. 3)). Although the Attorney General did not address the specific adjustment related to RCN, she argues that, in order to conform to Department precedent, the Companies' test year pole attachment revenues should be adjusted upwards to reflect the test year-end number of pole attachments multiplied by the current pole attachment rates (Attorney General Brief at 199).

Like other revenues received by the Companies, pole attachment revenues are an offset to expenses and serve to reduce the revenue requirement that is used to design rates. In order to ensure that a representative level is used as an offset to expenses, the Department adjusts test year pole attachment revenues on the basis of the test year-end number of attachments, as well as the test year-end pole attachment rates. Fitchburg Gas and Electric Light Company, D.P.U. 11-01/D.P.U. 11-02, at 167-168 (2011); D.P.U. 09-39, at 121; D.P.U. 95-40, at 79; D.P.U. 85-266-A/85-271-A at 117; D.P.U. 1720, at 85.

Here, the Companies did not apply Department precedent (i.e., projected revenues based on actual test-year end number of attachments and attachment rates) when calculating the proposed level of pole attachment revenues to include as an offset in rates. Instead, the Companies propose to use test year pole attachment revenues as the baseline to apply a post-test year adjustment (Exhs. ES-DPH-1, at 33; ES-DPH-3 (East), WP DPH-5, at 2

(Rev. 3)). We find that the method proposed by the Companies is likely to understate the representative level of pole attachment revenues to include as an offset in rates.[36] Therefore, the Department declines to adopt the method proposed by the Companies, and will instead apply the Department's precedent to calculate the appropriate level of pole attachment revenues.

Applying Department precedent, the Attorney General offers a calculation of the representative level of test year-end pole attachment revenues to be included in cost of service (Attorney General Brief at 199-200, citing Exh. AG-51-17; RR-AG-26).[37] However, as noted by the Companies, the Attorney General incorrectly transposes the rates assigned to jointly- and solely-owned poles in her calculation (Exh. AG-51-17; RR-AG-24). While not proposing to use these revenue calculations as the baseline for their proposed revenue adjustments, but to demonstrate the error in the Attorney General's calculation, the Companies provide their own calculation of test year-end pole attachment revenues by multiplying the total number of attachments to jointly owned and solely owned poles by the respective rates for jointly and solely owned poles in each service territory (Companies Brief at 508-509, citing Exh. AG-51-17; RR-AG-26). Based upon the Companies' calculations,

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[36] It is generally anticipated that the number of pole attachments (as well as pole attachment rates) will increase over time. See e.g., D.P.U. 11-01/D.P.U. 11-02, at 167-168; D.P.U. 09-39, at 120-121.

[37] Using this method, the Attorney General maintains that the test year-end pole attachment revenues are $4,554,630 for NSTAR Electric and $810,302 for WMECo (Attorney General Brief at 199-200, citing Exh. AG-51-17; RR-AG-26).

total test year revenues would exceed test year-end revenues by $1,638,762.[38] The unexplained magnitude and direction of this difference between total test year revenues and test year-end revenues is significant, thereby causing the Department to question the reliability of the Companies' pole attachment data in this proceeding.

One possible explanation for the difference is that the Companies failed to account for revenues from antenna attachments in their test year-end calculation. Antenna attachments command a significantly higher rate than other types of attachments (i.e., $200 for solely owned poles and $100 for jointly owned poles, as compared to $10.00 and $5.00, for solely owned poles and jointly owned poles, respectively for NSTAR Electric, and $9.00 and $4.50, for solely owned poles and jointly owned poles, respectively for WMECo) (Exh. AG-51-17). The Companies have not, however, identified the test year-end number of antenna attachments or otherwise broken down the data by attachment type.

Additionally, the Department has identified other discrepancies with the Companies pole attachment data that lead us to conclude that they cannot be used to reliably calculate test-year end pole attachment revenues consistent with Department precedent. For example, in Exhibit AG-51-17, the Companies report a total of 87,267 pole attachments in WMECo's service territory. However, in response to Record Request AG-26, the Companies report a

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38 Using this method, the Companies indicate that test year-end pole attachment revenues are $2,994,480 for NSTAR Electric and $439,623 for WMECo (Companies Brief at 508-509, citing Exhs. ES-DPH-3 (East), WP DPH-5, at 2; ES-DPH-2 (West), Sch. DPH-5, at 1; AG-51-17; RR-AG-24; RR-AG-26). As noted above, the Companies have not proposed to include these numbers in cost of service. By comparison, actual test year pole attachment revenues as reported by the Companies are $4,632,577 for NSTAR Electric and $440,288 for WMECo (or a difference of $1,638,097 for NSTAR Electric and $665 for WMECo) (RR-AG-24).

total of 92,587 pole attachments for WMECo (i.e., 87,480 attachments on jointly owned poles and 5,107 attachments on solely owned poles). Therefore, there is an unexplained variance of 5,320 pole attachments between the two data sets. Accordingly, based on the evidence available in this proceeding, the Department is not able to apply our standard precedent to calculate a reliable, representative test year-end level of pole attachment revenues.

The Companies have the burden to demonstrate that they have included a reliable, representative level of pole attachment revenues as an offset in rates. Because the Companies have not presented data sufficient to allow us to calculate year-end pole attachment revenues in a manner consistent with our long-standing precedent, we must apply an alternate method in this case to arrive at a representative level of pole attachment revenues.

The Department found above that the Companies' proposal to adjust test year pole attachment revenues is likely to understate the representative level of pole attachment revenues to include as an offset in rates.[39] Accordingly, the Department declines to adopt the Companies' proposal, including the pro forma adjustment of $577,328. Rather, based on the evidence presented in this case, the Department finds that unadjusted test year pole

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[39] The Companies proposed to adjust test year revenues by $577,328 to account for an anticipated change in pole attachment revenues from RCN (Exh. ES-DPH-3 (East), WP DPH-5, at 2 (Rev. 3)). If the Companies had correctly applied Department precedent in this case, no adjustment to account for a change in RCN-related revenues would be required because the correct rates for all RCN attachments would already be reflected in the test-year end calculation. Because RCN adjusted the amount it paid NSTAR Electric for pole attachments starting January 1, 2016 (i.e., halfway through the test year), the change would have been reflected in an end-of-test year calculation of the number of pole attachments (by type) multiplied by the then-current pole attachment rates (Exh. DPU-38-7; Tr. 15, at 3087).

attachment revenues will provide a reasonable, representative level of pole attachment revenues to include as an offset in rates. Any concerns that our inability to apply Department precedent would underrepresent the pole attachment revenue offset are addressed by the use of unadjusted test year revenues, as we find it will produce the most reasonable, representative test year-end level of pole attachment revenues given the available evidence in this case. Accordingly, the Companies shall include the following amounts in revenues: $4,632,577 for NSTAR Electric and $440,288 for WMECo (RR-AG-24).

Our adoption of this method in the instant case is not intended to change Department precedent regarding pole attachment revenues. In all future rate proceedings, the Companies shall calculate test year-end pole attachment revenues based on the test year-end number of pole attachments by type and the then-current rates for each attachment type (e.g., antenna attachments). The Companies shall provide sufficient data to support the reasonableness and reliability of these calculations, including pole attachment numbers, attachment types, and attachment rates.

ii. NSTAR Electric's Other Electric Revenues

As noted above, Eversource proposes to increase NSTAR Electric's Other Electric Revenue by $1,264,577 (Exhs. ES-DPH-3 (East), WP DPH-5, at 1 (Rev. 3); DPU-25-8, Att.). This adjustment comprises a proposed increase of $1,713,654 to account for adjustments related to restoration and other fees, and a proposed decrease of $449,077 associated with the expected cancellation of the Belmont Service Agreement (Exhs. ES-DPH-3 (East), WP DPH-5, at 1 (Rev. 3); DPU-25-9). The reasonableness of

NSTAR Electric's proposed fees is addressed in Section XVII.C below. Consistent with the Department's findings therein, NSTAR Electric's Other Electric Revenue shall be reduced by $1,073,517.

Regarding the Belmont Service Agreement, the Attorney General urges the Department to deny the Companies' proposal to reduce revenues by $449,077 to reflect the termination of the agreement (Attorney General Brief at 196-198; Attorney General Reply Brief at 50-51). Specifically, the Attorney General argues that Eversource did not establish that the termination of the Belmont Service Agreement is outside the normal ebb and flow of revenue changes resulting from the addition and departure of larger customers (Attorney General Brief at 196-198). Although the Companies maintain that the adjustment is known and measurable, they do not address arguments about ebb and flow (Companies Reply Brief at 144-145).

The Department seeks to include in rates the likely cost of providing the same level of service as was provided in the test year. Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 17; Boston Gas Company, D.P.U. 88-67 (Phase I) at 140. Therefore, the Department does not normally make adjustments for post-test year changes in revenues attributed to customer growth unless the change is significant and outside of the normal "ebb and flow" of customers. D.T.E. 03-40, at 27; Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 77 (2002); Massachusetts American Water Company, D.P.U. 88-172, at 7-8 (1989); Bay State Gas Company, D.P.U. 1122, at 46-49 (1982). The rationale for this policy is that revenue adjustments of this nature would also require a number of

corresponding adjustments to expense and could disrupt the relation of test year revenues to test year expenses. D.T.E. 03-40, at 27; New England Telephone and Telegraph Company, D.P.U. 86-33-G at 322-327 (1989). However, the addition or deletion of a customer or a change in a customer's consumption, either during or after the test year, that (1) represents a known and measurable increase or decrease to test year revenues, and (2) constitutes a significant change outside of the "ebb and flow" of customers, may warrant an adjustment. D.T.E. 03-40, at 28. A change can be significant in one set of circumstances and insignificant in another. In cases where a significant change is found to exist, the Department may include (or exclude) a representative level of sales corresponding to a proven change in the derivation of a utility's revenue requirement. D.T.E. 03-40, at 28; D.T.E. 02-24/25, at 80; D.T.E. 99-118, at 14-20; D.P.U. 88-172, at 7-9. In making the "ebb and flow" determination, the Department has consistently considered the effect on a company's total distribution operating revenues. See D.T.E. 02-24/25, at 80; D.T.E. 99 118, at 18. Total distribution revenues are the standard for comparison – not some subset such as special contracts. See, e.g., D.T.E. 02-24/25, at 80-81.

Here, NSTAR Electric's total test year distribution revenues are $854,286,489 (Exh. ES-DPH-2 (East), Sch. DPH-5, at 1). The proposed $449,077 reduction in revenues due to the termination of the Belmont Service Agreement represents a decrease of 0.05 percent in total distribution operating revenues. The Department finds that the impact of the loss of revenues from the termination of the Belmont Service Agreement is not significant and is within the normal ebb and flow of business. D.P.U. 03-40, at 27-31;

Dedham Water Company, D.P.U. 1217, at 7-9, 39 (1983). Accordingly, we deny the pro forma adjustment to NSTAR Electric's other operating revenues in the amount of $449,077.[40]

iii. WMECo's Restoration and Other Fees Revenues

As noted above, Eversource proposes to increase WMECo's restoration and other fees revenues by $436,148 to account for adjustments related to restoration and other fees (Exh. ES-DPH-3 (West), WP DPH-5 (Rev. 3); AG-19-41, Att.). The reasonableness of WMECo's proposed fees is addressed in Section XVII.C below. Consistent with the findings contained therein, WMECo's Other Electric Revenue shall be reduced by $358,726.

c. Other Adjustments

During the rate design track of this proceeding, Eversource proposed to discontinue the separate accounting methods currently used by NSTAR Electric and WMECo for net metering, and instead move to a single, uniform method (Exh. DPU-63-11). More specifically, Eversource seeks to modify the reporting currently applied by WMECo in its billing and accounting processes in order to be consistent with NSTAR Electric's method for recovering net metering credits through the net metering recovery surcharge ("NMRS") (Exh. DPU-63-11). Thus, for both NSTAR Electric and WMECo, the non-reconciling distribution portion of revenue displaced ("DDR") no longer would be recovered through the NMRS but, instead, would be recovered through the Companies' revenue decoupling

[40] Having found the proposed revenue adjustment is not significant, we need not address the Attorney General's argument that the proposed revenue adjustment was also not "known and measurable."

mechanism (Exh. DPU-63-11).[41] Eversource states that it does not expect to incur any significant information technology-related costs in order to implement this change (Exh. DPU-63-12).

The Department finds that Eversource's proposal to implement a uniform accounting method for the recovery of net metering credits and DDR is reasonable and, therefore, is approved. As a result of this modification, WMECo's test year distribution revenues and energy sales will need to be lowered by $464,646 and 13,780,890 kWh, respectively, to reflect a common accounting treatment for billed revenues (Exh. DPU-65-1). In addition, the revenue decoupling normalizing adjustment will need to be increased by $464,646 to meet the target revenue of $132,415,739 (Exh. DPU-65-1). Accordingly, the Department will reduce WMECo's test year distribution revenue by $464,646 and increase the normalizing adjustment for revenue decoupling by $464,646.

VII. RATE BASE

A. Introduction

NSTAR Electric's test year rate base was calculated as $2,649,117,430 (Exh. ES-DPH-2-3 (East), Sch. DPH-27 (Rev. 4)).[42] To this amount, NSTAR Electric proposes to add $88,730,573 in adjustments for a total proposed rate base of $2,737,848,003

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41 Eversource's revenue decoupling proposal will be addressed in our subsequent Order addressing rate design issues.

42 Minor discrepancies in any of the amounts appearing in this section are due to rounding.

(Exh. ES-DPH-2-3 (East), Sch. DPH-27 (Rev. 4)).[43] NSTAR Electric's total proposed rate base consists of: (1) $3,630,658,728 in net utility plant in service; (2) $34,922,056 in materials and supplies; (3) $60,537,693 in regulatory assets; and (4) $37,582,185 in cash working capital, less (1) $984,848,121 in accumulated deferred income taxes; and (2) $41,004,538 in customer deposits and advances (Exh. ES-DPH-2-3 (East), Sch. DPH-27 (Rev. 4)).

WMECo's test year rate base was calculated as $436,819,949 (Exh. ES-DPH-2-3 (West), Sch. DPH-27 (Rev. 3)). To this amount, WMECo proposes to add $2,821,938 in adjustments for a total proposed rate base of $439,641,887 (Exh. ES-DPH-2-3 (West), Sch. DPH-27 (Rev. 4)).[44] WMECo's total proposed rate base consists of (1) $581,503,227 in net utility plant in service; (2) $2,242,787 in materials and supplies; (3) $19,209,890 in regulatory assets; and (4) $7,641,476 in cash working capital, less (1) $168,549,368 in accumulated deferred income taxes; and (2) $2,406,125 in customer deposits and advances (Exh. ES-DPH-2-3 (West), Sch. DPH-27 (Rev. 4)).

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[43] NSTAR Electric's pro forma adjustment includes an increase of $105,536,686 in net utility plant less $16,818,289 in accumulated deferred income taxes (Exh. ES-DPH-2-3 (East), Sch. DPH-27 (Rev. 3)).

[44] WMECo's pro forma adjustment includes an increase of $3,488,926 in net utility plant less $672,829 in accumulated deferred income taxes (Exh. ES-DPH-2-3 (West), Sch. DPH-27 (Rev. 3)).

B. Test Year Plant Additions

1. Introduction

From January 1, 2005 through June 30, 2016,[45] NSTAR Electric added $2,622,881,608 to its net distribution plant in service (Exhs. ES-LML-2 (East) (Rev); ES-CAH-1, at 17). NSTAR Electric's adjusted test year actual plant in service as of June 30, 2016 totaled $5,177,571,546 (Exh. ES-DPH-2 (East), Sch. DPH-28 (Rev. 3)).

From January 1, 2010 through June 30, 2016,[46] WMECo added $238,919,345 to its net distribution plant in service (Exh. ES-LML-2 (West)). WMECo's adjusted test year actual plant in service as of June 30, 2016 totaled $829,598,715 (Exh. ES-DPH-2 (West), Sch. DPH-28 (Rev. 3)).

NSTAR Electric's 2016 actual plant in service amount includes $58,901,659 of plant moved from construction work in progress ("CWIP")[47] to plant accounts during calendar year 2016 (Exhs. AG-1-2, Att. 7(j) at 118-119; AG-1-2, Att. (a) at 126-127 (Supp. 3)).

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45 NSTAR Electric's most recent test year ended on June 30, 2005 (Exh. ES-LML-1, at 4). Although the Company provided calendar year-end plant balances to align with financial reports that supported these balances, capital additions placed into service prior to June 30, 2005 are already included in NSTAR Electric's rate base (Exhs. ES-LML-1, at 22; ES-LML-2 (Rev.); Tr. 4, at 760-777).

46 WMECo's most recent test year ended on December 31, 2009 (see Exh. ES-LML-1, at 4). See also D.P.U. 10-70, at 57.

47 CWIP is a temporary holding account used to collect costs during the design and construction of a capital project. 220 CMR 51.01(1); 18 CFR Chapter 1, Part 101, Balance Sheet Chart of Accounts, Account 107 (Construction Work in Progress – Electric). For accounting purposes, CWIP is represented as an asset; under traditional ratemaking, CWIP is not included in rate base until the project is completed and in service. D.P.U. 11-43, at 34, n.35. Once a capital project is completed, the CWIP balance is transferred to the appropriate plant accounts.

NSTAR Electric's 2016 actual plant in service amount also includes a pro forma adjustment of $30,733,095 related to post-test year plant additions moved from CWIP to plant accounts as part of its proposal to include these additions in the test year end rate base in this proceeding (Exh. AG-1-2, Att. (a) at 126-127 (Supp. 3)).[48] In sum, the 2016 plant in service amount includes a net increase of $89,634,754 attributable to a net decrease of equal magnitude to 2016 CWIP balances (Exhs. AG-1-2, Att. 7(j) at 118-119; AG-1-2, Att. (a) at 126-127 (Supp. 3)).

2. Project Documentation

a. Introduction

Eversource's Project Authorization Policy ("PAP") governs the decision-making, evaluation, and approval of all capital and reimbursable project spending (Exh. ES-LML-1, at 7). The Companies' strategic plan ("Strategic Plan"), a component of the PAP, serves as the foundation for annual investment addressing infrastructure needs, system conditions, new customer growth, and other factors (Exh. ES-LML-1, at 8-10). Although the PAP and the Strategic Plan are currently enterprise-wide, NSTAR Electric and WMECo retained separate project-level capital authorization processes for much of the period between the Companies' last base rate proceedings and the end of the test year in this proceeding (Exh. ES-LML-1, at 7-8, 14-18). Specifically, WMECo's project authorization process was conducted through reviews by its Operating Company Review Committee ("OCRC"). We discuss NSTAR Electric's and WMECo's capital authorization processes and associated project documentation below.

[48] We address the post-test year plant additions separately below.

b. NSTAR Electric

NSTAR Electric's capital authorization process, governed by the PAP, sets initial documentation requirements based on project size (Exh. ES-LML-1, at 11-14). Specifically, projects that incur or are estimated to incur direct charges over $100,000 require a purpose and necessity ("P&N") document (Exh. ES-LML-1, at 11-12). A P&N includes: (1) a project description and objectives; (2) a scope and justification; (3) a financial evaluation; (4) a risk assessment; (5) alternatives considered; (6) a technology assessment (for information system projects only); (7) a project schedule; (8) project milestones; and (9) an implementation plan (Exh. ES-LML-1, at 11-12). Additionally, projects whose direct costs exceed the initially authorized budgeted amount by predetermined amounts require a supplemental P&N explaining the changes that affect the cost and requesting supplemental authorization (Exh. ES-LML-1, at 13). In particular, a project requires a supplemental P&N if direct costs exceed the authorized budgeted amount by: (1) $25,000 for projects more than $50,000, but less than or equal to $250,000; (2) $50,000 for projects more than $250,000, but less than or equal to $500,000; (3) ten percent for projects greater than $500,000; and (4) ten percent for any project with a variance greater than $1.0 million (Exh. ES-LML-1, at 13).

In the instant proceeding, Eversource provided several listings of NSTAR Electric's capital additions along with supporting documentation (Exhs. ES-LML-1, at 36; ES-LML-2 (East) (Rev.); ES-LML-3 (East); ES-LML-3A (East); ES-LML-4 (East); ES-LML-5 (East)). Eversource also provided a summary of NSTAR Electric's distribution capital additions that

shows total capital additions by year (Exhs. ES-LML-1, at 34; ES-LML-2 (East)). Further, Eversource provided NSTAR Electric's plant in service summary sheets by year for January 1, 2005 through June 30, 2016 that reconcile to the respective FERC Form 1 along with supporting schedules (Exhs. ES-LML-1, at 34; ES-LML-3 (East); ES-LML-3A (East)). Additionally, Eversource provided a chronological list of all NSTAR Electric projects/work orders for specific projects with direct charges over $100,000 and blanket programs, including original budgeted estimate, last revised pre-construction estimate, actual direct costs, percentage variance of pre-construction estimate compared to initial estimate, and percentage variance of actual direct costs compared to pre-construction estimate (Exhs. ES-LML-1, at 35; ES-LML-4 (East)).

For the purposes of documentation provision, NSTAR Electric classified capital additions as either distribution plant, general plant, or intangible plant (Exh. ES-LML-1, at 28). Each of these types of plant additions are further divided into the following five project types to reflect distinct documentation requirements: (1) specific projects with direct charges over $100,000; (2) blanket programs; (3) blanket work orders with direct charges over $50,000; (4) specific projects with direct charges under $100,000; and (5) blanket work orders with direct charges under $50,000 (Exh. ES-LML-1, at 28).

Eversource provided project documentation for NSTAR Electric's specific projects with direct charges over $100,000, blanket programs, blanket work orders with direct charges over $50,000, and specific projects with direct charges over $50,000 and less than $100,000 (Exhs. ES-LML-1, at 35-36; ES-LML-4 (East); ES-LML-5 (East)). Specifically,

the documentation for NSTAR Electric's specific projects with direct charges over $100,000 includes capital authorization analyses, P&N documents, supplemental P&N documents where applicable, variance analyses, funding information, and closing reports (Exhs. ES-LML-1, at 36; ES-LML-5 (East)). The documentation for NSTAR Electric's blanket programs, blanket work orders with direct charges over $50,000, and specific projects with direct charges over $50,000 and less than $100,000 includes closing reports and variance data where applicable (Exhs. ES-LML-1, at 35-36; ES-LML-4 (East); ES-LML-5 (East)).

Of note, NSTAR Electric's accounting data and project documentation for 2005-2013 differs in format, but not in content from that of 2014-2016 (Exh. ES-LML-1, at 22-23; see, e.g., Exh. ES-LML-5 (East), "15 NSTAR 2007 Box 1 of 3," "35 NSTAR 2015 Box 1 of 1"). Following the merger of Northeast Utilities and NSTAR, Eversource replaced the varied financial processes and systems previously in place across the individual operating companies (Exh. ES-LML-1, at 20-21). As part of the Financial Simplification and Standardization Project ("FSSP") project, Eversource implemented a single general ledger, a single budgeting tool, a centralized cost repository, and a new information technology platform (Exh. ES-LML-1, at 20-21). The new systems catalogue similar information as the legacy systems but present certain information differently (Exh. ES-LML-1, at 20-21).

In order to aid data conversion to the new systems, Eversource temporarily adjusted NSTAR Electric's authorization threshold for P&N documents. Specifically, NSTAR Electric, which normally requires a P&N for projects with direct costs over $100,000,

switched to requiring a P&N for project with total costs over $200,000 for calendar year 2014 (Exh. ES-LML-1, at 23-24).

c. WMECo

From the end of WMECo's last test year through 2016, WMECo's project-authorization process was conducted through reviews by its Operating Company Review Committee ("OCRC"), which consists of directors of the Engineering and Operation functions, managers of each operating area (Springfield, Hadley/Greenfield, and Pittsfield), Managers of Engineering, Substations, the Projects Group, Business Services and Facilities/Stores, Senior Engineering team members, and, occasionally, WMECo's Vice President and President (Exh. ES-LML-1, at 7, 14). The OCRC reviewed projects proposed by Engineering staff and provided initial project funding approval for all capital projects implemented in WMECo's service territory (Exh. ES-LML-1, at 14). The OCRC received project details in the form of project-need statements and revisions, visual presentations, and verbal discussion (Exh. ES-LML-1, at 17). The OCRC also monitored project progress, responded to changes in system needs, and adjusted the capital plan when necessary (Exh. ES-LML-1, at 14, 16-17). In 2016, WMECo transitioned its capital authorization process from the OCRC to the Eversource-wide process governed by the PAP (Exh. ES-LML-1, at 18). Though the Operations, Investment Planning, and Engineering personnel still continue to discuss and evaluate projects, WMECo's ultimate capital project authorization process is now conducted according to the PAP (Exh. ES-LML-1, at 18).

In the instant proceeding, Eversource provided for WMECo several listings of, along with supporting documentation for, the capital additions included in rate base as of June 30, 2016 (Exhs. ES-LML-1, at 37; ES-LML-2 (West); ES-LML-3 (West); ES-LML-3A (West); ES-LML-4 (West); ES-LML-5 (West)). Eversource also provided a summary of WMECo's distribution capital additions that shows total capital additions by year that fully reconcile to the respective FERC Form 1 (Exhs. ES-LML-1, at 37; ES-LML-2 (West); ES-LML-3 (West)). Further, Eversource provided WMECo's plant in service summary sheets by year for January 1, 2010 through June 30, 2016 along with supporting schedules (Exhs. ES-LML-1, at 38; ES-LML-3 (West); ES-LML-3A (West)). Additionally, Eversource provided a chronological list, along with supporting documentation, of all WMECo projects/work orders for specific and annual projects with total costs over $100,000, including variance analyses for each capital addition to the revised amount for each addition (Exhs. ES-LML-1, at 39; ES-LML-4 (West); ES-LML-5 (West)).

For the purposes of documentation provision, WMECo also classified capital additions as either distribution plant, general plant, or intangible plant (Exh. ES-LML-1, at 28). Each of these types of plant additions are further divided into the following three project types to reflect distinct documentation requirements: (1) specific projects with total costs over $100,000; (2) annual projects with total costs over $100,000; and (3) projects with total costs under $100,000 (Exh. ES-LML-1, at 28). Eversource provided documentation for WMECo's specific and annual projects with total costs over $100,000 including capital authorization analyses, system planning project proposals, asset management project

proposals, asset management multi-year project estimates, and project closing reports (Exh. ES-LML-5 (West)). Eversource also submitted WMECo's project-need statements and revisions, as well as variance analysis documentation for any project with a final variance that exceeds ten percent (Exh. ES-LML-1, at 18).

As with NSTAR Electric, Eversource's implementation of the FSSP in 2014 caused WMECo's accounting data and project documentation for 2010-2013 to differ in format, but not in content from that of 2014-2016 (Exh. ES-LML-1, at 22-23). The Companies did not identify any interim changes to WMECo's project authorization thresholds similar to those made to NSTAR Electric's project authorization thresholds associated with the data conversion to the new systems (see Exh. ES-LML-1, at 23-24).

3. Positions of the Parties

a. Attorney General

The Attorney General contends that the Companies' test year level of capital additions is inflated and constitutes a "spending spree" (Attorney General Brief at 101). The Attorney General claims that the Companies spent an average of $265 million per year on capital additions in the three years leading up to the test year and then spent $404 million on capital additions in the test year (Attorney General Brief at 102-103, citing Exhs. AG-1-17; AG-1-17, Atts. (a) and (b)). According to the Attorney General, these costs contribute to a pro forma cost of service that is unrepresentative of, and greatly exceeds, the Companies' normal costs (Attorney General Brief at 101).

The Attorney General also disputes Eversource's position that a review and clean-up of its CWIP account caused the increase in test year capital additions for two reasons (Attorney General Reply Brief at 8-10). First, the Attorney General maintains that the Companies do not explain why such a review took place mainly during the test year (Attorney General Reply Brief at 8). The Attorney General adds that the 52 percent increase in test year capital additions as compared to the previous year shows that the Companies' efforts to update plant balances are tipped heavily toward the test year (Attorney General Reply Brief at 10, citing Companies Brief at 421). Second, the Attorney General argues that, despite the Companies' claim that its CWIP review and post-test year additions are the drivers of increased test year capital additions, test year spending in some capital accounts is anomalously high (Attorney General Reply Brief at 10). In particular, the Attorney General contends that the following accounts exhibit unusually high spending patterns during the two six-month periods that comprise the test year as compared to the two six-month periods immediately before and after (January through June of 2015 and July through December of 2016): (1) office furniture and equipment (Account 391); (2) transportation equipment (Account 392); (3) tools, shop, and garage equipment (Account 394); and (4) communication equipment (Account 397) (Attorney General Reply Brief at 10). The Attorney General argues that the spending patterns of these accounts demonstrate markedly high test year capital spending not attributable to the CWIP review or post-test year capital additions (Attorney General Reply Brief at 10).

b. DOER

DOER argues that the Companies' proposed test year is unrepresentative of its overall pattern of capital investments over time (DOER Brief at 14). In particular, DOER claims that NSTAR Electric's test year capital expenditures of $363 million are a significant outlier in comparison to prior years' capital expenditures (DOER Brief at 14). In particular, DOER asserts that NSTAR Electric's test year capital expenditures are $123 million, or 51 percent, greater than the twelve-year annual average from 2005 to 2016 (DOER Brief at 14-15). DOER also contends that WMECo's test year capital expenditures of $56 million are less anomalous than NSTAR Electric's, but still elevated when compared to WMECo's historic average capital expenditures (DOER Brief at 15-16). Specifically, DOER asserts that WMECo's test year capital expenditures are $10 million, or 22 percent, greater than the eight-year annual average from 2009 to 2016 (DOER Brief at 16). DOER recommends that the Department take several steps to ensure that the high level of test year capital spending does not result in unjust and unreasonable rates for customers, including: (1) reviewing supporting documentation for test year capital projects; (2) reviewing pro forma adjustments for post-test year additions; and (3) considering the test year levels of capital spending when determining whether or a not a ratemaking mechanism designed to fund additional capital spending is warranted in this proceeding (DOER Brief at 17-18).

c. Companies

The Companies assert that they have properly supported the net plant in service through June 30, 2016 (Companies Brief at 267). Specifically, the Companies argue that they have demonstrated the prudent incurrence and used and useful status of the capital

additions proposed for inclusion in rate base by providing thousands of pages of documentation, including project cover sheets, approved amounts, actual costs, cost variance information, and closure papers (Companies Brief at 267, citing Exhs. ES-LML-1 through ES-LML-8). Additionally, the Companies claim that they provided information regarding the allocation, cost, and cost control of capital expenditures in direct testimony (Companies Brief at 267, citing Exh. ES-LML-1, at 33-42). Finally, the Companies argue that they provided additional information regarding project management cost control in oral testimony (Companies Brief at 267, citing Tr. 6, at 1208). The Companies thus maintain that the Department should include all capital additions through June 30, 2016, including those associated with specific projects, blanket projects, and blanket programs, in the rate base calculation (Companies Brief at 277-278).

Eversource contends that the increase in test year capital spending relative to previous years is not a result of the Companies' efforts to "inflate" test year capital additions (Companies Brief at 420, citing Attorney General Brief at 102-104). Rather, the Companies argue that a 2015 effort to clear CWIP balances on projects placed into service prior to the test year resulted in the increase in test year capital additions (Companies Brief at 420). Eversource adds that it further reduced the CWIP balance by the post-test year plant additions for a total net CWIP balance decrease, and concordant net plant in service increase, of $89,634,754 (Companies Brief at 421, citing Exh. AG-1-2 & Att., part 7; AG-1-2, Att. (a) (Supp. 3)). The Companies thus argue that the Attorney General's allegations are unsupported and that the Department should reject them.

Moreover, Eversource asserts that the increase in particular plant accounts is attributable to several large projects being placed into service during the test year, rather than unusually high spending (Companies Reply Brief at 105). Specifically, the Companies assert that the Electric Gas Insulated Switchgear 2011 HW Child project, the NSTAR VoiceOver IP project, and the Companies' ongoing annual replacement of fleet vehicles, explain the account balance increases in accounts 391, 397, and 392, respectively (Companies Reply Brief at 105-106). As such, the Companies claim that the Attorney General's allegations that the Companies have gone on a "spending spree" is factually incorrect and inconsistent with record evidence (Companies Reply Brief at 106-107). Thus, Eversource asserts that the Department should find that it did not impermissibly inflate test year capital spending (Companies Brief at 423).

4. Analysis and Findings

a. Standard of Review

For costs to be included in rate base the expenditures must be prudently incurred and the resulting plant must be used and useful to ratepayers. Western Massachusetts Electric Company, D.P.U. 85-270, at 20 (1986). The prudence test determines whether cost recovery is allowed at all, while the used and useful analysis determines the portion of prudently incurred costs on which the utility is entitled to a return. D.P.U. 85-270, at 25-27.

A prudence review involves a determination of whether the utility's actions, based on all that the utility knew or should have known at that time, were reasonable and prudent in light of the extant circumstances. Such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the Department merely to substitute its

own judgment for the judgments made by the management of the utility. Attorney General v. Department of Public Utilities, 390 Mass. 208, 229-230 (1983). A prudence review must be based on how a reasonable company would have responded to the particular circumstances and whether the company's actions were in fact prudent in light of all circumstances that were known, or reasonably should have been known, at the time a decision was made. D.P.U. 93-60, at 24-25; D.P.U. 85-270, at 22-23; Boston Edison Company, D.P.U. 906, at 165 (1982). A review of the prudence of a company's actions is not dependent upon whether budget estimates later proved to be accurate but rather upon whether the assumptions made were reasonable, given the facts that were known or that should have been known at the time. Massachusetts-American Water Company, D.P.U. 95-118, at 39-40 (1996); D.P.U. 93-60, at 35; Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A at 26 (1985).

The Department has cautioned utility companies that, as they bear the burden of demonstrating the propriety of additions to rate base, failure to provide clear and cohesive reviewable evidence on rate base additions increases the risk to the utility that the Department will disallow these expenditures. Boston Gas Company/Colonial Gas Company/Essex Gas Company, D.P.U. 10-55-B at 13-16 (2013); Bay State Gas Company, D.P.U. 09-30, at 144-145 (2009); Boston Gas Company, D.P.U. 96-50 (Phase I) at 21-24 (1996); D.P.U. 95-40, at 7-8; D.P.U. 93-60, at 25-26; The Berkshire Gas Company, D.P.U. 92-210, at 24 (1993). In addition, the Department has stated that:

> In reviewing the investments in main extensions that were made without a cost benefit analysis, the [c]ompany has the burden of demonstrating the prudence

> of each investment proposed for inclusion in rate base. The Department cannot rely on the unsupported testimony that each project was beneficial at the time the decision was made. The [c]ompany must provide reviewable documentation for investments it seeks to include in rate base.

D.P.U. 92-210, at 24.

b. Plant Additions

i. NSTAR Electric

As described above, NSTAR Electric follows a project authorization policy to manage its capital projects (Exh. ES-LML-1, at 7). In accordance with the authorization policy, projects that incur or are estimated to incur more than $100,000 in direct costs require a P&N. NSTAR Electric explained that it temporarily increased the P&N threshold to $200,000 in total costs for calendar year 2014 in order to aid data conversion to the new unified system (Exh. ES-LML-1, at 20-21). Further, projects whose direct costs exceed the authorized budgeted amount by predetermined thresholds require a supplemental P&N (Exh. ES-LML-1, at 12-13). During the course of a particular project or program, NSTAR Electric controls costs and maintains oversight at multiple levels (Exh. ES-LML-1, at 18-19). In addition to the use of supplemental P&N authorization, individual project managers review invoices and labor costs charged to projects on a monthly basis to ensure that the invoices, employee time, and all associated costs are properly charged to the projects (Exh. ES-LML-1, at 20). Additionally, senior management reviews the scope, size, design, and status of each current project on a monthly basis to ensure that the cost estimates remain accurate as well as to determine if projects should be altered or delayed based on the most recent system and cost information available (Exh. ES-LML-1, at 19). We find that NSTAR

Electric's project authorization and review policy and cost control measures are reasonable and appropriate.

No party challenged the prudence of the costs associated with or the in-service status of NSTAR Electric's capital projects proposed for inclusion in test year end rate base. Although the Attorney General argues that the level of capital additions in the test year constitutes a "spending spree," the Department is not persuaded that this is the case. An account-level review of the test year's capital additions reveals that several large projects, some spanning multiple years, placed into service during the test year contributed to the test year capital additions amount (Exhs. ES-LML-3A (East), Sch. LML-2015-A-2, lines 127-129, 1587-1609; ES-LML-3A (East), Sch. LML-2016-A-2, lines 51-53, 73-185; ES-LML-5 (East), "29 NSTAR 2011 Box 2 of 2," "038-35086"; ES-LML-5 (East), "33 NSTAR 2013 Box 2 of 2," "017-35103"; ES-LML-5 (East), "35 NSTAR 2015 Box 1 of 1," "035-05319"). Of the four accounts noted by the Attorney General, three accounts included large, multi-year projects. Specifically, a five-year technical systems upgrade was placed into service in December 2015, a three-year voice communication system consolidation project was placed into service in June 2016, and an annually recurring fleet vehicle replacement program was operating during the test year (Exhs. ES-LML-3A (East), Sch. LML-2015-A-2, lines 127-129, 1587-1609; ES-LML-3A (East), Sch. LML-2016-A-2, lines 51-53, 73-185; ES-LML-5 (East), "29 NSTAR 2011 Box 2 of 2," "038-35086"; ES-LML-5 (East), "33 NSTAR 2013 Box 2 of 2," "017-35103"; ES-LML-5 (East), "35 NSTAR 2015 Box 1 of 1," "035-05319"). The Department has found that decisions

regarding the level and types of capital investment to be made by a company rest, in large part, with company management. D.P.U. 85-266-A/85-271-A at 11; D.P.U. 09-30, at 145. The Department also has recognized that distribution companies have full discretion to exercise judgement in maintaining the safety and reliability of their distribution system. Boston Gas Company/Colonial Gas Company/Essex Gas Company, D.P.U. 10-55, at 134 (2010); D.P.U. 10-114, at 66. In pursuit of this goal, a company may, in a particular year, spend more or less on capital additions than any particular multi-year average of annual capital additions. There is no evidence that the higher level of capital expenditures incurred during the test year represents some form of "catch up" for under-investment in prior years, or that NSTAR Electric's practice of closing completed construction to plant is deficient. C.f. Bay State Gas Company, D.T.E. 05-27, at 103, n. 78 (2005) (prolonged delay in booking completed construction out of CWIP can produce unnecessary litigation as to whether such plant is used and useful). Thus, we are not convinced that a particular level of capital spending in the test year or other years is the result of evidence of anything other than the year-to-year fluctuations inherent to any capital-intensive enterprise. Therefore, the Department is not persuaded by the Attorney General's and DOER's argument that the increase in test year capital spending relative to previous years is a result of the Companies' efforts to "inflate" test year capital additions. Accordingly, we conclude that no adjustment to rate base is necessary with respect to NSTAR Electric's level of capital additions during the test year. As noted above, Eversource provided project documentation for the various categories of NSTAR Electric's proposed plant additions. The Department has reviewed the

information provided on behalf of NSTAR Electric for the projects it proposes to include in rate base, and we find that the project costs were prudently incurred and the projects are used and useful in service to customers (Exhs. ES-LML-1; ES-LML-2 (East) (Rev.); ES-LML-3 (East); ES-LML-3A (East); ES-LML-4 (East); ES-LML-5 (East)). Accordingly, the Department allows the cost of these projects to be included in rate base.

ii. WMECo

As described above, WMECo followed a project-authorization process through reviews by the OCRC to manage its capital projects (Exh. ES-LML-1, at 7). The OCRC reviewed projects proposed by Engineering staff and provided initial approval and funding for these projects (Exh. ES-LML-1, at 14). The OCRC controlled costs by monitoring the progress of capital projects, comparing the capital spending to the financial targets established in the capital operating plan, and making necessary adjustments to maximize the value of these investments given a constrained budget (Exh. ES-LML-1, at 16-17). In addition to this monitoring process, WMECo controlled costs through monthly "Work Plan" meetings in which senior management reviewed the scope, size, design, and status of each approved project to determine if any alterations were necessary (Exh. ES-LML-1, at 19). If a change to a capital plan or budget was deemed necessary, project managers submitted their recommendations to senior management for review and approval, allowing management a high level of control over ongoing and planned projects (Exh. ES-LML-1, at 19). We find that WMECo's project authorization and review policy and cost control measures are reasonable and appropriate.

No party challenged the prudent cost incurrence or in-service status of WMECo's capital projects proposed for inclusion in test year end rate base. Similar to our findings above, we are not persuaded that WMECo's increase in test year capital spending relative to previous years is a result of Eversource's efforts to inflate test year capital additions. We reiterate that distribution companies have full discretion to exercise judgement in the level and types of capital investment necessary to maintain the safety and reliability of their distribution system. D.P.U. 10-55, at 134; D.P.U. 10-114, at 66. Accordingly, we conclude that no adjustment to rate base is necessary with respect to WMECo's level of capital additions during the test year.

As noted above, Eversource provided project documentation for the various categories of WMECo's proposed plant additions. The Department has reviewed the information provided on behalf of WMECo for the projects it proposes to include in rate base and finds that the project costs were prudently incurred and the projects are used and useful in service to customers (Exhs. ES-LML-1; ES-LML-2 (West); ES-LML-3 (West); ES-LML-3A (West); ES-LML-4 (West); ES-LML-5 (West)). Accordingly, the Department allows the cost of these projects to be included in rate base.

C. Post-Test Year Capital Additions

1. Introduction

Eversource proposes to include four post-test year projects in rate base, of which three represent post-test year additions by NSTAR Electric and one represents a post-test year addition by WMECo (Exh. ES-LML-1, at 42-43). In particular, Eversource proposes to include the costs for a new substation on Electric Avenue in Boston ("Electric Avenue"), a

new substation on Seafood Way in Boston ("Seafood Way"), and a new service center in New Bedford ("New Bedford service center") in NSTAR Electric's rate base (Exh. ES-LML-1, at 43). Eversource also proposes to include the cost for its Montague substation improvement project ("Montague") in WMECo's rate base (Exh. ES-LML-1, at 45-46). These projects are further described below.

2. NSTAR Electric Projects

Eversource states that Electric Avenue is intended to support increased load growth, and, as such, is constructed to ultimately support 39 distribution circuits (Exh. ES-LML-1, at 43-44). According to Eversource, one distribution circuit was energized in November 2016, six additional distribution circuits are scheduled to be energized in 2017, and twelve are scheduled to be energized in 2018-2019 (Exh. ES-LML-1, at 44). The remaining circuits are reserved for future use (Exh. ES-LML-1, at 44).

Eversource states that Seafood Way is intended to provide back-up load relief for the existing K Street substation in South Boston (Exh. ES-LML-1, at 44). Eversource states that two distribution circuits are scheduled to be energized by February 2017, three additional distribution circuits are scheduled to be energized by the end of 2017, and a total of 12 distribution circuits are scheduled to be energized in 2018-2019 (Exh. ES-LML-1, at 45). The remaining circuits are reserved for future use (Exh. ES-LML-1, at 45).

Eversource states that the New Bedford service center relocates the existing electric and gas service center in New Bedford to a new facility at a nearby location in the same city (Exh. ES-LML-1, at 46). According to Eversource, the old facility is in need of extensive

repairs and must be vacated because of the poor environmental conditions (Exh. ES-LML-1, at 46-47). Eversource states that the cost of the new property was $8.3 million, and additional costs must be incurred to complete renovation work, including costs associated with a new HVAC system, a new electrical system, mechanical and plumbing work, a complete fit-out for electric and gas operations, and site work (Exh. ES-LML-1, at 48-49).[49] Eversource received a temporary certificate of occupancy for this facility on August 25, 2017 (Exh. ES-14).

Eversource initially proposed to include $31,800,000 in plant additions for the Electric Avenue project, $44,500,000 in plant additions for the Seafood Way project, and $24,000,000 in plant additions for the New Bedford project, for a total of $100,300,000 in NSTAR Electric plant additions (Exh. ES-DPH-3 (East), WP DPH-28, at 1). During the course of the proceeding, Eversource updated the proposed plant additions to recognize their actual costs as of April 30, 2017 (Exhs. ES-DPH-2-3 (East), WP DPH-28, at 1 (Rev. 3)); ES-LML-8 (Supp. 2), at 1; Tr. 13, at 2767; Tr. 15, at 3086). Eversource now proposes to include in NSTAR Electric's rate base $32,949,477 in plant additions for Electric Avenue, $42,718,949 in plant additions for Seafood Way, and $29,868,260 in plant additions for the New Bedford service center, for a total of $105,536,686 in plant additions (Exh. ES-DPH-2-3 (East), WP DPH-28, at 1 (Rev. 3)). Eversource estimates that once the three NSTAR Electric projects are fully built-out, the total distribution-related costs of

[49] NSTAR Gas is expected to occupy 32 percent of the facility and is expected to contribute $1,581,582 to NSTAR Electric annually as rent expense (Exhs. ES-DPH-1, at 34; ES-DPH-2 (East), WP DPH-5, at 2-3).

Electric Avenue, Seafood Way, and the New Bedford service center will be $61 million, $66 million, and $30 million,[50] respectively (Exhs. ES-LML1, at 44-49; AG-24-5; AG-24-6).

3. WMECo Project

Eversource states that the Montague project, at WMECo's substation in the Town of Montague, is intended to replace nine oil circuit breakers for the eight feeders and bus tie, replace two vacuum breakers for two substation transformers, and refurbish the substation yard (Exh. ES-LML-1, at 46). Eversource planned to substantially complete the project by spring 2017 (Exh. ES-LML-1, at 46).

Eversource initially proposed to include $5,400,000 in plant additions and $325,049 in plant retirements, associated with the Montague substation improvement project ("Montague") (Exh. ES-DPH-3 (West), WP DPH-28, at 1). During the course of the proceeding, Eversource updated the proposed plant additions and plant retirements to recognize actual costs as of April 30, 2017 (Exhs. ES-DPH-2-3 (East), WP DPH-28, at 1 (Rev. 3); ES-LML-8 (Supp. 2), at 1; Tr. 13, at 2767; Tr. 15, at 3086). Eversource now proposes to include in WMECo's rate base $3,813,975 in plant additions, less $325,049 in plant retirements, associated with Montague (Exh. ES-DPH-2-3 (West), WP DPH-28, at 1 (Rev. 3)).

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[50] The $30 million estimate for the New Bedford service center includes the sale of the old service center, the purchase of the new property, and all renovations and upgrades (Exh. ES-LML-1, at 49).

4. Positions of the Parties

a. Attorney General

The Attorney General argues that Eversource's proposal to include in NSTAR Electric's rate base three post-test year plant additions and in WMECo's rate base one post-test year addition is inappropriate (Attorney General Brief at 105; Attorney General Reply Brief at 10). The Attorney General claims that none of the four projects proposed by the Companies meet the Department's standards for post-test year plant additions (Attorney General Brief at 108). Specifically, the Attorney General contends that Electric Avenue, Seafood Way, and the New Bedford service center represent only 0.61 percent, 0.86 percent, and 0.46 percent, respectively, of NSTAR Electric's actual test year-end plant in service (Attorney General Brief at 107, citing Tr. 13, at 2771-2772). Further, she contends that Montague represents only 0.61 percent of WMECo's test year-end plant in service (Attorney General Brief at 107, citing Tr. 13, at 2773). The Attorney General thus maintains that none of these four projects is significant enough in amount to meet the Department's standard for inclusion in test year end rate base (Attorney General Brief at 107-108, citing Bay State Gas Company, D.P.U. 13-75, at 106-107 (2014)).

Further, the Attorney General asserts that Eversource did not account for related post-test year changes to either of the Companies' rate bases that would serve to partially offset the inclusion of these projects in rate base (Attorney General Brief at 108). First, the Attorney General claims that Eversource made no post-test year adjustment to the Companies' accumulated depreciation, which is deducted from rate base and would partially offset the effects of the plant additions' increase to rate base (Attorney General Brief

at 105-106, citing Exh. AG-DJE-1, at 12-13). Second, the Attorney General claims that Eversource made no post-test year adjustment to the Companies' sales to reflect load growth that the substation projects are designed to support (Attorney General Brief at 106, 108, citing Exh. AG-DJE-1, at 12-13). Third, the Attorney General argues that Eversource made no post-test year adjustment to NSTAR Electric's proposed materials and supplies balance to annualize the effect of an approximately $10 million transfer from the materials and supplies inventory to the Electric Avenue substation project (Attorney General Brief at 106-107, citing Exhs. ES-DPH-1, at 178; ES-DPH-3 (East), WP DPH-27; ES-LML-1, at 43-44; Tr. 13, at 2768-2770). Consequently, the Attorney General maintains that this $10 million in materials and supplies has been counted twice in Eversource's proposal for NSTAR Electric's test year-end rate base (Attorney General Brief at 107).

Finally, the Attorney General argues that Eversource's attempts to analogize this situation to that experienced in NSTAR Gas' most recent base rate case in order to justify the inclusion of these post-test year additions is not supported by evidence (Attorney General Reply Brief at 10-11, citing D.P.U. 14-150, at 48). The Attorney General distinguishes this case from that in D.P.U. 14-150 on the basis that: (1) unlike the 24-month lag between the end of the test year and the rate year used in D.P.U. 14-150, Eversource has experienced a corresponding lag of only 18 months; (2) unlike Eversource, NSTAR Gas adjusted all rate base elements beyond the end of the test year, including all increases in accumulated depreciation and other offsets to its post-test year plant additions; and (3) unlike Eversource, NSTAR Gas adjusted test year sales to reflect load growth accompanying its post-test year

plant additions (Attorney General Reply Brief at 11, citing D.P.U. 14-150, at 48-49). Thus, the Attorney General asserts that the Companies' proposed treatment of post-test year plant additions is improper and one-sided in that it recognizes changes to rate base that increase its revenue requirement but not those that have an offsetting effect (Attorney General Reply Brief at 12).

Based on these considerations, the Attorney General recommends that the Department reject Eversource's proposal to include all four proposed post-test year additions (Attorney General Brief at 108). Accordingly, the Attorney General asserts that NSTAR Electric's rate base should be reduced by $88,718,397, with its depreciation expense reduced by $1,919,677, and that WMECo's rate base should be reduced by $3,294,282, with its depreciation expense reduced by $96,992 (Attorney General Brief at 108).

b. Cape Light Compact

The Cape Light Compact agrees with the Attorney General that the Department should reject Eversource's proposal to include in NSTAR Electric's rate base three post-test year plant additions and to include in WMECo's rate base one proposed post-test year addition (Cape Light Compact Brief at 79-80, citing Exh. AG-DJE-1, at 10-14). Thus, Cape Light Compact asserts that the proposed post-test year plant additions and related expenses should be eliminated from the Companies' revenue requirements (Cape Light Compact Brief at 80).

c. Companies

Eversource argues that the Department should approve its proposal to include three post-test year plant additions in NSTAR Electric's rate base, and one post-test year plant

addition in WMECo's rate base (Companies Brief at 425; Companies Reply Brief at 107). The Companies present four arguments in support of their petition that the post-test year plant additions be included in rate base (Companies Brief at 426-430).

First, the Companies claim that the post-test year plant additions are significant under Department precedent (Companies Brief at 425, citing D.P.U. 13-75, at 109 and 112). In support of this argument, the Companies illustrate that NSTAR Electric's post-test year plant additions represent the following increases as percentages of test year-end rate base: (1) Electric Avenue represents 1.2 percent of rate base ($32,949,477/$2,734,402,771); (2) Seafood Way represents 1.5 percent of rate base ($42,718,949/$2,734,402,771); and (3) the New Bedford service center represents 1.1 percent of rate base (29,868,260/$2,734,402,771) (Companies Brief at 427, citing Exhs. ES-DPH-2 (East), Sch. DPH-28; ES-DPH-3 (East), WP DPH-28). The Companies argue that, taken together, the three NSTAR Electric post-test year plant additions represent 3.8 percent of rate base (Companies Brief at 427). Eversource also illustrates that WMECo's proposed post-test year project represents approximately 0.08 percent of that company's rate base ($3,813,975/$440,871,528) (Companies Brief at 427). The Companies therefore conclude that the post-test year plant additions represent a significant amount of rate base under Department precedent (Companies Brief at 426-427, citing D.P.U. 13-75, at 109, 112).

Second, Eversource asserts that each of the proposed post-test year capital additions meets the Department's known and measurable and in-service requirements for inclusion in rate base (Companies Brief at 425, citing D.P.U. 14-150, at 43-44; Dedham Water

Company, D.P.U. 84-32, at 17 (1984); D.P.U. 906, at 7-11). The Companies claim that they have provided documentation supporting the in-service status of each post-test year addition, as well as their known and measurable nature (Companies Brief at 425, citing Exhs. ES-CAH-1, at 13-16; ES-LML-1, at 42-49; ES-LML-8; ES-LML-8 (Supp. 1); ES-LML-8 (Supp. 2); ES-DPH-2 (East), Sch. DPH-28 (Rev. 2); ES-DPH-2 (East), WP DPH-28 (Rev. 2); ES-DPH-2 (West), Sch. DPH-28 (Rev. 2); ES-DPH-2 (West), WP DPH-28 (Rev. 2); AG-19-4; AG-19-37; AG-24-6).

Third, Eversource argues that "unique circumstances" similar to those present in NSTAR Gas' last base rate case warrant the inclusion of the proposed projects in rate base (Companies Brief at 428, citing D.P.U. 14-150, at 45-50). The Companies note that in D.P.U. 14-150, NSTAR Gas experienced a 24-month lag between the end of the test year used in that case and the effective date of the rates approved in that order (Companies Brief at 428, citing D.P.U. 14-150, at 45-50). The Companies represent that the 18-month lag in the instant proceeding is similar to the circumstances facing NSTAR Gas (Companies Brief at 428). Thus, the Companies maintain that the Department should include the post-test year additions to rate base to mitigate the impact of the lag between the end of the test year and the effective date of the rates being approved in this order (Companies Brief at 429).

Finally, the Companies claim that in the event that the PBR and the accompanying five year stay-out provision are approved, disallowing the proposed projects and delaying cost recovery for five years would be "punitive" (Companies Brief at 430). Eversource adds that

such a result would cause the rates effective January 1, 2018 to misrepresent the Companies' actual cost structure (Companies Brief at 430).

Eversource also specifically addresses some of the arguments raised by the Attorney General in support of her recommendation to disallow the proposed post-test year plant additions (Companies Reply Brief at 107). First, the Companies claim that the Department should disregard the Attorney General's contention that the projects are not significant because her analysis of the additions' significance is flawed (Companies Brief at 427, citing Attorney General Brief at 107). The Companies maintain that the Attorney General, in executing the significance test, incorrectly used gross plant in service as the denominator, which yielded skewed results (Companies Brief at 427). Second, Eversource argues that the Department should reject the Attorney General's concerns regarding the Companies' failure to account for load growth, reasoning that any increase in sales will be in and addressed by the implementation of revenue decoupling in this proceeding (Companies Reply Brief at 107). Third, Eversource argues that should the Department find it appropriate to make any offsetting adjustments, the Companies have provided the necessary information to adjust rate base for the increase in accumulated depreciation associated with the post-test year plant additions (Companies Reply Brief at 107). The Companies thus affirm that they have demonstrated that the post-test year plant additions warrant inclusion in rate base and have been properly included as such in the instant proposal (Companies Reply Brief at 110-111).

5. Analysis and Findings

a. Introduction

The Department does not recognize post-test year additions or retirements to rate base, unless the utility demonstrates that the addition or retirement represents a significant investment that has a substantial effect on its rate base. Boston Gas Company, D.P.U. 96-50-C at 16-18, 20-21 (1997); D.P.U. 96-50 (Phase I) at 15-16; D.P.U. 95-118, at 56, 86; D.P.U. 85-270, at 141 n.21; Massachusetts-American Water Company, D.P.U. 1700, at 5-6 (1984). See also Southbridge Water Supply Company v. Department of Public Utilities, 368 Mass. 300 (1975). As a threshold requirement, a post-test year addition to plant must be known and measurable, as well as in service. D.P.U. 84-32, at 17; D.P.U. 906, at 7-11. The Department has historically judged the significance of an investment by comparing the size of the addition in relation to rate base and not based on the particular nature of the addition. Western Massachusetts Electric Company, D.P.U. 1300, at 14-15 (1983).

b. Proposed Post Test-Year Plant Additions

i. Significance of Proposed Plant Additions

Eversource claims that the subject post-test year plant additions are significant under Department precedent (Companies Brief at 425, citing D.P.U. 13-75, at 109, 112). Specifically, the Companies argue that, taken together, the three NSTAR Electric post-test year plant additions represent 3.8 percent of rate base and the one WMECo project represents

0.8 percent of rate base (Companies Brief at 427).[51] According to the Companies, these post-test year plant additions meet the Department standard for significance (Companies Brief at 426-427, citing D.P.U. 13-75, at 109-112).

As an initial matter, the Department finds that Eversource's presentation of the three NSTAR Electric projects as one, aggregated project for purposes of executing the significance test is inconsistent with the Department's typical practice of evaluating individual post-test year projects for inclusion in rate base. D.P.U. 13-75, at 108-109; Oxford Water Company, D.P.U. 1699, at 4 (1984); D.P.U. 1700, at 5-6. Although the Department, on occasion, has combined individual plant additions for purposes of examining significance, we have done so based on a finding that the individual projects are integral to one another from an engineering or operational perspective. Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 35 (2009); D.P.U. 95-118, at 56. Here, Eversource's proposed plant additions, while entirely within the scope of the Companies' ongoing efforts to provide safe and adequate service to their customers, have not been demonstrated to be so interrelated to one another that they warrant examination on a combined basis. Therefore, the Department

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[51] Eversource's briefs inadvertently present the rate base comparison calculation as 0.08 percent (Companies Brief at 427; Companies Reply Brief at 109). In addition to correcting the typographical error, the Department notes that Eversource's application of the significance test inappropriately uses gross plant additions as the numerator and proposed test year end rate base as the denominator, which is inconsistent with the Department's practice of using net plant as the numerator and unadjusted test year-end rate base as the denominator (Companies Brief at 427). D.P.U. 13-75, at 108-109; D.P.U. 1699, at 4; D.P.U. 1700, at 5-6. As such, the Department presents the correct application of the significance test which yields a conclusion that Montague represents 0.8 percent of WMECo's test year end rate base ($3,488,926/$436,819,949) (Exh. ES-DPH-2 (West), WP DPH-28, at 1 (Rev. 3)).

will evaluate the significance of each proposed post-test year addition on an individual basis. Further, although Eversource has petitioned in this proceeding to merge NSTAR Electric and WMECo into a single corporate entity, it is not proposing to consolidate the revenue requirement calculation at this time (Exh. ES-DPH-1, at 3). Accordingly, the Department will review each post-test year plant addition relative to each operating company's test year-end rate base.

Eversource's post-test year plant additions proposed for inclusion in NSTAR Electric's rate base, Electric Avenue, Seafood Way, and the New Bedford service center, total $39,949,477, $42,718,949, and $29,868,260, respectively, as of April 30, 2017 (Exh. ES-DPH-2 (East), WP DPH-28, at 1 (Rev. 3)). The Department finds that, when compared to a test year-end rate base of $2,649,117,430 (Exh. ES-DPH-2 (East), Sch. DPH-27 (Rev. 3)), the Electric Avenue project, the Seafood Way project, and the New Bedford service center project each represent significant additions to NSTAR Electric's test year-end rate base.[52] Eversource's post-test year plant addition proposed for inclusion in WMECo's rate base, the Montague substation improvement project, represents $3,488,926 in net plant additions (Exh. ES-DPH-2 (West), WP DPH-28, at 1 (Rev. 3)).[53] The Department finds that, when compared to a test year-end rate base of $436,819,949, Montague does not

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[52] The Department notes that the Attorney General's application of the significance test uses plant in service as the denominator, which is inconsistent with the Department's typical practice of using test year-end rate base as the denominator (Attorney General Brief at 107, citing Tr. 13, at 2771-2773). D.P.U. 13-75, at 108-109; D.P.U. 1699, at 4; D.P.U. 1700, at 5-6.

[53] $3,813,975 in plant additions - $325,049 in plant retirements = $3,488,926 in net plant additions (Exh. ES-DPH-2-3 (West), WP DPH-28, at 1 (Rev. 3)).

represent a significant addition to WMECo's test year-end rate base (Exh. ES-DPH-2 (West), Sch. DPH-27 (Rev. 3)). Therefore, the Department will only consider Electric Avenue, Seafood Way, and the New Bedford service center for further review – i.e., whether the costs associated with the projects are known and measurable and were prudently incurred, and whether the projects are in service and used and useful.

Before we turn to that analysis, we note that we are not persuaded by Eversource's arguments concerning the purported similarities between the instant case and the factual scenario in D.P.U. 14-150. As we found in D.P.U. 14-150, at 50, the circumstances presented there were unique, and we did not intend for that decision to mark a wholesale change in the standard of review for post-test year plant additions and the required showing of significance. Further, we find unconvincing the Companies' arguments with respect to the relevance of the PBR term to the proposed post-test year plant additions. D.P.U. 96-50 (Phase I) at 15. Instead, we find no reason in the instant case to depart from our historical evaluation of the significance of proposed post-test year rate base additions vis-à-vis a company's test year-end rate base.

Having determined that the three projects proposed for inclusion in NSTAR Electric's rate base represent significant additions, the Department next determines whether (1) the costs associated with the projects are known and measurable, (2) the costs were prudently incurred, and (3) the projects are in service and used and useful. The Department will evaluate Electric Avenue, Seafood Way, and the New Bedford service center in turn.

ii. Status of Electric Avenue Substation

Eversource has provided sufficient evidence to document the reported cost of the Electric Avenue project of $32,949,477 (Exh. ES-LML-8, at 183, 323 (Supp. 2)). As such, we find that the costs incurred as of April 30, 2017, are known and measurable.

Next the Department considers whether the costs associated with Electric Avenue as of April 30, 2017 were prudently incurred. No parties have contested NSTAR Electric's decision to commence the Electric Avenue project or NSTAR Electric's management of the project. The Department finds that the Electric Avenue substation is necessary to support increased load requirements for portions of the City of Boston neighborhoods of Brighton, Allston, Longwood Avenue Medical and the Town of Watertown (Exhs. ES-CAH-1, at 13; ES-LML-1, at 43). Further, the record shows that Eversource provided documentation supporting the prudency of the costs associated with this project, including purpose and necessity documents, capital budget estimates, work orders, project cost sheets, variance explanations as of December 21, 2016, project authorization forms, and closing reports as of April 30, 2017 (Exhs. ES-LML-8, at 56-110 (Supp. 1); ES-LML-8, at 183-323 (Supp. 2); AG-19-3, Atts. (a), (b); Tr. 15, at 3086). Thus, the Department finds that the costs associated with Electric Avenue as of April 30, 2017, were prudently incurred.[54]

Finally, the Department considers whether Electric Avenue is in service and used and useful to customers. The record indicates that Electric Avenue includes twelve 115-kilovolt

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[54] We address the Attorney General's argument regarding the materials and supplies balance attributable to Electric Ave in Section VII.E below.

("kV") gas insulated switchgear breakers to interconnect to two transmission lines, three 15 kV, 62.5 megavolt-ampere ("MVA") 115/14-kV distribution transformers, six sections of distribution switchgear and three 15 kV, 9.6 megavolt ampere reactive ("MVAR") capacitor banks, a cutover of 19 existing distribution lines, and 39 distribution circuits (Exh. ES-LML-1, at 43-44). Of these substation components, the record indicates that: (1) transmission line 282-521 was energized and placed in service on December 6, 2016; (2) all gas insulated switchgear breaker equipment[55] was in service as of December 21, 2016; and (3) distribution line work will continue through 2018 (Exh. ES-LML-8, at 99-110 (Supp. 1)). In addition, Eversource represents that seven distribution circuits are scheduled to be energized in 2017 (Exh. ES-LML-1, at 44). The remaining components of the substation are still in progress, or are being held for future use as the substation is built to provide for future load growth (Exh. ES-LML-1, at 43-44; ES-LML-8, at 99-110 (Supp. 1); AG-24-6). Based on these considerations, we conclude that Electric Avenue was initially placed into service in December of 2016, and remains in service today (Exhs. ES-LML-1, at 44; ES-LML-8; ES-LML-8, at 99-110 (Supp. 1); AG-19-3, Atts. (a), (b); AG-19-4, Att.).

iii. Status of Seafood Way Substation

Eversource has provided sufficient evidence to document the reported cost of the Seafood Way project of $42,718,949 (Exh. ES-LML-8, at 324, 468 (Supp. 2)). As such, we find that the costs incurred as of April 30, 2017, are known and measurable.

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[55] Gas insulated switchgear breaker equipment is transmission plant and, accordingly, the costs associated with this equipment are not proposed for recovery in this proceeding (Exh. AG-34-5).

Next the Department considers whether the Seafood Way project costs as of April 30, 2017, were prudently incurred. No parties have contested NSTAR Electric's decision to commence the Seafood Way project or NSTAR Electric's management of the project. The Department finds that the Seafood Way substation is necessary to provide back-up relief for Eversource's existing substation in South Boston, used to serve the Seaport district of Boston, which has experienced significant load growth in recent years (Exhs. ES-CAH-1, at 14; ES-LML-1, at 44). Further, the record shows that Eversource provided documentation supporting the prudency of the costs associated with this project, including purpose and necessity documents, capital budget estimates, work orders, project cost sheets, variance explanations as of December 21, 2016, project authorization forms, and closing reports as of April 30, 2017 (Exhs. ES-LML-8, at 1-155 (Supp. 1); ES-LML-8, at 324-468 (Supp. 2); AG-19-3, Atts. (e), (f)). Thus, the Department finds that the costs associated with the Seafood Way project as of April 30, 2017, were prudently incurred.

Finally, the Department considers whether Seafood Way is in service and used and useful to customers. Seafood Way includes three gas insulated 115-kV breakers and twelve 115-kV gas insulated switchgear breakers to interconnect with two transmission lines, three 62.5 MVA 115/14-kV distribution transformers, four sections of distribution switchgear, four 1-5kV 9.6 MVAR capacitor banks, 17 existing distribution lines from the K Street substation, and 32 distribution circuits (Exh. ES-LML-1, at 45). Of these substation components, the record indicates that: (1) transmission line 385-516 was energized on December 6, 2016; and

(2) GIS[56] was energized on December 9, 2016 (Exh. ES-LML-8, at 44-45 (Supp. 1)). In addition, Eversource represents that five distribution circuits are scheduled to be energized in 2017 (Exh. ES-LML-1, at 45). The remaining components of the substation are still in progress, or are being held for future use as the substation is intended as a backup for the K Street substation and is built to meet future load growth (Exh. ES-LML-1, at 44-45; ES-LML-8, at 44-55 (Supp. 1); AG-24-5). Based on these considerations, we conclude that Seafood Way was placed into service in December 2016, and remains in service today (Exhs. ES-LML-1, at 45; ES-LML-8; ES-LML-8, at 44-55 (Supp. 1); AG-19-3, Atts. (e), (f); AG-19-4, Att.)

iv. Status of New Bedford Service Center

Eversource has provided sufficient evidence to document the reported cost of the New Bedford Service Center of $29,868,260 (Exh. ES-LML-8, at 97 (Supp. 2)). The total amount of $29,868,260 comprises $18,856,557 in costs incurred through April 30, 2017 and $11,011,703 in remaining committed costs incurred after April 30, 2017 (Exh. ES-LML-8, at 1 (Supp. 2); Tr. 4, at 802).[57] As such, we find that the costs of $29,868,260 associated with the New Bedford service center are known and measurable.

Next the Department considers whether the costs associated with the New Bedford Service Center were prudently incurred. No parties have contested NSTAR Electric's

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56 GIS is transmission plant and, accordingly, the costs associated with this plant are not proposed for recovery in this proceeding (Exh. AG-34-7).

57 These committed costs are costs under a fixed price contract associated with securing the service center's certificate of occupancy (Exh. ES-LML-8, at 1 (Supp. 2); Tr. 4, at 802).

decision to relocate the New Bedford service center or NSTAR Electric's management of the project. The Department finds that this project was necessary to replace the NSTAR Electric's current older facility and to provide an operations center for NSTAR Electric and NSTAR Gas (Exhs. ES-CAH-1, at 16; ES-LML-1, at 46-47). Further, we note that Eversource conducted a cost-benefit analysis of several alternatives before determining that relocating was the most cost effective option (Exhs. ES-LML-1, at 47; AG-19-5 & Att.). In addition, Eversource provided documentation supporting the prudency of the costs associated with this project, including project authorization forms, supplement request forms, project cost sheets, variance analyses as of December 12, 2016, and invoices (Exhs. ES-LML-8, at 111-131 (Supp. 1); ES-LML-8, at 76-182 (Supp. 2); AG-19-3, Atts. (c), (d); Tr. 15, at 3084-3085). Eversource's initial estimate of $30 million included the sale of the old service center (Exh. ES-LML-1, at 49). Eversource's instant proposal to include $29,868,260 in costs associated with the service center, however, does not include the sale of the old property (Exhs. AG-24-7; AG-43-3). Based on the above, the Department finds that the costs associated with the New Bedford service center were prudently incurred.

Finally, the Department considers whether the New Bedford Service Center is in service and used and useful to customers. Eversource submitted a 30-day temporary certificate of occupancy for the New Bedford service center project on August 25, 2017 (Exh. ES-14). The certificate states that the work authorized by the permit had been partially completed and approved by the City of New Bedford, Office of the Building Commissioner (Exh. ES-14). Further, it is noted that all City of New Bedford inspectors had made their

final inspections of the land and building and that the premises were safe to occupy (Exh. ES-14). Based on these considerations, the Department is satisfied that the New Bedford service center meets the standard for in service and used and useful (Exhs. ES-LML-8; AG-19-3, Atts. (c), (d); AG-19-4, Att.; AG-24-6; ES-14). See D.P.U. 95-118, at 20, 56.

v. Conclusion

Having found that NSTAR Electric's arguments concerning the purported similarities between the instant case and the factual scenario in D.P.U. 14-150 were not persuasive, we need not address the Attorney General's arguments regarding the differences between the instant case and the factual scenario in D.P.U. 14-150. Further, because we determine that our decision in D.P.U. 14-150 is inapplicable in this case, we also decline to adopt the Attorney General's recommendation to adjust the Companies' test year sales to reflect load growth accompanying its post-test year plant additions. However, the Department finds it appropriate to adjust NSTAR Electric's rate base for accumulated depreciation, as agreed to by the Companies and discussed in further detail below. Finally, as noted below in Section VII.E, we decline to adopt the Attorney General's "double counting" argument with respect to the Electric Avenue project.

Based on the above considerations, we approve Eversource's proposal to include in NSTAR Electric's rate base the following expenditures as of April 30, 2017: (1) $32,949,477 associated with Electric Avenue; (2) $42,718,949 associated with the Seafood Way project; and (3) $29,868,260 associated with the New Bedford service center.

c. Accumulated Deferred Income Taxes and Accumulated Depreciation

Consistent with our inclusion of the three NSTAR Electric post-test year plant additions and exclusion of one WMECo post-year plant addition, we will make certain corresponding adjustments to Accumulated Deferred Income Taxes ("ADIT") and accumulated depreciation, as detailed below.[58] Otherwise, the rates being approved here would misrepresent the Companies' underlying cost structure.

Eversource proposes to include $16,818,289 in ADIT for all three NSTAR Electric post-test year plant additions (Exh. ES-DPH-2 (East), Sch. DPH-30 (Rev. 3)). The proposed ADIT is not provided on a project-specific basis (Exh. ES-DPH-2 (East), Sch. DPH-30 (Rev. 3)). In this case, however, the Department has approved the inclusion of all three NSTAR Electric post-test year plant additions in test year-end rate base. Accordingly, the Department accepts Eversource's proposal to increase NSTAR Electric's test year-end reserve for deferred income taxes by a total of $16,818,289 (Exh. ES-DPH-2 (East), Sch. DPH-30 (Rev. 3)).

Eversource also proposes to include $672,829 in ADIT for WMECo's post-test year plant addition (Exh. ES-DPH-2 (West), Sch. DPH-30 (Rev. 3)). For reasons discussed above, the Department has denied Eversource's proposal to include the Montague substation improvement project in WMECo's test year-end rate base. Accordingly, the Department

[58] The effects of the Department's decision here on the Companies' depreciation expense are addressed below in Section VIII.E of this Order.

denies Eversource's proposal to increase WMECo's test year-end reserve for deferred income taxes by a total of $672,829.

In its reply brief, Eversource provides a recommended accumulated depreciation amount for each of the three NSTAR Electric post-test year plant additions (Companies Reply Brief at 110, 110, n. 34). Given that this recommended adjustment was made on brief and not during the evidentiary phase of the proceeding, the Department declines to accept it. Rather, in calculating the investment balance upon which to accumulate depreciation, the Department will use the plant addition amounts approved in this case. More specifically, the Department multiplies the annual depreciation rate by the plant addition amount approved in this case, adjusted for the number of days the plant addition has been in service as of the date rates go into effect (January 1, 2018). The Department adds the accumulated depreciation amounts for each plant account with a positive balance to arrive at a total accumulated depreciation amount for each addition.

For the Electric Avenue project, the $32,949,477 addition comprises $24,556,686 in Account 362, Station Equipment, and $8,392,791 in Account 366, Underground Conduit (Exh. ES-DPH-2 (East), WP DPH-28 (Rev. 3)). NSTAR Electric's depreciation rates during this proceeding for Accounts 362 and 366 were 2.384 percent and 2.432 percent, respectively (Exh. AG-1-24, Att. (B)). Electric Avenue was energized from the transmission system on December 6, 2016, and so it will be in service for 390 days on January 1, 2018

(Exh. ES-LML-8, at 101 (Supp. 1)). Therefore, the Department increases NSTAR Electric's test year-end reserve for depreciation by $843,622 for Electric Avenue.[59]

For the Seafood Way project, the $42,718,949 addition comprises $33,983,164 in Account 362, Station Equipment, and $8,735,785 in Account 366, Underground Conduit (Exh. ES-DPH-2 (East), WP DPH-28 (Rev. 3)). NSTAR Electric's depreciation rates during this proceeding for Accounts 362 and 366 were 2.384 percent and 2.432 percent, respectively (Exh. AG-1-24, Att. (B)). Seafood Way was energized from the transmission system on December 6, 2016, and so it will be in service for 390 days on January 1, 2018 (Exh. ES-LML-8, at 46 (Supp. 1)). Therefore, the Department increases NSTAR Electric's test year-end reserve for depreciation by $1,092,655 for Seafood Way.[60]

Eversource also provides a 2017 accumulated depreciation amount of $430,642 for the New Bedford service center in its proposed post-test year adjustment to lease revenue in recognition of NSTAR Gas' use of the New Bedford service center (Exh. ES-DPH-2 (East), WP DPH-5 (Rev. 3)). Therefore, the Department increases NSTAR Electric's test year-end reserve for depreciation by $430,642 for the New Bedford service center.

Finally, consistent with our decision to deny Eversource's proposal to include the Montague substation improvement project in WMECo's test year end rate base, we will make no adjustments to WMECo's test year-end reserve for depreciation for Montague.

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[59] $24,556,686 * (.02384 * (390/365))+$8392791 * (.02432 * (390/365)) = $843,622.

[60] $33,983,164 * (.02384 * (390/365))+$ 8,735,785 * (.02432 * (390/365)) = $1,092,655

d. Conclusion

In accordance with the above findings, the Department denies Eversource's proposal to include in WMECo's test year-end rate base $3,813,975 in post-test plant additions and $325,049 in plant retirements associated with the Montague substation improvements. The Department approves Eversource's proposal to include in NSTAR Electric's test year-end rate base a total of $105,536,686 in plant additions, comprising $32,949,477 for Electric Avenue, $42,718,949 for Seafood Way, and $29,868,260 for the New Bedford service center (Exhs. ES-DPH-2 (East), Sch. DPH-28 (Rev. 3)); ES-DPH-2, (East), WP DPH-28 (Rev. 3)). Additionally, the Department approves Eversource's proposal to increase NSTAR Electric's test year-end reserve for deferred income taxes by a total of $16,818,289. Finally, the Department increases Eversource's test year-end reserve for depreciation by a total of $2,351,645, comprising $843,622 for Electric Avenue, $1,092,655 for Seafood Way, and $430,642 for the New Bedford service center. The effect of these adjustments on the Companies' rate bases is provided in Schedule 4 for NSTAR Electric and Schedule 4 for WMECo below.

D. Cash Working Capital

1. Introduction

In their day-to-day operations, utilities require funds to pay for expenses incurred in the course of business, including O&M expenses. These funds are either generated internally by a company or through short-term borrowing. Department policy permits a company to be reimbursed for costs associated with the use of its funds or for the interest expense incurred on borrowing. D.P.U. 96-50 (Phase I) at 26, citing Western Massachusetts Electric

Company, D.P.U. 87-260, at 22-23 (1988). This reimbursement is accomplished by adding a cash working capital component to the rate base calculation.

Cash working capital costs have been determined through either the use of a lead-lag study or a conventional 45-day O&M expense allowance. D.T.E. 03-40, at 92. In the absence of a lead-lag study, the Department has previously relied on a 45-day convention as reasonably representative of O&M working capital requirements. D.T.E. 05-27, at 98; D.P.U. 88-67 (Phase I) at 35.[61] The Department has expressed concern that the 45-day convention, first developed in the early part of the 20th century, may no longer provide a reliable measure of a utility's working capital requirements. D.T.E. 03-40, at 92, citing Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 15 (1998); D.P.U. 96-50 (Phase I) at 27. In recent years, lead-lag studies have resulted in savings for ratepayers by reducing the cash working capital requirement below the 45-day convention. D.P.U. 11-01/D.P.U. 11-02, at 163, citing D.P.U. 10-114, at 108; D.P.U. 10-70, at 78; D.P.U. 10-55, at 204-205; D.P.U. 09-39, at 114; D.P.U. 09-30, at 151-152; New England Gas Company, D.P.U. 08-35, at 38 (2009); D.T.E. 05-27, at 99-100. For these reasons, the Department requires all electric and gas companies serving more than 10,000 customers to conduct a fully developed and reliable O&M lead-lag study. D.P.U. 11-01/D.P.U. 11-02, at 164.

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61 When a fully developed and reliable lead-lag study is not available, FERC applies a 45-day convention to determine the cash working capital allowance. Carolina Power and Light Company, 6 FERC ¶ 61,154, at 61,296 (1979). As a result, companies occasionally refer to the 45-day convention as the FERC convention. D.P.U. 11-01/D.P.U. 11-02, at 150 n.81.

2. Companies Proposal

In WMECo's last base rate case, the Department excluded basic service cash working capital from the cash working capital allowance recovered through base rates. D.P.U. 10-70, at 77-78.[62] The Department calculated separate lead-lag factors for O&M expense and for basic service, and provided for the recovery of a basic service cash working capital allowance as a separate cost component through the Basic Service Costs Adjustment ("BSCA") factor.[63] D.P.U. 10-70, at 78, 367. Here, Eversource proposes to use the same method for NSTAR Electric as well and states that it removed the basic service cash working capital allowance from the total cash working capital included in rate base (Exh. ES-DPH-1, at 198-199).

Eversource conducted a lead-lag study to determine its cash working capital requirements for both O&M and basic service (Exhs. ES-DPH-1, at 194-195; ES-DPH-6). Each component uses revenue lag days and expense lead days to determine the cash working capital requirement (Exh. ES-DPH-1, at 195). Eversource conducted its lead-lag study using in-house personnel to update the net lag days associated with each component of its proposed cash working capital allowance (Exhs. ES-DPH-6; DPU-40-2).

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62 Basic service cash working capital provides cash working capital for expenses paid by NSTAR Electric and WMECo on behalf of customers for wholesale electric power supply and renewable energy contracts (Exh. ES-DPH-1, at 198).

63 Eversource's proposed Basic Service tariff, M.D.P.U. No. 516, includes revisions to provide for the recovery of a working capital allowance associated with basic service within its BSCA factor. Eversource states that it will update its BSCA filings based on the lead-lag factors approved in this proceeding (Exh. ES-DPH-1, at 198-199). Revisions to the Basic Service tariff are addressed in Section XVII.H below.

Eversource calculated a revenue lag to be used in both the O&M and basic service cash working capital net lag factors. The revenue lag consists of a "meter reading or service lag," "collection lag," and a "billing lag" (Exh. ES-DPH-1, at 196). The sum of the days associated with these three lag components is the total revenue lag experienced by Eversource (Exh. ES-DPH-1, at 196). Eversource calculated a meter reading or service lag of 15.21 days (Exhs. ES-DPH-1, at 196; ES-DPH-6, Sch. WC-2, at 1). This lag was derived by dividing the number of billing days in the test year by twelve months and then in half to arrive at the midpoint of the monthly service periods (Exhs. ES-DPH-1, at 196; ES-DPH-6, Sch. WC-2, at 1). The collection lag, which reflects the time delay between the mailing of customer bills and the receipt of the billing revenues from customers, totaled 30.82 days (Exhs. ES-DPH-1, at 196; ES-DPH-6, Sch. WC-2, at 1). The collection lag was obtained by dividing the average daily accounts receivable balance by the average daily revenue amount to arrive at the collection lag (Exhs. ES-DPH-1, at 197; ES-DPH-6, Sch. WC-2, at 1). Finally, Eversource applied a billing lag of one day, based on the fact that most of Eversource's customers are billed the day after meters are read (Exhs. ES-DPH-1, at 197; ES-DPH-6, Sch. WC-2, at 1).[64] Based on the foregoing, Eversource calculated a total revenue lag of 47.03 days by adding the number of days associated with each of the three revenue lag components (Exhs. ES-DPH-1, at 198; ES-DPH-6, Sch. WC-2, at 1).

Eversource's O&M cash working capital is comprised of O&M expense, payroll taxes, and property taxes (Exh. ES-DPH-1, at 199). Eversource pays these expenses to

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64 Eversource made no adjustment in the lead-lag study to account for customers for which additional time is required to process bills (Exh ES-DPH-1, at 197).

finance the activities conducted in service to customers before the Companies receive payment from customers for those services (Exh. ES-DPH-1, at 199-200). To calculate the O&M expense lead period, Eversource disaggregated its O&M expense into eight major cost categories: net payroll, regulatory commission expenses, corporate insurance, other O&M, property taxes, FICA & Medicare, federal unemployment tax, and state unemployment tax (Exhs. ES-DPH-1, at 201; ES-DPH-6, Sch. WC-4). Eversource reviewed test year payments and calculated the lead days for each category based on either all payments or a sampling of payments (Exh. ES-DPH-1, at 201). Once Eversource determined lead days for each category, it used the sum of the lead days weighted by dollars to arrive at an O&M expense lead of 13.73 days (Exh. ES-DPH-6, Sch. WC-4). Eversource then subtracted the expense lead of 13.73 days from the revenue lag of 47.03 days to produce a net O&M expense lag of 33.30 days (Exhs. ES-DPH-1, at 203; ES-DPH-6, Sch. WC-1). Eversource derived an O&M expense cash working capital factor of 9.12 percent by dividing the net lag days of 33.30 by 365 days (Exh. ES-DPH-6, Sch. WC-1 at 1). This factor, multiplied by the total costs applicable to cash working capital[65] of $411,936,870 for NSTAR Electric, and $83,757,914 for WMECo, produces a proposed cash working capital allowance of $37,582,186 and $7,641,475 for NSTAR Electric and WMECo, respectively (Exhs. ES-DPH-1, at 203-204; ES-DPH-2 (East), Sch. DPH-32 (Rev. 4); ES-DPH-2 (West), Sch. DPH-32 (Rev. 4)).

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[65] These costs are comprised of total O&M expense, less uncollectible accounts, plus taxes other than income taxes (Exhs. ES-DPH-2 (East), Sch. DPH-32 (Rev. 4); ES-DPH-2 (West), Sch. DPH-32 (Rev. 4)).

Eversource determined the basic service net lag by comparing the revenue lag of 47.03 days to the expense lead associated with basic service (Exh. ES-DPH-6, Sch. WC-1). To determine the expense lead associated with basic service, Eversource identified all supplier invoices that were paid during the test year and calculated for each invoice the number of days from the midpoint of the related service period to the date the invoice was paid (Exhs. ES-DPH-1, at 199; ES-DPH-6, Sch. WC-3). Eversource then dollar weighted, totaled, and averaged the days to arrive at an overall weighted average basic service expense lead (Exhs. ES-DPH-1, at 199; ES-DPH-6, Sch. WC-3). Eversource's study produced an expense lead associated with basic service of 45.31 days (Exh. ES-DPH-6, Schs. WC-1, WC-3, at 2). When compared to the revenue lag of 47.03 days, the net lag for basic service is 1.72 days (Exhs. ES-DPH-1, at 199; ES-DPH-6, Sch. WC-1).

3. Positions of the Parties

On brief, Eversource summarizes its calculation of the basic service and other O&M cash working capital requirements and asserts that the Companies' calculations are consistent with Department precedent (Companies Brief at 169-171). No other party addressed Eversource's proposed cash working capital calculations.

4. Analysis and Findings

The purpose of conducting a cash working capital lead-lag study is to determine a company's "cash in-cash out" level of liquidity in order to provide the company an appropriate allowance for the use of its funds. D.P.U. 87-260, at 22-23. Such funds are either generated internally or through short-term borrowing. See D.P.U. 96-50 (Phase I) at 26. Department policy permits a company to be reimbursed for costs associated with the

use of its funds and for the interest expense incurred on borrowing. D.P.U. 96-50 (Phase I) at 26; D.P.U. 87-260, at 22. The Department requires all electric and gas companies serving more than 10,000 customers to conduct a fully developed and reliable O&M lead-lag study. D.P.U. 11-01/D.P.U. 11-02, at 164. In the event that the lead-lag factor is not below 45 days, a company will face a high burden to justify the reliability of such a study and the reasonableness of the steps the company has taken to minimize all factors affecting cash working capital requirements within its control, such as the collections lag. D.P.U. 11-01/D.P.U. 11-02, at 164.

The Department has reviewed the evidence in support of Eversource's lead-lag study and we conclude that Eversource properly calculated the total revenue lag of 47.03 days to be applied to both the O&M and basic service expense leads (Exhs. ES-DPH-1, at 196-197; ES-DPH-6, Sch. WC-2, at 1). Further, the Department finds that Eversource properly calculated the O&M expense lead of 13.73 days and the resulting net lag of 33.30 days (Exhs. ES-DPH-1, at 203; ES-DPH-6, Schs. WC-1, WC-4). Eversource's proposed O&M net lag factor of 33.30 days is lower than the Department's 45-day convention (Exhs. ES-DPH-1, at 204; ES-DPH-6, Sch. WC-1). Additionally, we find that Eversource's decision to perform a lead-lag study with in-house personnel was a cost-effective means to determine its cash working capital requirement (Exh. DPU-40-2). See Bay State Gas Company, D.P.U. 12-25, at 97 (2012). For these reasons, the Department accepts Eversource's lead-lag study and the resulting O&M cash working capital factor of 9.12 percent (33.30 days/365 days).

Application of the O&M cash working capital factor of 9.12 percent to the level of O&M and taxes other than income tax expense authorized by this Order produces a cash working capital allowance of $34,945,015 for NSTAR Electric and $7,188,554 for WMECo. The derivation of this cash working capital allowance is provided in Schedule 6 of this Order.

Further, the Department finds that Eversource properly calculated the expense lead for basic service of 45.31 days and the net lag for basic service of 1.72 days (Exhs. ES-DPH-1, at 199; ES-DPH-6, Schs. WC-1, WC-3, at 2). This results in a basic service net lag factor of 1.72 days for purposes of the cash working capital allowance in the BSCA.

E. Materials and Supplies

1. Introduction

The Department typically allows a company to include a representative level of its materials and supplies balance in rate base, which is determined using a 13-month average balance. Boston Edison Company, D.P.U. 19991, at 16 (1979); Housatonic Water Works Company, D.P.U. 86-235, at 3-4 (1987); High Wood Water Company, D.P.U. 1360, at 7-8 (1983); D.P.U. 1300, at 29. Eversource reports a balance of $34,922,056 in materials and supplies for NSTAR Electric and a balance of $2,242,787 in materials and supplies for WMECo, both based on a 13-month average of the respective account balances during the period of June 2015 through June 2016 (Exhs. ES-DPH-2 (East), WP DPH-27 (Rev. 3); ES-DPH-2 (West), WP DPH-27 (Rev. 3); ES-DPH-3 (East), WP DPH-27 (Rev. 3); ES-DPH-3 (West), WP DPH-27 (Rev. 3)).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Electric Avenue substation project discussed above in Section VII.C includes approximately $10 million in inventory that was delivered from the warehouse in Avon, Massachusetts, to the project site in August 2015 (Attorney General Brief at 106-107, citing Exh. AG-19-1; Tr. 8, at 2668-2770). She contends that no adjustment was made on the balance of materials and supplies included in NSTAR Electric's rate base to annualize the effect of this transfer of inventory (Attorney General Brief at 107, citing Tr. 8, at 2668-2770). Thus, according to the Attorney General, NSTAR Electric's proposed rate base includes a "partial double counting" of the $10 million transferred from the materials and supplies inventory to the Electric Avenue substation project (Attorney General Brief at 107; Attorney General Reply Brief at 13). The Attorney General has not proposed any specific recommendation regarding any adjustments to Eversource's materials and supplies balance.

b. Companies

Eversource argues that it has calculated its materials and supplies balances included in rate base based on the 13-month average balances, consistent with Department precedent (Companies Brief at 169, 433). According to the Companies, the intent of relying on a 13-month average is to normalize from the balance included in rate base any abnormal month-to-month variability, or to avoid the reliance on a single data point that might skew the average balance (Companies Brief at 433). In this regard, Eversource contends that the Attorney General's argument is an attempt to "cherry pick" a large transaction in order to

reduce the materials and supplies balance included in rate base (Companies Brief at 434). However, Eversource contends that an adjustment to annualize the $10 million is not necessary or appropriate as the transfer does not represent a "double-count" of costs (Companies Brief at 433). Rather, Eversource claims that it properly calculated the materials and supplies balances and it has properly included post-test year additions in rate base (Companies Brief at 433). Based on all of these considerations, Eversource asserts that the Department should approve the Companies' proposed materials and supplies balances (Companies Brief at 434).

3. Analysis and Findings

Utilities keep on hand various materials and supplies for use in the course of normal operations. The Department's long-standing practice has been to include a representative level of a company's materials and supplies balance in rate base. D.P.U. 19991, at 16. The Department allows this adjustment to compensate a utility for the carrying cost associated with its inventory. Because of the month-to-month fluctuations in this account, a 13-month average balance is used. D.P.U. 86-235, at 3-4; D.P.U. 1300, at 29. The Department's 13-month convention requires the use of monthly balances for the twelve months of the test year, plus the month prior to the first month of the test year. See D.P.U. 15-155, at 146; D.P.U. 10-114, at 101-102; D.P.U. 86-235, at 3-4.

The Department has reviewed Eversource's schedules and the monthly balances provided in the record (Exhs. ES-DPH-2 (East), WP DPH-27 (Rev. 3); ES-DPH-2 (East), WP DPH-27 (Rev. 3); ES-DPH-3 (East), WP DPH-27 (Rev. 3); ES-DPH-3 (West),

WP DPH-27 (Rev. 3)). The record shows that Eversource calculated the materials and supplies balances for NSTAR Electric and WMECo using the 13-month average of the account balances from June 2015 (the month preceding the start of the test year) through June 2016 (the end of the test year) (Exhs. ES-DPH-3 (East), WP DPH-27 (Rev. 3); ES-DPH-3 (West), WP DPH-27 (Rev. 3)).[66] Thus, the Department concludes that Eversource properly calculated the average balance of materials and supplies consistent with Department precedent. D.P.U. 15-155, at 146; D.P.U. 10-114, at 101-102; D.P.U. 86-235, at 3-4; D.P.U. 1300, at 29.

As noted above, the Department recognizes that a company's materials and supplies account balance will fluctuate as inventory is moved in and out of the account. In recognition of those month-by-month fluctuations, the Department does not rely on a spot balance, but rather uses a 13-month average balance for ratemaking purposes. Moreover, the purpose of the 13-month balance convention is to set a representative level of materials and supplies, not to track the movements of specific inventory items or to reconcile them to a company's plant investment balance in rate base.

Based on our review of the materials and supplies balances for the relevant 13-month period for NSTAR Electric, we find that the average balance of $34,922,056 is representative of the monthly activity in that account. Similarly, we find that the average balance of $2,242,787 is representative of the monthly activity in WMECo's materials and supplies account. Because the Department's 13-month convention is meant to account for the

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66 The test year used by Eversource was the twelve-month period from July 1, 2015 through June 30, 2016 (Exhs. ES-CAH-1, at 8; ES-DPH-1, at 8).

movement of inventory in and out of this account, including that associated with construction projects, we reject the Attorney General's argument that there is "partial double counting" of the inventory transferred to the Electric Avenue substation.[67]

Based on all of these considerations, the Department finds that no adjustments to Eversource's proposed materials and supplies balances are warranted. Accordingly, the Department allows in the Companies' respective rate base the materials and supplies balances of $34,922,056 for NSTAR Electric and $2,242,787 for WMECo.

VIII. OPERATIONS AND MAINTENANCE EXPENSES

A. Employee Compensation and Benefits

1. Introduction

When determining the reasonableness of a company's employee compensation expense, the Department reviews the company's overall employee compensation expense to ensure that its compensation decisions result in a minimization of unit-labor costs. D.P.U. 10-55, at 234; D.P.U. 96-50 (Phase I) at 47; Cambridge Electric Light Company, D.P.U. 92-250, at 55 (1993). This approach recognizes that the different components of

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[67] The Department acknowledges that it previously made a specific adjustment to materials and supplies in a prior base rate case to avoid double counting of certain inventory proposed for inclusion in rate base. Boston Edison Company, D.P.U. 160, at 12-13 (1980). However, at that time, the Department used an electric distribution company's year-end materials and supplies balance to establish a representative level for ratemaking purposes, rather than the 13-month average balance now in use. See D.P.U. 160, at 12-13; D.P.U. 160, Policy Statement of the Commission Concerning the Adoption of Year-End Rate Base (1980); see also D.P.U. 19991, at 16 (rejecting the 13-month average balance convention for electric distribution companies). As noted above, the use of the current 13-month average materials and supplies balance levelizes the month-to-month fluctuations, including those associated with large construction projects. Accordingly, we find that the adjustment in D.P.U. 160 is inapplicable in the instant case.

compensation (i.e., wages and benefits) are, to some extent, substitutes for each other and that different combinations of these components may be used to attract and retain employees. D.P.U. 92-250, at 55. In addition, the Department requires a company to demonstrate that its total unit-labor cost is minimized in a manner supported by its overall business strategies. D.P.U. 92-250, at 55.

A company is required to provide a comparative analysis of its compensation expenses to enable a determination of reasonableness by the Department. D.P.U. 96-50 (Phase I) at 47. The Department evaluates the per-employee compensation levels, both current and proposed, relative to the companies in the utility's service territory and utilities in the region that compete for similarly skilled employees. D.P.U. 96-50 (Phase I) at 47; D.P.U. 92-250, at 56; Bay State Gas Company, D.P.U. 92-111, at 103 (1992); Massachusetts Electric Company, D.P.U. 92-78, at 25-26 (1992).

2. Non-Union Wages

a. Introduction

During the test year, NSTAR Electric booked $45,084,065 in payroll expense for non-union personnel, including base wages and overtime pay (Exh. ES-DPH-2 (East), Sch. DPH-13, at 2 (Rev. 3)). Eversource proposes to increase NSTAR Electric's non-union payroll expense by $3,707,986 based on: (1) a non-union wage increase of three percent effective April 1, 2016; (2) a non-union wage increase of three percent effective April 1,

2017; and (3) a non-union wage increase of 2.75 percent effective April 1, 2018 (Exhs. ES-DPH-2 (East), Sch. DPH-13, at 2 (Rev. 3); ES-15,[68] at 2).

During the test year, WMECo booked $12,488,174 in payroll expense for non-union personnel, including base wages and overtime pay (Exh. ES-DPH-2 (West), Sch. DPH-13, at 2 (Rev. 3)). Eversource proposes to increase WMECo's non-union payroll expense by $1,027,103 based on: (1) a non-union wage increase of three percent effective April 1, 2016; (2) a non-union wage increase of three percent effective April 1, 2017; and (3) a non-union wage increase of 2.75 percent effective April 1, 2018 (Exhs. ES-DPH-2 (West), Sch. DPH-13, at 2 (Rev. 3); ES-15, at 2).

The Companies determined their non-union wage increases based on a comparative analysis of non-union base salaries and total compensation against median base salaries and total compensation in the energy/utility and general industry sectors in the Northeast, using studies performed by Towers Watson (Exhs. ES-SL-1, at 16; ES-SL-6; ES-SL-7; ES-SL-8). The Companies also analyzed whether their actual and proposed merit wage increases were in line with the market by surveying the actual and projected wage increases in the

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[68] As noted below, Eversource provided a letter, dated August 24, 2017, which indicates its commitment to institute (1) a 2.0 percent payroll increase for non-exempt union employees of NSTAR Electric, effective June 2, 2018; and (2) a 2.75 percent payroll increase for the Companies' exempt and non-exempt non-union employees, effective on or before April 1, 2018. Eversource designated the letter as Exhibit ES-13. However, that exhibit designation was given to a different exhibit at the evidentiary hearings (Tr. 19, at 3656). Further, Eversource has provided an exhibit in this proceeding relative to the New Bedford service center, which it has marked as Exhibit ES-14 (see Section VII.C above). As such, the Department will designate the August 24, 2017, letter as Exhibit ES-15 and cite to it as such in the remainder of this Order.

energy/utility and general industry sectors (Exhs. ES-SL-1, at 16, 23; ES-SL-9). In addition, the Companies provided a historical comparison of non-union base wage increases to union base wage increases (Exhs. ES-SL-1, at 21; ES-SL-5).

b. Positions of the Parties

i. Attorney General

The Attorney General asserts that the Department should deny NSTAR Electric and WMECo's proposed non-union payroll expense in 2018 for two reasons (Attorney General Brief at 136). First, the Attorney General claims that the Companies have not demonstrated that the proposed increases of 2.75 percent are reasonable (Attorney General Brief at 137). The Attorney General states that the non-union salary studies included in the Companies' filing demonstrate that the Companies' non-union employees are already making more than two percent above industry averages for positions of similar responsibilities (Attorney General Brief at 137, citing Exhs. ES-SL-6; ES-SL-7; ES-SL-8). Second, the Attorney General argues that by not providing a management commitment letter for the 2018 payroll increases, the Companies have not provided evidence to support the proposed increases (Attorney General Brief at 137). The Attorney General contends that the Companies have not provided an affidavit, sworn testimony from senior management, or any other contractual or firm commitment to the wage increase (Attorney General Brief at 137). For these reasons, the Attorney General recommends that the Department deny the Companies' proposed 2018 non-union payroll increases (Attorney General Brief at 137).

ii. Companies

The Companies assert that the adjustments for non-union employees represent the actual percentage wage increases for the years 2016 and 2017 and thus are known and measurable (Companies Brief at 202). With respect to the 2018 compensation, Eversource claims that it establishes a base pay range for each job based on 90 percent to 110 percent of the median market rate derived in conjunction with Towers Watson, a global human resources consulting firm that assists the Companies in setting competitive salary ranges, variable pay levels, and evaluating and recommending changes to employee benefit plans (Companies Brief at 461, citing Exh. ES-SL-1, at 4-5). The Companies assert that this base pay range is consistent with standard compensation practices (Companies Brief at 461, citing Exh. ES-SL-1, at 5). Further, the Companies argue that they test the competitiveness of the non-union base salaries and total compensation levels against the external market on an ongoing basis, and they annually review non-union employee salary adjustments and total compensation, both current and projected, against external market trends for energy/utility companies and general industry to determine if they are reasonable (Companies Brief at 461-462, citing Exh. ES-SL-1, at 15). According to Eversource, these efforts demonstrate that the Companies' non-union salary adjustments are closely aligned with the relevant markets (Companies Brief at 462, citing Exhs. ES-SL-1, at 15-18; ES-SL-6 through ES-SL-9). Finally, Eversource notes that the Department has found that similar compensation data and analyses, including those used by NSTAR Gas in its last base rate proceeding, have demonstrated the reasonableness of non-union salary levels (Companies

Brief at 462, citing D.P.U. 14-150, at 143; D.P.U. 10-55, at 245; D.T.E. 05-27, at 109; D.T.E. 02-24/25, at 94).

Regarding the 2018 payroll increase to non-union employees, the Companies assert on brief that they will provide a management commitment letter by September or October of 2017, prior to the Order being issued in this proceeding (Companies Brief at 463, citing Exh. DPU-45-18; Tr. 15, at 3116). According to the Companies, in recent base rate proceedings, the Department has found acceptable the production of a management commitment letter prior to the issuance of the Order (Companies Brief at 463-464, citing D.P.U. 14-150, at 142-143; D.P.U. 13-75, at 146-147, 151-152).

Based on the above considerations, the Companies assert that they have demonstrated that the non-union salary levels, including the planned 2018 base wage increase, are reasonable and consistent with Department's precedent (Companies Brief at 462-463). As such, the Companies argue that the Attorney General's recommendations regarding the disallowance of these costs are without merit and should be rejected (Companies Brief at 464).

c. Analysis and Findings

The Department's well-established standard for post-test year non-union payroll adjustments requires a company to demonstrate that: (1) the non-union salary increase is scheduled to become effective no later than six months after the date of the Department's Order; (2) if the increase has not occurred, there is an express commitment by management to grant the increase; (3) there is a historical correlation between union and non-union raises;

and (4) the non-union increase is reasonable. D.P.U. 85-266-A/85-271-A at 107; D.P.U. 96-50 (Phase I) at 42; D.P.U. 95-40, at 21; Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 14 (1983).

Two of the Companies' proposed non-union wage increases occurred before the issuance of the Department's Order: on April 1, 2016 and April 1, 2017 (Exhs. ES-DPH-2 (East), Sch. DPH-13, at 2 (Rev. 3); ES-DPH-2 (West) at 2 (Rev. 3)). Additionally, on August 24, 2017, following the submission of briefs, the Companies provided a management commitment letter stating that a 2.75 percent payroll increase for non-union employees will take place on or before April 1, 2018 (Exh. ES-15, at 2). Based on this information, the Department finds that non-union salary increases are scheduled to become effective no later than six months after its Order, and there is a commitment by management to grant the increase that has not yet occurred.

In addition, Eversource provided a historical correlation of non-union and union wage increases, and demonstrated that it awarded non-union and union pay increases every year since 2006 (Exhs. ES-SL-1, at 13; ES-SL-5). Between 2006 and 2017, union wage increases were between 2.75 percent and 4.8 percent, and non-union wage increases were between 2.5 percent and 3.25 percent (Exh. ES-SL-5). Based on this information, the Department finds that a sufficient correlation exists between union and non-union wage increases. See Fitchburg Gas and Electric Light Company, D.P.U. 07-71, at 76 (2008); Essex County Gas Company, D.P.U. 85-59-A at 18 (1988).

With respect to the reasonableness of the non-union wage increases, the Companies annually review their current and projected salary levels against external energy companies and the general industry to determine if they are competitive to the market median (Exh. ES-SL-1, at 15). Specifically, Eversource compared its current and projected annual base salaries for non-union employees against median annual salaries for comparable positions in the Northeast by using survey data from a Towers Watson study (Exhs. ES-SL-1, at 15; ES-SL-6; ES-SL-7; ES-SL-8). This comparison showed that for NSTAR Electric, non-union total cash compensation is 2.3 percent above market median, WMECo's non-union total compensation is 1.1 percent below market median, and service company non-union total compensation is 2.4 percent above market median (Exhs. ES-SL-6; ES-SL-8). The results of this comparison demonstrates that NSTAR Electric's total cash compensation is 101.2 percent of the external market, WMECo's total cash compensation is 101.7 percent of the external market, and ESC's total cash compensation is 100.2 percent of the external market (Exhs. ES-SL-1, at 17-20; ES-SL-6; ES-SL-7; ES-SL-8). The Department finds that the Companies have demonstrated that their total proposed compensation is competitive with the market median and, therefore, reasonable (Exh. ES-SL-1, at 15).

Based on the above, the Department finds that Eversource has demonstrated: (1) non-union salary increases are scheduled to become effective no later than six months after the Department's Order; (2) there is an express management commitment to grant a 2.75 percent non-union wage increase that is scheduled to occur after the date of this Order; (3) there is a historical correlation between union and non-union payroll increases;

and (4) the non-union wage increases are reasonable. Accordingly, we allow the Companies' adjusted non-union payroll expense.

3. Union Wages

a. Introduction

During the test year, NSTAR Electric booked $74,441,305 in payroll expense for union personnel, including base wages and overtime pay (Exh. ES-DPH-2 (East), Sch. DPH-13, at 2 (Rev. 3)). Eversource proposes to increase NSTAR Electric's union payroll expense by $5,363,174 based on: (1) a union wage increase of 2.75 percent effective June 2, 2016; (2) a union wage increase of 2.50 percent effective June 2, 2017; and (3) a union wage increase of two percent effective June 2, 2018 (Exhs. ES-DPH-2 (East), Sch. DPH-13, at 2 (Rev. 3); ES-15, at 1).

WMECo booked $10,511,256 in payroll expense for union personnel, including base wages and overtime pay during the test year (Exh. ES-DPH-2 (West), Sch. DPH-13, at 2 (Rev. 3)). Eversource proposes to increase WMECo's union payroll expense by $667,536 based on: (1) a union wage increase of 2.50 percent effective October 1, 2015; (2) a union wage increase of 2.50 percent effective October 1, 2016; (3) a union wage increase of three percent effective October 1, 2017; and (4) a post-test year adjustment of $173,600 for the annualization of new hires needed to comply with a union settlement mandating a staffing level of 206 represented employees (Exhs. ES-DPH-1, at 65; ES-DPH-2 (West), Sch. DPH-13, at 2 (Rev. 3)).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that WMECo's pro forma adjustment of $173,600 to account for the annualization of new hires and maintain a mandated staffing level of 206 employees should be disallowed (Attorney General Brief at 109; Attorney General Reply Brief at 19). According to the Attorney General, the fluctuations in employee levels experienced by WMECo are not large enough to require an expense adjustment – i.e., they are not outside the normal ebb and flow of employee levels (Attorney General Brief at 109). The Attorney General underscores that the total WMECo employee complement was 298 in June 2016 and was down to 288 in December 2016 (Attorney General Brief at 109; Attorney General Reply Brief at 19). She contends that this fluctuation represents the normal ebb and flow of employee levels and, therefore, the Department should deny WMECo's adjustment to annualize the cost of having a 206-employee complement and reduce its pro forma O&M expense by $173,600 (Attorney General Brief at 109; Attorney General Reply Brief at 19).

The Attorney General did not take issue with the Companies' proposed adjustments to payroll expense for union wage increases scheduled to occur in calendar years 2015, 2016, 2017, and 2018.

ii. Companies

The Companies assert that the Department should reject the Attorney General's argument that the change in the number of employees represents the normal ebb and flow in the workplace (Companies Brief at 434). The Companies explain that at the end of the test year, WMECo hired additional union employees to comply with a union arbitration

settlement that required WMECo to maintain a bargaining unit staffing level of 206 represented employees (Companies Brief at 202, citing Exh. ES-DPH-1, at 65). Thus, Eversource states that it made an adjustment to WMECo's payroll expense to annualize the cost of labor hires in the test year to reflect the annualized level of labor in the revenue requirement (Companies Brief at 202, citing Exh. ES-DPH-1, at 66). The Companies maintain that in calculating this adjustment, WMECo accounted for union employees who were hired in the test year to meet the employee commitment level as well as the employees who left WMECo during that period, and included only the incremental costs to annualize the new union hires made during the test year (Companies Brief at 435, citing Exhs. ES-DPH-1, at 65-67; ES-DPH-3, WP DPH-13, at 2 (West); Tr. 13, at 2781). Based on these considerations, the Companies assert that they properly reflected the costs associated with union staffing levels in the cost of service and that its union compensation adjustments are appropriate and should be approved by the Department (Companies Brief at 202, 435-436; Companies Reply Brief at 116).

c. Analysis and Findings

The Department's standard for post-test year union payroll adjustments requires that three conditions be met: (1) the proposed increase must take effect before the midpoint of the first twelve months after the date of the rate increase; (2) the proposed increase must be known and measurable (i.e., based on signed contracts between the union and the company); and (3) the proposed increase must be reasonable. D.P.U. 11-01/D.P.U. 11-02, at 174; D.P.U. 96-50 (Phase I) at 43; D.P.U. 95-40, at 20; D.P.U. 92-250, at 35.

The Companies' proposed union payroll adjustments appropriately include only those increases that have been granted before July 1, 2018, the midpoint of the first twelve months after the Department's Order in this proceeding (Exhs. ES-DPH-2 (East), Sch. DPH-13, at 2 (Rev. 3); ES-DPH-2 (West), Sch. DPH-13, at 2 (Rev. 3)). Additionally, the union payroll increases that occurred in 2016 and 2017 are based on signed collective bargaining agreements between the Companies and the respective unions (Exhs. DPU-45-08, Att.; DPU-45-12, Att.; DPU-45-14, Att.). Further, on August 24, 2017, Eversource provided a management commitment letter stating that a two percent payroll increase for union employees of NSTAR Electric will take effect on June 2, 2018 (Exh. ES-15, at 1). Thus, the Department finds that the proposed union wage increases are known and measurable.

Further, with respect to the reasonableness of the union wage increases, the Companies submitted a comparison of their average union wages with other employers in the Northeast (Exhs. ES-SL-1, at 9; ES-SL-2; ES-SL-3). The analysis provided demonstrates that hourly rates paid to the Companies' union employees are comparable to the median hourly rates other employers in the region pay for the selected union job titles (Exhs. ES-SL-2; ES-SL-3). Thus, we find that the Companies have demonstrated the reasonableness of the union wage increases.

Finally, Eversource proposes a normalizing adjustment to WMECo's union payroll O&M expense to account for union settlement obligations that mandate a staffing level of at least 206 employees by the end of 2016 (Exhs. ES-DPH-1, at 66 n.2; DPU-23-1, Att.; Tr. 13, at 2777-2783). The Companies included a pro forma adjustment for WMECo of

$173,600 to reflect the costs associated with this new level of staffing in the cost of service (Exh. ES-DPH-2 (West), Sch. DPH-13, at 2 (Rev. 3)).

The Department notes that employee levels routinely fluctuate because of retirements, resignations, hirings, terminations, and other factors. D.P.U. 88-172, at 12; D.P.U. 1270/1414, at 16-17. The Companies made no explicit effort to demonstrate that the level of union employees was significant or outside the normal fluctuation of union employee levels. Nonetheless, the Department will analyze the impact of WMECo's union employee hires and departures during the test year on employee staffing levels as well as payroll expense levels to determine whether they constitute a significant change. The record shows that there were seven net full-time union employees who were hired during the test year, which constitutes 3.08 percent of the total WMECo union employee count of 227 employees in the last month of the test year (Exhs. ES-DPH-3, WP DPH-13, at 2 (West); AG-1-44, Att. at 3). The proposed pro forma adjustment of $173,600 represents 1.34 percent of WMECo's union test year payroll expense (Exh. ES-DPH-2 (West), Sch. DPH-13, at 2 (Rev. 3)). The Department has previously found that similar fluctuations in the test year did not represent significant changes to test year employee levels or test year payroll expense. D.P.U. 15-155, at 160-162; Nantucket Electric Company, D.P.U. 88-161/168, at 67 (1989).

Further, the Department notes that WMECo maintained a level of 206 union employees or more during each month of the test year, with an average union employee count of 212 (Exh. AG-1-44, Att. at 3). Therefore, a level of payroll expense associated with at least 206 union employees is already represented in the proposed cost of service,

eliminating the need for an additional adjustment to annualize the payroll expense associated with maintaining a union employee level of 206. Based on the evidence provided above, the Department finds that the pro forma adjustment of $173,600 associated with WMECo union hires does not constitute a significant change and, therefore, we do not allow the adjustment to be included in WMECo's cost of service. In addition, concordant adjustments to payroll tax expense will be made, as set forth below in Section VIII.C.

4. Incentive Compensation

a. Introduction

The Companies' incentive compensation represents the portion of wages and salaries paid to non-union employees of NSTAR Electric and WMECo, and it is paid in March for performance in the prior year (Exh. ES-DPH-1, at 72). During the test year, NSTAR Electric booked $18,170,774 in incentive compensation for non-union personnel (Exh. ES-DPH-2 (East), Sch. DPH-14, at 2 (Rev. 3)). Eversource proposes to decrease NSTAR Electric's incentive compensation by $3,148,685 (Exh. ES-DPH-2 (East), Sch. DPH-14, at 1 (Rev. 3)).

During the test year, WMECo booked $3,177,908 in incentive compensation for non-union personnel (Exh. ES-DPH-2 (West), Sch. DPH-14, at 2 (Rev. 3)). Eversource proposes to decrease WMECo's incentive compensation by $714,682 (Exh. ES-DPH-2 (West), Sch. DPH-14, at 1 (Rev. 3)).

The factors contributing to the lower amount of proposed rate year incentive compensation expense for both NSTAR Electric and WMECo are as follows: (1) the test year level of expense was normalized to remove out-of-period and non-recurring items;

(2) the incentive compensation amounts awarded during the test year were reduced to target levels; and (3) further reductions to test year levels were necessary because of changes in the executive management team (Exh. ES-DPH-1, at 70-71).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that the Department should remove executive incentive compensation that is based on the attainment of financial goals from the Companies' cost of service because it is contrary to Department precedent and the Companies have not demonstrated a ratepayer benefit (Attorney General Brief at 118-119, citing D.P.U. 10-55, at 253-254; D.P.U. 11-01/D.P.U. 11-02, at 192-194; D.P.U. 08-35, at 97; Attorney General Reply Brief at 21). First, the Attorney General notes that incentive compensation for the Chief Executive Officer, James Judge, and the Chief Financial Officer, Philip Lembo, is based on the achievement of individual goals related to the overall corporate financial goals of earnings per share, dividend growth, and credit rating (Attorney General Brief at 119-120, citing Exh. DPU-45-21(e); Tr. 4, at 827). The Attorney General states that even the Companies acknowledge that they have made an error in requesting incentive compensation recovery for the Chief Executive Officer and Chief Financial Officer (Attorney General Reply Brief at 20). Thus, the Attorney General recommends the elimination of $577,135 from the revenue requirement for incentive compensation tied to the Companies' Chief Executive Officer and Chief Financial Officer (Attorney General Brief at 120, citing RR-AG-4; RR-AG-4, Att. at 2).

Next, the Attorney General contends that the amount of incentive compensation attributable to the Companies' other three named executive officers, Messrs. Leon Olivier, Werner Schweiger, and Gregory Butler ("Named Executives") should be reduced by 70 percent. She bases this recommendation on the structure of the Companies' incentive compensation program for these individuals, which she contends is split 70 percent for financial performance and 30 percent on operational performance (Attorney General Brief at 120, citing Exh. DPU-45-21, Att. at 46). She argues that Eversource's financial goals are inherent in the Named Executives' positions, regardless of whether the Companies have written in operational goals for these executives (Attorney General Reply Brief at 21). In addition, the Attorney General asserts that each of the Named Executives is responsible for financial performance through the budget that each oversees (Attorney General Reply Brief at 20).

The Attorney General does not challenge the fact that these Named Executives have certain operational goals, rather, she emphasizes that through their positions, they have the means and obligation to meet the corporate financial goals, and the Companies have not met their burden to show otherwise (Attorney General Reply Brief at 21). Shareholders are the beneficiaries of increases to earnings, according to the Attorney General, and they should bear the cost of incentive compensation linked to earnings, not the Companies' ratepayers (Attorney General Brief at 121). Thus, the Attorney General recommends the additional elimination of $295,592, or 70 percent of the Named Executives' incentive compensation that

is linked to the achievement of financial targets (Attorney General Brief at 121; Attorney General Reply Brief at 21).

ii. Companies

The Companies agree that goals that are directly tied to achieving financial targets, such as earnings per share, dividend growth, and credit rating, are not recoverable under Department precedent (Companies Brief at 443-444). The Companies do not challenge the Attorney General's recommendation to remove the Chief Executive Officer and Chief Financial Officer's portion of incentive compensation from the cost of service (Companies Brief at 444). The Companies do not, however, agree with the proposed adjustment calculated by the Attorney General (Companies Reply Brief at 117). Eversource argues that the Attorney General calculated the disallowance based on information provided in the Companies' response to Record Request AG-4, which only shows the reduction of the cash incentive to target for the test year and is inclusive of transmission and distribution amounts (Companies Reply Brief at 117). The Companies maintain that $533,160 is the correct reduction to cost of service and that it is the amount actually incorporated in the revenue requirement in this proceeding (Companies Reply Brief at 116-117).

The Companies oppose the Attorney General's recommendation to remove 70 percent of the incentive compensation paid to the Named Executives, and claim that they do not have incentive compensation tied to achieving financial targets (Companies Brief at 444, citing Exh. DPU-45-21). The Companies assert that the goals of the Named Executives are tied to operational targets, such as safety, customer satisfaction, cost reductions, increasing

efficiencies, and complying with state and federal laws and regulations (Companies Brief at 444, citing Exh. DPU-45-21). These goals provide a direct benefit to ratepayers, according to the Companies, and therefore the Department should reject the Attorney General's recommendation (Companies Reply Brief at 119). Moreover, the Companies express that the Named Executives' careful management and adherence to operational budgets benefits customers in terms of lower rates (Companies Reply Brief at 119). Finally, the Companies argue that they use financial goals as the trigger for funding the incentive compensation plan in a given year (Companies Reply Brief at 117, citing Tr. 6, at 1156, 1163, 1166-1167). The Companies explain that the incentive compensation pool cannot be funded unless specific financial goals are met, and they maintain that this structure is consistent with Department precedent (Companies Reply Brief at 117-118, citing Tr. 6, at 1156, 1163, 1166-1167).

c. Analysis and Findings

The Department has traditionally allowed incentive compensation expenses to be included in a utility's cost of service if: (1) the expenses are reasonable in amount, and (2) the incentive plan is reasonably designed to encourage good employee performance. D.P.U. 07-71, at 82-83; Massachusetts Electric Company, D.P.U. 89-194/195, at 34 (1990). For an incentive plan to be reasonable in design, it must both encourage good employee performance and result in benefits to ratepayers. D.P.U. 93-60, at 99.

First, the Department must determine whether the costs associated with Eversource's incentive compensation program are reasonable in amount. The Companies normalized the

test year level of expense to remove out-of-period and non-recurring items for both NSTAR Electric and WMECo (Exhs. ES-DPH-1, at 41, 44, 72; ES-DPH-2, Sch. DPH-14, at 2 (East); ES-DPH-2, Sch. DPH-14, at 2 (West)). Further, since the Companies awarded incentive compensation payouts above the target level during the test year, they reduced the revenue requirement to include only the amount of incentive compensation at target levels (Exhs. ES-DPH-1, at 72; ES-DPH-2, Sch. DPH-14, at 2 (East); ES-DPH-2, Sch. DPH-14, at 2 (West); DPU-45-32). Finally, Eversource adjusted the test year levels of incentive compensation to reflect changes in the executive management team to ensure that the representative amount of incentive compensation for the current executive team is reflected in the revenue requirement (Exhs. ES-DPH-1, at 72-73; ES-DPH-2, Sch. DPH-14, at 2 (East); ES-DPH-2, Sch. DPH-14, at 2 (West); DPU-45-32). Based on our review of this evidence, the Department finds that Eversource has demonstrated that its incentive compensation costs are reasonable in amount. See D.P.U. 10-70, at 103; D.P.U. 09-39, at 140.

Second, the Department must determine whether the Companies' incentive compensation plan is reasonable in design. The record shows that Eversource's incentive compensation program for both its union and non-union employees is based on the individual performance of the employee or targeted goals for safety, reliability, customer and community responsiveness, and costs control, as well as the performance of the business unit in which employees work (Exhs. ES-SL-1, at 24; DPU-23-9). Specifically, incentive compensation is awarded when business unit objectives are reached, which establishes an incentive pool (Exhs. ES-SL-1, at 24; DPU-45-20, AG-19-18). An individual employee's

compensation is then tied to a variable pay component that is dependent on his or her job scope level (Exhs. ES-SL-1, at 24-25; DPU-58-13; AG-19-17). Payment to the employee is based on the employee's individual performance against pre-determined goals relating to his or her position, as evaluated by his or her supervisor (Exhs. ES-SL-1, at 26; DPU-45-23; DPU-58-13, AG-19-18). Further, Eversource ensures that its employees are committed to meeting customer needs by establishing performance goals that are based on providing safe and reliable services at reasonable costs to customers (Exhs. ES-SL-1, at 26; DPU-45-23).

A portion of Eversource's incentive plan is tied to meeting financial performance objectives (Exh. DPU-45-21, at 3). The Department has previously articulated its expectations on the use of financial targets in incentive compensation plans and the burden to justify recovery of such costs in rates. D.P.U. 15-80/D.P.U. 15-81, at 115-116; Fitchburg Gas and Electric Light Company, D.P.U. 13-90, at 82-83 (2014); D.P.U. 11-01/D.P.U. 11-02, at 192-193; D.P.U. 10-70, at 105-106; D.P.U. 10-55, at 253-254. Specifically, where a company seeks to include financial goals as a component of incentive compensation design, the Department expects to see the attainment of such goals as a threshold component, with job performance standards designed to encourage good employee performance (e.g., safety, reliability, customer satisfaction goals) used as the basis for determining individual incentive compensation awards. D.P.U. 14-150, at 147; D.P.U. 13-90, at 82-83; D.P.U. 11-01/D.P.U. 11-02, at 192-193; D.P.U. 10-70, at 105-106; D.P.U. 10-55, at 253-254. A company that nonetheless wishes to maintain financial metrics as a component of the formula used to determine individual incentive

compensation must be prepared to demonstrate direct ratepayer benefit from the attainment of these goals or risk disallowance of the related incentive compensation costs. D.P.U. 13-90, at 83; D.P.U. 11-01/D.P.U. 11-02, at 193; D.P.U. 10-70, at 106; D.P.U. 10-55, at 253-254.

The incentive compensation paid to the Companies' Chief Executive Officer and Chief Financial Officer is directly tied to meeting financial metrics, such as earnings per share, dividend growth, and credit rating (Exh. DPU-45-21, at 3). The Companies recognize that incentive compensation for their Chief Executive Officer and Chief Financial Officer should be removed from the cost of service because their individual incentive compensation goals are directly tied to achieving financial targets (Companies Brief at 443-444, citing Exh. DPU-45-21, at 3; Companies Reply Brief at 116). The Attorney General calculates the incentive compensation for the Chief Executive Officer and Chief Financial Officer to be $577,135 (Attorney General Brief at 120, citing RR-AG-4, Att. at 2; Attorney General Reply Brief at 20). The Companies contend that the correct amount attributable to these executives is $533,160 and assert that the Attorney General relies on the wrong record request to calculate her figure (Companies Reply Brief at 117). The Companies, however, do not provide a derivation of the $533,160 figure (Companies Reply Brief at 117).

In calculating the correct disallowance, the Department relies on the information contained in the Companies' response to Record Request DPU-18, in which the Companies present incentive compensation included in the cost of service and the estimated payroll tax expense. We find the total incentive compensation associated with the Chief Executive

Office and the Chief Financial Officer and subject to disallowance to be $460,042 ($108,807 + $351,235) for NSTAR Electric and $85,221 ($20,156 + $65,065) for WMECo (RR-DPU-18). Accordingly, the Department will remove these amounts from the Companies' respective revenue requirement. In recognition of these incentive compensation adjustments, concordant adjustments to payroll tax expense will be made, as set forth below in Section VIII.C.

The Attorney General also contends that the Department should reduce the Companies' requested recovery of incentive compensation paid to the Companies' Named Executives because, she claims, 70 percent of their incentive compensation is based on the Companies' overall financial performance (Attorney General Brief at 120). Eversource utilizes financial goals, specifically earnings per share, as the trigger for funding the incentive compensation plan in a given year (Exh. AG-19-18; AG-19-19, at 1; Tr. 6, at 1156, 1163, 1166-1167). However, we find that only the Chief Executive Officer and the Chief Financial Officer are awarded incentive compensation based on the achievement of the overall corporate financial goals, such as earnings per share, dividend growth, and/or credit rating (Exh. DPU-45-21, at 3; Tr. 6, at 1155-1156). We are persuaded that the Named Executives' incentive compensation is tied to the achievement of operational targets, such as fostering a safety culture, implementing process improvements that drive improved customer satisfaction, increasing efficiencies and reducing costs, implementation of advanced cybersecurity protocols and plans, ensuring compliance with state and federal mandates, laws and regulations, and meeting the Commonwealth's energy and environmental policy goals

(Exh. DPU-45-21, at 4-5; Tr. 6, at 1156). We conclude that these goals are directly aligned with the interests of ratepayers. D.P.U. 14-150, at 147; D.P.U. 10-70, at 104. Further, while the Named Executives may have some departmental financial goals, such as budgeting (see Exh. DPU-45-21, at 4-5; Tr. 6, at 1158), the Named Executives' incentive compensation is not based on the achievement of the Companies' overall corporate financial goals, such as earnings per share, dividend growth, and/or credit rating (Exh. DPU-45-21, at 3; Tr. 6, at 1155-1156). Based on these considerations, we conclude that the incentive compensation paid to the Named Executives is consistent with Department precedent and, therefore, we decline to adopt the Attorney General's recommendations. For all of the foregoing reasons, we find that Eversource's incentive compensation plan is reasonable in design.

5. Employee Benefits

a. Introduction

Eversource booked $19,870,555 in test year employee benefits expense for NSTAR Electric (Exh. ES-DPH-2, Sch. DPH-11, at 2 (East)).[69] Eversource proposes to increase NSTAR Electric's employee benefits expense by $2,652,549, comprising the following adjustments: (1) an increase of $2,498,028 for health care expense (i.e., medical/prescription, vision, and dental) based on a 7.2 percent working rate;[70] (2) an increase of $323,914 in 401(k) savings plan costs by applying to the test year level of

[69] The test year amounts of employee benefits booked by Eversource to NSTAR Electric and WMECo represent amounts booked solely to O&M expense and do not represent any capitalized amounts (see Exhs. AG-1-50 & Atts.; AG-51-5 & Atts.).

[70] A "working rate" represents the per-employee expected claims levels for the following year and is provided by the Companies' benefits consultants and external vendor partners, Cigna and Express Scripts (Exhs. ES-DPH-1, at 58; DPU-45-34).

expense a payroll percentage adjustment of 7.589 percent; and (3) a decrease of $169,393 to reflect the allocation of a representative amount of basic service administrative costs in the basic service adder (Exhs. ES-DPH-1, at 57-59; ES-DPH-2 (East), Sch. DPH-11, at 2 (Rev. 3)).

Eversource booked $3,047,400 in test year employee benefits expense for WMECo (Exh. ES-DPH-2, Sch. DPH-11, at 2 (West)). Eversource proposes to increase WMECo's employee benefits expense by $412,040, comprising the following adjustments: (1) an increase of $465,944 for health care expense (i.e., medical/prescription, vision, and dental) based on a 7.2 percent working rate; (2) an increase of $24,483 in 401(k) savings plan costs by applying to the test year level of expense a payroll percentage adjustment amount of 7.313 percent; and (3) a decrease of $78,387 to reflect the allocation of a representative amount of basic service administrative costs in the basic service adder (Exhs. ES-DPH-1, at 57-59; ES-DPH-2 (West), Sch. DPH-11, at 2 (Rev. 3)).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that because the Companies self-insure, their medical costs are not based on contractual increases, but on working rates that Eversource develops (Attorney General Brief at 122). In this regard, the Attorney General claims that in order to derive the working rate, the Companies used a "health care growth rate"[71] of 9.5 percent, which she claims does not represent the actual increase in the Companies' employee medical

[71] While the Attorney General refers to the "health care growth rate," it appears from her arguments and references in her briefs that she is referring to the annual medical and prescription trend rate, as it appears in Exhibit DPU-45-31, Attachment (b).

costs, is beyond any credible growth rate observed in the market, is not known and measurable, and is unsupported by any record evidence (Attorney General Brief at 122-123, citing Exh. DPU-45-31; Attorney General Reply Brief at 21, citing Exh. DPU-45-31, Att. (b)).

More specifically, the Attorney General claims that the Companies do not incur higher health care costs at the 9.5 percent growth rate through a fixed premium; rather, they only pay actual costs (Attorney General Reply Brief at 22). Further, the Attorney General adds that the Companies incur no penalty if the health care growth rate forecast is over-inflated, so if the 9.5 percent health care growth rate is higher than actual costs, the benefits will flow to shareholders (Attorney General Reply Brief at 22). Additionally, the Attorney General argues that the Companies' management "made up" the growth rate, and that there is no independent study or survey supporting the 9.5 percent growth rate for health care costs (Attorney General Reply Brief at 22).

Based on these arguments, the Attorney General contends that the Companies have calculated adjustments to their test year medical expenses based on inflated estimates of health care growth rates (Attorney General Brief at 122).[72] Thus, the Attorney General asserts that if the Department allows an increase to the Companies' health care expense, it

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[72] In further support of her arguments, the Attorney General claims that the Companies' actuarial reports for retiree benefit costs forecast a growth rate of 6.25 percent, while general inflation in the economy has been around two percent (Attorney General Brief at 124, citing Exhs. AG-JRW-1, at 82; AG-JRW-14, at 6; ES-RBH-1, at 35; Tr. 6, at 1113-1115; Attorney General Reply Brief at 22). The Attorney General also claims that the Society of Actuaries' model is forecasting a 5.5 percent growth rate for 2018 for health care costs (Attorney General Reply Brief at 22).

should do so based on "more reasonable health care trends" (Attorney General Brief at 124). In this regard, the Attorney General claims that a more reasonable health care growth rate of 6.5 percent (rather than 9.5 percent) should be used (Attorney General Brief at 124, citing RR-AG-8; Attorney General Reply Brief at 21-22). She states that using this health care growth rate to derive the working rate would result in an increase of medical costs of $1,668,140 for NSTAR Electric and an increase of $329,237 for WMECo (Attorney General Brief at 124, citing RR-AG-8).

ii. Companies

The Companies argue that the Attorney General mischaracterizes the Department's precedent on the use of working rates (Companies Brief at 445; Companies Reply Brief at 124). According to the Companies, their working rate calculation conforms to Department requirements as they developed their working rates in a similar manner to the working rates approved by the Department in D.P.U. 15-155 (Companies Brief at 447; Companies Reply Brief at 119). Specifically, the Companies note that they designed their working rates with the support of consultants that employed an underwriting process to make projections for the upcoming year (Companies Brief at 447, citing Exh. ES-MPS-1, at 10). Further, the Companies claim that their consultants estimated total plan expenses and benefit payments, and reviewed Eversource's own claims as well as national trend data in order to determine work rate trends (Companies Brief at 447). Eversource asserts that the working rates used to calculate the adjustment are correlated to NSTAR Electric's and WMECo's experience,

rather than that of a broad-based pool of insured entities (Companies Brief at 197; Companies Reply Brief at 119).

Next, Eversource disputes the Attorney General's representation that the Companies used an annual health care growth rate of 9.5 percent (Companies Brief at 448; Companies Reply Brief at 119). Rather, the Companies contend that the 9.5 percentage rate is actually the annual medical and prescription drug growth rate and just one component of the overall projected percentage increase in health care costs, which the Companies assert is 7.2 percent (Companies Brief at 448, citing Exh. DPU-45-31, Att. (b); Companies Reply Brief at 119, citing Attorney General Brief at 21-23). Moreover, the Companies disagree with the Attorney General's purported health care growth rate of 6.5 percent and claim (1) that the Attorney General "cherry picked" the Companies' working rates calculation, and (2) that the Attorney General's recommended value is out of line with the history and expected future of healthcare costs for Eversource employee health plans (Companies Brief at 449, citing Exh. DPU-45-31, Att. (b); RR-AG-8; Companies Reply Brief at 122-124). The Companies reiterate that actual claims experience in combination with actuarial assumptions were used to develop their working rate for the 2017 plan year, and, therefore, the Department should disregard the Attorney General's recommendation (Companies Brief at 448; Companies Reply Brief at 124). Further, Eversource states that since it is self-insured, it is in the Companies' interest to develop accurate and reasonable working rates in order to include the appropriate medical expense in rates (Companies Reply Brief at 123).

Based on these considerations, Eversource asserts that the Department should accept the Companies' proposed medical cost adjustments (Companies Brief at 449; Companies Reply Brief at 124).

c. Analysis and Findings

i. Health Care Expenses

To be included in rates, health care expenses, such as medical, dental, and vision, must be reasonable. The Berkshire Gas Company, D.T.E. 01-56, at 60-61 (2002); D.P.U. 92-78, at 29-30; Nantucket Electric Company, D.P.U. 91-106/91-138, at 53 (1991). Further, companies must demonstrate that they have acted to contain their health care costs in a reasonable, effective manner. D.T.E. 01-56, at 60; D.P.U. 96-50 (Phase I) at 46; D.P.U. 92-78, at 29; D.P.U. 91-106/91-138, at 53. Finally, any post-test year adjustments to health care expense must be known and measurable. D.T.E. 01-56, at 60; D.P.U. 96-50 (Phase I) at 46; North Attleboro Gas Company, D.P.U. 86-86, at 8 (1986).

As an initial matter, the Department finds that Eversource's health care expenses are reasonable and that the Companies have taken reasonable and effective measures to contain these costs (Exh. ES-MPS-1, at 8-10). For example, Eversource is self-insured (Exh. ES-MPS-1, at 10). Further, the Companies introduced a "High Deductible Health Plan" design that encourages consumerism; consolidated medical carriers and streamlined options; negotiated an agreement with its pharmacy manager that resulted in discounts for prescription drugs, lower fees, and larger rebates; employs a number of utilization-management programs such as Step Therapy programs, which encourages the use of lower-cost generic medications; uses quantity-limit programs that utilize the U.S. Food

and Drug Administration guidelines regarding dosage limits; is involved in prior-authorization programs that require clinical evidence before filling certain higher-cost and higher-risk medications; uses mail order for maintenance drugs to generate savings associated with the elimination of dispensing fees; and targets intervention on use of brand-name medications when generics are available (Exh. ES-MPS-1, at 9).

Eversource also employs pricing strategies that encourage employees to consider lower-cost health-plan options and also encourage the evaluation of alternate health-plan coverage available to employed family members (Exh. ES-MPS-1, at 13). Additionally, the Companies introduced three new plan designs for non-union employees, and negotiated the implementation of the same health plan offerings for its unions (Exh. ES-MPS-1, at 13). Under its employee-contribution model, Eversource applies strategies that encourage employees to consider lower-cost health plan options and encourage the use of alternate coverage for family members (Exh. ES-MPS-1, at 13). The Companies' non-union employees pay a lower percentage of their own premium cost and a higher percentage of premiums for dependents, and they bear the cost of buying a higher level of coverage (Exh. ES-MPS-1, at 13). Further, the Companies periodically benchmark their health care benefit programs against the programs of other employers (Exh. ES-MPS-1, at 5). Finally, Eversource offers wellness programs to help manage and improve employee health, which in turn helps to moderate health costs over time (Exh. ES-MPS-1, at 4, 14-15).

Turning to the specifics of Eversource's proposed health care expense, the Companies maintain that they have relied on the most recent working rates to develop the appropriate

adjustments to test year costs to reflect the increases that are expected through July 2018 (Companies Brief at 196; Companies Reply Brief at 119). The Department has previously denied recovery of pro forma health care expenses based on working rates derived from actuarial estimates encompassing a broad-based pool of insured parties. D.P.U. 15-80/D.P.U. 15-81, at 137; D.P.U. 13-90, at 94. In the instant case, however, Eversource's working rate is derived using Eversource-specific data such as medical and prescription drug claims expense, enrollment figures, plan design details, administration costs, and fees (Exhs. ES-DPH-1, at 57; ES-MPS-1, at 12; ES-MPS-2; DPU-45-31; DPU-45-34; Tr. 6, at 1117-1130). The Companies' external benefits consultants developed the working rate using actuarial principles; the rate is based on the Companies' actual insurance claims and cost trends experienced during the two years prior to the test year (Exh. ES-MPS-1, at 11). Therefore, we conclude that Eversource's proposed working rates are sufficiently correlated to NSTAR Electric's and WMECo's experience, rather than that of a broad-based pool of insured entities, to warrant their use in determining the Companies' health care expense in this proceeding. See D.P.U. 15-155, at 176-177.[73]

Having found that Eversource's working rates are acceptable and consistent with Department precedent, we accept the Companies' working rates of 7.2 percent and decline to

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[73] The Department recognizes that disallowing Eversource's post-test year adjustments on the basis of working rates could provide a disincentive for companies to implement aggressive cost control measures, such as switching to self-insurance, when such measures otherwise would be deemed cost-effective. D.P.U. 15-155, at 177; D.P.U. 95-40, at 26; D.P.U. 92-210, at 22. However, we reiterate that working rates must be correlated to the petitioner's experience, rather than that of a broad-based pool of insured entities.

adopt the Attorney General's recommendations. In this regard, we note that the Attorney General's recommended health care growth rate of 6.5 percent, which she claims would produce a working rate of 2.4 percent (see Tr. 6, at 1129-1130; RR-AG-8), does not sufficiently correlate to the Companies' experience with health care costs for active employees.[74] Based on these findings, the Department accepts the Companies' proposed adjustments to test year health care expenses.

ii. 401(k) Savings Plan Costs

As noted above, Eversource proposes to increase NSTAR Electric's 401(k) savings plan costs by $323,914, which represents a proposed 7.589 percent salary increase for union and non-union employees (Exhs. ES-DPH-1, at 57-59; ES-DPH-2 (East), Sch. DPH-11, at 2 (Rev. 3)). Similarly, Eversource proposes to increase WMECo's 401(k) savings plan costs by $24,483, which represents a proposed 7.313 percent salary increase for union and non-union employees (Exhs. ES-DPH-1, at 57-59; ES-DPH-2 (West), Sch. DPH-11, at 2 (Rev. 3)). The Department has found that employee contributions to utility-sponsored savings plans are voluntary and, thus, subject to fluctuation. D.P.U. 13-90, at 102-104; Commonwealth Electric Company/Cambridge Electric Light Company, D.P.U. 89-114/90-331/91-80 (Phase One) at 66-67 (1991); Commonwealth Electric Company, D.P.U. 88-135/151, at 68 (1989). In the absence of a demonstration that the

[74] We also are not persuaded by the Attorney General's reliance on the Society of Actuaries' forecast of a 5.5 percent growth rate, which she presented for the first time on brief (Attorney General Reply Brief at 22). Unlike the Companies' derivation of working rates, the Society of Actuaries' forecast is based on inflation, real income per capita, and excess medical cost growth, not data specific to the Companies (see https://www.soa.org/research-reports/2016/research-hlthcare-trends/).

post-test year participation levels are more representative of future participation than the total employee contributions made during the test year, the Department declines to permit any adjustment above the expense booked during the test year. D.P.U. 92-250, at 48; D.P.U. 89-114/90-331/91-80 (Phase One) at 66-67; D.P.U. 88-135/151, at 68.

Here, the Companies' proposed increases are based on the assumption that the increase in savings plan contributions will be consistent with the overall increases in salaries (Exh. ES-DPH-1, at 58-59). Thus, the Companies' proposed increases are based on percentage increases to union and non-union salaries regardless of whether an employee participates in or makes contributions to the 401(k) savings plan. In addition, the Companies have not demonstrated that the post-test year participation levels are more representative of future participation that those contributions made during the test year. Thus, the Department disallows the Companies' proposed increases associated with 401(k) savings plan costs. D.P.U. 92-250, at 48; D.P.U.89-114/90-331/91-80 (Phase One) at 66-67; D.P.U. 88-135/151, at 68; see also D.P.U. 14-150, at 152-153. Accordingly, the Department reduces NSTAR Electric's proposed cost of service by $323,914 and reduces WMECo's proposed cost of service by $24,483.

B. Service Company Charges

1. Introduction

Beginning with the April 10, 2012 effective date of the merger of Northeast Utilities and NSTAR (see Section V.A above) and through December 31, 2013, Northeast Utilities Service Company ("NUSCO") and NSTAR Electric & Gas Service Company ("NE&G") operated as a single service company organization despite being separate legal entities

(Exh. ES-DPH-1, at 26). Effective January 1, 2014, NE&G was legally merged into NUSCO, with NUSCO as the surviving entity (Exh. ES-DPH-1, at 26). Effective February 2, 2015, Northeast Utilities and all of its subsidiaries began doing business as Eversource Energy, and NUSCO was renamed ESC (Eversource Service Company) (Exh. ES-DPH-1, at 26).

ESC provides administrative, corporate, and management services to NSTAR Electric, WMECo, and other operating subsidiaries of Eversource Energy (Exh. ES-DPH-1, at 26). The Companies incur expenses from ESC in two ways: (1) through direct charges, which are billed to the Companies for costs incurred and work performed by ESC personnel; and (2) through common costs, which are allocated among the respective subsidiaries that receive services provided by ESC based on allocation factors (Exh. ES-DPH-1, at 27).[75] All ESC charges are billed to NSTAR Electric and WMECo in conformance with service agreements, which specify the services that are provided to the Companies (Exh. ES-DPH-1, at 27). ESC provides services to NSTAR Electric and WMECo in numerous functional areas such as accounting, communications, conservation and load management services, construction, customer relations, demand side management, energy supply, engineering, facilities, finance and business planning, human resources, information technology, legal, rates and regulation, and taxes (Exh. AG-1-26, Atts. (a), (b)).

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[75] ESC uses an internal document called the Cost Charging and Allocation Manual to determine the allocation of costs among its operating subsidiaries. When costs cannot be charged directly because they benefit more than one business segment, the allocators are used. The cost allocation method is intended to ensure the accurate charging of service company costs to its affiliates (Exh. AG-1-28, Att. (d)).

Eversource included ESC charges in the corresponding expense categories in the test year (e.g., salary and wages) (Exhs. ES-DPH-2 (East), Schs. DPH-11, DPH-13 (Rev. 3); ES-DPH-2 (West), Schs. DPH-11, DPH-13 (Rev. 3)). Additionally, Eversource included various ESC charges in the normalizing or known and measurable adjustments to the cost of service in the appropriate expense categories. For example, salaries of ESC employees are included in the Companies' proposed adjustment to payroll expense (Exhs. ES-DPH-2 (East), Sch. DPH-13 (Rev. 3); ES-DPH-2 (West), Sch. DPH-13 (Rev. 3).

ESC's charges include an equity rate of return component, which is intended to provide for a return on ESC's assets that are used for the benefit of its affiliates (Exh. AG-1-25; Tr. 15, at 3065; RR-AG-21). During the test year, NSTAR Electric booked $32,133,446 in charges from ESC, of which $1,988,563 was related to ESC's equity rate of return component (Exh. AG-1-25, Att. (a)). During the test year, WMECo booked $6,653,794 in charges from ESC, of which $414,549 was related to ESC's equity rate of return component (Exh. AG-1-25, Att. (b)).

2. Positions of the Parties

a. Attorney General

The Attorney General identifies two issues related to service company charges. First, the Attorney General explains that ESC charges related to general service company overhead are applied with the ESC labor costs to the accounts in which the labor costs are charged (Attorney General Brief at 111). The overhead charges include a return on equity on ESC assets, among others (Attorney General Brief at 111). The Attorney General calculates that during the test year, ESC charges for the return on equity component of total service

company overhead were $1,988,563 for NSTAR Electric and $414,549 for WMECo (Attorney General Brief at 111, citing Exhs. AG-DR-1, at 4; AG-1-25, Atts. (a), (b)). The Attorney General argues that the return on equity that ratepayers pay on ESC assets should be limited to the return on equity found to be fair and reasonable by the Department in this proceeding (Attorney General Brief at 111-112, citing Exh. AG-DR-1, at 5). Thus, the Attorney General calculates reductions to ESC overhead costs included in the test year to be $307,754 for NSTAR Electric and $31,307 for WMECo based on her recommended return on equity of 8.875 percent (Attorney General Brief at 112, citing Exhs. AG-DR-1, at 5; AG-DR-2, Sch. 2).

Second, the Attorney General proposes that test year charges from ESC should be reduced for the impacts of Eversource's proposed acquisition of Macquarie Utilities, Inc. ("Macquarie"), then pending before the Department in docket Eversource Energy/Macquarie Utilities, Inc. Acquisition, D.P.U. 17-115 (Attorney General Brief at 112-113).[76] According to the Attorney General, mergers and acquisitions of utility companies typically result in significant cost savings for the post-merger and post-acquisition companies by merging the

[76] On June 29, 2017, Eversource and Macquarie filed a petition with the Department seeking approval, pursuant to G.L. c. 165, § 2, and G.L. c. 164, § 96, of a change of control of Macquarie, which is a holding company of Aquarion Water Company of Massachusetts ("AWC-MA") and its subsidiaries in Connecticut and New Hampshire. The petition seeks approval of a transaction whereby Eversource will acquire Macquarie, including AWC-MA and its subsidiaries, for approximately $1.675 billion, comprised of approximately $880 million in cash and an estimated $795 million of assumed Macquarie debt (see Exh. AG-1-2, Att. (a) at 2, 5-7 (Supp. 4)). The Department approved the acquisition on November 28, 2017. Eversource Energy/Macquarie Utilities, Inc. Acquisition, D.P.U. 17-115 (November 28, 2017).

service company functions and thus reducing the allocation of service company costs to the operating companies (Attorney General Brief at 113; Attorney General Reply Brief at 27). In support of her position, the Attorney General cites multiple examples of mergers and acquisitions that resulted in cost savings, such as the merger between Northeast Utilities and NSTAR; the merger and acquisition involving Boston Edison Company and Commonwealth Energy; the Northeast Utilities and Yankee Gas merger; and Northeast Utilities' acquisition of Public Service Company of New Hampshire (Attorney General Brief at 113-114). The Attorney General claims that the acquisition of Macquarie should result in the consolidation of functions between Eversource and Macquarie's subsidiaries Aquarion Water Company of Massachusetts, Aquarion Water Company of New Hampshire and Aquarion Water Company of Connecticut (hereinafter collectively as "Aquarion"), which would reduce the costs to be allocated to NSTAR Electric and WMECo post-acquisition (Attorney General Brief at 113-114).

The Attorney General recommends using the Companies' C05 allocation factor as a reasonable means of reducing indirect costs allocated to NSTAR Electric and WMECo as a result of the acquisition, as this factor includes plant, revenues, and expense, and it is based on a 50/50 split of allocation codes C04 and B10 (Attorney General Brief at 115). The Attorney General calculates the impacts of the inclusion of Aquarion in the calculation of the C05 allocation factor and computes an estimated 5.31 percent reduction in costs charged to NSTAR Electric, or a $6,285,012 reduction in test year O&M expenses (Attorney General Brief at 117; Attorney General Reply Brief at 27). Similarly, she produces a 5.52 percent

reduction in costs charged to WMECo, or a $1,054,299 reduction in test year O&M expenses (Attorney General Brief at 117; Attorney General Reply Brief at 27). The Attorney General emphasizes that, contrary to the Companies' interpretation, her recommended adjustments are not based on a reduction of costs incurred by ESC, but rather are based on the impact of including Aquarion in the allocation factors utilized by the service company (Attorney General Reply Brief at 28). The Attorney General recommends that the Department reduce the Companies' pro forma cost of service to reflect these cost reductions from Eversource's purported consolidation with Aquarion (Attorney General Brief at 117).

b. Companies

The Companies contend that in calculating a proposed reduction of ESC overhead costs, the Attorney General incorrectly applies the Companies' most recently authorized rates of return of 10.5 percent for NSTAR Electric and 9.6 percent for WMECo (Companies Brief at 438, citing Exh. AG-DR-2, Sch. 2). The Companies submit that the return on equity used by ESC during the test year was 9.71 percent from July 2015 to December 2015 and 9.78 percent from January 2016 to June 2016 (Companies Brief at 438). According to the Companies, ESC's rate of return is determined annually by calculating the average authorized return for each regulated entity, weighted based on Eversource's C09 allocator, which considers Gross Plant Assets and Net Income (Companies Brief at 438, citing RR-AG-21). The Companies maintain that the Department should disregard the Attorney General's recommended return on equity of 8.875 percent and should instead approve Eversource's

suggested return on equity of 10.5 percent, which the Companies claim would set the most appropriate basis for reducing ESC overhead costs (Companies Brief at 439).

Turning to Eversource's recently approved acquisition of Macquarie, the Companies agree with the Attorney General that although there were significant savings associated with the Northeast Utilities/NSTAR merger as well as others, they claim that savings in those mergers cannot be used as a measure for potential savings related to the Macquarie acquisition because Eversource does not have plans to integrate Aquarion functions with the existing Eversource organization (Companies Brief at 442; Companies Reply Brief at 126, citing D.P.U. 17-115, Exh. DPU-1-20)). Eversource explains that as a result, the operational savings will be more limited than those achieved in the Northeast Utilities/NSTAR merger (Companies Brief at 442, citing D.P.U. 17-115, Exh. ES-AQ-1, at 17). Instead, Eversource proposes that it will directly bill Macquarie for any services provided such as cash management, tax compliance, executive management, and legal (Companies Reply Brief at 126).

3. Analysis and Findings

a. Introduction

The Department permits rate recovery of payments to affiliates where these payments are: (1) for services that specifically benefit the regulated utility and that do not duplicate services already provided by the utility; (2) made at a competitive and reasonable price; and (3) allocated to the utility by a method that is both cost-effective in application and nondiscriminatory for those services specifically rendered to the utility by the affiliate and for general services that may be allocated by the affiliate to all operating affiliates.

D.P.U. 15-155, at 270-271; D.P.U. 13-75, at 184; D.P.U. 12-25, at 231 ; D.P.U. 89-114/90-331/91-80 (Phase I) at 79-80; Hingham Water Company, D.P.U. 88-170, at 21-22 (1989); AT&T Communications of New England, Inc., D.P.U. 85-137, at 51-52 (1985). In addition, 220 CMR 12.04(3) provides that an affiliated company may sell, lease, or otherwise transfer an asset to a distribution company, and may also provide services to a distribution company, provided that the price charged to the distribution company is no greater than the market value of the asset or service provided.

b. Services

In determining whether the services rendered by an affiliate specifically benefit a regulated utility and do not duplicate services already provided by the utility, it is necessary to examine whether there is any overlap between the services rendered by an affiliate and the operating company's functions. D.P.U. 13-75, at 184; D.P.U. 08-27, at 80-81; D.P.U. 1699, at 11-12. The services provided to the Companies by ESC employees include administrative, technical, and professional services within numerous functional groups, including: accounting, auditing, conservation and load management, construction, demand side management, energy supply, engineering, environmental, facilities, finance and business planning, human resources, information technology, insurance, legal, procurement, rates and regulation, taxes, and many other various functions (Exhs. ES-DPH-1, at 26; AG-1-26, Atts. (a), (b)). The Companies require these types of services on a continuing basis for the proper operation of their business and the delivery of electric service to their customers. Therefore, these services specifically benefit NSTAR Electric and WMECo in providing

service to their customers, and the services provided by ESC are not duplicative of services already provided by the Companies' personnel.

c. Price

Next, the Department evaluates whether ESC charges to NSTAR Electric and WMECo are competitive and reasonable. In prior cases, when determining whether services were charged at a competitive and reasonable price, the Department accepted a review of employer compensation structures compared to the market because service company charges tend to be primarily labor-related. D.P.U. 15-155, at 272; D.P.U. 13-75, at 186; D.P.U. 12-25, at 233; D.P.U. 09-39, at 260. The record shows that compensation of ESC employees is competitive compared to the market median (Exhs. ES-SL-1, at 15; ES-SL-8). The Companies provided evidence of the competitiveness and reasonableness of ESC costs by comparing ESC base salaries and total cash compensation against median base salaries and total cash compensation in the energy/utility and general industry sectors in the Northeast using a Towers Watson study (Exh. ES-SL-8). In particular, the cost comparisons show that ESC employees' base salary is approximately 100.4 percent of the external market and that total cash compensation is approximately 100.2 percent of the external market (Exhs. ES-SL-1, at 20; ES-SL-8). The defined competitive market range is between 90 and 110 percent of the market median (Exh. ES-SL-1, at 20). Thus, Eversource's analysis demonstrates that the services provided by ESC are closely aligned with third-party rates observed in the market (Exh. ES-SL-8). Based on the foregoing, the Department finds that

the Companies have adequately demonstrated that ESC services provided to NSTAR Electric and WMECo were charged at a competitive and reasonable price.

The Attorney General proposes that overhead costs charged by ESC during the test year should be reduced to reflect the return on equity approved by the Department in this proceeding (Attorney General Brief at 111). The Attorney General calculates reductions to ESC overhead costs included in the test year of $307,754 for NSTAR Electric and $31,307 for WMECo based on the 8.875 percent return on equity recommended by the Attorney General (Attorney General Brief at 112, citing Exhs. AG-DR-1, at 5; AG-DR-2, Sch. 2).

The Companies did not challenge the Attorney General's recommendation as it pertains to using the return on equity set in this proceeding, however, they indicate that the return on equity used by ESC during the test year was 9.71 percent from July 2015 to December 2015 and 9.78 percent from January 2016 to June 2016, not 10.5 percent for NSTAR Electric and 9.6 percent for WMECo, as cited by the Attorney General (Companies Brief at 438). Further, the Companies argue that the appropriate return on equity to use to set the basis for any reduction in ESC overhead costs should be 10.5 percent (Companies Brief at 438-439).

The Department agrees that the return on equity on ESC overhead costs should be based on the return on equity found to be just and reasonable in this proceeding. Aquarion Water Company of Massachusetts, D.P.U. 11-43, at 145 (2012); D.P.U. 08-27, at 82. As set forth in Section XVI.E below, the Department has concluded that a return on equity of

10.0 percent is appropriate for the Companies. Therefore, the Department will use a return of equity of 10.0 percent to determine ESC's overhead costs.

Next, we find that the Attorney General's recommended calculation of the ESC overhead costs adjustment (Exh. AG-DR-2, Sch. 2) inappropriately overlooks the fact that the ESC's equity rate of return component is derived from multiple entities (RR-AG-21). Therefore, we decline to adopt the Attorney General's recommendations. Similarly, we are not persuaded by the Companies' use of a C09 allocator to determine ESC's annual equity rate of return component (RR-AG-21). In particular, we note that the record shows that the C09 allocator relies on data from WMECo, CL&P, and Yankee Gas Services Company (Exhs. AG-1-28, Att. (d) at 7; AG-1-92, Att. at 1). We find that the absence of NSTAR Electric data as part of the allocator calls into question the validity of the use of the C09 allocator to apportion ESC's equity rate of return component. Therefore, the Department concludes that it is appropriate to use a different allocator.

The Department has examined the allocators used in the Cost Charging and Allocation Manual. Given the scope of services provided by ESC and its role in the operations of Eversource's affiliates, including NSTAR Electric and WMECo, the Department considers it appropriate to select an allocator that covers a broad range of affiliates. Based on this consideration, the Department finds that the C11 allocator covers a wide range of Eversource affiliates, and includes the allocation factors for both NSTAR Electric and WMECo (Exh. AG-26-23, Att. at 1). As such, we conclude that using the C11 allocator to apportion ESC's return on equity is reasonable and appropriate.

Using the C11 allocator and the return on equity approved by the Department in this proceeding, ESC's equity rate of return component can be calculated as follows. First, the Department notes that during the first half of the test year (i.e., July 2015 through December 2015), ESC charged NSTAR Electric and WMECo $486,590 and $99,511, respectively, in equity rate of return components (Exh. AG-1-25, Atts.). During the second half of the test year (i.e., January 2016 through June 2016), ESC charged NSTAR Electric and WMECo $1,501,973 and $315,038, respectively, in equity return components (Exh. AG-1-25, Atts). Thus, ESC's total equity rate of return component during this period was $2,403,112 (Exh. AG-1-25, Atts.). ESC used an equity rate of return component during the split test year of 9.71 percent from July 2015 to December 2015, and 9.78 percent from January 2016 to June 2016 (RR-AG-21). These returns, weighted by ESC's equity rate of return components during these periods, produce a weighted return on equity for ESC of 9.76 percent.[77]

Because the C11 allocator would represent a weighted average of allowed returns on equity, it is necessary to develop a composite return on equity component for the Companies' other affiliates used in the C11 allocator. Using ESC's weighted return on equity of 9.76 percent as calculated above, as well as the allocation factors provided in Exhibit AG-26-23, NSTAR Electric's currently allowed return on equity of 10.5 percent, and WMECo's currently allowed return on equity of 9.6 percent, the return on equity for the

[77] (((($486,590 + $99,511) x 9.71 percent) + ($1,501,973 + $315,038) x 9.78) / $2,403,112 = 9.76 percent).

other entities in the C11 allocator can be mathematically derived as 9.35 percent.[78] With this data, and using the 10.0 percent return on equity being granted to the Companies, ESC's test year weighted average return on equity can be mathematically calculated as 9.60 percent.[79]

Finally, the Department multiplies the return on equity component included in ESC's overhead charges ($1,988,563 for NSTAR Electric and $414,549 for WMECo) by the percentage change in ESC's equity component of 0.16 percent (9.76 – 9.60 = 0.16) to calculate the appropriate reduction to overhead costs charged by ESC during the test year (Exhs. AG-1-25, Atts. (a), (b)). Based on these calculations, we find that NSTAR Electric's proposed ESC charges should be reduced by $3,778 and WMECo's proposed ESC charges should be reduced by $662. Accordingly, the Department reduces NSTAR Electric's proposed cost of service by $3,778 and reduces WMECo's proposed cost of service by $662.

d. Allocation

Finally, we evaluate the method of allocating costs from ESC to NSTAR Electric and WMECo. When allocating costs among affiliates, it is preferable that costs associated with a specific utility are directly assigned to that utility. In the absence of a clear relationship between the cost and the affiliate, or when costs cannot be directly assigned, these costs preferably should be allocated using cost-causative allocation factors to the extent such allocation factors can be applied, with general allocation factors used to allocate any

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78 (9.76 percent – (34.67 percent x 10.5 percent) – (4.41 percent x 9.60 percent) / (1.00 - 0.03467 - 0.0441)) = 9.35 percent.

79 (10.0 percent x 34.67 percent) + (10.0 percent x 4.41 percent) + (9.35 percent x 60.92 percent) = 9.60 percent).

remaining costs. D.P.U. 15-155, at 274; D.P.U. 13-75, at 188; D.P.U. 11-01/D.P.U. 11-02, at 318-321; D.P.U. 10-114, at 271-274.

ESC provides services to NSTAR Electric and WMECo pursuant to service agreements, and ESC costs are charged based on the method of allocation set forth in the service agreements (Exhs. ES-DPH-1, at 27; AG-1-26, Atts. (a), (b)). ESC charges are made directly to the Companies and, when direct assignment is not possible, through allocation factors (Exh. AG-1-26, Atts. (a), (b)). ESC expenses are directly charged to the appropriate business segment whenever possible for costs incurred in carrying out activities or conducting business for that entity (Exh. AG-1-28). When more general costs are incurred to serve the operating companies that cannot be directly assigned, such costs are allocated among the operating companies based on an allocation method (Exh. AG-1-28). The allocations are designed to be proxies for cost causation within a particular function (Exh. AG-1-28).[80] Allocations are made only after it is determined that it is not practical or reasonably possible to perform a direct assignment of the costs (Exh. AG-1-28).

To ensure accuracy of the allocations, ESC is required to maintain a system for accumulating all costs by direct charges as much as possible (Exh. AG-1-26, Atts. (a) at 7, (b) at 7). Additionally, the Companies require ESC employees to charge their time and expenses appropriately and to keep time records that identify hours worked, account numbers charged, departments, and other code designations that ensure proper charging of ESC costs (Exh. AG-1-26, Atts. (a) at 7, (b) at 7). Finally, ESC accounting records are required to

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[80] For example, the Human Resources function uses an allocator based on labor charged to each company (Exh. AG-1-28).

specify the nature of the services performed in detail so that charges may be determined and correctly accounted for by the operating company under its Uniform System of Accounts (Exh. AG-1-26, Atts. (a) at 7, (b) at 7). The Department has reviewed the method of allocation for ESC's charges, and finds that it is cost-effective in application and nondiscriminatory.

The Attorney General recommends that the Department reduce the overall level of costs allocated to the Companies to account for potential savings associated with Eversource's acquisition of Macquarie (Attorney General Brief at 117; Attorney General Reply Brief at 27). Proposed changes to test year revenues, expenses, and rate base require a finding that the adjustment constitutes a "known and measurable" change to test year cost of service. See Eastern Edison Company, D.P.U. 1580, at 13-17, 19 (1984); D.P.U. 84-32, at 17; Massachusetts Electric Company, D.P.U. 136, at 3 (1980); Chatham Water Company, D.P.U. 19992, at 2 (1980); D.P.U. 18204, at 4; New England Telephone & Telegraph Company, D.P.U. 18210, at 2-3 (1975); Boston Gas Company, D.P.U. 18264, at 2-4 (1975). It is also well-recognized that cost savings arising from merger activities may be considered by the Department, to the extent that such savings can be quantified under a known and measurable standard. Plymouth Water Company, D.P.U. 14-120, at 108-112 (2015); Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 09-39, at 275 (2009); Bay State Gas Company/Unitil Corporation, D.P.U. 08-43-A at 45 (2008).

While the Department has approved Eversource's proposal to acquire Macquarie, Eversource does not plan to integrate Aquarion's operations with the existing Eversource

organization following the transaction, and thus does not anticipate allocating any centralized services costs to Aquarion's operations. Eversource Energy/Macquarie Utilities, Inc. Acquisition, D.P.U. 17-115, at 66 (November 28, 2017). To the extent that Eversource implements any changes to Aquarion's operations or integrates functions between the two entities, those changes will take place over time and as Eversource becomes familiar with Aquarion's water operations. D.P.U. 17-115, at 66-67. As a result, any future allocation of costs are speculative at this time. Accordingly, the Department declines to accept the Attorney General's recommended adjustments to account for any savings associated with Eversource's proposed acquisition of Macquarie.

e. Conclusion

Based on the foregoing analysis, the Department has adjusted the Companies' charges from ESC in recognition of the return on equity being approved in this proceeding. Accordingly, the Department reduces NSTAR Electric's proposed cost of service by $3,778 and reduces WMECo's proposed cost of service by $662.

C. Payroll Taxes

1. Introduction

During the test year, NSTAR Electric booked $9,689,692 in adjusted payroll taxes (Exh. ES-DPH-2 (East), Sch. DPH-26 (Rev. 3)). NSTAR Electric proposes to increase payroll tax expense by $594,616 to recognize the additional payroll taxes associated with its pro forma Federal Insurance Contribution Act ("FICA") and Medicare expense (Exh. ES-DPH-2 (East), Sch. DPH-26 (Rev. 3)).

During the test year, WMECo booked $1,652,894 in adjusted payroll taxes (Exh. ES-DPH-2 (West), Sch. DPH-26 (Rev. 3)). WMECo proposes to increase its payroll tax expense by $112,550 to recognize additional payroll taxes associated with its pro forma FICA and Medicare expense (Exh. ES-DPH-2 (West), Sch. DPH-26 (Rev. 3)).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should reject Eversource's proposal to include incentive compensation in its cost of service for the Chief Executive Officer, James Judge; the Chief Financial Officer, Philip Lembo; and the Named Executives (Attorney General Brief at 120-121). The Attorney General recommends corresponding associated payroll tax expense reductions (Attorney General Brief at 122).

b. Companies

The Companies state that they calculated the change in FICA payroll tax related to the various labor and incentive compensation adjustments, and have made applicable adjustments to payroll taxes as a result (Companies Brief at 249, citing Exh. ES-DPH-1, at 173). The Companies claim that the FICA taxable wage limit will continue to increase in the rate year since it has increased in all but three years since 1982 at a compound growth rate of four percent (Companies Brief at 250, citing RR-DPU-41; Tr. 15, at 3018-3021). The Companies assert that the FICA taxable wage cap percentage increase is commensurate with the payroll increase percentage used as the basis for the payroll tax adjustment, and thus, the Department should approve the Companies' calculation of payroll taxes (Companies Brief at 250).

Finally, addressing the Attorney General's arguments, the Companies concede that incentive compensation and accompanying payroll taxes associated with James Judge and Philip Lembo should be removed from the cost of service (Companies Brief at 444). However, as discussed above in Section VIII.A.4 above the Companies argue that the incentive compensation (and, therefore, accompanying payroll taxes) associated with the Named Executives are appropriate for inclusion in the cost of service.

3. Analysis and Findings

The Department has examined the record related to the Companies' payroll tax calculations (e.g., Exhs. ES-DPH-2 (East), Sch. DPH-26 (Rev. 3); ES-DPH-2 (West), Sch. DPH-26 (Rev. 3)). The record shows that the FICA taxable wage limit will increase by two percent for the rate year (RR-DPU-41 & Att. (Supp.)). Nonetheless, we find that revisions to the Companies' proposed payroll tax calculations are necessary.

First, as set forth above in Section VIII.A.4 above, the Department has excluded from NSTAR Electric's cost of service $460,042 in incentive compensation for the Chief Executive Officer and Chief Financial Officer. The level of estimated payroll tax proposed in the cost of service related to these adjustments for these two employees is $27,485 ($5,785 + 21,700 = $27,485) (RR-DPU-18, Att.). Therefore, the Department reduces NSTAR Electric's proposed cost of service by $27,485.

Likewise, the Department has excluded from WMECo's cost of service $85,221 in incentive compensation for the Chief Executive Officer and Chief Financial Officer. The level of estimated payroll tax proposed in the cost of service related to these adjustments for

these two employees is $5,092 ($1,072 + $4,020 = $5,092) (RR-DPU-18, Att.). Therefore, the Department reduces WMECo's proposed cost of service by $5,092.

Second, as set forth in greater detail in Section VIII.A.3 above, the Department has excluded from WMECo's cost of service $173,600 based on the elimination of the Companies' proposed adjustment to the annualization of union hires. To determine a representative level of payroll taxes, the Department divides total test year payroll tax expense by total test year payroll expense and finds that WMECo's overall payroll tax rate is 7.19 percent ($1,652,894 / $22,999,340 = 0.0719) (Exhs. ES-DPH-2 (West), Schs. DPH-13, at 2, DPH-26 (Rev. 3)). Accordingly, the Department further reduces WMECo's proposed cost of service by $12,482 ($173,600 * 0.0719 = $12,482) to account for the reduction in payroll taxes related to the elimination of WMECo's proposed adjustment to union hires.

Combining the effects of the Department's revisions to payroll tax expense, the total reduction to NSTAR Electric's pro forma payroll tax expense is $27,485. Likewise, the total reduction to WMECo's pro forma payroll tax expense is $17,574.[81]

D. Uncollectible Expense

1. Introduction

During the test year, NSTAR Electric and WMECo booked $15,073,652 and $5,163,634 respectively in bad debt expense (uncollectible expense) related to its total operations (Exhs. ES-DPH-2 (East), Sch. DPH-8; ES-DPH-2 (West), Sch. DPH-8 (Rev. 3)).

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[81] For purposes of presentation, the Department records these adjustments on the FICA line of Schedules 7.

NSTAR Electric proposes to decrease its distribution-related bad debt expense by $3,573,684 over the test year level based on the application of a bad debt ratio of 0.7084 percent (Exhs. ES-DPH-2 (East), Sch. DPH-8, at 2 (Rev. 3); ES-DPH-3 (East), WP DPH-8, at 1 (Rev. 3)). WMECo proposes to decrease its distribution-related bad debt expense by $2,063,199 over the test year level based on the application of a bad debt ratio of 1.2435 percent (Exhs. ES-DPH-2 (West), Sch. DPH-8, at 2 (Rev. 3); ES-DPH-3 (West), WP DPH-8, at 1 (Rev. 3)).

NSTAR Electric calculated its distribution-related bad debt ratio by dividing its total delivery service net write-offs for the twelve-month periods ending on June 30, 2014,[82] June 30, 2015, and June 30, 2016, of $11,307,976,[83] by its average retail revenues for that same period of $1,596,307,390 (Exh. ES-DPH-3 (East), WP DPH-8, at 1 (Rev. 3)).[84] This calculation results in a bad debt ratio of 0.7084 percent (Exh. ES-DPH-3 (East), WP DPH-8, at 1 (Rev. 3)). NSTAR Electric then multiplied the bad debt ratio of 0.7084 percent by test year retail revenues of $1,623,411,077 to arrive at a bad debt expense of $11,499,968

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82 Eversource states that the Companies' net write-offs are comprised of the actual customer accounts written off for non-payment minus recoveries related to previously written-off account balances (see Exh. ES-DPH-1, at 48-49). Eversource states that the resulting net write-off ratio is intended to represent the portion of the Companies' respective non-basic service billed revenues that they will ultimately be unable to collect from their customers (see Exh. ES-DPH-1, at 49).

83 NSTAR Electric's net write-offs do not include write-offs associated with the arrearage management program, prior judgments, or basic service (Exhs. AG-22-3; ES-DPH-3 (East), WP DPH-8, at 2 (Rev. 3)).

84 NSTAR Electric's retail revenues do not include revenues associated with basic service (Exh. ES-DPH-2 (East), WP DPH-8, at 2 (Rev. 3)).

(Exh. ES-DPH-2 (East), Sch. DPH-8, at 2 (Rev. 3)). The resulting bad debt expense represents a decrease of $3,573,684 when compared to NSTAR Electric's test year level of expense of $15,073,652 (Exh. ES-DPH-2 (East), Sch. DPH-8, at 2 (Rev. 3)).

NSTAR Electric also calculated a bad debt expense associated with the proposed revenue increase. NSTAR Electric multiplied the bad debt ratio of 0.7084 percent by its proposed revenue increase of $56,098,325 to arrive at a proposed bad debt adjustment of $397,391 (Exh. ES-DPH-2 (East), Sch. DPH-3 (Rev. 4)).

WMECo calculated its distribution-related bad debt ratio by dividing its total delivery service net write-offs for the twelve-month periods ending on June 30, 2014, June 30, 2015, and June 30, 2016, of $3,095,807,[85] by its average retail revenues for that same period of $248,968,008 (Exh. ES-DPH-3 (West), WP DPH-8, at 1(Rev. 3)).[86] This calculation results in a bad debt ratio of 1.2435 percent (Exh. ES-DPH-3 (West), WP DPH-8, at 1 (Rev. 3)). WMECo then multiplied the bad debt ratio of 1.2435 percent by test year retail revenues of $249,340,158 to arrive at a bad debt expense of $3,100,435 (Exh. ES-DPH-2 (West), Sch. DPH-8, at 2 (Rev. 3)). The resulting bad debt expense represents a decrease of $2,063,199 when compared to the Company's test year level of expense of $5,163,634 (Exh. ES-DPH-2 (West), Sch. DPH-8, at 2 (Rev. 3)).

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85 WMECo's net write-offs do not include write-offs associated with the arrearage management programs, year round hardships, or basic service (Exhs. AG-22-1; ES-DPH-3 (West), WP DPH-8, at 2 (Rev. 3)).

86 WMECo's retail revenues do not include revenues associated with basic service (Exh. ES-DPH-3 (West), WP DPH-8, at 2 (Rev. 3)).

WMECo also calculated a bad debt expense associated with the proposed revenue increase. WMECo multiplied the bad debt ratio of 1.2435 percent by its proposed revenue increase of $34,676,801 to arrive at a proposed bad debt adjustment of $431,191 (Exh. ES-DPH-2 (West), Sch. DPH-3 (Rev. 4)).

2. Positions of the Parties

Eversource argues that it has met the Department's standard for the inclusion of a representative level of bad debt expense in the Companies' respective cost of service (Companies Brief at 188). Thus, Eversource asserts that the Department should approve the Companies' respective proposed bad debt expense (Companies Brief at 188). No other parties address the Companies' bad debt calculations.

3. Analysis and Findings

The Department permits companies to include for ratemaking purposes a representative level of bad debt in their cost of service. D.P.U. 09-39, at 164; D.P.U. 96-50 (Phase I) at 70-71; D.P.U. 89-114/90-331/91-80 (Phase I) at 137-140. The Department has found that the use of the most recent three years of data available is appropriate in the calculation of bad debt expense. D.P.U. 96-50 (Phase I) at 71. A company's bad debt ratio is derived by dividing the three-year delivery service net write-offs by the delivery service billed revenues for the same period. Western Massachusetts Electric Company, D.P.U. 84-25, at 113-114 (1984); D.P.U. 1720, at 27; Massachusetts American Water Company, D.P.U. 1700, at 22 (1984). This bad debt ratio is then multiplied by test year delivery service billed revenues, adjusted for any distribution revenues increase or decrease

that is approved in the current rate case. See D.P.U. 07-71, at 106-109; D.P.U. 96-50 (Phase I) at 71.

The Department has reviewed Eversource's bad debt calculations and the materials supporting these calculations (Exhs. ES-DPH-1, at 48-50; ES-DPH-2 (East), Sch. DPH-8; ES-DPH-2 (East), Sch. DPH-3 (Rev. 3); ES-DPH-3 (East), WP DPH-8 (Rev. 3); ES-DPH-2 (West), Sch. DPH-8 (Rev. 3); ES-DPH-2 (West), Sch. DPH-3 (Rev. 3); ES-DPH-3 (West), WP DPH-8 (Rev. 3)). The Department concludes that the method used by Eversource to calculate its uncollectible expense adjustments is consistent with Department precedent. D.P.U. 09-39, at 164; D.P.U. 07-71, at 106-109; D.P.U. 96-50 (Phase I) at 70-71; D.P.U. 89-114/90-331/91 80 (Phase I) at 137-140. Therefore, the Department approves the application of NSTAR Electric's delivery service related bad debt ratio of 0.7084, applied to test year delivery service revenues (Exh. ES-DPH-2 (East), Sch. DPH-8, at 2 (Rev. 3)). Further, the Department approves the application of WMECo's delivery service related bad debt ratio of 1.2435 percent, applied to test year delivery service revenues (Exh. ES-DPH-2 (West), Sch. DPH-8, at 2 (Rev. 3)).

As set forth above, NSTAR Electric's application of the 0.7084 percent bad debt ratio to the test year normalized delivery service revenues of $1,623,411,077, produces a bad debt expense of $11,499,968 (Exh. ES-DPH-2 (East), Sch. DPH-8, at 2 (Rev. 3)). During the test year, the Company booked $15,073,652 in distribution-related bad debt expense (Exh. ES-DPH-2 (East), Sch. DPH-8 (Rev. 3)). Accordingly, the Department approves

NSTAR Electric's proposed decrease to its test year cost of service in the amount of $3,573,684.

Further, as set forth above, NSTAR Electric calculated a bad debt expense of $397,391 associated with its proposed revenue increase (Exh. ES-DPH-2 (East), Sch. DPH-3 (Rev. 4)). Applying the same 0.7084 percent bad debt ratio set forth above to the distribution revenue increase approved in this case of $12,244,581 results in a bad debt expense in the amount of $86,739. Accordingly, the Department reduces NSTAR Electric's proposed cost of service by $310,652.

WMECo's application of the 1.2435 percent bad debt ratio to the test year normalized delivery service revenues of $249,340,158 produces a bad debt expense of $3,100,435 (Exh. ES-DPH-2 (West), Sch. DPH-8, at 2 (Rev. 3)). During the test year, WMECo booked $5,163,634 in distribution-related bad debt expense (Exh. ES-DPH-2 (West), Sch. DPH-8 (Rev. 3)). Accordingly, the Department approves WMECo's proposed decrease to its test year cost of service in the amount of $2,063,199.

Further, WMECo calculated a bad debt expense of $431,191 associated with its proposed revenue increase (Exh. ES-DPH-2 (West), Sch. DPH-3 (Rev. 4)). Applying the same 1.2435 percent bad debt ratio set forth above to the distribution revenue increase approved in this case of $24,785,725 results in a bad debt expense in the amount of $308,200. Accordingly, the Department reduces WMECo's proposed cost of service by $122,990.

E. Depreciation Expense

1. Introduction

During the test year, NSTAR Electric booked $153,841,701 in depreciation and amortization expense, and WMECo booked $25,799,702 in depreciation and amortization expense (Exhs. ES-DPH-1, at 135; ES-DPH-2 (East), Sch. DPH-23 (Rev. 3); ES-DPH-2 (West), Sch. DPH-23 (Rev. 3)). Eversource proposes to reduce the test year depreciation and amortization expense by $1,614,549 for NSTAR Electric[87] and to increase the test year depreciation and amortization expense by $4,432,822 for WMECo,[88] based on the application of proposed accrual rates to their pro forma plants in service (Exhs. DPH-1, at 135; DPH-2 (East), Sch. DPH-23 (Rev. 3); DPH-2 (West), Sch. DPH-23 (Rev. 3)). The proposed pro forma distribution and amortization expense is $152,227,152 for NSTAR Electric and $30,232,524 for WMECo (Exhs. DPH-1, at 135; DPH-2 (East), Sch. DPH-23 (Rev. 3); DPH-2 (West), Sch. DPH-23 (Rev. 3)).

The Companies' proposed accrual rates are the result of two depreciation studies, conducted separately for NSTAR and WMECo, establishing annual depreciation accrual rates by account as of June 30, 2016 for all electric plant (Exh. ES-JJS-1, at 2). In addition, based on the results of the individual depreciation studies, the Companies have provided

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87 Eversource states that the proposed decrease for NSTAR Electric is primarily driven by longer service lives, and longer amortization periods for intangible assets than what are reflected in the current rates (Exhs. ES-DPH-1, at 136; ES-JJS-4, at 4).

88 Eversource states that the proposed increase for WMECo results primarily from the use of higher net salvage values (Exhs. ES-DPH-1, at 136; ES-JJS-1, at 4-5).

weighted accrual rates, to be employed by the consolidated entity (Exhs. ES-DPH-1, at 135; ES-JJS-1, at 3).

The Attorney General sponsored a witness, providing an alternative set of depreciation accrual rates (Exhs. AG-WWD-1 through AG-WWD-17). The accrual rates the Attorney General proposed rely on the life analysis the Companies provided, as well as the dispersions and percent reserves (Exh. AG-WWD-1, at 32). The only adjustment to the Companies' accrual rate calculation that the Attorney General recommends is to reduce the Companies' proposed net salvage factors (Exh. AG-WWD-1, at 32).

2. Companies' Depreciation Studies

Eversource prepared depreciation studies for NSTAR Electric and WMECo, calculating annual depreciation accrual rates by account for all electric plant as of June 30, 2016 (Exhs. JJS-1, at 2; ES-JJS-2; ES-JJS-3). The Companies' studies employ the straight line remaining life method of depreciation,[89] using the average service life procedure (Exh. ES-JJS-1, at 7).[90] The annual depreciation rates seek to distribute the unrecovered cost

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89 The straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life (Exh. ES-JJS-1, at 13).

90 The average service life procedure defines the group or account for which the remaining life annual accrual is determined. Under this procedure, the annual accrual rate is determined for the entire group or account based on its average remaining life and the rate is then applied to the surviving balance of the group's cost. The average remaining life of the group is calculated by first dividing the future book accruals (original cost less allocated book reserve less future net salvage) by the average remaining life for each vintage. The average remaining life for each vintage is derived from the area under the survivor curve between the attained age of the vintage and the maximum age. The sum of the future book accruals is then divided by the

of fixed capital assets over the estimated remaining useful life of each unit, or group of assets, in a systematic and rational manner (Exh. ES-JJS-1, at 7). The Companies have also provided weighted accrual rates for future use by the consolidated entity (Exhs. ES-DPH-1, at 135; ES-JJS-1, at 3).

The two-step process of preparing the Companies' depreciation studies began with estimating the service life and net salvage values for each depreciable group of assets (Exh. ES-JJS-1, at 7). Eversource used the retirement rate method on the service life data to determine the average rates of retirement the Companies experienced during the time period covered by the studies (Exh. ES-JJS-1, at 8).[91] Eversource then plotted the average retirement rates to create original survivor curves for each property group, representing the average survivor patterns that several vintage groups experienced (Exh. ES-JJS-1, at 9). Next, the Companies compared the original survivor curves to a standard set of Iowa-type survivor curves ("Iowa curve") to smooth and extrapolate the data (Exh. ES-JJS-1, at 9).[92]

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sum of the annual accruals to determine the average remaining life of the entire group for use in calculating the annual depreciation accrual rate (Exh. ES-JJS-1, at 13-14).

91 The retirement rate method is an actuarial method of developing survivor curves based on the average rate of retirement (Exh. ES-JJS-1, at 8).

92 Iowa-type survivor curves are a widely used group of generalized survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies (Exh. ES-JJS-1, at 9). The Iowa curves were initially developed at the Iowa State College Engineering Experiment Station during the 1920s and 1930s; 18 curves were initially published in 1935, and four additional survivor curves were identified in 1957. D.P.U. 12-25, at 274 n.170.

Each study determines the average service life of the plant account, using the Iowa curve with the closest fit (Exh. ES-JJS-1, at 9).

The Companies estimated life expectancies for significant facilities, with anticipated concurrent retirements of the entire facility, using the life span technique (Exh. ES-JJS-1, at 10).[93] The Companies used interim survivor curves to describe the rate of retirement for non-structural elements of the facility, and probable retirement dates provided the rate of final retirement for each year of installation of the facility (Exh. ES-JJS-1, at 10). The Companies' estimates of the probable retirement dates and life spans for each facility were based upon consideration of the age, use, size, construction, management outlook, and the typical life spans experienced and used by other electric utilities for similar facilities (Exh. ES-JJS-1, at 11).

According to the Companies, net salvage value is the salvage value received for the asset upon retirement, less the cost of retiring the asset (Exh. ES-JJS-1, at 12). When the cost to retire the asset exceeds the salvage value, the result is a negative net salvage value (Exh. JJS-1, at 12). The net salvage factors the Companies proposed are based on a combination of statistical analyses and informed judgment (Exh. ES-JJS-1, at 13). The statistical analyses considered the cost of removal and gross salvage ratios to the associated retirements during a 24-year period for NSTAR Electric, and during a 17-year period for WMECo, along with data trends measured using three-year moving averages and the most

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[93] Under the life span technique, a property unit's final retirement date is estimated, and the estimated survivor curves applied to each vintage of interim replacements are truncated at the ages coinciding with the estimated final retirement date (Exh. ES-JJS-1, at 10).

recent five-year indications (Exh. ES-JJS-1, at 13). The Companies supplemented statistical data with information from management and operating personnel about practices and plans as well as the estimates used by other electric utilities, and analyzed the information to obtain reach informed judgments about average service lives and net salvage characteristics (Exh. ES-JJS-1, at 8). Based on the estimated service life and net salvage values, the Companies calculated the composite remaining lives and annual depreciation accrual rates, using the straight line remaining life method (Exh. ES-JJS-1, at 8, 13).[94]

For certain general plant accounts, Eversource relied on amortization accounting (Exh. ES-JJS-1, at 14). Eversource explains that amortization accounting is used for accounts with a large number of units, but small asset values, where the use of depreciation accounting would be difficult because of the need to conduct periodic inventories to properly account for plant in service (Exh. ES-JJS-1, at 14).[95] Under amortization accounting, each plant account or group of assets added in each vintage year is assigned an anticipated life during which the asset is expected to remain in service, and then removed from a company's books at the end of that period (Exh. ES-JJS-1, at 14). Consequently, plant that is retired before the end of the amortization period nonetheless remains on a company's books until the

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94 The straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life (Exh. ES-JJS-1, at 13).

95 NSTAR Electric uses amortization accounting for Accounts 391.10, 391.20, 393.00, 394.00, 395.00, 397.00 and 398.00; and WMECo uses amortization accounting for Accounts 391.10, 391.20, 393.00, 394.00, 397.00, 397.10, 397.30 and 398.00 (Exhs. ES-JJS-1, at 15; ES-JJS-2, at 45, 50-51; ES-JJS-3, at 45, 50-52). These accounts represent less than two percent of NSTAR Electric's depreciable plant and less than four percent of WMECo's depreciable plant (Exh. ES-JJS-1, at 15).

end of the amortization period, while plant that remains in service as of the end of the amortization period is retired for plant accounting purposes but is not necessarily removed from actual service (Exh. ES-JJS-1, at 14).

In the process of conducting the depreciation studies, the Companies identified deficiencies in the general plant amortization reserves for NSTAR Electric and WMECo (Exhs. ES-JJS-1, at 15; ES-JJS-2, at 50-51; ES-JJS-3, at 50-51). In order to adjust the amortization reserves and achieve more stable accrual rates for these accounts in the future, the Companies first identified, for each account, the reserve balance that would have existed had the proposed amortization rate been used for all assets in that account, as well as the unrecovered difference (Exhs. ES-JJS-2, at 50-51; ES-JJS-3, at 50-51). The Companies then calculated an aggregate unrecovered difference of $643,489 for NSTAR Electric and $2,376,406 for WMECo (Exhs. ES-JJS-2, at 50-51; ES-JJS-3, at 50-51). Eversource proposes to collect this unrecovered difference over a five-year period, resulting in an annual amortization of $128,698 for NSTAR Electric and $475,881 for WMECo (Exhs. ES-JJS-1, at 15, 17; ES-JJS-2, at 51; ES-JJS-3, at 51; ES-DPH-3 (East), WP DPH-23 (Rev. 3); ES-DPH-3 (West). WP DPH-23 (Rev. 3)).

The Companies applied the depreciation and amortization accrual rates to the account balances of depreciable plant, including the post-test year plant additions, to determine depreciation and amortization expense for each utility plant account

(Exh. ES-DPH-1, at 13).[96] The result is a proposed depreciation and amortization expense for NSTAR Electric of $152,227,152 and a proposed depreciation and amortization expense for WMECo of $30,232,524 (Exhs. DPH-1, at 135; DPH-2 (East), Sch. DPH-23 (Rev. 3); DPH-2 (West), Sch. DPH-23 (Rev. 3)).

3. Attorney General's Depreciation Analysis

The Attorney General retained a depreciation witness who sponsored testimony and offered modified depreciation accrual rates (Exhs. AG-WWD-1 through AG-WWD-17). The Attorney General did not contest Eversource's proposed life analyses, but challenged the net salvage factors the Companies used as excessive (Exh. AG-WWD-1, at 10).

The Attorney General first notes that based on Eversource's actual salvage experience, the Companies have been accruing net salvage values that are 2.9 times the actual net salvage costs incurred, with Account 366 (underground conduit) accruing salvage at a rate ten times in excess of actual salvage (Exh. AG-WWD-1, at 10-16). Furthermore, the Attorney General states that the Companies' percent reserve (i.e., book depreciation reserve divided by book plant in service) has grown from 28.2 percent to 31.8 percent since the Companies' previous depreciation studies, and there has been a corresponding increase in the depreciation reserve of 81 percent versus the increase of 61 percent in plant in service (Exh. AG-WWD-1,

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96 NSTAR Electric's proposed depreciable plant includes the post-test year additions of $42,718,949 for the Seafood Way substation, $32,949,477 for the Electric Avenue substation, and $29,868,260 for the New Bedford service center (Exhs. ES-DPH-1, at 137, 178; ES-DPH-3 (East), WP DPH-28 (Rev. 3). WMECo's proposed depreciable plant includes the post-test year addition of $3,488,926 for the Montague substation (Exhs. ES-DPH-1, at 137, 179; ES-DPH-3 (West), WP DPH-28 (Rev. 3)). Eversource's post-test year plant additions are addressed in Section VII.C above.

at 19-23). The Attorney General also compared the theoretical depreciation reserve to the actual depreciation reserve,[97] and states that the actual book depreciation reserve is slightly higher than the theoretical depreciation reserve (Exh. AG-WWD-1, at 23-24). Finally, the Attorney General states that Eversource's depreciation studies give greater weight to net salvage as a percentage of retirement, and thereby factor future inflation into the development of the Companies' proposed salvage factors (Exh. AG-WWD-1, at 36-42).[98]

Based on her analysis of the salvage data, the Attorney General determined that different salvage factors are warranted for a number of NSTAR Electric's and WMECo's plant accounts (Exh. AG-WWD-1, at 27-28, 31).[99] Using Eversource's life analyses and her proposed salvage factors, the Attorney General produced her own proposed depreciation accrual rates (Exhs. AG-WWD-1, at 32; AG-WWD-3, at 1-6). Based on the Companies' depreciable plant balances as of the end of the test year, the Attorney General proposed a

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97 The theoretical depreciation reserve assumes that the timing of future retirements and net salvage are exactly in conformance with the results predicted by the selected survivor curve. D.P.U. 10-114, at 129 n.57.

98 The Attorney General states that the concept of net salvage as a percentage of retirement was developed decades ago, when companies experienced positive salvage values (Exh. AG-WWD-1, at 40-41). She states that the Companies' use of net salvage as a percentage of retirement results in the net cost of removal being determined using the lower value of future dollars, but the collection of those costs in the more-valuable current dollars (Exh. AG-WWD-1, at 41-42).

99 The Attorney General proposed the use of different salvage factors for NSTAR Electric plant accounts 366, 367, 369.1, 369.2, and 373 and for WMECo plant accounts 362, 364, 365, 366, 367, 369.1, 369.2, 370, and 371 (Exh. AG-WWD-1, at 31).

decrease in depreciation expense of $6,539,020 for NSTAR Electric, and a decrease in depreciation expense of $2,972,154 for WMECo (Exh. AG-WWD-1, at 33).

4. Positions of the Parties

a. Attorney General

The Attorney General argues that the Companies' proposed depreciation accrual rates are excessive, and proposes an alternate set of depreciation accrual rates (Attorney General Brief at 154; Attorney General Reply Brief at 62). Alternatively, she argues that, at a minimum, the Department should employ the principal of gradualism by limiting any change in the net salvage value accrual rates to be no more than 20 percent of the existing net salvage accrual rate (Attorney General Brief at 154; Attorney General Reply Brief at 62). The Attorney General has not challenged any aspect of Eversource's depreciation accrual rate calculations, other than the Companies' selection of net salvage values.

First, the Attorney General argues that the net salvage rates Eversource used in its depreciation studies overstate the actual net salvage costs experienced by 2.9 times (Attorney General Brief at 156, citing Exh. AG-WWD-1, at 15; Attorney General Reply Brief at 51). She notes that the net salvage factors the Companies proposed would amount to an annual cost to ratepayers of $42,726,188, compared to the $14,755,633 average experienced between 2013 and 2015 (Attorney General Brief at 156, citing Exh. AG-WWD-1, at 10; Attorney General Reply Brief at 57, citing Exh. AG-WWD-1, at 4). The Attorney General notes that in a recent Connecticut Public Utilities Regulatory Authority ("CPUC")

decision,[100] the CPUC limited net salvage values to 1.2 times the values actually incurred (Attorney General Reply Brief at 57, citing Exh. AG-WWD-1, at 26). The Attorney General argues that her proposal would move the Companies' depreciation accrual rates to be more in line with the Companies' experience (Attorney General Reply Brief at 57, citing Exh. AG-WWD-1, at 28).

Further, the Attorney General cites the percent book reserve and its importance in the determination of depreciation expense calculations (Attorney General Brief at 154, citing RR-DPU-26, at 64-65).[101] She notes that the Companies' percent book reserve has been growing, and claims that when the depreciation accruals are significantly higher than the actual incurred net salvage and the actual retirements, the depreciation reserve will grow rapidly (Attorney General Brief at 155, citing Exh. AG-WWD-1, at 19). The Attorney General observes that the percent reserve grew 3.6 percentage points, from 28.2 to 31.8 percent (i.e., 12.8 percent) from the time of the Companies' prior depreciation studies (Attorney General Brief at 155, citing Exh. AG-WWD-1, at 19). She argues that during that period, depreciation accruals have been $19.2 million per year higher than necessary to maintain a constant percent reserve, and that the Companies have not disputed this growth (Attorney General Brief at 155, citing Exhs. AG-WWD-1, at 19; AG-WWD-5; AG-WWD-13; Attorney General Reply Brief at 52). Additionally, the Attorney General argues that the book depreciation reserve is currently above its theoretically correct level

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100 United Illuminating Company, No. 16-06-04, at 46 (2016).

101 The percent reserve is calculated by dividing the book depreciation reserve by the book cost of gross plant.

(Attorney General Brief at 155, citing Exhs. AG-WWD-1, at 23–24; AG-WWD-7). She argues that the depreciation rates the Companies proposed would continue to increase the percent reserve by $11.2 million per year, further demonstrating that the proposed depreciation accrual rates are excessive (Attorney General Brief at 155, citing Exhs. AG-WWD-1, at 20; AG-WWD-5; ES-JJS-1, at 4; Attorney General Reply Brief at 52).

The Attorney General notes that the Companies fail to explain why the growth in the percent reserve is necessary, but instead dismiss the growth as "irrelevant" (Attorney General Reply Brief at 52, citing Company Brief at 546). She argues that the percent reserve is not irrelevant, but rather provides a gauge, demonstrating in this case that the Companies' depreciation accruals collect an excessive amount of depreciation expense (Attorney General Reply Brief at 52). The Attorney General points out that the National Association of Regulatory Utility Commissioners' ("NARUC") Depreciation Practices Manual states that "if further analysis confirms a material imbalance, one should make immediate depreciation accrual adjustments" (Attorney General Reply Brief at 53, citing RR-DPU-26, at 187-194). The Attorney General argues that her proposal would maintain the depreciation reserve at or near its theoretically correct level (Attorney General Reply Brief at 54).

Next, the Attorney General argues that the Companies have incorrectly included future inflation in the calculation of the net salvage values (Attorney General Brief at 158, citing Exhs. AG-WWD-1, at 36; ES-JJS-1, at 13; Attorney General Reply Brief at 54, citing Exh. AG-WWD-1, at 34–40). She notes that the first step in performing a salvage analysis

is to convert the observed dollars to constant dollars, which she maintains the Companies have failed to do (Attorney General Brief at 158, citing Exh. AG-WWD-Surrebuttal-2). She argues that because the ratio of salvage to retirements the Companies used includes both current dollars and future dollars, the salvage values incorporate inflation (Attorney General Brief at 158). In addition, the Attorney General argues that the Companies have given more weight to the ratio, unconverted to constant dollars, than they have to the dollar value of experienced net salvage, thereby overstating the values by the time value of money (Attorney General Brief at 158). She asserts that the Companies' analysis produced misleading results by relying on a ratio that includes the impact of inflation that occurs between the time the investment goes into service and the time it is retired (Attorney General Brief at 158; Attorney General Reply Brief at 55). Additionally, she claims that the Companies have conceded that future inflation had an impact on the net salvage values (Attorney General Reply Brief at 54, citing Companies Brief at 545). The Attorney General argues that using a constant dollar analysis would result in a significantly lower negative percent net salvage value (Attorney General Brief at 159, citing Tr. 9, at 1771-1773; Attorney General Reply Brief at 54). Using FERC Account 364 to illustrate her argument, the Attorney General calculates that a constant dollar analysis would yield a negative 37 percent net salvage value, rather than the negative 60 percent calculated in the Companies' depreciation studies (Attorney General Brief at 159; Attorney General Reply Brief at 54, citing Exh. AG-WWD-1, pp. 34–40; Tr. 9, at 1771-73).

The Attorney General further argues that the Companies' calculation of net salvage using current dollars does not result in a cost-based rate and violates NARUC's Public Utility Depreciation Practices Manual, which clearly states that future inflated costs should not be used (Attorney General Brief at 159-160, citing RR-DPU-26, Att. at 21–22). Further, the Attorney General claims that the Companies have mischaracterized her argument, which is not that future customers should bear the cost of retirement, rather that customers should pay only the cost of retirement and not an artificially inflated one (Attorney General Reply Brief at 55).

The Attorney General argues that the Companies' proposed net salvage values would also result in intertemporal subsidization of future ratepayers who would potentially benefit from a smaller rate base and lower returns (Attorney General Brief at 160; Attorney General Reply Brief at 57).[102] She also notes that the proposed net salvage factors are significantly more negative than those currently approved by the Department, representing an increase from negative 35 percent to negative 60 percent and adding $2,526,650 to the Companies' depreciation expense (Attorney General Brief at 157, citing Exh. AG-WWD-1, at 17). The Attorney General points out that the Companies' proposed net salvage factors are inconsistent with other similarly situated utility companies (Attorney General Brief at 157, citing Exh. AG-6-17).

The Attorney General argues that the Companies' proposal would in effect transfer the burden of raising capital from shareholders to ratepayers, to the detriment of ratepayers

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[102] Intertemporal subsidization is the incidence of ratepayers bearing the cost of benefits that accrue to previous or future customers.

(Attorney General Reply Brief at 61, citing Exh. ES-JJS-Rebuttal at 48). She argues that because the effect of higher depreciation accruals on rate base does not affect distribution rates until a subsequent rate case, ratepayers will not receive a return on the depreciation expense they have been charged, resulting in an interest free loan to the Companies (Attorney General Reply Brief at 61, citing Tr. 9, at 1791-1796). Further, she argues that the Companies' position about future net rate base being lower is based on the assumption that the current rate-base regulation will continue unchanged for decades into the future (Attorney General Reply Brief at 61, citing Tr. 9, at 1791-1796). She contends that ratepayers would be better off paying off credit card debt than paying more in depreciation expense (Attorney General Brief at 160; Attorney General Reply Brief at 61).

The Attorney General notes that other jurisdictions have adopted the net salvage approach she is recommending (Attorney General Brief at 161; Attorney General Reply Brief at 56, citing Exh. AG-WWD-1, at 28). She argues that her proposal would charge ratepayers 2.2 times the actual net salvage experienced, rather than the 2.9 times actual net salvage that the Companies' proposal would produce (Attorney General Brief at 162; Attorney General Reply Brief at 57). The Attorney General claims that adopting her proposed method would be a gradual improvement, taking into consideration the interest of ratepayers as well as those of the Company's shareholders (Attorney General Brief at 163; Attorney General Reply Brief at 57).

The Attorney General notes that Eversource has proposed net salvage values that are more negative than current values for 13 of 23 accounts, many being significantly more

negative (Attorney General Reply Brief at 62, citing Exh. AG-WWD-1, at 35).[103] Thus, she recommends that, barring the approval of her proposed depreciation accrual rates, the Department employ gradualism, limiting any change in the net salvage value accrual rates to 20 percent of the existing net salvage accrual rate, to dampen the impact of rate increases from other aspects of this base rate proceeding (Attorney General Brief at 164; Attorney General Reply Brief at 62). She notes that the Department considered gradualism when evaluating the reasonableness of a company's proposed net salvage factors (Attorney General Reply Brief at 62, citing Fitchburg Gas and Electric Light Company, D.P.U. 15-80/15-81, at 217-18).

b. Cape Light Compact

The Cape Light Compact supports the use of the Attorney General's proposed depreciation accrual rates (Cape Light Compact Brief at 82, 83). The Cape Light Compact contends that the Attorney General has provided ample rationale to support her proposal (Cape Light Compact Brief at 82).

c. Companies

Eversource argues that the Attorney General's proposal is a radical departure from both nationally accepted regulatory policy and Department precedent, and would result in intergenerational inequity (Companies Brief at 542). The Companies maintain that the cost of net salvage must be allocated over the period of time that an asset will be in service, so that the future costs of net salvage are charged to the customers receiving the benefit

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[103] Of the remaining ten accounts, the Companies proposed less negative net salvage values for six accounts, and no change for four accounts (Attorney General Reply Brief at 62, citing Exh. AG-WWD-1, at 28).

(Companies Brief at 542, citing Exh. ES-JJS-Rebuttal-1, at 6-7, 16, 21, 34). The Companies argue that the Attorney General's proposal establishes net salvage rates based on an approximation of recent net salvage costs, which is akin to treating salvage costs as an operating expense (Companies Brief at 453; Companies Reply Brief at 163). Additionally, Eversource argues that future removal costs are likely to be higher than current removal costs because retirements will likely be higher in the future (Companies Brief at 544, citing Exh. ES-JJS-Rebuttal-1, at 36-37, 40). The Companies contend that the Attorney General's excessive focus on current net salvage costs would give rise to significant under-recoveries of salvage costs, and result in deferring these costs to future customers who will not have received the benefits of these assets (Companies Brief at 544, citing Exh. ES-JJS-Rebuttal-1, at 36; Companies Reply Brief at 163).

The Companies note that the Attorney General made a similar argument in Bay State Gas Company's ("Bay State Gas") 2012 base rate proceeding, in which she recommended that the Department reduce the net salvage component of depreciation expense for Bay State (Companies Brief at 547, citing D.P.U. 12-25, at 278, 309; Companies Reply Brief at 163, citing D.P.U. 12-25, at 278, 283). Eversource maintains that while the Attorney General criticized Bay State Gas' net salvage, as including inflated future cost of removal, Bay State Gas responded that the costs of annual retirements in the future will exceed current levels of retirements, and that its approach would result in intergenerational equity (Companies Brief at 547, citing D.P.U. 12-25, at 282, 297). Eversource states that in the end, the Department rejected the Attorney General's arguments on net salvage, and contends that the Department

should reject the Attorney General's proposal in this proceeding as well (Companies Brief at 547, citing D.P.U. 12-25, at 309-312; Companies Reply Brief at 163).

The Companies also contend that the Attorney General has not sufficiently supported her claim that her net salvage approach has been adopted in multiple jurisdictions, as she cites only to Connecticut and Maine as the other jurisdictions that have adopted the approach (Companies Reply Brief at 160-161). Moreover, Eversource argues that the Attorney General's proposal in the instant docket is actually inconsistent with the approaches adopted by both Connecticut and Maine (Companies Reply Brief at 161). The Companies point out that while the Attorney General proposes net salvage rates based on multiplying the three-year average net salvage rate by 2.2, Connecticut adopted a net salvage method of multiplying a company's three-year average of the net salvage cost by a factor of 1.2, and Maine relied on a three-year average net salvage factor with no multiplication factor (Companies Reply Brief at 160-161, citing Exh. AG-WWD-Surrebuttal-1, at 31; Tr. 9, at 1717-1719).

The Companies contest the Attorney General's argument that they have incorporated future inflation into their net salvage factors (Companies Brief at 544-545). The Companies contend that their proposed depreciation rates are based on the nominal costs for both the original and the net salvage costs, and that neither is adjusted for inflation (Companies Brief at 545, citing Exh. ES-JJS-Rebuttal-1, at 46; Companies Reply Brief at 164). They argue that to the extent that there is any future inflation included in their net salvage analysis, the inclusion has only a minimal impact on the results, and maintain that the Attorney General

implicitly incorporates inflation by using a multiple of current net salvage costs (Companies Brief at 545, citing Exh. ES-JJS-Rebuttal-1, at 44-45; Companies Reply Brief at 163). The Companies argue that their approach assures that the future cost to remove an asset will be recovered from current customers over the service life of the asset (Companies Brief at 545; Companies Reply Brief at 163). Additionally, the Companies challenge the amount of inflation that is actually included. Using NSTAR Electric's Account 364 for illustrative purposes, Eversource points out that while the average age of retirements in this account is 20.7 years, the average age of assets in the account is 18.0 years, thus concluding that there are only 2.7 years of inflation included (Companies Brief at 545, citing Exh. ES-JJS-Rebuttal-1, at 45; Companies Reply Brief at 163, citing Exh. ES-JJS-Rebuttal-1, at 44-45).

The Companies argue that the estimated net salvage values used in their studies are based primarily on company-specific information, not on data from other electric utilities, and that industry data are only used as a guide (Companies Brief at 545). They assert that net salvage rates are often higher for companies in or near large metropolitan areas, where removal costs are greater, which limits the relevance of a comparison to industry averages (Companies Brief at 546). The Companies further note that other distribution firms use net salvage values that are more negative, and claim that the net salvage values used in their own depreciation studies were well within the industry range (Companies Brief at 546, citing Exhs. ES-JJS-Rebuttal-1, at 53; AG-6-17, Att.).

The Companies dismiss as irrelevant the Attorney General's argument regarding the increase in the book reserve, and do not consider the increase to be a basis upon which to reject their proposal (Companies Brief at 546). The Companies argue that the book reserve percentage increases over time as assets depreciate, and that such increases do not indicate in any way that the Companies' depreciation rates are too high (Companies Brief at 546, citing Exh. ES-JJS-Rebuttal-1, at 51; Companies Reply Brief at 165).

The Companies argue that while the Attorney General's proposal may produce a reduction in customer rates in the short-term, through lower depreciation accrual rates, it will result in higher costs to customers over the long term (Companies Brief at 547; Companies Reply Brief at 164). Eversource contends that reducing depreciation rates would reduce the level of accumulated depreciation over time and, consequently, produce a larger rate base in the future, thus requiring customers to pay a larger return on rate base (Companies Brief at 547; Companies Reply Brief at 164, 165). The Companies note that the Attorney General's witness acknowledged the increase in future rate base would result with her proposed accrual rates (Companies Brief at 547, citing Tr. 9, at 1791, 1795).

The Companies oppose the Attorney General's alternative proposal to limit increases in net salvage factors to twenty percent, stating that their proposed net salvage factors overall are not significantly higher than a twenty percent increase (Companies Brief at 548, citing Exhs. ES-JJS-Rebuttal-1, at 45; AG-6-21(a); ES-JJS-2, at 154, 158; ES-JJS-3, at 128-129; Companies Reply Brief at 165-166). The Companies note that there are number of large plant accounts for which they have proposed a net salvage rate that is either less negative or

unchanged,[104] as well as several accounts where their proposed net salvage rates are less negative than the historical net salvage analysis indicated (Companies Brief at 548, citing Exhs. ES-JJS-Rebuttal-1, at 45; AG-6-21(b) Att.; ES-JJS-3, at 128; Companies Reply Brief at 166).[105] Eversource claims, therefore, that it has already adopted a conservative approach and that the Attorney General's recommendation is unnecessary (Companies Brief at 548, citing Exh. ES-JJS-Rebuttal-1, at 45; D.P.U. 15-80/D.P.U. 15-81, at 217-218; Companies Reply Brief at 166). Eversource argues that, on a consolidated basis, the proposal represents a reduction in test year depreciation expense of approximately $8.4 million (Companies Brief at 550; citing Exhs. ES-JJS-1, at 17; ES-JJS-5; Companies Reply Brief at 166).

Based on these considerations, the Companies argue that the Attorney General's recommendation would overturn the Department's ratemaking precedents on depreciation and will harm intergenerational equity (Companies Brief at 550). Thus, they assert that the Department should reject the Attorney General's depreciation rates and associated recommendations in this proceeding and instead adopt the Companies' depreciation proposal (Companies Brief at 550).

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104 NSTAR Electric Account 365 (Overheard Conductor and Devices), NSTAR Electric Account 367 (Underground Conductors and Devices), NSTAR Electric Account 368 (Line Transformers), and NSTAR Electric Account 369.1 (Services – Overhead) (Exh. AG-6-21(a), Att.).

105 WMECo Account 364 (Poles, Towers and Fixtures), WMECo Account 365 (Overhead Conductors and Devices), NSTAR Account 364 (Poles, Towers and Fixtures), and NSTAR Account 366 (Underground Conduit) (Exh. AG-6-21(a), Att.; AG-6-21(b), Att.).

5. Standard of Review

Depreciation expense allows a company to recover its capital investments in a timely and equitable fashion over the service lives of the investments. D.T.E. 98-51, at 75; D.P.U. 96-50 (Phase I) at 104; Milford Water Company, D.P.U. 84-135, at 23 (1985); Boston Edison Company, D.P.U. 1350, at 97 (1983). Depreciation studies rely not only on statistical analysis but also on the judgment and expertise of the preparer. The Department has held that when a witness reaches a conclusion about a depreciation study that is at variance with that witness' engineering and statistical analysis, the Department will not accept such a conclusion absent sufficient justification on the record for such a departure. D.P.U. 92-250, at 64; The Berkshire Gas Company, D.P.U. 905, at 13-15 (1982); Massachusetts Electric Company, D.P.U. 200, at 21 (1980).

The Department recognizes that the determination of depreciation accrual rates requires both statistical analysis and the application of the preparer's judgment and expertise. D.T.E. 02-24/25, at 132; D.P.U. 92-250, at 64. Because depreciation studies rely by their nature on examining historic performance to assess future events, a degree of subjectivity is inevitable.[106] Nevertheless, the product of a depreciation study consists of specific accrual rates to be applied to specific account balances associated with depreciable property. A mere assertion that judgment and experience warrant a particular conclusion does not constitute

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[106] This is especially relevant in the calculation of net salvage factors where the cost to demolish or retire facilities cannot be established with certainty until the actual event occurs. D.P.U. 92-250, at 66; D.P.U. 1720, at 44; D.P.U. 1350, at 109-110.

evidence. See Eastern Edison Company, D.P.U. 243, at 16-17 (1980); D.P.U. 200, at 20-21; Lowell Gas Company, D.P.U. 19037/19037-A at 23 (1977).

It thus follows that the reviewer of a depreciation study must be able to determine, preferably through the direct filing, and at least in the form of comprehensive responses to well-prepared discovery, the reasons why the preparer of the study chose one particular life-span curve or salvage value over another. The Department will continue to look to the expert witness for interpretation of statistical analyses but will consider other expert testimony and evidence that challenges the preparer's interpretation and expects sufficient justification on the record for any variances resulting from the engineering and statistical analyses. D.P.U. 89-114/90-331/91-80 (Phase One) at 54-55. To the extent a depreciation study provides a clear and comprehensive explanation of the factors that went into the selection of accrual rates, such an approach will facilitate Department and intervenor review.

6. Analysis and Findings

a. Life Analyses

The Department has reviewed Eversource's depreciation studies and supporting workpapers, and finds that the Companies have properly supported their proposed service lives and survivor curves (Exhs. ES-JJS-1; ES-JJS-2; ES-JJS-3; AG-6-2, Atts. (a) through (f); AG-6-3(a); AG-6-2(b)). Therefore, the Department accepts the Companies' proposed life and survivor curves.

b. Net Salvage Factors

The selection of salvage factors is more subjective than the determination of service lives and survivor curves. This subjectivity occurs because salvage values are theoretically

intended to represent the future cost of retirements, which cannot be known with certainty until the actual retirement occurs. D.P.U. 92-250, at 66; D.P.U. 1350, at 109. Despite this lack of certainty, the determination of net salvage factors is critical to any depreciation study. If the negative net salvage cost (i.e., cost of removal is greater than anticipated salvage value) is overestimated, the depreciation reserve is inflated by the over-accrual of depreciation, and thus will understate a company's rate base in future rate case proceedings. Conversely, if net positive salvage costs (where salvage value is greater than removal costs) are overestimated, capital recovery is deferred, and both the utility and ratepayers face increased risk. D.P.U. 1350, at 107. Consequently, it is necessary to exercised reasoned judgment in the determination of salvage values.

In the instant filing, the Attorney General has challenged, with the support of the Cape Light Compact, Eversource's proposed net salvage factors (Attorney General Brief at 155; Attorney General Reply Brief at 51; Cape Light Compact Brief at 82). Specifically, the Attorney General argues that the Companies fail to account for inflation in their calculation of the proposed net salvage values (Attorney General Brief at 155; Attorney General Reply Brief at 51). The Companies counter-argue that the traditional depreciation approach was followed, and that to the extent any inflation is included in the calculation, the effect is minimal (Companies Brief at 542, 545).

The Companies' book percent reserve has grown from 28.2 percent at the time of the prior depreciation studies to 31.8 percent in the June 30, 2016 (Exh. AG-WWD-1,

at 19-20).[107] Book percent reserve measures the portion of depreciated plant that has already been recovered from past ratepayers (RR-DPU-26, Att. at 64-65). One approach to calculating the depreciation accrual rate is to use percentages as follows,

$$depreciation\ accrual\ rate\ = \frac{100 - u - c'}{E}$$

where u is the percent reserve, c' is the percent future net salvage, and E is estimated average remaining life (RR-DPU-26, Att. at 64-65). Therefore, the book percent reserve directly affects the depreciation accrual rate, and acts as an auto-corrective mechanism (RR-DPU-26, Att. at 65). Because depreciation accruals are credited to the depreciation reserve account, to the extent that the accrual rates are too high, the depreciation reserve will grow, as well as the book percent reserve, assuming all other factors being equal. That growth will in turn yield lower depreciation accrual rates in future calculations (RR-DPU-26, Att. at 64-65). Therefore, the Companies' assertion that the percent reserve is irrelevant is incorrect. Nevertheless, the growth in percent reserve informs us only that prior period depreciation accrual rates were too high, and does not in itself indicate whether the currently proposed depreciation accrual rates are also excessive.[108] Consequently, this finding does not represent the end of our analysis.

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[107] The book percent reserve is calculated as the book depreciation reserve divided by the book plant in service (RR-DPU-26, Att. at 65).

[108] In the case of small companies where capital additions have been minimal, the percent reserve will increase over time, and may reach 100 percent. Harbor Electric Energy Company, D.P.U. 15-157, at 115-116 & n.42 (2016) (percent reserve of 100 percent); South Egremont Water Company, D.P.U. 95-119/122, at 12 (1996) (percent

The Companies' average annual net salvage cost between 2013 and 2015 was $14,755,633, while the Companies' estimated net salvage costs over this same period of $42,726,188 (Exh. AG-WWD-1, at 10). Eversource defends its salvage estimates, maintaining that future removal costs are likely to be higher than current removal costs because retirements will likely be higher in the future (Companies Brief at 156; Companies Reply Brief at 54). Labor costs are a significant component of the cost of removal, and while they may increases over time, so do placement labor costs, and a higher removal cost related to a higher value of plant retired may result in essentially no change in the percentage cost of removal (RR-DPU-26, Att. at 160-161).[109] Unless expectations of life or inflation change, the salvage ratio should be constant (Exh. AG-WWD-Surrebuttal-2, at 5). The Companies have not provided any evidence that they anticipate a change in inflation, but they state that average service lives have increased for many accounts (Exh. JJS-1, at 4). The effect of longer average service lives, however, would be to decrease the salvage ratio, rather than to increase it (Exh. AG-WWD-Surrebuttal-2, at 4-5).[110] Furthermore, if labor costs and/or the

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reserve of 93 percent) Granville Centre Water Company, D.P.U. 89-241, at 2 (1990) (percent reserve of 79 percent).

[109] Cost of removal is essentially labor, although transportation, costs of disposing of wastes, repaying costs, and other items are also includable (RR-DPU-26, Att. at 34).

[110] The salvage ratio is a function of age and inflation and can be modeled using the equation $\left(\frac{V}{B}\right) x\ (1+p)^{A}$ where V is the salvage value, B is the installation cost, p is past inflation and A is the years since installation[110] (Exh. AG-WWD-Surrebuttal-2, at 4-5). Then the future salvage of the replacement is $Vx(1+f)^{L}$ where f is the future inflation rate and L is the life of the replacement
(Exh. AG-WWD-Surrebuttal-2, at 4). The future salvage ratio then, is $\frac{Vx(1+f)^{L}}{Bx(1+p)^{K}}$ and if

number of items to be removed are increasing, it becomes economical in many cases to invest in special tools that may actually result in an overall decrease in removal cost per item removed (RR-DPU-26, Att. at 160-161). The factors that cause future costs of removal to differ from the past, such as changes in labor costs and removal techniques, are difficult to predict with accuracy over the considerably long periods of time between the placement of plant and its retirement (RR-DPU-26, Att. at 161).

The Attorney General argues that the salvage values are too high because Eversource fails to convert the salvage ratio to constant dollars, thereby ignoring the time value of money (Attorney General Brief at 158). The Companies counter that the Attorney General only considers inflation in the net salvage values, but not the initial installation costs (Companies Brief at 545; Companies Reply Brief at 163). Additionally, the Companies contend that to the extent that any inflation is included, it is only for the difference between the average age of the assets and the average age of retirements (Companies Brief at 545; Companies Reply Brief at 163). Salvage ratios are a function of inflation (Exhs. AG-WWD-Surrebuttal-2, at 5; ES-1, at 7). The numerator is measured in dollars at the time of retirement, while the denominator is measured in dollars at the time of installation (Exh. AG-WWD-1, at 37). A first step in salvage analysis is to convert the observed dollars to constant dollars, which removes inflation from the ratio so that the salvage schedules can be analyzed (Exhs. AG-WWD-Surrebuttal-2, at 8; ES-1, at 5). The Companies argue that the

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the past inflation rate is equal to the future inflation rate, and the life of the original equals that of the replacement, then the salvage ratio will be V/B, unchanged from the original (Exh. AG-WWD-Surrebuttal-2, at 4). That is, the ratio of net salvage cost to retirement costs will be unchanged after L years.

Attorney General selectively applies the concept of inflation by adjusting only the net salvage and ignoring the initial installation costs (Companies Brief at 545; Companies Reply Brief at 163). The Department disagrees. The Companies earn a return on the net plant at the weighted cost of capital. D.T.E. 03-40, at 321; Assabet Water Company, D.P.U. 95-92, at 31 (1996); D.P.U. 1580, at 13 (see Schedules 4 below). The weighted cost of capital consists of equity and debt. Debt earns a nominal interest rate which is the real interest rate, plus expected inflation. Equity earns a return, which can be calculated as the cost of debt, plus a risk premium. Therefore, the inflation is embedded in the Companies' return on investment. Additionally, the Companies argue that any inflation for net salvage is only for the period represented by the difference between the average age of the plant and the average age of retirement (Companies Brief at 545; Companies Reply Brief at 163). The Companies use NSTAR Electric's Account 364 to demonstrate that an inflation is nominal,[111] citing to 2.7 years of inflation for that particular account (Companies Brief at 545; Companies Reply Brief at 163). However, that would belie the argument that the net salvage costs are expected to be 1.7 times the current costs experienced for that particular account.[112]

The effect of including a future cost of removal without discounting it for the time value of money is to give the Companies the equivalent of an interest free loan. The Companies begin collecting the cost of removal when the plant is installed, which it should, as the ratepayers that benefit from the plant should be the ratepayers who pay for the plant to

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111 NSTAR Electric's Account 364 is associated with Poles, Towers and Fixtures.

112 The three-year average net salvage amount for NSTAR Account 364 is $2,762,226, while Eversource proposes to include $4,800,217 in the calculation of depreciation expense (Exh. AG-WWD-1, at 15, Table 1).

avoid intergenerational subsidization. By including an inflated net salvage value, however, the ratepayers pay for a cost that the Companies will not incur for some time into the future. See D.T.E. 98-51, at 76; D.P.U. 1350, at 107. During that time period, Eversource has the use of those depreciation funds. Assuming that Eversource invests in itself, the Companies would realize the benefit of something akin to the allowed rate of return. However, in the future when the Companies file a petition seeking new base distribution rates, the inflated depreciation rates will have the effect of increasing the Companies' accumulated depreciation. This in turn reduces the net plant on which the Companies will earn a return going forward, by the difference in the inflation for the period since the most recent base rate case. Therefore, the money "borrowed" from ratepayers will effectively be given back, compounding for the period of time between rate case filings. In turn, assuming that Eversource files rate cases once every five years, the new depreciation rates in the subsequent base rate case filing would then repeat the process, effectively resulting in a series of short term, interest free loans of five-, four-, three-, two- and one-year durations, repeated indefinitely. Additionally, a PBR mechanism, that increases the entire rate base annually, would exacerbate the situation. Because rate-base includes the depreciation expense, which is composed, in part, of the estimated net salvage values, each year the amount that ratepayers are charged for net salvage would be inflated by the PBR factor, which would increase the over-collection.

The Companies argue that lower depreciation rates would result in a larger rate base in future rate cases, against which ratepayers would pay a return (Companies Reply Brief

at 164). While this is true, the additional future cost to ratepayers would only be the product of the weighted cost of capital and the reduction in depreciation accruals. The savings to ratepayers would be (1-WCC) multiplied by the reduction in depreciation accruals. Therefore, the argument is unpersuasive and, because rates are based on uninflated net salvage values, irrelevant to our analysis here.

The Companies also argue that the Attorney General would prefer to treat net salvage costs as the equivalent of an operating expense rather than to allocate the costs over the time in which assets serve customers (Companies Reply Brief at 163). The NARUC Depreciation Manual reports that many jurisdictions have chosen to treat salvage costs as operating expenses, in part because the difficulty in accurately estimating gross salvage values and the future costs of removal has generated considerable controversy (RR-DPU-26, Att. at 157). Additionally, the NARUC Depreciation Manual cites the trend towards negative salvage values as an incentive for some jurisdictions to treat the costs as operating expenses (RR-DPU-26, Att. at 157). Notwithstanding NARUC's evaluation of depreciation practices, however, the Department has long recognized the incorporation of net salvage in a company's depreciation accrual rates, as embodied in the remaining life method. D.P.U. 12-25, at 307; D.P.U. 1350, at 97-98; Bay State Gas Company, D.P.U. 19497, at 16-17 (1978); Boston Gas Company, D.P.U. 19470, at 48 (1978). Our findings with respect to Eversource's net salvage analysis do not signal the Department's intention to require the expensing of salvage costs, but rather the Department's recognition that the Companies have overstated their salvage estimates.

Based on the foregoing considerations, the Department finds that Eversource's proposed net salvage factors overstate the Companies' salvage costs and produce excessive depreciation accrual rates. As a partial remedy, the Attorney General has proposed the use of different salvage factors for five NSTAR Electric plant accounts and nine WMECo plant accounts (Exh. AG-WWD-1, at 31). The Department has examined both Eversource's and the Attorney General's proposed net salvage factors, including the assumptions behind the selection of each net salvage factor. Based on our examination, the Department finds that the Attorney General's proposed salvage factors for NSTAR Electric's accounts 366, 367, 369.1, 369.2, and 373, as well as her proposed accrual rates for WMECo's accounts 362, 364, 365, 366, 367, 369.1, 369.2, 370, and 371 strike a reasonable balance between historic net salvage trends, more recent net salvage trends, and the Companies' anticipated future net salvage costs, while maintaining the theoretical depreciation reserve. Therefore, the Department will use the Attorney General's proposed net salvage rates in determining Eversource's depreciation accrual rates.

c. Amortization Reserve Deficiency Adjustment

As noted above, Eversource proposes a five-year amortization of what it considers to be $643,489 in under-accruals in NSTAR Electric's general plant accounts and $2,376,406 in under-accruals in WMECo's general plant accounts (Exhs. ES-JJS-2, at 50-51; ES-JJS-3, at 50-51). An accrual rate must be sufficient to permit a company to recover its original capital investment over the productive life of the asset, while avoiding placing the financial burden solely on current or future customers. D.T.E. 98-51, at 76. Where the Department

determines that under-accruals have developed because of neglectful practices of management, ratepayers should not bear the financial burden of such negligence. D.P.U. 19470, at 49-50; Wannacomet Water Company, D.P.U. 13525 (1962).

The Companies' over- and under-accruals in general plant accounts occurred because of the inevitable variances among the vintage balance, theoretical reserve, and book reserve that occur with amortization accounting (Exh. DPU-11-11). There is no evidence that the over- and under-accruals in these accounts are the result of any imprudent actions on the part of NSTAR Electric or WMECo. Accordingly, the Department finds that the Companies have correctly calculated the under-accruals associated with their general plant accounts. In reaching this conclusion, the Department finds that the Companies' proposed amortization rates for Accounts 391 through 398 are reasonable and supported by the evidence (Exhs. ES-JJS-2, at 45-46, 50-51; ES-JJS-3, at 45-46, 50-51).

The Department has examined the Companies' proposed method to eliminate their amortization under-accruals. Eversource proposes the use of a five-year amortization period, reasoning that this particular amortization period is the most commonly used amortization period, correlates with the shortest amortization period for each of the accounts, and is generally close to the period by which the Companies would prepare their next depreciation studies (Exh. DPU-11-11). For NSTAR Electric, the remaining lives of general plant assets booked to Accounts 391.1, 391.2, 393, 394, 395, 397, and 398 range from 3.5 years for Account 391.2 to 24.0 years for Account 393, with a dollar-weighted overall average of 7.8 years (see Exh. NSTAR-JJS-2, at 50-51). Most of NSTAR Electric's over- and

under-accruals are associated with Accounts 391.1, 391.2, and 397, of which Accounts 391.1 and 397 and have remaining lives of approximately ten years (Exh. NSTAR-JJS-2, at 50-51). For WMECo, the remaining lives of general plant assets booked to Accounts 391.1, 391.2, 393, 394, 395, 397 (GPS), 397 (Other), and 398 range from 3.2 years for Account 391.1 to 24.7 years for Account 397 (GPS), with a dollar-weighted overall average of 8.0 years (see Exh. NSTAR-JJS-3, at 50-51). Most of WMECo's under-accruals are associated with Account 397, which has a remaining life of 6.7 years (Exh. NSTAR-JJS-3, at 50-51).

Based on this information, the Department finds that using a five-year amortization results in excessive charges to ratepayers. Based on our examination of the remaining life of the assets and accounts most significantly affected by the over- and under-accruals, the Department finds an amortization period of eight years strikes a reasonable balance between the need to eliminate the overall under-accruals and the need for intergenerational equity among current and future customers. Accordingly, the Department will apply an eight-year amortization to NSTAR Electric's under-accrual of $643,489, which produces an annual amortization of $80,436 for its general plant under-accruals. The Department will apply an eight-year amortization to WMECo's under-accrual of $2,376,406, which produces an annual amortization of $297,051 for its general plant under-accruals.

d. Conclusion

In order to calculate the Company's annual depreciation expense based on the revised accrual rates, the Department has applied the accrual rates approved by this Order to the Company's depreciable plant balances included in rate base. As discussed in Section VII.C

above, the Department has allowed the inclusion of NSTAR Electric's proposed post-test year plant additions, but has excluded $3,335,790 in post-test year additions associated with WMECo's Montague substation upgrades. Finally, the Department has reduced NSTAR Electric's amortization reserve deficiency adjustment from the proposed $128,698 to $80,436, and has reduced WMECo's amortization reserve deficiency adjustment from the proposed $475,881 to $297,051. Based on this analysis, the Department finds that NSTAR Electric's annual depreciation and amortization expense is $145,626,751, and that WMECo's annual depreciation and amortization expense is $29,984,446. Accordingly, NSTAR Electric's proposed depreciation expense is reduced by $6,600,402, and WMECo's proposed depreciation expense is reduced by $3,248,078.

F. Lease Expense

1. Introduction

During the test year, NSTAR Electric and WMECo booked $3,660,277 and $749,592, respectively, in lease expense associated with various facilities (Exhs. ES-DPH-2 (East), Sch. DPH-18 (Rev. 3); ES-DPH-2 (West), Sch. DPH-18 (Rev. 3)). The test year lease expense includes rent and facility expenses allocated to NSTAR Electric and WMECo associated with Eversource's use of property located at 56 Prospect Street in Hartford, Connecticut ("56 Prospect Street") (Exhs. AG-26-13, Atts. (a) at 2, (b); AG-26-22, Atts. (a), (b); AG-31-15; AG-50-12; Tr. 4, at 829-833). Specifically, the Companies' respective test year costs of service include $110,453 and $18,300 associated with rent expense and $89,397 and $8,867 associated with facility expense related to 56 Prospect Street (Exhs. AG-26-13, Atts. (a) at 2, (b); AG-26-22, Atts. (a), (b); AG-31-15; AG-50-12).

Eversource proposes a net increase of $620,331 in NSTAR Electric's test year lease expense pertaining to the following adjustments: (1) an increase of $348,979 associated with a lease for the Waltham Service Center executed in August 2016; (2) an increase of $377,297 associated with an increase in the net plant value of Eversource's facility in Southborough, along with an increase in the occupancy rate of that facility from 25 percent to 32 percent; and (3) a decrease of $105,945 associated with an intercompany rent general ESC overhead rate ("GSCOH") offset (Exh. ES-DPH-2 (East), Sch. DPH-18 (Rev. 3)). These adjustments result in a pro forma test year lease expense of $4,280,608 for NSTAR Electric (Exh. ES-DPH-2 (East), Sch. DPH-18 (Rev. 3)).

Eversource proposes a net increase of $13,819 in WMECo's test year lease expense pertaining to the following adjustments: (1) an increase of $12,795 associated with scheduled increases in several leases between WMECo and various communications companies; (2) an increase of $1,342 associated with scheduled increases in lease payments beginning in September 2016 for Eversource's satellite facility in Lee; and (3) a decrease of $317 associated with an intercompany rent GSCOH offset (Exh. ES-DPH-2 (West), Sch. DPH-18 (Rev. 3)). These adjustments result in a pro forma test year lease expense of $763,412 for WMECo (Exh. ES-DPH-2 (West), Sch. DPH-18 (Rev. 3)).

2. Positions of the Parties

a. Attorney General

The Attorney General does not challenge the Companies' proposed pro forma adjustments to lease expense. However, the Attorney General argues that the Companies have inappropriately included in their test year costs of service the aforementioned expenses

associated with 56 Prospect Street (Attorney General Brief at 134, citing Exhs. ES-DPH-2 (East), Sch. 18, at 2 (Rev. 2); ES-DPH-2 (West), Sch. 18, at 2 (Rev. 2); AG-50-12; Tr. 4, at 829-833; Attorney General Reply Brief at 28). According to the Attorney General, the Companies have failed to provide persuasive evidence that 56 Prospect Street is necessary for providing electric distribution service to Massachusetts ratepayers, or that the facility benefits such ratepayers (Attorney General Brief at 134; Attorney General Reply Brief at 29). Further, the Attorney General notes that the Companies already have a Massachusetts headquarters consisting of 25,676 square feet of space in the Prudential Center Tower in Boston, as well as significant additional office space in Westwood and New Bedford (Attorney General Brief at 134, citing Exhs. ES-DPH-2 (East), Sch. DPH-18, at 2 (Rev. 2); ES-DPH-2 (West), Sch. DPH-18, at 2 (Rev. 2); AG-26-13 & Atts.; AG-50-15). Finally, the Attorney General contends that the Connecticut Public Utility Regulatory Authority ("PURA") denied the Companies' affiliate, Connecticut Light & Power Company ("CL&P"), recovery of costs associated with leasing 56 Prospect Street on the basis that those costs were superfluous and unnecessary (Attorney General Brief at 135; Attorney General Reply Brief at 28). Accordingly, the Attorney General asserts that the Department should disallow the rent and facility expenses associated with 56 Prospect Street (Attorney General Brief at 136; Attorney General Reply Brief at 30).

b. Companies

As an initial matter, the Companies challenge the Attorney General's reliance on PURA's decision concerning 56 Prospect Street (Companies Brief at 458). According to the

Companies, PURA did not find that 56 Prospect Street was unnecessary, but instead disallowed the costs associated with the facility because Northeast Utilities made the explicit decision to purchase the property rather than expand the utility's prior location in Berlin, Connecticut (Companies Brief at 458, citing Exh. AG-15, at 39-40).

Further, Eversource argues that, regardless of the PURA decision, the Companies have demonstrated in this proceeding that Massachusetts customers directly benefit from the lease of 56 Prospect Street (Companies Brief at 458-459). For example, Eversource notes that senior staff meetings and presentations related to the Massachusetts distribution functions are conducted at that facility (Companies Brief at 458-459, citing Exh. ES-DPH-1, at 1; Tr. 4, at 833).

In addition, Eversource contends that only costs related to the Companies' distribution functions are included in their respective revenue requirements, and that such costs are properly allocated to the Companies based on the square footage of floor space occupied by each business unit (Companies Brief at 459). As such, the Companies claim that lease expenses associated with 56 Prospect Street are reasonable in nature and, therefore, appropriate for recovery (Companies Brief at 459-460, citing D.P.U. 15-155, at 298; D.P.U. 89-114/90-331/91-80 (Phase I) at 96; Companies Reply Brief at 128).

Finally, the Companies assert that the remaining pro forma adjustments to their lease expenses reflect known and measurable changes in rent expense through July 1, 2018, and are reasonable in nature (Companies Brief at 220-221). Therefore, Eversource asserts that

the Department should approve the Companies' proposed pro forma adjustments (Companies Brief at 221).

3. Analysis and Findings

a. Introduction

A company's lease expense represents an allowable cost qualified for inclusion in its overall cost of service. D.T.E. 03-40, at 171; D.P.U. 88-161/168, at 123-125. The standard for inclusion of lease expense is one of reasonableness. D.P.U. 89-114/90-331/91-80 (Phase One) at 96. Known and measurable increases in rental expense based on executed lease agreements with unaffiliated landlords are recognized in cost of service as are operating costs (e.g., maintenance, property taxes) that the lessee agrees to cover as part of the agreement. D.P.U. 95-118, at 42 n.24; D.P.U. 88-67 (Phase I) at 95-97. When facility leases have been entered into with affiliated companies, the Department will limit the return component to the weighted cost of capital applicable to the petitioning company, and limit depreciation expense to the amount generated by the petitioning company's own accrual rates. D.P.U. 10-55, at 266-267; D.P.U. 08-27, at 84.

b. Companies' Test Year Lease Expense Associated with 56 Prospect Street Lease

As noted above, the Companies' respective test year costs of service include $110,453 and $18,300 associated with rent expense, and $89,370 and $8,867 associated with facility expense related to 56 Prospect Street (Exhs. AG-26-13, Atts. (a) at 2, (b); AG-26-22, Atts. (a), (b); AG-31-15; AG-50-12). Eversource argues that Massachusetts customers directly benefit from the lease of 56 Prospect Street and, therefore, it is appropriate to

include a portion of the lease expenses associated with that property in the Companies' costs of service (Companies Brief at 458-459). We disagree.

The record shows that, at most, one Eversource employee who otherwise exclusively focuses on Massachusetts operations sometimes travels to 56 Prospect Street for "senior team presentations and other meetings" (Tr. 4, at 435). The Companies have failed to provide any persuasive evidence regarding the nature, frequency, or duration of the meetings, why Massachusetts personnel were invited, or the extent to which Massachusetts operations were even discussed.[113] Based on the record, we simply cannot discern any benefits to Massachusetts ratepayers associated with Eversource's share of the lease expenses related to 56 Prospect Street. As such, the Department finds that the Companies have failed to sustain their burden of demonstrating that these lease expenses are reasonable. See, e.g., Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 32 (2009); Bay State Gas Company, D.P.U. 05-27, at 93-96 (2005); Phelps v. Hartwell, 1 Mass. 71, 73 (1804). Accordingly, the Department will reduce NSTAR Electric's proposed cost of service by $199,850,[114] and will also reduce WMECo's proposed cost of service by $27,167.[115]

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113 On brief, the Companies note that one of their witnesses in the instant case has his primary office at 56 Prospect Street, and, therefore given his "significant involvement in this case and as the Project Director for any future NSTAR Electric and WMEC[o] [electric vehicle] and [s]torage programs ... the Compan[ies'] distribution customers are deriving a direct benefit from the 56 Prospect Street facility" (Companies Brief at 458-459). The Companies' arguments on brief are not evidence and, therefore, cannot be relied upon in reaching our decision.

114 $110,453 in rent expense + $89,397 in facility expense.

115 $18,300 in rent expense + $8,867 in facility expense.

c. Eversource's Proposed Adjustments to NSTAR Electric's Test Year Lease Expense

As noted above, Eversource proposes a net increase of $620,331 in NSTAR Electric's test year lease expense pertaining to three adjustments: (1) an increase of $348,979 associated with a lease for the Waltham Service Center executed in August 2016; (2) an increase of $377,297 associated with an increase in the net plant value of Eversource's facility in Southborough, along with an increase in the occupancy rate of that facility from 25 percent to 32 percent; and (3) a decrease of $105,945 associated with a GSCOH offset (Exh. ES-DPH-2 (East), Sch. DPH-18 (Rev. 3)).

Regarding the rental expense for the Waltham Service Center, the record shows that NSTAR Electric entered into written lease agreement with an unaffiliated party for this facility, and that NSTAR Electric presently occupies space at this location pursuant to the terms and conditions of the executed lease agreement (Exhs. ES-DPH-1, at 92-93; DPU-3-1; AG-1-64, Att. (c)). The Department has reviewed the terms and conditions of the executed lease agreements and related documents, as well as the explanations for the pro forma adjustment, and we find that NSTAR Electric's total lease expense and operating costs are appropriately documented and, as such, represent a known and measurable change to NSTAR Electric's test year cost of service (Exhs. ES-DPH-1, at 92-93; DPU-3-3; AG-1-64, Att. (c)). Accordingly, the Department allows the proposed increase of $348,979 to NSTAR Electric's proposed cost of service.

Turning to the lease expense associated with NSTAR Electric's use of the Southborough facility, the Department finds that Eversource incorrectly calculated both the

test year expense and the pro forma expense. The Southborough facility is a shared facility owned by NSTAR Gas (Exhs. ES-DPH-1, at 93; DPU-3-2; DPU-3-4; DPU-32-13; DPU-32-15). NSTAR Gas allocates a portion of its revenue requirement to NSTAR Electric as intercompany rent based on the square footage of the facility occupied by NSTAR Electric (Exhs. ES-DPH-1, at 93; DPU-3-2; DPU-3-4). In addition, there is no lease agreement associated with NSTAR Electric's use of the Southborough facility (Exh. DPU-3-2). Eversource booked to NSTAR Electric a test year lease expense of $513,428, and Eversource proposes an adjustment of $377,297, which results in a pro forma test year lease expense of $890,725 associated with the Southborough facility (Exhs. ES-DPH-2 (East), Sch. DPH-18, at 2 (Rev. 1); DPU-32-17, Att.).[116] Eversource states that the proposed adjustment is due to NSTAR Electric's increased occupancy of the facility from 25 percent to 32 percent, as well as an increase in the net plant value of the Southborough facility (Exhs. ES-DPH-1, at 93; DPU-3-4; DPU-32-13). Further, a portion of the lease expense purportedly recognizes a depreciation expense rate of 2.13 percent and a carrying charge rate of 11.16 percent, which represents the pre-tax rate of return approved for NSTAR Gas in D.P.U. 14-150 (Exhs. DPU-3-4; DPU-32-15; DPU-32-15, Att.; DPU-32-17).

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[116] In the initial filing, Eversource reported that NSTAR Electric's test year rent expense for the Southborough facility was $513,428, and Eversource proposed an adjustment of $71,462 (Exhs. ES-DPH-1, at 93; ES-DPH-2, Sch. DPH-18, at 2 (East)). Eversource subsequently revised these amounts to reflect an increase in net plant balance as of December 31, 2016, as well as a correction to the calculation of depreciation expense (Exhs. ES-DPH-2 (East), Sch. DPH-18, at 2 (Rev. 1); DPU-3-4; DPU-32-17).

Eversource asserts that it is appropriate to use NSTAR Gas' approved cost of capital and depreciation rate to determine intercompany rent allocated to NSTAR Electric for use of the Southborough facility because NSTAR Gas is the owner of the facility (Exhs. DPU-32-15; DPU-32-17). The Department has found, however, that where a petitioning company pays depreciation expense and/or a return component on a facility owned by an affiliate, customers of the petitioning company are forced to subsidize the operations of the affiliate. D.P.U. 10-55, at 266-267; D.P.U. 08-27, at 84. As such, the Department has limited the return component to the weighted cost of capital applicable to the petitioning company, and limited the depreciation expense to the amount generated by the petitioning company's own accrual rates. D.P.U. 10-55, at 266-267; D.P.U. 08-27, at 84. Therefore, the Department finds that application of NSTAR Gas' 11.16 percent weighted cost of capital and 2.13 percent depreciation rate to determine NSTAR Electric's allocated share of the Southborough facility understates the required lease expense. D.P.U. 10-55, at 266-267; D.P.U. 08-27, at 84.

To derive appropriate test year lease expense for ratemaking purposes, the Department will apply the pre-tax weighted cost of capital of 10.90 percent and depreciation rate of 3.90 percent being approved in this Order. This produces a pro forma annual lease expense for the Southborough facility of $936,074. Accordingly, the Department will increase NSTAR Electric's proposed cost of service by $45,354.[117]

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[117] $936,079 - $890,725 - $45,354.

Finally, Eversource proposes a decrease in NSTAR Electric's test year lease expense of $105,945 associated with a GSCOH offset (Exhs. ES-DPH-1, at 92; ES-DPH-2 (East), Sch. DPH-18 (Rev. 3)). The GSCOH is an ESC overhead rate, which is an adder to labor and charged to the account in which the associated labor is charged (Exh. ES-DPH-1, at 37, 94). The Department has reviewed this adjustment and we find that it represents a known and measurable change to NSTAR Electric's test year lease expense (Exh. ES-DPH-2 (East), Sch. DPH-18 (Rev. 3)). Accordingly, we allow the proposed decrease of $105,945 to NSTAR Electric's proposed cost of service.

d. Eversource's Proposed Adjustments to WMECo's Test Year Lease Expense

As noted above, Eversource proposes a net increase of $13,819 in WMECo's test year lease expense pertaining to three adjustments: (1) an increase of $12,795 associated with scheduled increases in several leases between WMECo and various communications companies; (2) an increase of $1,342 associated with scheduled increases in lease payments beginning in September 2016 for Eversource's satellite facility in Lee; and (3) a decrease of $317 associated with an intercompany rent GSCOH offset (Exh. ES-DPH-2 (West), Sch. DPH-18 (Rev. 3)).

Regarding WMECo's communications leases, the record shows that they are subject to written agreements with unaffiliated parties, and that WMECo uses these services to listen to conversations between workers and dispatchers across a whole district area, as well as to enhance system reliability and reduce outage times (Exhs. ES-DPH-1, at 93; DPU-3-5; AG-1-64, Att. (k)). The Department has reviewed the terms and conditions of these executed

lease agreements and related documents, as well as the explanations for the pro forma adjustments, and we find that WMECo's total lease expense and operating costs are appropriately documented and, as such, represent a known and measurable change to WMECo's test year cost of service (Exhs. ES-DPH-1, at 93; DPU-3-5; AG-1-64, Att. (k)). Accordingly, the Department allows the proposed increase of $12,795 to WMECo's proposed cost of service.

Similarly, with respect to the Lee satellite facility, the record shows that WMECo entered into written lease agreement with an unaffiliated party for this facility, and that WMECo presently occupies space at this location pursuant to the terms and conditions of the executed lease agreement (Exhs. ES-DPH-1, at 93; DPU-3-7; AG-1-64, Att. (i)). The Department has reviewed the terms and conditions of the executed lease agreements and related documents, as well as the explanations for the pro forma adjustment, and we find that WMECo's total lease expense and operating costs are appropriately documented and, as such, represent a known and measurable change to NSTAR Electric's test year cost of service (Exhs. ES-DPH-1, at 93; DPU-3-7; AG-1-64, Att. (i)). Accordingly, the Department allows the proposed increase of $1,342 to WMECo's proposed cost of service.

Finally, Eversource proposes a decrease in WMECo's test year lease expense of $317 associated with a GSCOH offset (Exhs. ES-DPH-1, at 92; ES-DPH-2 (West), Sch. DPH-18 (Rev. 3)). The Department has reviewed this adjustment and we find that it represents a known and measurable change to WMECo's test year lease expense (Exh. ES-DPH-2 (West),

Sch. DPH-18 (Rev. 3)). Accordingly, we allow the proposed decrease of $317 to WMECo's proposed cost of service.

G. Information System Expense

1. Introduction

Eversource proposes to include the costs associated with its Supply Chain Project as a post-test year adjustment to information systems expense (Exhs. ES-DPH-1, at 96; ES-DPH-2, Sch. DPH-19 (Rev. 3); DPU-9-11; DPU-45-57; AG-43-2; AG-54-4; Tr. 6, at 1192). Eversource explains that the Supply Chain Project will consolidate and standardize all supply chain activities across each Eversource Energy operating company to eliminate redundancy, leverage industry-best practices, and introduce modern technology to sourcing, contracting, and materials management-related activities (Exh. ES-DPH-1, at 94). Eversource states that it will need to deploy Ariba, Maximo, and Oracle Accounts Payable software tools in order to achieve these objectives (Exh. ES-DPH-1, at 94). Once the project is completed, Eversource states that there may be cost savings as soon as the first year of implementation due to process efficiencies and reduced labor (Exhs. ES-LML-8, at 145 (Supp. 1)); DPU-9-5; Tr. 6, at 1209-1210). Eversource originally estimated a project in-service date for the Supply Chain Project of February 17, 2017, but the Companies subsequently amended the in-service date to July 3, 2017 (Exhs. ES-LML-8, at 145 (Supp. 1); AG-19-22; AG-42-1; AG-42-2; AG-42-3; AG-50-18; Tr. 6, at 1190; Tr. 9, at 1827; Tr. 15, at 3054, 3059).

Eversource explains that the Supply Chain Project comprises three main components: (1) Supply Chain software; (2) eSourcing/Portal software; and (3) System Integrator

(Exh. AG-42-8; AG-42-9). Because the Supply Chain Project makes use of several external software tools, as well as externally contracted labor, Eversource states that it issued RFPs to multiple qualified sources to facilitate a competitive bidding process (Exhs. ES-DPH-1, at 94-95; AG-42-8; AG-42-9; AG-42-12; AG-50-19). Specifically, Eversource issued RFPs to three bidders on April 10, 2015, for the Supply Chain software and eSourcing software (Exh. AG-42-8). Eversource ultimately executed an agreement with IBM on July 31, 2015 for the Maximo software solution and with SAP on September 21, 2015, for the Ariba solution (Exh. AG-42-8). Further, Eversource issued RFPs to six bidders on April 17, 2015, for the System Integrator, and ultimately executed an agreement with Infosys on October 19, 2015 (Exh. AG-42-8).

Eversource proposes to treat the Supply Chain Project as a capital asset on ESC's books, and to recover the costs associated with this project, including depreciation, property taxes, and a return component, through a post-test year adjustment to expense to be reflected in NSTAR Electric's and WMECo's revenue requirements (Exhs. ES-DPH-1, at 96; DPU-9-10; DPU-9-11). Eversource proposes to allocate the costs associated with the Supply Chain Project using its budgeted service company labor allocator and to charge the associated expenses to each operating company using GSCOH, the general ESC overhead rate, which Eversource describes as an adder to labor to be charged to the account to which the associated labor is charged (Exhs. ES-DPH-1, at 96-98; ES-DPH-4, Sch. DPH-8, at 1-2; DPU-9-3; DPU-45-52; DPU-45-53; AG-1-92; AG-1-92, Att. at 5; AG-42-10; AG-42-11). Eversource states that while there are general service contracts between ESC and its

affiliates, including NSTAR Electric and WMECo, there is not a specific service agreement for the Supply Chain Project (Exh. DPU-9-9; AG-1-26, Atts. (a), (b)).

During the test year, NSTAR Electric and WMECo booked $6,100,492 and $1,397,941, respectively, in information systems expense unrelated to the Supply Chain Project (Exhs. ES-DPH-2 (East), Sch. DPH-19 (Rev. 3); ES-DPH-2 (West), Sch. DPH-19 (Rev. 3); DPU-45-57; Tr. 9, at 1827). Eversource requests a pro forma adjustment to test year information systems expense of $1,248,167 and $237,936 for NSTAR Electric and WMECo, respectively, to reflect project costs of $36,420,160 associated with the Supply Chain Project incurred through April 30, 2017 (Exhs. ES-DPH-2 (East), Sch. DPH-19 (Rev. 3); ES-DPH-2 (West), Sch. DPH-19 (Rev. 3); AG-42-1; AG-43-2; Tr. 6, at 1216; Tr. 9, at 1830). Eversource states that although it anticipates the total project capital costs to be $41.2 million, it plans on deferring additional cost recovery until its next base rate proceeding because the project is expected to be placed into service after the close of the evidentiary record in this proceeding (Exh. AG-42-5; AG-43-2; Tr. 6, at 1189-1190; Tr. 15, at 3059).

2. Position of the Parties

a. Attorney General

The Attorney General recommends that the Department disallow the costs associated with the Supply Chain Project (Attorney General Brief at 126). The Attorney General provides three distinct arguments to support this recommendation, each of which she asserts provides an independent basis for rejection from NSTAR Electric's and WMECo's revenue requirements (Attorney General Brief at 126).

First, the Attorney General argues that the Supply Chain Project is a post-test year plant addition at the service company level and did not go into service prior to the end of hearings in this case (Attorney General Brief at 127). The Attorney General notes that Eversource initially estimated an in-service date of February 2017, but subsequently updated its estimate to July 3, 2017 (Attorney General Brief at 127, citing Exhs. DPU-9-7; DPU-9-7, Att. at 5; AG-42-1). Further, because Eversource still will be testing the platform after July 3, 2017, the Attorney General claims that the Supply Chain Project cannot be considered in service, and instead should be classified as construction work in progress (Attorney General Brief at 127, citing Tr. 15, at 3054-3055, 3064).

Second, the Attorney General contends that the costs associated with the Supply Chain Project are not known or measurable and thus do not meet the Department's standard for adjustments to test year cost of service (Attorney General Brief at 127-128). The Attorney General asserts that, although actual project expenditures included for recovery may be known as of April 30, 2017, the amount that will be charged to NSTAR Electric and WMECo is not known or measurable (Attorney General Brief at 128). To support this assertion, the Attorney General notes that ESC proposes to allocate costs associated with the Supply Chain Project to its affiliates using a budgeted labor allocator, which the Attorney General claims is not the actual labor allocator that ultimately will be used to assign costs to the Companies (Attorney General Brief at 128, citing Exh. ES-DPH-4, Sch. DPH-8 (Rev. 1). The Attorney General argues that as a result, the actual level of costs Eversource will

allocate to NSTAR Electric and WMECo for the Supply Chain Project are unknown (Attorney General Brief at 128-129).

Third, the Attorney General argues that the Department should reject the post-test year adjustment to expense associated with the Supply Chain Project because it fails to recognize any of the associated, offsetting savings and benefits (Attorney General Brief at 129, citing Exh. ES-LML-8 (Supp. 1) at 141-151). In particular, the Attorney General asserts that the Companies estimate that efficiencies and reductions to materials will result in $5.4 million in direct annual recurring savings and $2.8 million in one-time savings, as well as potential indirect savings, at the service company level (Attorney General Brief at 129, citing Exh. ES-LML-8, at 141-151 (Supp. 1)). The Attorney General argues that the anticipated cost savings and benefits contributed to Eversource's decision to go forward with the project, and, as such, should not be treated as potential or conceptual savings, but rather real savings to be reflected in the net costs of this project (Attorney General Brief at 129-130, citing Tr. 6, at 1212-1213; Tr. 15, at 3054-3058; Attorney General Reply Brief at 16). Thus, the Attorney General characterizes the Companies' proposed adjustments as one-sided, and argues that if cost savings were considered in conjunction with a more reasonable rate of return, the Supply Chain Project would have a net negative impact Eversource's overall revenue requirement (Attorney General Brief at 130, citing Exh. AG-DR-1, at 8). Therefore, the Attorney General recommends that the Department reject the Companies' pro forma adjustments to increase NSTAR Electric's and WMECo's information systems expense (Attorney General Brief at 130).

Alternatively, the Attorney General argues that if the Department allows the Companies' proposed post-test year adjustment to expense, the Department should make two modifications to the proposed increases (Attorney General Brief at 131-132). First, the Attorney General contends that Eversource's use of NSTAR Electric's and WMECo's proposed consolidated capital structure and cost rates is inappropriate and overstates the revenue requirement to be allocated to NSTAR Electric and WMECo (Attorney General Brief at 131, citing Exh. ES-DPH-4, Sch. DPH-8 (Rev. 1) at 8). According to the Attorney General, if the Department approves the Companies' proposed adjustments to information systems expense, it should recalculate the adjustments using ESC's capital structure and cost of debt rate, and the return on equity approved in this case using the cost of debt information contained in Exhibit AG-26-2, as is consistent with prior Department findings (Attorney General Brief at 132, citing Exh. AG-26-2; Tr. 9, at 1833-1834; D.P.U. 15-155, at 303).

Second, the Attorney General contends that the allocation rate used to apportion Supply Chain Project costs to NSTAR and WMECo is overstated because it does not reflect Eversource's pending acquisition of the Aquarion Water Company (Attorney General Brief at 126). Specifically, the Attorney General notes that the Supply Chain Project is intended to benefit all Eversource Energy operating companies, including Aquarion Water Company (Attorney General Brief at 131). The Attorney General argues that a failure to reduce the costs to be allocated to NSTAR Electric and WMECo due to Eversource's recent acquisition of Aquarion Water Company would not be fair or reasonable to ratepayers, and, therefore,

she recommends reducing the allocation rate used to apportion the Supply Chain Project costs to NSTAR Electric and WMECo (Attorney General Brief at 131).

b. Companies

Eversource argues that the Department should approve its proposed post-test year adjustment to information systems expense to reflect known and measurable Supply Chain Project costs incurred through April 30, 2017 (Companies Brief at 222-223, 452, citing Exhs. DPH-1, at 94; DPU-9-7; DPU-45-57; AG-19-22; AG-42-1; AG-43-2). Eversource additionally claims that the project was placed in service on July 3, 2017 (Companies Brief at 221-223, citing Tr. 6, at 1190). Eversource contends that it has appropriately calculated the Supply Chain Project expense adjustment, and requests the Department's approval to incorporate this adjustment to the revenue requirements of NSTAR Electric and WMECo (Companies Brief at 223).

Eversource also argues that the Department should reject the Attorney General's recommendation to disallow the costs associated with the Supply Chain Project, and provides several responses to the Attorney General's assertions (Companies Brief at 450). First, Eversource asserts that the Attorney General mischaracterizes the in-service date of the Supply Chain Project (Companies Brief at 450). Eversource claims that it transitioned to the new supply chain system from June 30, 2017, to July 3, 2017, at which point the supply chain software solution was deployed and, as it was fully operational, used to support the procure-to-pay process (Companies Brief at 451, citing Tr. 15, at 3055). Eversource contends that this process is typical for new information system projects and platforms, and

states that the Department has previously approved recovery of post-test year information system platforms with similar testing procedures (Companies Brief at 451, citing D.P.U. 13-75, at 1, 110, 117). Further, the Companies claim that the Attorney General has not provided evidence that the Supply Chain Project is not in service and providing a benefit to the Companies' customers (Companies Brief at 451). In addition, the Companies contend that there is no Department standard requiring capital projects that result in post-test year expense adjustments to be in service (Companies Reply Brief at 112).

Second, Eversource asserts that the Attorney General's allegation that the Supply Chain Project costs are not known and measureable is without merit (Companies Brief at 452). Eversource claims that it is only seeking recovery of costs through April 30, 2017, resulting in a revenue requirement of $1,248,167 for NSTAR Electric and $237,936 for WMECo (Companies Brief at 452, citing Exhs. ES-LML-8 (Supp. 2); ES-DPH-2 (East), Sch. DPH-19 (Rev. 2); ES-DPH-2 (West), Sch. DPU-19 (Rev. 2)). Eversource further asserts that the allocated costs, as developed using the GSCOH allocator, are known and measurable (Companies Brief at 452). In addition, Eversource claims that the labor allocator used to allocate the costs associated with the Supply Chain Project to the operating companies is the actual rate ESC uses to assign costs for the period it incurs the costs (Companies Reply Brief at 112).

Third, Eversource argues that the Attorney General's recommendation to reduce the Companies' proposed revenue requirement due to potential savings does not meet the Department's known and measurable standard, and therefore should be rejected (Companies

Brief at 454). Eversource notes that it identified and calculated potential savings associated with the Supply Chain Project on an Eversource-wide basis (Companies Brief at 453, citing Exh. ES-LML-8 (Supp. 2), at 8). In addition, Eversource notes that these savings are based on a 60 percent realization probability and can only be considered preliminary and, therefore, are speculative (Companies Brief at 453, citing Exh. ES-LML-8 (Supp. 2), at 8). Eversource claims that the Department has previously rejected proposed adjustments for savings achieved by information system projects when the record showed that the savings did not meet the Department's known and measurable standard (Companies Brief at 453-454, citing D.P.U. 15-155, at 307-308; D.T.E. 03-40, at 11; D.T.E. 02-24/25, at 76; D.P.U. 95-118, at 130-131; D.P.U. 92-111, at 142; D.P.U. 92-78, at 50-51).

Next, Eversource argues that the Attorney General's recommendation to adjust the post-test year information system expense associated with the Supply Chain Project to reflect ESC's capital structure and actual cost of debt provided in Exhibit AG-26-2 should be rejected (Companies Brief at 455). Eversource claims that the cost of debt provided in this exhibit, which provides the actual capitalization for ESC as of December 31, 2016, includes both short-term and long-term debt (Companies Brief at 455). Further, Eversource claims that its actual capitalization reflects the fact that it is structured to provide shared services, and, therefore, the cost of debt and capital structure for ESC fluctuates significantly from month to month based on intercompany charges (Companies Reply Brief at 115).[118]

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[118] On brief, Eversource recreates its capitalization to reflect only the inclusion of long-term debt (Companies Brief at 455-456).

In any event, Eversource claims that neither its actual capitalization as of December 31, 2016, which reflects approximately 40 percent equity, nor its capitalization as of December 31, 2016, exclusive of short-term debt, which results in approximately 82 percent equity, is appropriate for ratemaking purposes (Companies Brief at 457). Rather, Eversource argues that both the capital structure and return on equity approved in this case for the Companies should be used for the computation of NSTAR Electric's and WMECo's revenue requirements associated with the Supply Chain Project (Companies Brief at 457).

Finally, Eversource argues that the Attorney General's recommendation to disallow the Supply Chain Project expense adjustment on grounds that the Companies have not reflected the Aquarion Water Company acquisition is without merit and should be rejected (Companies Brief at 454). Eversource notes that any adjustment to reduce ESC charges is premature and not known and measurable (Companies Brief at 440).

3. Analysis and Findings

As noted above, Eversource seeks to treat the Supply Chain Project as a post-test year adjustment to the Companies' information systems expense (Exhs. ES-DPH-1, at 94, 96; AG-43-2; Tr. 9, at 1830). Rates are designed to allow for recovery of a representative level of a company's revenues and expenses based on a historic test year adjusted for known and measurable changes. D.T.E. 02-24/25, at 161; D.P.U. 92-250, at 106. The selection of the test year is largely a matter of a distribution company's choice, subject to Department review and approval. See D.P.U. 07-50-A at 51; D.P.U. 1720, Interlocutory Order at 7-11 (January 17, 1984).

In the instant case, the Companies did not incur any Supply Chain Project-related costs in the test year (Exh. DPU-45-57; see also ES-DPH-2 (East), Sch. DPH-19 (Rev. 3); ES-DPH-2 (West), Sch. DPH-19 (Rev. 3)). In fact, according to Eversource the costs were not allocated to the Companies until July 3, 2017, the date upon which Eversource claims that the Supply Chain Project was placed in service, and more than a year after the end of the test year (Exh. DPU-45-57; Tr. 9, at 1827; Tr. 15, at 3055, 3058-3059, 3064). Nevertheless, the Companies seek a post-test year adjustment to their costs of service in order to reflect a level of costs that will be incurred in the rate year (Exh. ES-DPH-1, at 96).

Proposed changes to test year revenues, expense, and rate base require a finding that the adjustment constitutes a "known and measurable" change to test year cost of service. See D.P.U. 1580, at 13-17, 19; D.P.U. 84-32, at 17; D.P.U. 136, at 3; D.P.U. 19992, at 2; D.P.U. 18204, at 4; D.P.U. 18210, at 2-3; D.P.U. 18264, at 2-4. A "known" change means that the adjustment must have actually taken place, or that the change will occur based on the record evidence. A "measurable" change means that the amount of the required adjustment must be quantifiable on the record evidence. D.T.E. 98-51, at 62.

In the instant case, Eversource calculated a gross investment base of $36,420,160 based on ESC's actual spending through April 30, 2017 (Exh. ES-LML-8, at 2 (Supp. 2); Tr. 9, at 1830). Eversource calculated an estimated revenue requirement associated with the Supply Chain Project based on the weighted average cost of capital, capital structure, and depreciation expense that it requested in this case (Exh. ES-DPH-1, at 96-97; Tr. 9, at 1830-1831). As noted above, Eversource then used a budgeted service company allocator

to derive the amount of costs it seeks to assign to NSTAR Electric and WMECo (Exh. ES-DPH-1, at 97).

Although Eversource claims that costs were allocated to the Companies following the Supply Chain Project's in service date of July 3, 2017, Eversource has failed to adequately support this representation with sufficient record evidence. In particular, the record contains no billing statements, invoices, or other related documentation to substantiate the actual allocation of costs to the Companies in the amounts claimed by the Eversource. Therefore, the Department cannot determine whether Eversource's proposed adjustments to test year information systems expense represent the level of expense to be incurred by the Companies during the rate year.[119]

Based on these considerations, the Department is not persuaded that Eversource's proposed adjustments to the Companies' information systems expense represent known and measurable changes to the Companies' costs of service. Therefore, the Department declines to accept Eversource's proposed adjustment. Accordingly, we reduce NSTAR Electric's

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[119] The Department acknowledges the Attorney General's arguments regarding Eversource's acquisition of Macquarie, a holding company of Aquarion Water Company of Massachusetts and its subsidiaries in Connecticut and New Hampshire. As noted above in Section VIII.B.3, while the Department has approved Eversource's proposal to acquire Macquarie, Eversource does not plan to integrate Aquarion's operations with the existing Eversource organization following the transaction, and thus does not anticipate allocating any centralized services costs to Aquarion's operations. D.P.U. 17-115, at 66 (November 28, 2017). To the extent that Eversource implements any changes to Aquarion's operations or integrates functions between the two entities, those changes will take place over time and as Eversource becomes familiar with Aquarion's water operations. D.P.U. 17-115, at 66-67. As a result, any future allocation of costs is speculative at this time.

proposed test year cost of service by $1,248,167 and reduce WMECo's proposed test year cost of service by $237,936.

H. GIS Verification Adjustment

1. Introduction

Eversource proposes to include the costs associated with NSTAR Electric's Geographic Information System ("GIS") Verification Project ("GIS Project") as a post-test year adjustment to expense (Exhs. ES-DPH-1, at 103; ES-DPH-2, Sch. DPH-20 (Rev. 3); DPU-22-10; AG-42-14). Eversource explains that its current GIS requires an upgrade in order to, among other things, support any level of grid modernization (Exh. ES-DPH-1, at 98). According to Eversource, the existing GIS was developed using historical paper records mapping the overhead distribution system as it was constructed (Exh. ES-DPH-1, at 98-99). Eversource states that these historical records were created based on system needs and requirements at the time the records were created and, by design, did not capture the level of specificity as to customer connections and other information now necessary to move forward with technological innovation (Exh. ES-DPH-1, at 99). Thus, Eversource states that an upgrade to the data stored in GIS is necessary in order to enable the proposed grid modernization base commitment (see Section X.B below), to enable other non-modernization requirements of the system, and to best utilize the utility's new Outage Management System ("OMS") (Exh. ES-DPH-1, at 99).

Eversource states that the GIS Project involves a comprehensive survey of the system, data collection, and data assembly into a format that can be uploaded into the existing GIS system (Exh. ES-DPH-1, at 99, 103). Thus, on October 20, 2016, Eversource issued a RFP

to four outside contractors and sought cost estimates for completion of this work (Exhs. ES-DPH-1, at 100, 103; DPU-22-14). Eversource received responses from three of the bid recipients (Exhs. ES-DPH-1, at 100, 103; DPU-22-14). On April 27, 2017, Eversource executed a fixed-price contract with Davey Resource Group for a final total cost of $5,956,381 for work to be completed in 2018 (Exhs. ES-DPH-2 (East), Sch. DPH-20 (Rev. 3); AG-19-26; AG-42-17, Att. (c), at 1, 39; Tr. 13, at 2776-2777).

Eversource proposes to treat the GIS Project as a one-time, non-recurring expense, to be amortized over five years (Exhs. ES-DPH-1, at 103; DPU-22-15; AG-42-20). As such, Eversource proposes to include in NSTAR Electric's cost of service an annual amortization expense of $1,191,276 (Exhs. ES-DPH-2 (East), Sch. DPH-20 (Rev. 3)).

2. Positions of the Parties

a. Attorney General

The Attorney General recommends that the Department disallow the costs associated with the GIS Project (Attorney General Brief at 146). The Attorney General argues that this non-recurring expense does not meet the Department's standards for pro forma post-test year adjustments to cost of service (Attorney General Brief at 146). Specifically, the Attorney General contends that the actual costs associated with the proposed adjustment are not known and measurable (Attorney General Brief at 146). To support this assertion, the Attorney General claims that the actual cost of the GIS Project was not known at the time of Eversource's initial filing (Attorney General Brief at 146, citing Exh. AG-19-26). Further, the Attorney General claims that Eversource still was in the technical review stage of the

project during the discovery period of this proceeding (Attorney General Brief at 146-147, citing Exhs. ES-DPH-1, at 103; AG-19-26).

The Attorney General submits that while Eversource did eventually introduce into the record a contract for the GIS Project, the Companies have acknowledged that the contract is subject to regulatory approval (Attorney General Brief at 147, citing Exhs. AG-42-17, Att. (c); AG-50-23; Tr. 13, at 2777). Further, the Attorney General argues that a contract entered into after the test year and before the record closes still does not meet the known and measurable standard, as contracts can be adjusted and conditions of the contract may not be met (Attorney General Reply Brief at 32, citing D.P.U. 15-155, at 277-278 n.199). In this regard, the Attorney General contends that costs associated with the GIS Project are likely to change over time as the work will not be completed until 2018, which is anywhere from one and a half to two and a half years after the end of the test year (Attorney General Brief at 147, citing Tr. 13, at 2776-2777).

In addition, the Attorney General argues that an annual expense of $1,191,276 is not outside the normal ebb and flow of changes in expenses over time for a company the size of NSTAR Electric (Attorney General Brief at 147, citing Dedham Water Company, D.P.U. 1217, at 7-9 (1983); Bay State Gas Company, D.P.U. 1122, at 46-49 (1982)). Finally, the Attorney General asserts that the GIS Project costs only represent approximately 0.04 percent of total Company revenues, and therefore this adjustment does not comply with the Department's standards for a post-test year expense (Attorney General Reply Brief at 34).

For all of the above reasons, the Attorney General cautions against allowing the proposed pro forma adjustment and setting a standard for cost recovery "more akin to a future test[]year" (Attorney General Reply Brief at 32). Thus, she asserts that Eversource's proposal must be rejected and NSTAR Electric's proposed cost of service reduced by $1,191,276 (Attorney General Brief at 147; Attorney General Reply Brief at 34).

b. Cape Light Compact

Cape Light Compact supports the Attorney General's recommendation to reduce NSTAR Electric's proposed cost of service by eliminating the adjustment associated with the GIS Project (Cape Light Compact Brief at 79). Cape Light Compact agrees with the Attorney General's assertion that the costs associated with the GIS Project are not known, and the associated annual expense is not outside the normal ebb and flow of changes in expense over time for a company the size of NSTAR Electric (Cape Light Compact Brief at 79, citing Exh. AG-DJE-1, at 7-8).

c. Companies

According to Eversource, the GIS Project is important for customer satisfaction because it will assist NSTAR Electric in: (1) achieving the capability to quickly identify and respond to customer outages; (2) implementing automated communication with customers affected by outages; and (3) managing the distribution system from both a capacity and voltage perspective (Companies Brief at 224, citing Exh. ES-DPH-1, at 99). Further, Eversource asserts that it has received the lowest possible cost for completing this project through the RFP process (Companies Brief at 224, citing Exh. ES-DPH-1, at 99). In addition, Eversource contends that the executed contract presents a fixed price, which is

known and measurable, and contains a scope of work and monthly milestone schedule (Companies Brief at 467, citing Exh. AG-42-17, Att. (c); Tr. 13, at 2777). Specifically, Eversource claims that the terms of the executed contract demonstrates that the total project cost is $5.95 million, while the annual expense is $1.19 million (Companies Brief at 467, citing Exh. ES-DPH-2 (East), Sch. DPH-20).

In response to the Attorney General's argument that the contract is subject to regulatory approval, Eversource contends that the only approval that is necessary is that of the Department in this proceeding (Companies Brief at 467, citing Exh. ES-DPH-1, at 103). In addition, in response to the Attorney General and Cape Light Compact's argument that the expense is within the ebb and flow of NSTAR Electric's expenditures, Eversource contends that the ratemaking process is intended to develop a representative level of revenue requirement to be collected from customers and, absent exigent circumstances, it is not intended to track and recover costs on a dollar for dollar basis (Companies Brief at 468, citing D.P.U. 14-150, at 45-46; D.P.U. 13-75, at 106; D.P.U. 10-70, at 174; D.P.U. 07-50-A at 51). Further, Eversource asserts that neither the Attorney General nor the Cape Light Compact have provided support or analysis for the assertion that the annual GIS expense is not significant, and, therefore, their argument that the project costs are within the normal ebb and flow of expense does not have merit (Companies Brief at 512).

Finally, Eversource argues that the GIS Project is significant in both nature and expenditure (Companies Reply Brief at 130). In particular, Eversource contends that the GIS Project is critical to the Companies' grid modernization base commitment investments,

including advanced load flow and distribution management system investments, which benefit customers and advance the Commonwealth's energy and environmental policies (Companies Reply Brief at 130, citing Exhs. ES-GMBC-2, at 26; AG-42-15). In addition, Eversource asserts that the approximately $6 million GIS Project cost is a significant investment for NSTAR Electric and therefore merits the Department's approval (Companies Reply Brief at 130).

3. Analysis and Findings

As noted above, Eversource seeks to treat the GIS Project as a one-time, non-recurring expense, to be amortized over five years (Exhs. ES-DPH-1, at 103; DPU-22-15; AG-42-20; Companies Brief at 467-468, 512; Companies Reply Brief at 130). The Attorney General and Cape Light Compact argue that recovery of this particular expense is inappropriate because, among other reasons, Eversource has failed to demonstrate that the costs are known and measurable or extraordinary (Attorney General Brief at 146-147; Attorney General Reply Brief at 34; Cape Light Compact Brief at 79). In this instance, we need not reach the merits of these arguments.

The purpose of the GIS Project is primarily to enable Eversource's proposed grid modernization investments (see, e.g., Exhs. ES-DPH-1, at 99; ES-GMBC-2, at 19, 21, 26, 64; AG-42-15; AG-50-21; NECEC-4-4; Tr. 7, at 1228-1233; Tr. 8, at 1625-1626, 1632-1633, 1649-1650. While we acknowledge that the GIS Project will be used for some important non-grid modernization requirements on the system, such as the OMS and Customer Interface System (Exhs. ES-DPH-1, at 99; AG-42-16, at 2-3; AG-50-22), we

conclude that the GIS Project is so inextricably linked to grid modernization efforts, that the costs associated with the project are more suitable for review as a proposed grid modernization investment. The Companies' proposed grid modernization investments are discussed in Section X.B below.

As noted above, Eversource proposes to include in NSTAR Electric's cost of service an annual amortization expense of $1,191,276 associated with the costs of the GIS Project (Exhs. ES-DPH-2 (East), Sch. DPH-20 (Rev. 3)). Based on our findings above, costs associated with the GIS Project will not be recovered in base distribution rates. Accordingly, the Department reduces NSTAR Electric's proposed cost of service by $1,191,276.

I. Insurance Expense

1. Introduction

The Companies propose increases to test year insurance expense of $158,407 for NSTAR Electric and $22,675 for WMECo associated with insurance policy distributions (Exh. ES-DPH-1, at 42, 45). More specifically, in March 2016, Eversource Energy received a check in the amount of $456,242 from one of its excess general liability insurance carriers, Energy Insurance Mutual ("EIM"), for its portion of a distribution of policyholders' surplus to EIM member companies (Exhs. AG-1-61, Att. (c) at 1; AG-19-13, Att. (o)). Of this amount, $158,407 (34.72 percent of the total surplus) was allocated to NSTAR Electric and $22,675 (4.97 percent of the total surplus) was allocated to WMECo (Exhs. AG-DR-1, at 12; AG-19-13, Att. (o)). The Companies considered these distributions to be non-recurring, and, therefore, removed the distributions from their respective test year costs of service through normalization adjustments (Exhs. ES-DPH-1, at 38; ES-DPH-2 (East), Sch. DPH-12, at 2

(Rev. 3); ES-DPH-2 (West), Sch. DPH 12, at 2 (Rev. 3). These adjustments result in corresponding increases in both test year insurance expense and the level of insurance expense being sought for recovery in this proceeding (Exhs. ES-DPH-2 (East), Sch. DPH-12, at 2 (Rev. 3); ES-DPH-2 (West), Sch. DPH-12, at 2 (Rev. 3)).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the EIM insurance distributions allocated to the Companies are not non-recurring events, and, therefore, the distributions should remain as offsets to test year cost of service and reduce the Companies' proposed rate year insurance expense (Attorney General Brief at 109-111). In particular, the Attorney General notes that EIM has consistently made policy surplus distributions to NSTAR Electric and WMECo in each of the last four years between 2013 and 2016 (Attorney General Brief at 110-111, citing Exh. AG-1-61, Atts. (f), (g); Attorney General Reply Brief at 24-25). Further, she suggests that future policy surplus distributions are likely as EIM experienced substantial growth in its presently existing policy holder surplus from $890 million to $972 million as of March 2016 (Attorney General Brief at 111, citing Exh. AG-19-13, Att. (o)).

In addition, the Attorney General contends that because the Companies' cost of service includes costs associated with its most recent policies provided by EIM, the cost of service also should include surplus payments (Attorney General Reply Brief at 25). Additionally, the Attorney General argues that even if Eversource chooses not to retain EIM going forward, the change in insurance carrier would be in order to obtain "the best available coverage at the best available rate," so it is unclear how the Companies would be harmed by

changing insurers under those circumstances (Attorney General Reply Brief at 26, citing Companies Brief at 437). Rather, according to the Attorney General, any such cost reductions achieved by the Companies after this case would be retained by the Companies until a future rate case, in which case the adjusted test year would be based on the expense associated with the most recent premiums for the actual policies in place, including the EIM policies (Attorney General Reply Brief at 26).

Based on these considerations, the Attorney General asserts that the surplus payments received during the test year should be considered in setting the Companies' revenue requirement (Attorney General Brief at 111; Attorney General Reply Brief at 26). Consequently, the Attorney General recommends that the Department reduce NSTAR Electric's proposed cost of service by $158,407 and reduce WMECo's proposed cost of service by $22,675 (Attorney General Brief at 111; Attorney General Reply Brief at 26).

b. Companies

Eversource argues that the Department should reject the Attorney General's recommendation and accept the Companies' proposal to remove EIM's policy surplus distribution from the revenue requirement (Companies Brief at 436). In support of their position, the Companies contend that the EIM surplus distribution is not a recurring event and any potential future disbursement is not known and measurable (Companies Brief at 436; Companies Reply Brief at 125). The Companies note that for the years 2009 through 2012, EIM did not pay out surpluses (Companies Brief at 436, citing Exhs. DPU-23-17; AG-1-61, Atts. (f), (g)). Further, the Companies argue that there is no guarantee or commitment by

EIM to make future surplus distributions (Companies Brief at 436-437, citing Exh. AG-19-13, Att. (o); Companies Reply Brief at 124). Consequently, the Companies argue that the fact that EIM has paid out surpluses in the past cannot be used as a foundation for including these surplus payments going forward absent any type of commitment from EIM (Companies Brief at 437).[120]

Additionally, the Companies note that they may not retain EIM as their insurance carrier going forward (Companies Brief at 437). The Companies explain that ESC has specific policies and processes in place to manage insurance costs, and annually evaluates all insurance programs and policies with the aid of insurance brokers in order to secure the best available coverage at the best available rate (Companies Brief at 437, citing Exh. ES-DPH-1, at 61).[121] Eversource maintains that, given ESC and the Companies' focus on managing insurance costs, there is the potential that this annual review process could result in a determination to seek coverage from an insurance carrier other than EIM (Companies Brief at 437-438). The Companies state that under the Attorney General's proposal, if it is later

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120 The Companies note that while the Attorney General objects to the inclusion of rate year salary increases for non-union employees in the revenue requirement absent a letter of commitment from Eversource management (see Section VIII.A.2 above), she seeks a reduction to test year insurance expense absent a third-party commitment to disburse insurance surpluses in the future (Companies Brief at 437 n.51, citing Attorney General Brief at 137).

121 Regarding this evaluation, the Companies state that approximately three to four months prior to the renewal date of its insurance program, the Companies' insurance team holds a strategy meeting with Eversource's insurance broker to discuss: (1) the current coverage in place; (2) opportunities for improvement in coverage and upcoming renewal requirements; and (3) strategies for presenting the Companies' risk mitigation requirements to the market in order to optimize the coverage Eversource has in place (Companies Brief at 437, citing Exh. ES-DPH-1, at 62).

determined that EIM will no longer be used as an insurance carrier, the effect of those disbursements would still be embedded in the cost of service, even though the Companies would no longer be eligible to receive surplus distributions (Companies Brief at 438). The Companies argue that to avoid this inequitable result, the Department should disregard the Attorney General's recommendations (Companies Brief at 438).

3. Analysis and Findings

Rates are designed to allow for recovery of a representative level of a company's revenues and expenses based on a historic test year adjusted for known and measurable changes. D.P.U. 10-55, at 276; D.P.U. 09-30, at 218; D.T.E. 02-24/25, at 161; D.P.U. 92-250, at 106. The Department finds that the Companies undertook proper measures to control property and liability insurance expense, and that the test year insurance costs were reasonable (Exh. ES-DPH-3, WP DPH-12 (East); Exh. ES-DPH-3, WP DPH-12 (West)).

The record shows, however, that EIM made policy surplus distributions during the test year and for each of the last four consecutive years (Exh. AG-1-61, Atts. (f), (g)). Given this recent history of payments, we are not persuaded by the Companies' argument that the policy surplus distributions are non-recurring and not known and measurable.[122] Rather, the Department finds that EIM's policy surplus distributions are analogous to those made by Nuclear Electric Insurance Limited ("NEIL"). See D.P.U. 87-260, at 26-36. As a

[122] While we acknowledge that the Companies may, at some point in the future, decide that continued coverage under EIM is no longer compatible with their business needs, much the same can be said for every one of Eversource's insurance carriers.

mutual non-profit carrier, NEIL makes policyholder distributions to recognize a return of a portion of the policy's surplus. The Department has required participants to credit policyholder distributions and other adjustments to customers in a manner approved by the Department. New England Power Company/Montaup Electric Company, D.P.U. 1251, at 10 (1983); Western Massachusetts Electric Company, D.P.U. 990-A at 10 (1982); D.P.U. 990, at 4 (1981); Boston Edison Company, D.P.U. 376-A at 2 (1981); D.P.U. 376, at 15-16 (1980); Western Massachusetts Electric Company, D.P.U. 147-B at 2-3 (1981). The Department has historically treated such credits as an offset against the current NEIL premium for ratemaking purposes because "policyholder distribution is a known and measurable change that should be included as an offset to the Company's current NEIL premiums."[123] D.P.U. 87-260, at 38-39. Consistent with the treatment of NEIL surplus distributions in prior cases, the Department finds that it is appropriate to adjust the Companies' cost of service to recognize the refund of the insurance proceeds from EIM.[124]

Based on the above considerations, the Department will adjust the Companies' cost of service. Accordingly, the Department reduces NSTAR Electric's proposed cost of service by

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123 This ratemaking treatment is similar in concept to patronage refunds associated with CoBank, a lending institution that focuses on water systems, where the refunds serve to reduce the effective cost of the loan. Whitinsville Water Company, D.P.U. 08-33, at 14 (2008).

124 Contrary to Eversource's claim, the Attorney General's argument on EIM distributions is not inconsistent with her argument on rate year non-union salary increases (see n.120 above). EIM policy distributions are governed solely by EIM, and are wholly outside a company's control. In contrast, a company's decision to grant rate year non-union salary increases is entirely within that company's control, so a letter of commitment might be appropriately required.

$158,407, and reduces WMECo's proposed cost of service by $22,675 (Exhs. ES-DPH-1, at 42, 45; ES-DPH-2 (East), Sch. 6, at 4 (Rev. 3); ES-DPH-2 (West), Sch. 6, at 4 (Rev. 3)).

J. Property Tax Expense

1. Introduction

The Department's policy is to base the level of property taxes in the revenue requirement on the most recent property tax bills received from communities in which a company has property. D.P.U. 15-80/D.P.U. 15-81, at 166; D.P.U. 12-25, at 330; D.P.U. 08-35, at 150; D.P.U. 96-50 (Phase I) at 108-109; Colonial Gas Company, D.P.U. 84-94, at 19 (1984). In D.P.U. 15-155, at 214-215, however, the Department stated that it would consider alternative ratemaking proposals to address property tax expense.

In this proceeding, the Companies propose to adopt a new method for determining property tax expense (Exh. ES-DPH-1, at 162). The proposed method focuses on personal property tax and varies based on which valuation method a municipality uses. For municipalities that use the "reproduction cost new less depreciation" ("RCNLD") method[125] for assessing the value of personal property, the Companies propose to continue to use the most recent tax bills to determine property tax expense (Exh. ES-DPH-1, at 167). For

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[125] The RCNLD valuation method applies a cost-inflationary factor to age the property in question, with a 20 percent floor on the value of the asset. See Boston Gas Company v. The Board of Assessors of Boston, Docket Nos. F275055, F275056, at Appellate Tax Board 2009-1232 (December 16, 2009).

municipalities that use the "new book value" ("NBV") valuation method[126] for personal property, the Companies propose to use the most recent Form of Lists ("FOLs"),[127] as well as the most recent tax bills, to determine property tax expense (Exh. ES-DPH-1, at 166). Specifically, the Companies propose to use the value of the personal property identified in the most recent FOLs, along with the real property assessment, mill rate, Community Preservation Act ("CPA") charge, and water/sewer charge from the most recent tax bills, to determine property tax expense in communities that use the NBV valuation method (Exh. ES-DPH-1, at 166).

During the test year, NSTAR Electric booked $87,288,884 and WMECo booked $14,965,006 in property tax expense (Exhs. ES-DPH-2 (East), Sch. DPH-25, at 1 (Rev. 3); ES-DPH-2 (West), Sch. DPH-25, at 1 (Rev. 3)). Using the most recent FOLs for the NBV communities and the most recent tax bills for the RCNLD communities, the Companies propose to increase these amounts by $3,043,683 for NSTAR Electric and $2,477,473 for WMECo (Exhs. ES-DPH-2 (East), Sch. DPH-25, at 1 (Rev. 3); ES-DPH-2 (West), Sch. DPH-25, at 1 (Rev. 3)).

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126 Under the NBV valuation method, personal property valuations are determined by using the net book value of a company's personal property (Exh. ES-DPH-1, at 163).

127 A FOL is a municipality-specific report that identifies the net book value of a taxpayer's assets in a specific community (Exh. ES-DPH-1, at 164-165). In the first quarter of each calendar year, Eversource produces and submits a FOL to each municipality in which the Companies own property (Exh. ES-DPH-1, at 164). The FOL reports the net book value of the assets owned by the Companies in each municipality as of the end of the most recent calendar year (Exh. ES-DPH-1, at 164-165).

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that property tax expense must be based on verifiable and non-controversial evidence (Attorney General Brief at 188-189, citing D.P.U. 12-25, at 329-330). By contrast, the Attorney General argues that the Companies' proposal is unduly complicated and speculative (Attorney General Brief at 188-189).

The Attorney General maintains that the Companies' proposal is similar to a property tax proposal rejected by the Department in D.P.U. 15-155 (Attorney General Brief at 188-189, citing D.P.U. 15-155, at 213-214). Specifically, the Attorney General contends that, in D.P.U. 15-155, at 213-214, the Department rejected as speculative a company's attempt to calculate rate year property tax expense by applying current mill rates to the most recent valuations (Attorney General Brief at 189-190). The Attorney General argues that the Companies' proposed use of potential, future personal property tax valuations in the instant case is similarly speculative and must be rejected (Attorney General Brief at 189-190). Further, the Attorney General contends that the Companies' proposal would allow Eversource to over collect property taxes as it is based on potential, future valuations, while its actual property tax expense is based on lower, past valuations (Attorney General Brief at 189).

b. Companies

The Companies maintain that in D.P.U. 15-155, at 215, the Department invited alternate proposals to address property tax expense (Companies Brief at 495). The Companies argue that their proposal is distinct from the proposal rejected by the Department

in D.P.U. 15-155 because it relies on known and measurable information, not speculation (Companies Brief at 495-497).

According to the Companies, their proposed method is appropriate because, by using the most recent FOLs, the proposal incorporates the most current property tax information available (Companies Brief at 495). That is, the Companies argue that their proposal uses FOLs to compute property tax in exactly the same manner as the NBV communities, specifically using the appropriate municipal tax rate and updating for known and measurable (and documented) personal property valuations (Companies Brief at 495-496, citing Exhs. ES-DPH-1, at 167-173, ES-DPH-7 (East and West); DPU-39-5). Accordingly, the Companies maintain that their proposed use of the latest FOLs to determine property taxes will produce a highly reliable, known and measurable determination of the rate year property tax expense (Companies Brief at 495-497).

3. Analysis and Findings

Historically, the Department has set property tax expense based on the most recent property tax bills that a company has received. D.P.U. 15-80/D.P.U. 15-81, at 166; D.P.U. 12-25, at 330; D.P.U. 08-35, at 150; D.P.U. 96-50 (Phase I) at 108-109; D.P.U. 84-94, at 19. Because they are considered verifiable, non-controversial evidence, the Department holds the record open in a proceeding to receive a utility's most current, post-test year tax bills. D.P.U. 88-67 (Phase I) at 165-166; D.P.U. 84-94, at 19.

For communities that use the RCNLD valuation method, the Companies propose to continue to use the most recent tax bills to determine property tax expense (Exh. ES-DPH-1,

at 167). We find that the Companies' proposal is consistent with Department precedent and results in a known and measurable change to test year property tax expense (Exhs. ES-DPH-7 (East) (Rev. 3); ES-DPH-7 (West) (Rev. 3)).[128] See D.P.U. 15-155, at 213-214; 320 n.237.

Communities that use the NBV valuation method rely on FOLs to determine personal property valuations (Exhs. ES-DPH-1, at 168-172; DPU-39-11). In support of the reasonableness of their proposal to use FOLs to calculate property tax expense in NBV communities, the Companies calculated past property taxes using this method and FOLs from prior years, and compared the results to the actual corresponding tax bills for those years (Exhs. ES-DPH-1, at 168-172; DPU-39-11). After review, the Department finds that use of the most recent FOLs in conjunction with information contained in the most recent tax bills (i.e., real property assessment, mill rate, CPA charge, and water/sewer charge), produces a non-speculative, reliable measure of the Companies' rate year tax expense and satisfies the Department's known and measurable standard. See D.P.U. 12-86, at 243-245; D.P.U. 95-118, at 148. Accordingly, the Department approves the Companies' proposed method to calculate property tax expense for communities that use the NBV valuation method and finds that use of the method in the instant case results in a known and measurable change

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[128] As discussed below in Section XII, Eversource has pending challenges at the Massachusetts Appellate Tax Board concerning communities' use of the RCNLD valuation method and has withheld a portion of the tax assessments pending the outcome of these appeals. The Department has found that when a company has an active appeal related to an abatement request, the most recent tax bill remains the basis for determining property tax expense. D.P.U. 15-155, at 325-326.

to test year property tax expense (Exhs. ES-DPH-7 (East) (Rev. 3); ES-DPH-7 (West) (Rev. 3)).

During the test year, NSTAR Electric booked $87,288,884 and WMECo booked $14,965,006 in property tax expense (Exhs. ES-DPH-2 (East), Sch. DPH-25, at 1 (Rev. 3); ES-DPH-2 (West), Sch. DPH-25, at 1 (Rev. 3)). Based on the methods approved above, the Department approves an adjustment to test year property tax expense of $3,043,683 for NSTAR Electric and $2,477,473 for WMECo, resulting in a final property tax expense of $90,332,567 for NSTAR Electric and $17,442,479 for WMECo (Exhs. ES-DPH-2 (East), Sch. DPH-25, at 1 (Rev. 3); ES-DPH-2 (West), Sch. DPH-25, at 1 (Rev. 3)).

K. Rate Case Expense

1. Introduction

Initially, the Companies estimated that they would incur $2,359,880 in rate case expense for NSTAR Electric and $1,556,395 in rate case expense for WMECo, for a total rate case expense of $3,916,275 (Exhs. ES-DPH-2 (East), Sch. DPH-16; ES-DPH-2 (West), Sch. DPH-16). Based on their final invoices and projected costs to complete the compliance filing, the Companies propose a final rate case expense of $3,126,793 for NSTAR and $1,741,529 for WMECo for a total rate case expense of $4,868,322 (Exhs. ES-DPH-2 (East), Sch. DPH-16 (Rev. 4); ES-DPH-2 (West), Sch. DPH-16 (Rev. 4); AG-4-14, Atts. (a), (b) (Supp. 5)). The Companies' proposed rate case expenses include costs related to legal representation, miscellaneous expenses associated with preparing the rate case (e.g., fees, production costs, and temporary employees), and expert consulting services related to:

(1) the PBR proposal; (2) allocated cost of service; (3) marginal cost of service; (4) depreciation; and (5) cost of capital (Exh. AG-4-10, Atts. (a), (b)).

The Companies propose to normalize the rate case expense over five years (Exhs. ES-DPH-1, at 87; ES-DPH-2 (East), Sch. DPH-16 (Rev. 4); ES-DPH-2 (West), Sch. DPH-16 (Rev. 4)). Normalizing the Companies' proposed rate case expense of $3,126,793 for NSTAR Electric over five years produces an annual expense of $625,359 (Exh. ES-DPH-2 (East), Sch. DPH-16 (Rev. 4)). Normalizing the Companies' proposed rate case expense of $1,741,529 for WMECo over five years produces an annual expense of $348,306 (Exh. ES-DPH-2 (West), Sch. DPH-16 (Rev. 4)).

2. Positions of the Parties

a. Attorney General

i. Introduction

The Attorney General asserts that the Companies have not met their burden to justify full recovery of their rate case expense in this proceeding (Attorney General Brief at 147). Specifically, the Attorney General argues that the Companies should not recover expenses associated with their revised rate design proposal as these expenses were not reasonable and were incurred due to the Companies' imprudence (Attorney General Brief at 148). The Attorney General also submits that the Companies should be limited in their recovery of expenses associated with their PBR consultant and allocated cost of service consultants, on the grounds that the Companies did not select the lowest qualified bidders to perform those studies (Attorney General Brief at 148). Finally, the Attorney General contends that the Companies should not recover expenses associated with work performed by temporary

employees, as she claims that temporary employees were unnecessary given the size of the Companies' full-time workforce and that temporary employees worked on matters beyond this rate case (Attorney General Brief at 148). Each of these arguments is discussed in further detail below.

ii. Rate Design

The Attorney General submits that the Companies should not recover rate case expense associated with the Companies' revised rate design on the grounds that these costs were not reasonable, appropriate, or prudently incurred under the circumstances (Attorney General Brief at 147; Attorney General Reply Brief at 38). In support of her argument, the Attorney General notes that the Companies filed a significantly revised rate design in the middle of this proceeding (Attorney General Brief at 148-149). The Attorney General also maintains that the revised rate design necessitated a new discovery period and additional evidentiary hearings, which she states will cause the Companies and their consultant to incur additional expenses (Attorney General Brief at 149).

The Attorney General attributes these additional expenses to the Companies' own imprudence as the Companies were solely responsible for the development and direction of their rate design (Attorney General Brief at 149-150). In support, the Attorney General asserts that the Companies' revised rate design is an implicit admission that the Companies' initial rate design was unreasonable (Attorney General Reply Brief at 39).

The Attorney General similarly argues that the Companies' decision to file a revised rate design constitutes a failure to contain rate case expense (Attorney General Brief

at 149-150). She asserts that the flaws of the rate design were evident to the public, and therefore the unreasonableness of the initial rate design should have been obvious to the Companies and their consultant (Attorney General Reply Brief at 38). Further, the Attorney General contends that the public hearings were held early enough in the proceeding to give the Companies notice of the inadequacy of their initial rate design with sufficient time to file a revised rate design without triggering a second rate design proceeding (Attorney General Reply Brief at 39).

Finally, the Attorney General asserts that allowing Eversource to recover expenses associated with the revised rate design will set a negative precedent, as the Companies will benefit by recovering costs incurred due to their own imprudence in developing a flawed rate design and their unreasonable delay in filing the revised rate design (Attorney General Brief at 149-150; Attorney General Reply Brief at 38, 40). The Attorney General recommends that the Companies should be responsible for all expenses associated with the revised rate design (Attorney General Brief at 150).

iii. Competitive Bidding Process

The Attorney General contends that the Companies' expenses associated with their PBR consultant and allocated cost of service consultant are excessive (Attorney General Brief at 150). In support, the Attorney General points out that the Companies did not select the lowest bidders to perform these studies (Attorney General Brief at 150). She argues that the lowest bidders had substantial regulatory experience and expert familiarity in their respective fields and asserts that the Companies failed to provide adequate justification for their

selection of higher cost consultants (Attorney General Brief at 151; Attorney General Reply Brief at 40).

The Attorney General additionally argues that the Companies' consultants failed to adequately control costs (Attorney General Reply Brief at 41). In support, the Attorney General maintains that the Companies' consultants had exceeded the budgets in their initial bids even before accounting for their work on evidentiary hearings or on briefs (Attorney General Reply Brief at 41). As a result, the Attorney General recommends that the Companies' recovery of costs associated with their PBR consultant and allocated cost of service consultant should be limited to the budgets proposed by the lowest bidders for those respective studies (Attorney General Brief at 151).

iv. Temporary Employees

Finally, the Attorney General argues that the Companies should not recover expenses associated with their temporary employees, as those costs were not reasonable or incurred exclusively in support of the Companies' rate case (Attorney General Brief at 151-152). As an initial matter, the Attorney General notes that prior petitioners have used very limited, if any, assistance from temporary employees in support of rate cases (Attorney General Brief at 152, citing D.P.U. 15-155, at 228-29; D.P.U. 14-150, at 219-20; D.P.U. 10-55, at 313; D.P.U. 09-39, at 278-79). Moreover, the Attorney General maintains that the Companies have between eleven and 13 full-time employees in their rates and revenue requirements department (Attorney General Brief at 152). She argues that these staffing levels were capable of supporting the Companies' rate case without the need for temporary employees

(Attorney General Brief at 152). For these reasons, the Attorney General argues that the Companies should not recover these expenses (Attorney General Brief at 152).

Additionally, the Attorney General argues that the Companies failed to demonstrate that their temporary employees worked exclusively on the Companies' rate case (Attorney General Brief at 152; Attorney General Reply Brief at 41). In support, the Attorney General asserts that during discovery, the Companies specifically identified seven temporary employees who worked on the Companies' rate case, and described the responsibilities of each temporary employee (Attorney General Brief at 153). The Attorney General notes that the Companies included an eighth temporary employee on invoices provided in support of their rate case expense, but failed to identify this individual during discovery and failed to describe this individual's responsibilities (Attorney General Brief at 153). She argues that this discrepancy demonstrates that the Companies failed to properly document work performed by their temporary employees and calls into question whether the temporary employees worked on matters beyond this rate case (Attorney General Brief at 153). Based on the foregoing, the Attorney General argues that the Companies should not recover expenses associated with their temporary employees (Attorney General Brief at 153).

b. Companies

i. Introduction

Eversource contends that it has met its burden to justify full recovery of rate case expense by demonstrating that the Companies' expenses were reasonably and prudently incurred (Companies Brief at 212, 216). In particular, the Companies state that they followed the Department's requirements by engaging in a competitive request for proposal

("RFP") process for each of its outside service providers (Companies Brief at 212). Further, the Companies state that they evaluated the qualifications, experience and capabilities of each responsive bidder (Companies Brief at 212). The Companies maintain that they selected qualified consultants who provided the necessary services at a reasonable cost as determined by their evaluations of each bidder (Companies Brief at 212, 216). Finally, the Companies assert that the Department should reject the Attorney General's arguments regarding rate design-related expenses, the competitive solicitation process and temporary employees (Companies Brief at 470-479; Companies Reply Brief at 139-141). These arguments are addressed in further detail below.

ii. Rate Design

The Companies assert that they acted prudently, in good faith and consistent with Department precedent in developing their initial rate design proposal. Specifically, the Companies argue that the proposal was designed to further the Department's goals of achieving efficiency and simplicity, while ensuring continuity and fairness between rate classes and corporate earnings stability (Companies Brief at 469, citing D.P.U. 15-155, at 455; D.P.U. 15-80/D.P.U. 15-81, at 294; D.P.U. 13-75, at 330; D.P.U. 12-25, at 444; D.P.U. 10-114, at 341; D.P.U. 09-39, at 401; Companies Reply Brief at 139). The Companies further contend that it was reasonable and prudent to develop a revised rate design proposal in response to concerns raised by the Department, intervenors and the public, and that such a revised approach was consistent with the obligation to provide safe and reliable service at a reasonable cost (Companies Brief at 469-472; Report to the Legislature

Re: Maintenance and Repair Standards for Distribution Systems of Investor-Owned Gas and Electric Distribution Companies, D.P.U. 08-78, at 4 (2009); Incentive Regulation, D.P.U. 94-158, at 3 (1995); Companies Reply Brief at 139).[129] In this regard, Eversource argues that the prudence of the costs related to their revised rate design should be evaluated based on how a reasonable company would have responded to the particular circumstances and whether the Companies' actions were prudent in light of all circumstances that were known or reasonably should have been known (Companies Brief at 471-472, citing D.P.U. 15-155, at 110; D.P.U. 15-80/15-81, at 72-73; D.P.U. 14-150, at 42; D.P.U. 93-60, at 24-25; D.P.U. 85-270, at 22-23; D.P.U. 906, at 165). Applied in this instance, the Companies assert that the decision to develop the revised rate design was reasonable based on what the Companies reasonably knew at the time of development and in light of the extant circumstances (Companies Brief at 471-472; Companies Reply Brief at 139). Accordingly, the Companies argue that the costs were prudently incurred and should be allowed for recovery (Companies Brief at 471-472; Companies Reply Brief at 139).

iii. Competitive Bidding Process

Eversource concedes that its PBR consultant and allocated cost of service consultant were not the lowest bidders; however Eversource argues that it adequately justified its

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[129] Eversource argues that it developed the revised rate design to address specific concerns regarding the initial rate design and its associated bill impacts (Companies Brief at 470). The Companies note that customers raised these concerns over the course of ten public hearings and through written public comments (Companies Brief at 470). The Companies also contend that, based on the subject matter of some information requests posed to the Companies, the Department and intervenors appeared to share these concerns (Companies Brief at 470).

selection of consultants (Companies Brief at 474; Companies Reply Brief at 140-141). In support, the Companies state that the primary objective in the selection process was to select consultants who would provide high-quality services, at a reasonable price, and in a cost-effective manner (Companies Brief at 473, citing Exh. AG-4-6). Regarding the PBR consultant, Eversource states that it evaluated each bidder using specific criteria[130] and selected a consultant who, in the Companies' judgment, combined a reasonable cost for the study with a high level of expertise and experience (Companies Brief at 473-474, citing Exh. DPU-21-3). Similarly, regarding the allocated cost of service study, Eversource asserts that it evaluated each bidder using specific criteria,[131] and selected a consultant who, in the Companies' judgment, provided a high level of technical proficiency at a reasonable cost (Companies Brief at 473, citing Exh. DPU-21-3). Thus, according to the Companies, they

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130 The Companies maintain that they evaluated each bidder based on: (1) overall capability, including corporate experience with similar issues and familiarity with NSTAR Electric, WMECo, and Department precedent; (2) project team capabilities, including qualifications of the proposed staff in the subject matter; (3) technical approaches, including the response to the request for proposal process; (4) proposal quality; (5) pricing, including the proposed price for the work and proposed unit rates, including markup; and (6) commercial review, including commercial impediments and conflicts of interest (Companies Brief at 473-474, citing Exhs. ES-DPH-1, at 85; AG-4-6, Att. (e)).

131 The Companies maintain that they evaluated each bidder based on criteria that were similar to that used to evaluate the PBR consultant: (1) corporate capability, including experience with similar issues, and familiarity with the Companies and the Department; (2) project team capabilities, including qualifications of proposed staff; (3) technical approaches, including proposed innovative approaches and the response to the request for proposals; (4) proposal quality; (5) pricing, including the proposed price for the work and proposed unit rates, including markup; and (6) commercial review, including commercial impediments and conflicts of interest (Companies Brief at 473, citing Exh. ES-DPH-1, at 85).

selected consultants who struck a proper balance between cost considerations, levels of expertise, and technical knowledge necessary to support their rate case (Companies Brief at 474).

In addition to the competitive bidding process, the Companies state that they took affirmative steps to control their rate case expense by, inter alia, carefully scrutinizing invoices and selecting consultants who provided discounted, blended hourly fees and not-to-exceed price caps on services (Companies Brief at 475, citing Exhs. DPU-21-16; AG-4-9; Companies Reply Brief at 141). As a result of these cost control measures, the Companies maintain that they identified billing errors which reduced their rate case expense by approximately $10,000 (Companies Reply Brief at 141, citing Exh. AG-4-10, Atts. (d), (e) (Supp. 1); (a), (b) (Supp. 3); (a), (b) (Supp. 4)). The Companies also maintain that these cost control measures resulted in a credit of $245,000 for services after a consultant exceeded a price cap (Companies Reply Brief at 141, citing Exh. AG-4-10, Atts. (d), (e) (Supp. 1); (a), (b) (Supp. 3); (a), (b) (Supp. 4)).

Based on these considerations, the Companies argue that they adequately justified selecting consultants who were not the lowest responsive bidders, and that they successfully contained their rate case expense by using cost control mechanisms (Companies Brief at 474; Companies Reply Brief at 141). For these reasons, the Companies assert that the Department should reject the Attorney General's recommendations (Companies Brief at 475).

iv. Temporary Employees

The Companies argue that their use of temporary employees was reasonable and appropriate given the complexity and scope of this proceeding (Companies Brief at 475). As an initial matter, the Companies state that the full-time employees in their rates and revenue requirements division are responsible for supporting all of the Companies' regulatory filings before the Department, not just this rate case (Companies Brief at 475-76, citing Exh. AG-47-4, Atts. (a) through (n)). According to the Companies, these responsibilities include developing testimony and analyses to support regulatory filings, as well as preparing responses to information requests issued in Department adjudications (Companies Brief at 476, citing Exh. AG-47-4, Atts. (a) through (n)).

Regarding the rate case, the Companies assert that the amount of work required to support the Companies' filing necessitated using temporary employees (Companies Brief at 476). In support, the Companies note that the filing required "project documentation" covering a twelve-year period for NSTAR Electric and a seven-year period for WMECo (Companies Brief at 476). Collectively, the Companies assert that this work included compiling, summarizing, and producing documents for approximately 3,200 projects and lasted 18 months (Companies Brief at 476). The Companies argue that they did not have adequate staffing levels for this effort, given the responsibilities of the full-time employees in their rates and revenue requirements division in other proceedings (Companies Brief at 476).

In light of these circumstances, the Companies argue that their decision to use temporary employees was reasonable and appropriate (Companies Brief at 476-477).

Eversource also contends that it has demonstrated that the temporary employees worked solely in support the Companies' rate case (Companies Brief at 478, citing Exhs. AG-47-3; AG-47-5). Therefore, the Companies assert that they should recover the costs associated with their temporary employees as part of their rate case expense (Companies Brief at 479).

v. Normalization

The Companies propose to normalize their rate case expense over five years (Exhs. ES-DPH-1, at 87; ES-DPH-2 (East), Sch. DPH-16 (Rev. 3); ES-DPH-2 (West), Sch. DPH-16 (Rev. 3)).[132] The Companies assert that this normalization period is consistent with Department precedent (Companies Brief at 217, citing D.P.U. 15-155, at 244).

In support, the Companies note that the Department has historically determined the proper normalization period for rate case expense by calculating the average length of time between a company's last four rate cases (Companies Brief at 216-217). Using this method, the Companies maintain that eight years is the average period between the last four rate cases for both NSTAR and WMECo (Companies Brief at 216-217, citing Exhs. ES-DPH-4, Sch. DHP-6 (East); ES-DPH-4, Sch. DPH-6 (West)).[133] However, according to Eversource,

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132 Neither the Attorney General nor any other party commented on the Companies' proposed normalization period.

133 The Companies calculated 9,043 days between the last four rate cases for NSTAR Electric (Boston Edison Company, D.P.U. 92-92 (1992); D.P.U. 92-250; D.T.E. 05-85; D.P.U. 17-05), which averages 8.26 years between rate cases, rounded to 8 years (Exh. ES-DPH-4, Sch. DPH-6 (East)). The Companies calculated 9,167 days between the last four rate cases for WMECo (Western Massachusetts Electric Company, D.P.U. 91-290 (1992); Western Massachusetts Electric Company, D.T.E. 06-55 (2006); D.P.U. 10-70; D.P.U. 17-05), which averages 8.37 years, also rounded to eight years (Exh. ES-DPH-4, Sch. DPH-6 (West)).

the Department found in D.P.U. 15-155, at 244, that the Section 94 requirement for electric distribution companies to file rate cases every five years effectively caps the normalization period at five years (Companies Brief at 217). Therefore, the Companies contend that in instances where a normalization period calculated pursuant to Department precedent results in a period greater than five years, the Department instead will impose a five-year normalization period (Companies Brief at 217, citing D.P.U. 15-155, at 244).

3. Analysis and Findings

a. Introduction

The Department allows recovery for rate case expense based on two important considerations. First, the Department permits recovery of rate case expense that has actually been incurred and, thus, is considered known and measurable. D.P.U. 10-114, at 219-220; D.P.U. 07-71, at 99; D.T.E. 05-27, at 157; D.T.E. 98-51, at 61-62. Second, such expenses must be reasonable, appropriate, and prudently incurred. D.P.U. 10-114, at 220; D.P.U. 09-30, at 227; D.P.U. 95-118, at 115-119.

The overall level of rate case expense among utilities has been, and remains, a matter of concern for the Department. D.P.U. 10-114, at 220; D.P.U. 07-71, at 99; D.T.E. 03-40, at 147; D.T.E. 02-24/25, at 192; D.P.U. 93-60, at 145. Rate case expense, like any other expenditure, is an area in which companies must seek to contain costs. D.P.U. 10-114, at 220; D.P.U. 07-71, at 99; D.T.E. 03-40, at 147-148; D.T.E. 02-24/25, at 192; D.P.U. 96-50 (Phase I) at 79. All companies are on notice that the risk of non-recovery of rate case expenses looms should they fail to sustain their burden to demonstrate cost containment associated with their selection and retention of outside service providers.

D.P.U. 10-114, at 220; D.P.U. 09-39, at 289-293; D.P.U. 09-30, at 238-239; D.T.E. 03-40, at 152-154. Further, the Department has found that rate case expenses will not be allowed in cost of service where such expenses are disproportionate to the relief being sought. D.P.U. 10-114, at 220; D.P.U. 10-55, at 323; see also Barnstable Water Company, D.P.U. 93-223-B at 16-17 (1994).

b. Competitive Bidding Process

i. Introduction

The Department has consistently emphasized the importance of competitive bidding for outside services in a petitioner's overall strategy to contain rate case expense. See, e.g., D.P.U. 10-114, at 221; D.P.U. 09-30, at 227; D.T.E. 05-27, at 158-59; D.T.E. 03-40, at 148; D.T.E. 02-24/25, at 192. If a petitioner elects to secure outsider services for rate case expense, it must engage in a competitive bidding process for these services. D.P.U. 10-114, at 221; D.P.U. 09-30, at 227; D.P.U. 07-71, at 99-100, 101; D.T.E. 03-40, at 153. In all but the most unusual of circumstances, it is reasonable to expect that a company can comply with a competitive bidding requirement. D.P.U. 10-55, at 342. The Department fully expects that competitive bidding for outside rate case services, including legal services, will be the norm. D.P.U. 10-55, at 342.

The requirement of having to submit a competitive bid in a structured and organized process serves several important purposes. First, the competitive bidding and qualification process provides an essential, objective benchmark for the reasonableness of the cost of the services sought. D.P.U. 10-114, at 221; D.P.U. 09-30, at 228-229; D.P.U. 07-71, at 101; D.T.E. 03-40, at 152. Second, it keeps even a consultant with a stellar past performance

from taking the relationship with a company for granted. D.P.U. 10-114, at 221; D.P.U. 07-71, at 101; D.T.E. 03-40, at 152. Finally, a competitive solicitation process serves as a means of cost containment for a company. D.T.E. 03-40, at 152-153.

The competitive bidding process must be structured and objective, and based on a request for proposal ("RFP") process that is fair, open, and transparent. D.P.U. 10-114, at 221, 224; D.P.U. 09-30, at 227-228; D.P.U. 07-71, at 99-100; D.T.E. 03-40, at 153. The timing of the RFP process should be appropriate to allow for a suitable field of potential service providers to provide complete bids, and provide the company with sufficient time to evaluate the bids. D.P.U. 10-114, at 221; D.P.U. 10-55, at 342-343. Further, the RFP issued to solicit service providers must clearly identify the scope of work to be performed and the criteria for evaluation. D.P.U. 10-114, at 221-222; D.P.U. 10-55, at 343.

The Department does not seek to substitute its judgment for that of a petitioner in determining which service provider may be best suited to serve the petitioner's interests, and obtaining competitive bids does not mean that a company must necessarily retain the services of the lowest bidder regardless of its qualifications. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153. The need to contain rate case expense, however, should be accorded a high priority in the review of bids received for case work. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153. In seeking recovery of rate case expenses, companies must provide an adequate justification and showing, with contemporaneous documentation, that their choice of outside services is both reasonable and cost-effective. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153.

ii. Companies' Request for Proposal Process

The Companies issued RFPs to retain outside consultants associated with their: (1) depreciation analysis; (2) cost of capital analysis; (3) marginal cost of service analysis; (4) allocated cost of service analysis; (5) legal services; and (6) PBR proposal (Exhs. DPU-21-1; DPU-21-6; AG-4-2). As noted above, the Companies bear the burden of demonstrating that their selections of outside consultants and legal service provider are both reasonable and cost-effective. D.P.U. 10-55, at 343; D.P.U. 09-30, at 230-231; D.T.E. 03-40, at 153.

The Companies initially considered the capabilities of internal staff, including technical expertise, resources, and access to data, prior to soliciting outside consultants (Exh. DPU-21-5). We find that the Companies' decision to retain consultants, rather than using internal staff, to perform these tasks was reasonable given the complexity of the issues and the overall scope of this rate case.

As noted above, as part of their efforts to retain outside consultants, the Companies drafted RFPs for each outside service provider and distributed the RFPs to potential bidders via email and electronic sourcing systems (Exhs. AG-4-3; AG-4-4, at 1). The record demonstrates that each RFP set forth the scope of work to be performed and listed the criteria required for qualification (Exh. AG-4-2, Atts.). The RFPs also outlined the evaluation criteria that Eversource would apply to bidders, such as cost, strength of proposal, familiarity with the Companies' operation, industry experience, approach, depth of understanding, and familiarity with Department precedent (Exh. AG-4-2, Atts). Regarding

price, the RFPs required bidders to include a not-to-exceed price cap for certain phases of the rate case and encouraged responsive bidders to propose alternative fee structures (Exh. AG-4-2, Att. (a) at 3; Att. (b) at 5; Att. (c) at 4; Att. (d) at 5; Att. (e) at 3-4; Att. (f) at 8). The Companies created internal review committees for each RFP to evaluate responsive bids, and in certain instances conducted interviews with responsive bidders (Exhs. ES-DPH-1, at 81-82; AG-4-6).

The Companies issued the RFP for the depreciation analysis to four potential bidders and received three responsive bids (Exhs. DPU-21-1, at 2-3; AG-4-4, at 1-2; AG-4-5, at 1 & Atts. (a) through (c)). The Companies issued the RFP for the cost of capital analysis to five potential bidders and received four responsive bids (Exhs. DPU-21-1, at 3; AG-4-4, at 2-3; AG-4-5, at 1 & Atts. (d) through (g)). Regarding the marginal cost analysis, the Companies issued the RFP to four potential bidders and received one responsive bid (Exhs. DPU-21-1, at 3; AG-4-4, at 3; AG-4-5, at 1 & Att. (h)). Further, the Companies issued the RFP for the allocated cost of service analysis to six potential bidders and received three responsive bids (Exhs. DPU-21-1, at 4; AG-4-4, at 3-4; AG-4-5, at 1-2 & Atts. (i) through (k)). The Companies issued the RFP for the PBR analysis to seven potential bidders and received six responsive bids (Exhs. DPU-21-1, at 5-6; AG-4-4, at 5-6; AG-4-5, at 2 & Atts. (l) through (q)). Finally, the Companies issued the RFP for legal services to five potential bidders and received four responsive bids (Exhs. DPU-21-1, at 4-5; AG-4-4, at 4-5; AG-4-5, at 2 & Atts. (r) through (u)).

The Department has reviewed the bids associated with the six categories of rate case expense for which Eversource conducted a competitive solicitation, as well as the scoring and evaluation material submitted by the Companies and other evidence regarding the selection process, and we have considered the related arguments of the parties (Exhs. DPU-21-1; AG-4-4; AG-4-5 & Atts.; AG-4-6 & Atts.). The Department is satisfied that the selection process was appropriate and that the Companies scored and evaluated the bidders in a reasonable and equitable manner. Further, we find that Eversource gave appropriate weight to the billing structures of the various bidders and any differences among them, considered other important price factors, such as price caps and other cost-containment features, and, also considered important non-price factors, including familiarity with Department precedent and, where relevant, the Companies' operations (Exhs. ES-DHP-1, at 85; AG-4-5 & Atts.; AG-4-6 & Atts.).

Based on these considerations, the Department concludes that the Companies conducted a fair, open, and transparent RFP process to generate bids from outside consultants and that the RFPs clearly identified the scope of work to be performed and the criteria by which the Companies would evaluate responsive bidders. The Department further finds that the Companies' RFP process was adequately structured to allow the Companies to determine the capabilities, approach, and pricing offered by each responsive bidder.

iii. Retention of Specific Consultants

(A) PBR and Allocated Cost of Service Consultants

The Attorney General challenges the Companies' selection of consultants for the PBR consultant and the allocated cost of service consultant on the grounds that the Companies did

not select the lowest bidders (Attorney General Brief at 150-151; Attorney General Reply Brief at 40). The Companies concede that they did not select the lowest cost bidder for these studies, but contend that their selections were adequately justified (Companies Brief at 472-475; Companies Reply Brief at 141).

The Department does not require a company to choose the lowest bidder, provided that the company adequately justifies its decision to do so. See D.P.U. 15-155, at 238-239; D.P.U. 10-114, at 222; D.T.E. 03-40, at 153. While the Department will not substitute its judgment for that of a petitioner in determining which consultant may be best suited to serve the petitioner's interests, the petitioner must demonstrate that its choice is both reasonable and cost-effective. See D.P.U. 10-55, at 342-343.

Regarding the selection of the PBR consultant, the record demonstrates that the Companies interviewed key personnel from responsive bidders (Exh. ES-DPH-1, at 5). The Companies also provided the scoring sheets used in their evaluation of each responsive bidder as contemporaneous documentation of their decision making process (Exh. AG-4-6, Att. (e)). Given the complexity of the PBR issue, we are not persuaded by the Attorney General's suggestion that cost estimates should have been the sole driving factor behind the Companies' decision. Rather, based on our review of the evidence, we find that the Companies appropriately considered non-price factors in selecting their consultant, such as each bidder's level of expertise and overall capabilities (Exh. AG-4-6, Att. (e) at 1-2). Further, we find that the overall costs associated with the PBR consultant are not unreasonable or disproportionate to the overall scope of the work provided (Exhs. AG-4-2, Att. (f); AG-4-10,

Atts. (a), (b), (c) (Supps.)). Based on these considerations, we find that the Companies provided sufficient justification for not selecting the lowest bidder as their PBR consultant, and that the selection of such consultant was reasonable. Moreover, we find that the Companies took appropriate steps to control the costs associated with their PBR consultant, including a not-to-exceed lump sum component for specific portions of this rate case (Exhs. AG-4-5, Att. (n) at 28; AG-4-9). Accordingly, the Department concludes that Eversource's choice of PBR consultant was both reasonable and cost-effective.

Regarding the selection of the allocated cost of service consultant, the Companies interviewed the three responsive bidders (Exh. ES-DPH-1, at 85). The Companies also submitted the scoring sheet used in their evaluation of each responsive bidder as contemporaneous documentation of their decision making process (Exh. AG-4-6, Att. (c)). Our review of the evaluation shows that the Companies reasonably eliminated one bidder based on a lack of experience and eliminated the other bidder based on an unproven technical approach and lack of experience (Exh. AG-4-6, Att. (c) at 2). Further, we find that the costs related to the allocated cost of service consultant are not unreasonable or disproportionate to the overall scope of work provided (Exhs. AG-4-2, Att. (d); AG-4-10, Atts. (a), (b), (d) (Supps.)).

Based on these considerations, we find that the Companies provided sufficient justification for not selecting the lowest bidder as their allocated cost of service consultant, and that the selection of such consultant was reasonable. Moreover, we find that the Companies took appropriate steps to control the costs associated with the allocated cost of

service consultant, including a not-to-exceed lump sum component for specific portions of this rate case (Exhs. AG-4-5, Att. (i) at 36; AG-4-9). Accordingly, the Department concludes that Eversource's choice of allocated cost of service consultant was both reasonable and cost-effective.

(B) Remaining Consultants

Although the Attorney General does not challenge Eversource's retention of depreciation consultant, cost of capital consultant, marginal cost of service consultant, or outside legal services, the Companies bear the burden of demonstrating that their selections were both reasonable and cost-effective. D.P.U. 15-155, at 237-238; D.P.U. 10-55, at 343; D.P.U. 09-30, at 230-231; D.T.E. 03-40, at 153. The record demonstrates that the Companies analyzed responsive bids for each of these outside service categories based on pricing, experience, expertise, and overall capability (Exh. AG-4-6, Atts. (a), (b), (g)).[134] The Companies also submitted scoring sheets for each of these outside service categories as contemporaneous documentation of their decision-making process (Exh. AG-4-6, Atts.).

Based on our review of the bids and the bid evaluation process, we find that Eversource gave proper consideration to price factors, such as cost containment features and price caps, and find that the overall costs associated with its depreciation consultant, cost of

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[134] The Department has previously determined that a company may reasonably select the only responsive bidder to an RFP, provided the competitive solicitation process adequately established an objective benchmark for evaluating the consultant. See D.P.U. 10-114, at 230-231. In this case, the Department finds that the Companies' RFP process established an adequate benchmark for the capabilities, approach, and pricing for the marginal cost analysis, and that the Companies' selection of an outside consultant was reasonable and appropriate.

capital consultant, marginal cost of service consultant and attorneys are not unreasonable or disproportionate to the overall scope of work provided (Exhs. AG-4-2, Atts. (a), (b), (c), (e); AG-4-10, Atts. (a), (b), (e), (f), (g), (h) (Supps.)). Further, we find that Eversource gave proper consideration to non-price factors, such as corporate capability and familiarity with Department ratemaking precedent, and selected consultants who had an understanding of the tasks for which they were requested to bid and who it determined would provide the best combination of cost, expertise, and quality of service (Exhs. AG-4-5, Atts. (c), (e), (h), (i), (n), (u); AG-4-6, Atts.). Accordingly, the Department concludes that Eversource's choice of depreciation consultant, cost of capital consultant, marginal cost of service consultant, and legal services was both reasonable and cost-effective.

c. Various Rate Case Expenses

i. Introduction

The Department has directed companies to provide all invoices for outside rate case services that detail the number of hours billed, the billing rate, and the specific nature of the services performed. D.P.U. 10-114, at 235-236; D.T.E. 03-40, at 157; D.T.E. 02-24/25, at 193-194. These expenses must be reasonable, appropriate, and prudently incurred. D.P.U. 10-114, at 220; D.P.U. 09-30, at 227; D.P.U. 95-118, at 115-119.

ii. Rate Design

The Attorney General argues that costs associated with the Companies' revised rate design were not reasonably incurred, and argues the Department should limit the Companies' recovery to those costs incurred with the Companies' initial rate design. (Attorney General Brief at 147-150; Attorney General Reply Brief at 38-39). The Companies counter that it

was reasonable and prudent to develop a revised rate design proposal in response to concerns raised by the Department, intervenors and the public (Companies Brief at 469-472).

The Department has included consultant expenses as part of a petitioner's litigation expenses and we have declined to link recovery of these expenses to particular outcomes, as this would constitute an unwarranted intrusion into management affairs. D.P.U. 95-118, at 120. Further, we have recognized that imposing the Department's judgment concerning a company's actions during adjudication would have the undesirable effect of chilling management's exercise of its responsibility to vigorously pursue legal rights and remedies in accordance with management's own good faith judgment. See D.P.U. 11-43, at 176; D.P.U. 89-114/90-331/91-80 (Phase One), at 42; Boston Gas Company, D.P.U. 1100, at 107 (1982). As such, the Department typically is reluctant to interfere with management judgment unless shown to be frivolous or in bad faith. D.P.U. 11-43, at 176; D.P.U. 1100, at 103, 106-107, citing Fitchburg Gas and Electric Light Company, D.P.U. 19084, at 41 (1977). However, the Department has long held that a company's rate case expenses must be prudently incurred. D.P.U. 10-114, at 220; D.P.U. 09-30, at 227; D.P.U. 95-118, at 115-119.

In the instant proceeding, the Department finds that the Companies' decision to submit a revised rate design proposal was not frivolous or in bad faith. Rather, we are satisfied that the Companies revised the initial filing in response to meaningful concerns regarding bill impacts and related issues raised by the intervenors and the public throughout the discovery and public hearing phases of this proceeding (see, e.g., Exh. ES-RDP-Rebuttal-1, at 1-2).

Under the circumstances, we find that the Companies' decision to revise the rate design in response to these concerns was prudent and in good faith, and we decline to adopt the Attorney General's recommendation. Furthermore, given the scope of this proceeding and the complex rate design issues involved, we are not persuaded by the Attorney General's argument that the costs were unreasonable (Exh. AG-4-10, Att. (c) (Supps.)).

Nonetheless, the Department acknowledges the Attorney General's concerns about the level of rate case expense. As such, the Department expects that all companies filing base rate proceedings will exercise prudent judgement in submitting initial proposals, so as to avoid subsequent significant modifications that delay or extend the proceedings and/or increase rate case expense. The Department will continue to closely scrutinize the propriety of any such modifications and will deny rate case expense in instances where a petitioner acts in bad faith or imprudently.

iii. Temporary Employees

The Companies seek to recover $551,407 in rate case expense related to work performed by temporary employees in the preparation and support of this rate case, with 85 percent of this expense allocated to NSTAR Electric and 15 percent of this expense allocated to WMECo (Exhs. ES-DPH-3 (East), Sch. 16; ES-DPH-3 (West), Sch. 16; DPU-21-20; AG-4-22; AG-47-3). The Attorney General argues that the Companies should not recover expenses associated with their temporary employees, as those costs were not reasonable or incurred exclusively in support of the Companies' rate case (Attorney General Brief at 151-152). We disagree.

The staffing level of the Companies' rate and revenue requirements division ranged between eleven and 13 employees during the preparation of this rate case (Exhs. AG-47-5; AG-47-6). The Department recognizes that these employees are responsible for supporting all of the Companies' regulatory filings before the Department, including preparation of the Companies' filings, developing testimony and analyses in support those filings, and responding to information requests (Exh. AG-47-7, Atts. (a) through (n)).

Preparation of the Companies' filing began in 2015 and required a substantial amount of work, including the documentation of 3,200 projects, covering a twelve-year period for NSTAR Electric and a seven-year period for WMECo (Exhs. AG-47-3; AG-47-5). Given the level and duration of the work needed to prepare the rate case and the overall responsibilities of the Companies' rate and revenue requirements division, the Companies have demonstrated that it was reasonable to retain additional staffing to prepare the rate case. In addition, with the exception discussed below, the Department finds that the costs were reasonable and sufficiently documented.

The Companies identified seven temporary employees who provided support for the rate case (Exhs. DPU-21-20; AG-47-3; AG-47-4). The Companies produced the seven temporary employees' resumes and qualifications and identified the specific responsibilities, scope of work, and costs for each of these employees (Exhs. AG-47-3; AG-47-5). However, the documents provided by the Companies to support recovery of rate case expense related to temporary employees also included cost information associated with an eighth, previously unidentified, temporary employee (Exh. AG-4-10, Att. (i) (Supps. 2-5)). The Companies

concede that they failed to identify the eighth temporary employee in their discovery responses and further failed to detail the work performed by this individual (Companies Brief at 478 n. 56). As a result, neither the Department nor the intervenors had the opportunity to investigate the scope of work of this temporary employee or the costs associated with this worker. D.P.U. 09-39, at 293-294.

For the reasons discussed above, the Department finds that the Companies have failed to demonstrate that the costs for the eighth temporary employee were reasonable or prudently incurred, and therefore, we will disallow recovery of these costs. The Department calculates the costs for this eighth temporary employee to be $170,894 (Exh. AG-4-10, Att. (i) Supps.)). Based on the Companies' 85/15 percent cost allocation ratio for temporary employees, NSTAR Electric's proposed rate case expense shall be reduced by $145,260, and WMECo's proposed rate case expense shall be reduced by $25,634 (Exh. AG-4-22).

iv. Remaining Expenses

As noted above, the Department has found that the Companies' selection of PBR consultant, allocated cost of service consultant, depreciation consultant, cost of capital consultant, marginal cost of service consultant, and attorneys were reasonable and cost-effective. The Department has reviewed the invoices provided by the Companies that support these costs, and finds that such invoices are properly itemized and the costs are reasonable and prudently incurred (Exh. AG-4-10 & Atts. & Supps.). Accordingly, the Department approves the recovery as rate case expense of all costs associated with these consultants.

d. Fees for Rate Case Completion

In their proposed rate case expense, the Companies have included: $35,000 as a compliance phase flat fee for legal services; $200,000 as a compliance fee for their allocated cost of service study;[135] and $3,000 as a compliance fee regarding the marginal cost of service study (Exhs. AG-4-10, Atts. (a) & (b) (Supp. 5)). These amounts are included in the proposed final rate case expense amount of $4,697,428 (Exh. AG-4-10, Atts. (a) & (b) (Supp. 5)). The Department's long-standing precedent allows only known and measureable changes to test year expenses to be included as adjustments to cost of service. D.P.U. 10-114, at 237; D.T.E. 03-40, at 161; D.T.E. 02-24/25, at 195; D.T.E. 98-51, at 61-62. Proposed adjustments based on projects or estimates are not known and measureable, and recovery of those expenses is not allowed. D.P.U. 10-114, at 237;

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135 According to the Companies, the compliance filing for the allocated cost of service study includes: (1) revision of the allocated cost of service study with a new labor allocator; (2) pre-mitigation rate design and bill impact analyses; (3) preparation of pre-mitigation summaries and mitigation strategies; (4) preparation of mitigation bill impact files; (5) mitigation of rate design and bill impacts; and (6) preparation of all supporting exhibits (Exh. AG-4-10, Att. (d) at 19 (Supp. 5)). Further, Eversource states that if the Department directs the Companies to revise test year billing determinants for net-metering customers, the compliance filing will require revisions of billing determinants for 200 WMECo customers in ten class combinations (Exh. AG-4-10, Att. (d) at 19 (Supp. 5)). To comply with any such directive, the Companies state that the compliance filing will include revisions for: (1) billing determinant mapping files; (2) bill-impact files; (3) cost of service models for rate classes; and (4) consolidation mitigation (Exh. AG-4-10, Att. (d) at 19 (Supp. 5)). Finally, Eversource expects to perform the following tasks during the compliance phase: (1) new calculation of net-metering billing determinant with modifications to billing database and test year mapping; (2) modification of pre-mitigation bill impact files for net-metering customers; (3) revision of allocated cost of service accounting for change net-metering billing determinants; and (4) modification of mitigation bill impact files for net-metering customers. (Exh. AG-4-10, Att. (d) at 19-20 (Supp. 5)).

D.T.E. 03-40, at 161-162; D.T.E. 02-24/25, at 196; D.T.E. 01-56, at 75. The Department does not preclude recovery of fixed fees for completion of compliance filing work in a rate case but the reasonableness of the fixed fees must be supported by sufficient evidence. D.P.U. 10-114, at 237; D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196.

Given an adequate showing of the reasonableness of fixed contracts for services to complete a case after the records closes and briefs are filed, a company may qualify to recover such expenses. D.P.U. 10-114, at 237; D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196. Documented and itemized proof is a prerequisite for recovery. D.P.U. 10-114, at 237; D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196. Assuming that the fixed fee agreement is properly supported, the fact that the consultants and the company have agreed to complete the service for a fixed fee gives the Department a level of confidence in the reasonableness of the level of effort and consequent expenditure to carry the case through to a compliance filing. D.P.U. 10-114, at 237; D.P.U. 10-55, at 338.

The Department has reviewed the Companies' basis for their proposed fixed fee and has determined that this fixed fee is reasonable and supported by sufficient evidence (Exhs. AG-4-10, Atts. (a) & (b) (Supp. 5)). Accordingly, we allow the Companies to recover these costs as part of their rate case expense.

e. Normalization of Rate Case Expense

The Companies propose to normalize the rate case expense over five years, which they claim is consistent with Department precedent (Companies Brief at 217, citing

D.P.U. 15-155, at 244). No other party commented on the Companies' proposed normalization period.

The proper method to calculate a rate case expense adjustment is to determine the rate case expense, normalize the experience of an appropriate period, and then compare it to the test year level to determine the adjustment. D.P.U. 10-55, at 338-339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163; D.T.E. 02-24/25, at 197; D.T.E. 98-51, at 62; D.P.U. 95-40, at 58. The Department's practice is to normalize rate case expense so that a representative annual amount is included in the cost of service. D.P.U. 10-55, at 339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163; D.T.E. 02-24/25, at 191; D.T.E. 01-56, at 77; D.T.E. 98-51, at 53; D.P.U. 96-50 (Phase I), at 77; D.P.U. 1490, at 33. Normalization is not intended to ensure dollar-for-dollar recovery of a particular expense; rather it is intended to include the cost of service as a representative annual level of rate case expense. D.P.U. 10-55, at 339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163-164; D.T.E. 02-24/25, at 191; D.P.U. 96-50 (Phase I) at 77.

In determining the period for normalization for rate case expense, the Department typically looks to the average intervals between the filing dates of a company's last four rate cases. D.P.U. 15-155, at 243; D.P.U. 10-55, at 339; D.P.U. 1490, at 33-34. Applying this method here, the normalization period for NSTAR Electric would be eight years, and the normalization period for WMECo would also be eight years (Exhs. ES-DPH-4, Sch. DPH-6 (East) at 2; ES-DPH-4, Sch. DPH-6 (West), at 2; AG-4-23).

In D.P.U. 15-155, at 244, the Department stated that the requirement in Section 94 for electric distribution companies to file rate cases every five years effectively caps the normalization period at five years. Therefore, in instances where a normalization period calculated pursuant to Department precedent results in a period greater than five years, the Department stated that we would, instead, use a five-year normalization period. D.P.U. 15-155, at 244.

Issues raised in the instant case, however, lead us to refine our findings in D.P.U. 15-155. As the Companies correctly note, Section 94 requires the filing of rate schedules (as compared to "rate cases") no less than every five years, but does not specify that the schedules must be designed to allow for an increase in base rates (Exh. DPU-47-1, at 2). Accordingly, we will not treat the Section 94 requirement to file rate schedules no less than every five years as a de facto five-year cap on the normalization period. Instead, we will consider the filing requirements of Section 94, together with specific facts of the case, to establish a normalization period that is an appropriate basis for determining a representative annual level of rate case expense to include in cost of service.

The issue of rate case normalization period is particularly relevant where companies may seek to adopt PBR plans that have terms longer than five years, as Eversource initially proposed in the instant proceeding (Exh. DPU-24-1).[136] The Department has previously looked to the term of the PBR for guidance in establishing appropriate rate case expense normalization periods. D.P.U. 09-30, at 241; D.P.U. 07-71, at 105; D.T.E. 05-27,

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[136] The Companies noted during discovery that their proposed PBR mechanism was "designed to remain in place over the long-term" (Exh. DPU-24-1).

at 163-164; D.T.E. 03-40, at 163; D.T.E. 01-56, at 77; D.P.U. 96-50 (Phase I) at 78-79. In prior instances, the Department has normalized rate case expense over the term of a PBR, finding that a PBR prevents a company from filing rate cases for a predetermined period. See, e.g., D.P.U. 96-50 (Phase I) at 78-79. As such, we determined that the PBR term provided a more representative basis in establishing a normalization period for rate case expense. D.P.U. 96-50 (Phase I) at 78-79.

As discussed below in Section IX, the Department has approved a PBR for Eversource with a five-year term and a stay-out provision that prevents the Companies from filing a base rate case at any time during those five years. Based on the facts of this case, the Department concludes that a five-year normalization period is an appropriate basis for determining a representative amount of the Companies' rate case expense. NSTAR Electric's and WMECo's rate case expense adjustments are set forth below.

f. Requirement to Control Rate Case Expense

The Department recognizes the extraordinary nature of a base rate proceeding and the associated investment of resources that is required for a petitioner to litigate its case before the Department. This notwithstanding, we again emphasize the Department's concern with the amount of rate case expense associated with rate proceedings and the need for petitioners to control these costs. D.P.U. 14-150, at 224; D.P.U. 11-01/D.P.U. 11-02, at 270; D.P.U. 10-55, at 341; D.P.U. 09-39, at 286; D.P.U. 09-30, at 227; D.P.U. 08-35, at 129; D.P.U. 07-71, at 99; D.T.E. 03-40, at 147; D.T.E. 02-24/25, at 192; D.P.U. 93-60, at 145. Although we no longer require a company to file a specific proposal for shareholders to bear

a portion of rate case expense, the Department's ability to disallow a company's recovery of rate case expense for failure to adhere to our strict requirements concerning competitive bidding, or for failure to pursue other reasonable cost-containment measures, or for failure to properly itemize rate case expense invoices, provides a sufficient incentive for companies to control rate case expense. D.P.U. 15-155, at 245.

Before exercising discretion to disallow recovery of rate case expense, the Department will closely scrutinize company's the RFP process to ensure that it is rigorous and demonstrates that the selected outside consultants are reasonable and costs and cost-effective. D.P.U. 15-155, at 245; D.P.U. 14-150, at 224; D.P.U. 14-120, at 86-87; D.P.U. 11-01/D.P.U. 11-02, at 270; D.P.U. 10-55, at 343. We expect that cost containment provisions to be included in rate case expense and companies to be aggressive in their cost control measures. D.P.U. 15-155, at 245; D.P.U. 14-150, at 226-227; D.P.U. 13-90, at 177-178. We will exercise our discretion to disallow recovery of rate case expense where a company fails to adhere to Department precedent and in instances where the amount of overall rate case expense appears to be excessive or disproportionate to the work performed. See D.P.U. 15-155, at 246; D.P.U. 14-150, at 224; D.P.U. 14-120, at 86-87; D.P.U. 11-01/D.P.U. 11-02, at 270; D.P.U. 10-55, at 343.

As noted above, base rate cases are extraordinary in nature. This particular base rate proceeding, however, was more resource intensive than any recent case before the Department. Eversource filed this proceeding on behalf of two electric distribution companies, and the case involved the investigation of a number of complex issues, including

the Companies' request for corporate consolidation, their PBR and grid modernization base commitment proposals, and their request for rate design consolidation and alignment. There were 14 full party intervenors in this case and seven limited intervenors. The Department conducted 13 public hearings and 19 days of evidentiary hearings. The Companies responded to 242 sets of information requests and 111 record requests issued by various intervenors and the Department. Further, the Companies were required to respond to a number of different arguments raised by the parties on brief. Given these considerations, it stands to reason that the overall level of rate case expense would be higher than what other utilities have incurred in recent base rate proceedings. Nevertheless, we find that Eversource complied with the Department's cost-control mandates in this case, both in terms of competitive bidding and other measures, such as not-to-exceed price caps on portions of each consultant's work, discounted consultant rates, and blended rates, in that these measures reduced the Companies' overall rate case expense (Exhs. AG-4-5, Att. (c) at 6, 16, 17, Att. (e) at 10-11; Att. (h) at 8, 22-23; Att. (i) at 12, 39-44; Att. (n) at 28; Att. (u), at 2-5; AG-4-9;AG-4-10, Atts. (a) & (b) (Supp. 3) & (Supp. 4), Atts. (d) & (e) (Supp.1)). We reach our conclusion based on the specific facts of this case and fully expect companies in future cases to demonstrate that they have taken aggressive measures to control their rate case expenses. Failure to do so will result in the disallowance of all or a portion of rate case expense.

4. Conclusion

The Companies propose a rate case expense of $3,126,793 for NSTAR Electric and a proposed rate case expense of $1,741,529 for WMECo, for a total rate case expense of $4,868,322 (Exhs. ES-DPH-2 (East), Sch. DPH-16 (Rev. 4); ES-DPH-2 (West), Sch. DPH-16 (Rev. 4); AG-4-10, Atts. (a) & (b) (Supp. 5)). The Companies propose to normalize the rate case expense over five years, resulting in an annual expense of $625,359 for NSTAR Electric and an annual expense of $348,306 for WMECo (Exhs. ES-DPH-1, at 87; ES-DPH-2 (East), Sch. DPH-16 (Rev. 4); ES-DPH-2 (West), Sch. DPH-16 (Rev. 4)).

As noted above, the Department has reduced NSTAR Electric's proposed rate case expense by $145,260 for an allowable rate case expense of $2,981,533. Further, we have reduced WMECo's proposed rate case expense by $25,634, for an allowable rate case expense of $1,715,895. The Department also has concluded that the Companies' allowed rate case expense should be normalized over five years. Based on these findings, the Department determines the Companies' correct level of normalized rate case expense is $596,307 for NSTAR Electric and $343,179 for WMECo. Accordingly, the Department reduces NSTAR Electric's proposed cost of service by $29,052 ($625,359 - $596,307) and reduces WMECo's proposed cost of service by $5,127 ($348,306 - $343,179).

L. Amortization of Goodwill

1. Introduction

Eversource has $398,707,477 in remaining acquisition premiums associated with the BEC Energy and Commonwealth Energy System ("ComEnergy") merger ("BEC/ComEnergy

Merger"),[137] which it amortizes annually in the amount of $17,590,044 (Exh. ES-DPH-2 (East), Sch. DPH-24, at 1 (Rev. 3)). During the test year, NSTAR Electric booked $17,590,044 in goodwill amortization (Exh. ES-DPH-3 (East), WP DPH-24, at 4 (Rev. 3)). NSTAR Electric proposes to use its test year amortization expense to determine the revenue requirement in this proceeding (Exhs. ES-DPH-2 (East), Sch. DPH-24, at 1, 4 (Rev. 3); ES-DPH-3 (East), WP DPH-24, at 1 (Rev. 3)).

2. Background

In 1999, the Department approved a rate plan for Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company, and Commonwealth Gas Company (together, "NSTAR Companies") filed in conjunction with the BEC/ComEnergy Merger. D.T.E. 99-19, at 1. The Department also approved the recovery of an acquisition premium along with a 40-year amortization recovery period. See D.T.E. 99-19, at 59.

The Department issued its Order approving the BEC/ComEnergy Merger in July 1999. On November 23, 1999, the NSTAR Companies reported to the Department that the acquisition premium as of September 1, 1999, totaled $477,945,697 (Exh. ES-DPH-4, Sch. DPH-9, at 8). After allocating a portion of the acquisition premium to ComEnergy's unregulated affiliates, the NSTAR Companies allocated the remaining acquisition premium among the regulated affiliates of both BEC Energy and ComEnergy (Exh. DPU-14-1(e) at 8

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[137] Where a utility is purchased at a price above its depreciated original cost, the acquisition premium is the difference between that price and that cost and is recorded as goodwill on the balance sheet. D.P.U. 14-150, at 228 n.134.

(Supp.)). In its allocation process, the NSTAR Companies first increased the value of ComEnergy's unregulated affiliates by $11,881,441, to represent their aggregate fair market values net of tax effects as of August 31, 1999 (i.e., immediately prior to the BEC/ComEnergy Merger), as required by generally accepted accounting principles (Exh. ES-DPH-4, Sch. DPH-9, at 13, 15-18). See also D.T.E. 99-19, at 86-87. The $11,881,441 basis adjustment, as well as $8,676,000 in merger costs, were added to ComEnergy's preliminary common equity balance as of the date of the BEC/ComEnergy Merger (i.e., $439,947,850) to produce a revised common equity balance for ComEnergy as of September 1, 1999, of $460,507,291 (Exh. ES-DPH-4, Sch. DPH-9, at 8). The NSTAR Companies then subtracted the revised common equity balance of $460,507,291 from the $938,452,988 in total consideration paid for ComEnergy to produce an acquisition premium of $477,945,697 (Exh. ES-DPH-4, Sch. DPH-9, at 8).[138] This amount was allocated among the NSTAR Companies based on an equal weighting of the number of customers and distribution revenues, which produced an allocation of $386,874,268 (or 80.97 percent) in acquisition premiums to NSTAR's electric distribution affiliates (see Exh. ES-DPH-4, Sch. DPH-9, at 5, 9).

As part of the year-end close in 1999, the NSTAR Companies reconciled and finalized the goodwill calculation to recognize ComEnergy's actual common equity balance as of the date of the BEC/ComEnergy Merger, as well as $5,992,297 in loss contingencies

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[138] This calculation ensured that $11,881,411 of the total acquisition premium would be attributed to ComEnergy's unregulated operations, and not its regulated companies.

representing change-in-control payments to certain ComEnergy executives (Exhs. ES-DPH-4, Sch. DPH-9, at 13, 20; DPU-34-2, Att. A). The revised goodwill balance of $490,023,538 was reallocated among the NSTAR Companies, producing an allocation of $420,710,605 (or 85.86 percent) to the NSTAR Companies' electric distribution affiliates (Exhs. ES-DPH-3 (East), WP DPH-24, at 4 (Rev. 3); ES-DPH-4, Sch. DPH-9, at 14).

In 2014, the first litigated rate case for the NSTAR Companies after the BEC/ComEnergy Merger, the Department approved a rate increase for NSTAR Gas but questioned the calculation of the basis adjustment to the acquisition premium as applied to each of ComEnergy's unregulated affiliates. D.P.U. 14-150, at 232.[139] The Department did not adjust the calculation, but rather, put NSTAR Gas (and, by inference, Eversource) on notice that the calculation would be a subject of inquiry in NSTAR Gas' next base rate proceeding. D.P.U. 14-50, at 232. In addition, the Department excluded $5,992,297 in loss contingencies from the calculation of the acquisition premium attributable to NSTAR Gas. D.P.U. 14-150, at 232-234. NSTAR Gas filed a motion for reconsideration of the Department's decision, and that motion is still pending. D.P.U. 14-150, NSTAR Gas' Motion for Reconsideration and Clarification at 4-13 (November 19, 2015).[140] However, because the basis adjustment and loss contingency issues raised in D.P.U. 14-150 also affect

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139 See D.P.U. 14-150, at 228-230 for a full procedural background.

140 On the same date, NSTAR Gas filed a separate Motion to Reopen Evidentiary Record to provide documentation related to the goodwill computation.

NSTAR Electric's share of the acquisition premium, the Department finds it appropriate to address our concerns raised in D.P.U. 14-150 in the current proceeding.

3. Companies Proposal

Eversource reports that as of December 31, 2016, it will have recovered $182,283,534 in goodwill amortization, leaving a remaining recoverable balance of $238,427,071 (Exh. ES-DPH-3 (East), WP DPH-24, at 4 (Rev. 3)). Eversource adds to this balance deferred income taxes of $95,847,683 and a tax gross-up of $64,432,723,[141] to produce a total goodwill regulatory asset of $398,707,477 (Exh. ES-DPH-3 (East), WP DPH-24, at 4 (Rev. 3); Tr. 5, at 1023).

Eversource states that the remaining amortization amount of $398,707,477, amortized over the remaining 272 months of the 40-year (or 480-month) amortization period approved in D.T.E. 99-19, results in an annual amortization of $17,590,044 (Exh. ES-DPH-3 (East), WP DPH-24, at 4 (Rev. 3)). During the test year, NSTAR Electric booked $17,590,044 in goodwill amortization (Exh. ES-DPH-3 (East), WP DPH-24, at 4 (Rev. 3)). Therefore, NSTAR Electric proposes to use its test year amortization expense to determine the revenue requirement in this proceeding (Exhs. ES-DPH-3 (East), WP DPH-24, at 1 (Rev. 3); ES-DPH-2 (East), Sch. DPH-24, at 1, 4 (Rev. 3)).

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141 The goodwill amortization is not deductible for federal or Massachusetts income tax purposes. D.P.U. 14-150, at 230 n.137. Therefore, Eversource included a tax gross-up to recognize the appropriate tax treatment of the goodwill amortization and to ensure that NSTAR Electric is able to collect the income tax liability created as a result of the increase in billed revenue necessary to recover the acquisition premium (Exh. ES-DPH-3 (East), WP DPH-24, at 4 (Rev. 3)).

4. Positions of the Parties

Eversource states that the Department approved the actual acquisition premium of $490,023,438, of which approximately $420.7 million was allocated to NSTAR Electric (Companies Brief at 233, citing Exh. ES-DPH-1, at 140-141). Eversource raises two issues regarding the Department's treatment of the acquisition premium in NSTAR Gas' most recent rate case, D.P.U. 14-150. First, Eversource notes that the Department questioned some of the assumptions used by the NSTAR Companies to calculate the basis adjustment used to attribute a portion of the acquisition premium to unregulated affiliates (Companies Brief at 233-234, citing D.P.U. 14-150, at 232). The Companies assert that the Department specifically questioned the NSTAR Companies' decision not to write up the assets of ComEnergy Steam Company ("ComEnergy Steam") (Companies Brief at 233-234, citing D.P.U. 14-150, at 232). Eversource maintains that the absence of ComEnergy Steam from the list of unregulated affiliates provided in D.P.U. 14-150, Exh. AG-6-25(c),[142] did not mean that ComEnergy Steam had no market value, but rather that no adjustment to ComEnergy Steam's book value was warranted (Companies Brief at 234-235, citing Exhs. ES-DPH-1, at 142; ES-DPH-4, Sch. 9, at 8). As such, Eversource contends that it appropriately documented the necessary basis adjustments in D.T.E. 99-19 (Companies Brief at 235).

Second, Eversource argues that the Department erred in excluding the $5,992,297 in loss contingencies when calculating the amount of the acquisition premium in D.P.U. 14-150,

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142 The documents provided in Exhibit AG-6-25(c) of D.P.U. 14-150 were entered into the record of this proceeding as Exhibit ES-DPH-4, Schedule DPH-9.

because these loss contingencies represent costs associated with employment contracts that ComEnergy had in place with three of its officers prior to the BEC/ComEnergy Merger (Companies Brief at 235-236). Eversource maintains that these employment contracts were pre-existing arrangements that were part of the business acquired by NSTAR, and that the payments made under their change-in-control provisions were triggered by the BEC/ComEnergy Merger (Companies Brief at 235). Eversource argues that inclusion of these change-in-control provisions in the goodwill calculation is consistent with the accounting standards that governed the BEC/ComEnergy Merger at that time, Accounting Principles Board Opinion No. 16, Business Combinations ("APB 16"), issued in August 1970, and Statement of Financial Accounting Standards No. 38, "Accounting for Pre-Acquisition Contingencies of Purchased Enterprises" ("SFAS 38"), issued in September 1980 (Companies Brief at 235, citing Exh. ES-DPH-1, at 144).

Based on these considerations, Eversource contends that it has appropriately calculated the acquisition premium and amortization, including the required gross-up for income taxes, and therefore the Department should approve the proposed amortization (Companies Brief at 236).

No other party commented on the Companies' proposed adjustment in this proceeding. Nonetheless, the Department acknowledges the Attorney General's arguments raised in D.P.U. 14-150 regarding the loss contingencies. D.P.U. 14-150, Attorney General's Opposition to the Company's Motion to Reopen the Evidentiary Record and its Motion for Reconsideration and Clarification at 6-8 (December 11, 2015).

5. Analysis and Findings

Eversource seeks to amortize $398,707,477 in remaining acquisition premiums associated with the BEC/ComEnergy Merger, over 272 months, for an annual amortization expense of $17,590,044 (Exh. ES-DPH-2 (East), Sch. DPH-24, at 1 (Rev. 3)). The Department has reviewed Eversource's calculation of the acquisition premium associated with the BEC/ComEnergy Merger and accepts Eversource's proposed amortization expense (Exh. ES-DPH-4, Sch. DPH-9). First, the Department finds that, in determining the basis adjustment to be applied to their nonregulated affiliates, the NSTAR Companies appropriately determined the fair market value of each of ComEnergy's nine unregulated affiliates. Of the nine unregulated affiliates, the values of five affiliates were written up to their fair market value, the value of one affiliate was reduced, and the value of one affiliate was written off entirely (Exh. ES-DPH-4, Sch. DPH-9, at 16-18).[143] The values of Hopkinton LNG and ComEnergy Steam were found to have no change in book value, based on various contracts in effect at that time, and the NSTAR Companies determined that the fair market value of these affiliates was represented by their book value (Exh. ES-DPH-4, Sch. DPH-9, at 18). Based on our review, the Department is now satisfied that the NSTAR Companies appropriately calculated the basis adjustment applied to ComEnergy's unregulated affiliates and we no longer have the concern that we raised in D.P.U. 14-150, at 232.

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143 In the case of Advanced Energy Systems ("AES"), the tangible assets as represented by the MATEP Generating Facility were written up, and long-term debt was restated from $112.5 million to $105.008 million because the market rate for AES' debt was higher at that time than its actual rate (Exhs. ES-DPH-4, Sch. DPH-9, at 17; DPU-14-2; DPU-34-1; Tr. 5, at 1025).

Next, we turn to the inclusion of $5,992,297 in loss contingencies represented by change-in-control payments in the calculation of the acquisition premium. This amount represents anticipated payments to certain ComEnergy employees whose positions would be expected to be affected by a change-in-control of a company, such as would result in a merger or acquisition (Exh. ES-DPH-1, at 143). Change-in-control payment provisions are often found in employment contracts of key employees, and are distinguishable from severance packages that may be offered to employees in a post-merger or post-acquisition setting (Exh. ES-DPH-1, at 143; Tr. 5, at 1029).[144] At the time of the BEC/ComEnergy Merger, the NSTAR Companies estimated that three ComEnergy employees would qualify for change-in-control payments; however, based on the actual number of employees identified with change-of-control agreements and the timing of their exercise of these provisions, the total change-in-control payments ultimately paid out to ComEnergy employees was higher than the $5,992,297 estimate reported earlier by the NSTAR Companies (Exhs. DPU-14-3, Atts. (a), (b), (c); DPU-34-2, Att. (a) at 1; Tr. 5, at 1028-1029). The provisions of APB 16 and SFAS 38, which governed the transaction at that time, provide that these change-in-control payments be included in the goodwill computation (Exh. ES-DPH-1, at 144).

Given that the change in-control payments were made to certain former ComEnergy personnel under provisions of employment contracts that were triggered by the

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144 By way of comparison, 638 employees of the NSTAR Companies elected to take separation packages under a Voluntary Separation Program intended to reduce staffing redundancies in the post-acquisition NSTAR system (RR-DPU-40).

BEC/ComEnergy Merger, the Department finds that these change-in-control payments were appropriately part of the purchase price of ComEnergy. The Department further finds that the $5,992,297 in change-in-control payments was less than the total change-in-control payments ultimately paid out to ComEnergy employees, and thus represents a conservative measure of the actual change-in-control payments made as part of the BEC/ComEnergy Merger (Exhs. DPU-14-3, Atts. (a), (b), (c); DPU-34-2, Att. (a) at 1; Tr. 5, at 1028-1029). Accordingly, the Department approves the inclusion of $5,992,297 in the calculation of the acquisition premium.[145]

The inclusion of these change-in-control payments in the calculation of goodwill produces a total goodwill balance of $490,023,518, of which $420,710,605 is allocated to NSTAR Electric (Exh. ES-DPH-2 (East), Sch. DPH-24, at 4 (Rev. 3)). Based on the current amortization rate, the unamortized goodwill attributable to NSTAR Electric will be $238,427,071 as of the end of 2016 (Exh. ES-DPH-2 (East), Sch. DPH-24, at 4 (Rev. 3)). With the inclusion of an additional $95,847,683 in deferred income taxes and an additional $64,432,473 in associated income taxes, NSTAR Electric's unamortized goodwill and associated income taxes will be $398,707,477 as of the end of 2016 (Exh. ES-DPH-2 (East), Sch. DPH-24, at 4 (Rev. 3)).

The $398,707,477, divided by the remaining amortization period of 272 months as of the effective date of the rates being authorized by this Order, produces an annual

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145 The Department will address the inclusion of the loss contingencies in the calculation of NSTAR Gas' acquisition premium in its Order on NSTAR Gas' motion for reconsideration.

amortization expense of $17,590,044 (Exh. ES-DPH-2 (East), Sch. DPH-24, at 4 (Rev. 3)). Eversource proposed an amortization expense of $17,590,044 (Exh. ES-DPH-2 (East), Sch. DPH-24, at 4 (Rev. 3)). Therefore, the Department accepts Eversource's proposed amortization expense.

M. D.P.U. 10-170 Merger Costs and Savings

1. Introduction

Pursuant to the Merger Settlement in D.P.U. 10-170 (see Section V.A above) Eversource seeks to recover $26.2 million and $4.4 million in merger-related costs for NSTAR Electric and WMECo, respectively, over a ten-year period (Exhs. ES-DPH-3 (East), WP DPH-24, at 3 (Rev. 3); ES-DPH-3 (West), WP DPH-24, at 3 (Rev. 3)). The Companies assert that their merger-related savings for the ten-year amortization period will exceed their total merger-related costs (Exh. ES-DPH-1, at 156-157).

The Merger Settlement allows for the amortization of merger-related costs in the Companies' next rate case filing (Merger Settlement at Art. II (13), (14)). Further, pursuant to the Merger Settlement, Eversource was required to file interim reports on merger integration efforts, as well as a final merger integration report 60 days prior to the filing of the first base rate proceeding following the base rate freeze period provided for as part of the Merger Settlement (Merger Settlement at Art. II (15)). The Companies filed the interim reports, and provided a final merger integration report ("2016 Merger Report") on November 15, 2016 (Exhs. ES-DPH-1, at 153; ES-DPH-4, Sch. DPH-10).

2. Reported Merger-Related Savings and Costs

According to the 2016 Merger Report, the accrued enterprise-wide savings related to the merger through December 31, 2015, amounted to $268.2 million, of which $68.8 million was attributable to NSTAR Electric and $11.4 million to WMECo (Exh. ES-DPH-4, Sch. DPH-10, at 55). During the test year, Eversource experienced $106.2 million in merger savings, of which $27.3 million was attributable to NSTAR Electric and $4.5 million was attributable to WMECo (Exh. ES-DPH-4, Sch. DPH-10, at 56). In total, Eversource forecasts enterprise-wide savings from 2012 through 2022 of $1,158 million, of which $300.4 million would be attributable to NSTAR Electric and $49.9 million would be attributable to WMECo (see Exhs. ES-DPH-1, at 153; ES-DPH-4, Sch. DPU-10, at 54).

On an enterprise-wide basis, Eversource reports that it has incurred $125.9 million in merger-related costs, excluding executive retention and separation payments, through September 30, 2016 (Exh. ES-DPH-4, Sch. DPH-10, at 51, 52). Of these costs, $26.2 million (20.8 percent) was allocated to NSTAR, and $4.4 million (3.51 percent) was allocated to WMECo (Exhs. ES-DPH-1, at 156; ES-DPH-4, Sch. DPH-10, at 54). The Companies report that there were no merger-related costs after December 31, 2015, and state that no additional incremental merger-related costs are anticipated (Exh. ES-DPH-4, Sch. DPH-10, at 51).[146] As such, the Companies anticipate a net savings of $274.2 million

[146] As part of D.P.U. 10-170, the petitioners included a net benefits test, in which merger-related transaction and integration costs were estimated to total approximately $164 million. D.P.U. 10-170-B at 57. The actual total merger related costs incurred through the end of 2015 were $125,953,911, or 77 percent of the initial estimate (Exhs. ES-DPH-4, Sch. DPH-10, at 52; AG-26-4 (Rev.) at 1). The Companies used

for NSTAR Electric and $45.5 million for WMECo, during the ten-year period following the merger (see Exhs. ES-DPH-1, at 153-155; ES-DPH-4, Sch. DPU-10, at 54). [147]

The Companies propose to amortize merger-related costs over a ten-year period (Exh. ES-DPH-1, at 156). Thus, the Companies propose an annual amortization amount of $2,621,089 for NSTAR Electric and $442,096 for WMECo (Exhs. ES-DPH-1, at 156; ES-DPH-3 (East), WP DPH-24, at 3 (Rev. 3); ES-DPH-3 (West), WP DPH-24, at 3 (Rev. 3)).

3. Positions of the Parties

a. Attorney General

The Attorney General did not address the Companies' merger-related costs on brief. Nonetheless, during the proceeding, she stated that $642,920 in costs should be excluded from the calculation of Eversource's merger costs to achieve because these costs are not related to the D.P.U. 10-170 merger (see generally Exhs. AG-DR-1, at 13-16; AG-DR-SR1). Specifically, the Attorney General states that the Department should exclude: (1) $138,946 in costs associated with a cancelled strategic management project that had previously been recorded by Northeast Utilities as construction work in progress; (2) $305,651 in costs associated with a 2011 audit of Northeast Utilities' financial statements; and (3) $198,323 in

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a gross plant allocator to attribute 20.81 percent, or $26,210,885, of the costs to NSTAR and 3.51 percent, or $4,420,961, of the costs to WMECo (Exhs. ES-DPH-3 (East), WP DPH-24, at 3 (Rev. 3); ES-DPH-3 (West), WP DPH-24, at 3 (Rev. 3); AG-26-7, Att.).

147 As reported by Eversource, total net savings enterprise-wide are $1,032.4 million, net of $125.9 million in costs. Total net savings for NSTAR Electric are $274.2 million, net of $26.2 million in costs. Total net savings for WMECo are $45.5 million, net of $4.4 million in costs.

reclassification expenses (Exhs. AG-DR-SR1, at 3, 7-9, citing Exh. ES-DPH-Rebuttal-1, at 4, ES-DPH-Rebuttal-2, at 1, 6, 7, AG-26-4, Att.; AG-DR-Surrebuttal-1). The Attorney General notes that excluding the aforementioned costs results in a $13,379 reduction to NSTAR Electric's amortization expense and a $2,257 reduction to WMECo amortization expense (Exhs. AG-DR-SR1, at 9; AG-DR-Surrebuttal-1).

b. Companies

The Companies argue that they have demonstrated that merger-related savings equal or exceed merger-related costs and, therefore, the Companies are entitled to recover their merger-related costs (Companies Brief at 240). Eversource contends that the net merger-related benefits, as currently forecast, are expected to exceed those initially developed for the net benefits analysis performed for D.P.U. 10-170 (Companies Brief at 237).

The Companies also point out that Eversource has already paid out $46 million of the expected savings to customers as part of the Merger Settlement upon the merger closing, specifically, a $15 million credit to NSTAR Electric's ratepayers and a $3 million credit to WMECo's ratepayers (Companies Brief at 237-238). The Companies further argue that their proposal to amortize the merger-related costs over ten years is consistent with the Merger Settlement and the amortization period approved by the Department for NSTAR Gas in D.P.U. 14-150 (Companies Brief at 239; Companies Reply Brief, App. C at 22).

4. Analysis and Findings

Consistent with Department precedent, the Merger Settlement authorizes the Companies, subject to Department review and approval, to recover merger-related costs upon a showing that merger-related savings equal or exceed those costs (Merger Settlement

at Art. II (14)). See also D.P.U. 14-150, at 130-131; D.P.U. 10-170-B at 59. The Merger Settlement provides that the Companies shall, for ratemaking purposes, amortize merger-related transaction and integration costs over a ten-year period (Merger Settlement at Art. II (13)).

The Companies propose to recover $26.2 million in merger-related costs for NSTAR Electric, and $4.4 million for WMECo, over a ten-year period, or approximately $2.6 million and $0.4 million annually (Exhs. ES-DPH-3 (East), WP DPH-24, at 3 (Rev. 3); ES-DPH-3 (West), WP DPH-24, at 3 (Rev. 3)). The Companies argue that they have demonstrated that merger-related savings for the ten-year amortization period will exceed the total of merger-related costs (Companies Brief at 240).

Of the approximately $30.6 million in merger-related costs, the Attorney General contests $642,920 in expenses, consisting of $503,974 in costs from Northeast Utilities' auditor and $138,946 in consulting costs (Exh. AG-DR-S1, at 3-4, 7-9). The Department has examined the supporting documentation relative to these expenditures (Exhs. ES-DPH-Rebuttal-2, at 1-14; AG-26-4, at 23). The $503,974 in auditing costs consist of an invoice for $305,651 associated with Northeast Utilities' 2011 audit, and a journal entry of $198,323 reported to be associated with merger-related auditing services (Exh. ES-DPH-Rebuttal-2, at 1, 7). The $305,651 invoice consists of $290,000 in auditing fees plus $20,116 in expenses, less $14,486 in expenses allocated to NSTAR Electric, with the net expense of $295,630 grossed up for income taxes to $305,651 (Exh. DPH-Rebuttal-2, at 1). It is unclear from the evidence provided by the Companies whether the $290,000 in

fees is associated solely with the merger, or whether this represents WMECo's own audit expense. Therefore, based on the descriptions provided by Eversource, the Department is not persuaded that the $305,651 invoice is associated solely with the merger. As to the $198,323 journal entry, while it appears that some of the supporting documentation was not provided, the Department is satisfied that this expenditure was related to the merger.

The remaining $138,946 in contested expenses consist of consulting costs associated with a strategic management program that had been cancelled and written off by WMECo's parent company in 2012 (Exh. ES-DPH-Rebuttal-2, at 6). In the absence of further evidence as to the nature of this program, the Department is not persuaded that the underlying costs are appropriately associated with the merger. Therefore, the Department removes the $138,946 in consulting costs from the overall level of recoverable merger costs.

Based on the foregoing analysis, the Department has excluded a total of $444,597 in costs from the recoverable level of merger costs. Because Eversource had proposed a total merger cost of $125,953,317 (Exhs. ES-DPH-3 (East), WP DPH-24, at 3 (Rev. 3); ES-DPH-3 (West), WP DPH-24, at 3 (Rev. 3)), the Department finds that the level of recoverable merger costs is $125,508,720. Of this amount, 20.81 percent, or $26,118,365, is allocable to NSTAR Electric, and 3.51 percent, or $4,405,356, is allocable to WMECo.

The Department finds that the Companies' allocated share of merger-related costs is approximately $30,523,721 (see Exhs. ES-DPH-3 (East), WP DPH-24, at 3 (Rev. 3); ES-DPH-3 (West), WP DPH-24, at 3 (Rev. 3); AG-26-7 (Att.)). Accordingly, in order to

recover these costs, the Companies must show merger-related savings in excess of $30.5 million.

The Department has examined Eversource's calculations and assumptions and finds that the Companies have demonstrated that their merger-related savings exceed their merger-related costs (Exhs. ES-DPH-4, Sch. 10; AG-26-4 through AG-26-14 & Atts.; AG-29-1 through AG-29-27 & Atts.). The Companies calculated that their net savings, over the ten-year period following the merger, are expected to be $274.2 million for NSTAR Electric and $45.5 million for WMECo (see Exhs. ES-DPH-1, at 153; ES-DPH-4, Sch. DPU-10, at 54).[148] For NSTAR Electric, the annualized savings over the ten-year amortization period were calculated as $27.3 million, compared to an amortized annual cost of $2.6 million, resulting in an annual net benefit of $24.7 million (Exhs. ES-DPH-1, at 155; ES-DPH-4, Sch. DPH-10, at 56). For WMECo, the annualized savings was calculated to be $4.5 million, compared to an amortized annual cost of $0.4 million, resulting in an annual net benefit of $4.1 million ((Exhs. ES-DPH-1, at 155; ES-DPH-4, Sch. DPH-10, at 56). Even with the above disallowances, the Department finds that the Companies have demonstrated that their merger-related savings will exceed their merger-related costs. Therefore, consistent with the terms of the Merger Settlement, the Department finds that the Companies are eligible to recover $30,523,721 in merger-related costs over a ten-year period (see Merger Settlement at Art. II (13)). See also D.P.U. 14-150, at 130-131; D.P.U. 10-170-B, at 59. Based on the recoverable level of merger-related costs and the

[148] No party contested the savings calculations contained in the 2016 Merger Report.

ten-year amortization period established under the terms of the Merger Settlement, NSTAR Electric's annual amortization is $2,611,837, and WMECo's annual amortization is $440,536.

NSTAR Electric had proposed an amortization expense of $2,621,089, and WMECo had proposed an amortization expense of $442,096 (Exhs. ES-DPH-3 (East), WP DPH-24, at 3 (Rev. 3); ES-DPH-3 (West), WP DPH-24, at 3 (Rev. 3)). Accordingly, the Department reduces NSTAR Electric's proposed cost of service by $9,252, and reduces WMECo's proposed cost of service by $1,560 (see Exhs. ES-DPH-1, at 156; ES-DPH-3 (East), WP DPH-24, at 3 (Rev. 3); ES-DPH-3 (West), WP DPH-24, at 3 (Rev. 3)).

N. Amortization of Hardship Accounts

1. Introduction

Hardship protected accounts are residential accounts that are protected from shut-off by the utility for nonpayment. 220 CMR 25.03, 25.05. To qualify for protected status from service termination, customers must demonstrate that they have a financial hardship and meet certain other requirements, such as a household member suffering from a serious illness or residing with a child under twelve months of age. See 220 CMR 25.03(1), 25.03(3), 25.05(3).[149] All qualified accounts are protected from shut-off for nonpayment year round,

[149] An account qualifies for protected status where the customer certifies that the customer has a financial hardship, and: (1)a person residing in the household is seriously ill; (2) a child under the age of twelve months resides in the household; (3) the customer takes heating service between the period November 15th and March 15th, and the service has not been shut off for nonpayment prior to November 15th; or (4) all adults residing in the household are age 65 or older and a minor resides in the household. 220 CMR 25.03. Customers who are unable to pay an overdue bill and meet the income eligibility requirements for the Federal

except for heating customers with a financial hardship. These heating accounts are protected from shut-off for nonpayment only during the winter moratorium period (i.e., November 15th through March 15th). 220 CMR 25.03(1)(a)(3), 25.03(1)(b).

The Companies state that because hardship protected accounts cannot be disconnected, the accounts remain active and continue to receive service despite slow or non-payment of amounts due (Exh. ES-DPH-1, at 149). Further, the Companies note that as the accounts stay active, they do not become part of the write-off calculation to be included for recovery from customers (Exh. ES-DPH-1, at 149).

According to Eversource, NSTAR Electric's total active protected hardships accounts receivable balance overdue for payment more than 360 days was $19,162,406 as of June 30, 2016, the end of the test year (Exh. ES-DPH-3 (East), WP DPH-24, at 2 (Rev. 3)). The Companies propose to amortize the $19,162,406 hardship balance over a five-year period, which results in an annual amortization expense of $3,832,481 (Exhs. ES-DPH-2 (East), Sch. DPH-24 (Rev. 3); ES-DPH-3 (East), WP DPH-24, at 1 (Rev. 3)).

Additionally, the Companies state that WMECo's total active protected hardships accounts receivable balance overdue 360 days was $4,337,928 as of June 30, 2016 (Exh. ES-DPH-3 (West), WP DPH-24, at 2 (Rev. 3)). The Companies propose to amortize the $4,337,928 hardship balance over a five-year period, which results in an annual amortization expense of $867,586 (Exhs. ES-DPH-2 (West), Sch. DPH-24 (Rev. 3); ES-DPH-3 (West), WP DPH-24, at 1 (Rev. 3)).

Low-Income Home Energy Assistance Program are deemed to have a financial hardship. 220 CMR 25.01(2).

2. Positions of the Parties

Eversource argues that its proposed treatment of hardship balances is consistent with Department precedent, in particular the treatment afforded to WMECo in its last base rate proceeding (Companies Brief at 191-192, citing D.P.U. 10-70, at 214-216). Therefore, the Companies assert that the Department should approve the proposed amortizations (Companies Brief at 192). No other party commented on the proposed amortization of the balance of hardship protected accounts.

3. Analysis and Findings

Under current ratemaking practice, there is no cost of service mechanism for the Company to recover the balance of protected hardship accounts receivable. See D.P.U. 15-155, at 249; D.P.U. 14-150, at 236; D.P.U. 10-70, at 210-211, n.12. Unlike expenses that may be deferred for recovery in a subsequent rate case, the balance of protected hardship accounts receivable cannot be recovered in rates unless the asset is deemed impaired and written off. D.P.U. 15-155, at 249; D.P.U. 14-150, at 236; D.P.U. 10-70, at 210-211, n.12. Because a utility's hardship protected accounts remain active, the utility cannot write off the unpaid balance and, therefore, cannot recover the amounts as bad debt expense. D.P.U. 15-155, at 249-250; D.P.U. 14-150, at 235-236; D.P.U. 15-80/D.P.U. 15-81, at 169; D.P.U. 13-90, at 159; D.P.U. 10-70, at 213. Generally accepted accounting principles require that, without probable recovery of outstanding balances, a company must recognize an impairment loss through a charge to its

income statement and establish a reserve account on its balance sheet for the impaired asset. D.P.U. 15-155, at 250; D.P.U. 10-70, at 214-215.[150]

To provide for the probability of recovery and to avoid an impairment loss, the Department has permitted utilities to collect through distribution rates an amortized amount of significant protected hardship account receivables balances that are over 360 days past due. D.P.U. 15-155, at 249-250; D.P.U. 14-150, at 236; D.P.U. 15-80/D.P.U. 15-81, at 171; D.P.U. 14-150, at 236; D.P.U. 13-90, at 166; D.P.U. 10-70, at 219. Where such ratemaking treatment has been allowed, the Department requires companies to provide, in subsequent rate cases, information regarding collection efforts relative to outstanding hardship account balances recovered through Department-approved amortizations as well as the average annual amount of payments made by customers against these hardship account balances. D.P.U. 15-155, at 252.

WMECo was permitted to amortize and recover its outstanding hardship account balances over 360 days past due in D.P.U. 10-70. Consistent with the Department's directives in D.P.U. 10-70, at 220, the Department finds that WMECo has tracked the costs included in the balance of hardship protected accounts allowed for recovery and removed them from the bad debt expense (Exh. ES-DPH-2, Schs. DPH-6, at 4, DPH-8, at 2 (West)). Further, we find that, consistent with the Department's directives in D.P.U. 15-155, at 252, WMECo has provided information regarding its collection efforts relative to outstanding hardship account balances recovered through amortization since its last base rate case, as well

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150 See Statement of Financial Accounting Standards No. 144.

as the average annual amount of payments made by customers against these hardship account balances (Exh. DPU-28-11). The Department has reviewed WMECo's collection efforts, and we find them to be reasonable (Exh. DPU-28-11). In addition, consistent with D.P.U. 15-155, at 252, and D.P.U. 10-70, at 221, WMECo has credited through the Residential Assistance Adjustment Factor ("RAAF") payments made by customers toward the hardship balances since its last rate case and through the test year in this case (Exhs. ES-DPH-1, at 149; AG-51-10 & Att.).

Although NSTAR Electric has not previously sought to amortize and recover outstanding hardship balances, it has separately tracked hardship balances since the Department's decision in D.P.U. 14-150 in order to remove these costs from bad debt expense (Exhs. ES-DPH-1, at 39; ES-DPH-2, Schs. DPH-6, at 4, DPH-8, at 2 (East); DPU-28-4; DPU-28-5; DPU-28-12, at 1; AG-19-13 & Att. (g)).[151] Further, NSTAR Electric has provided information regarding its collection efforts relative to outstanding hardship account balances and customer payments toward those balances since the end of 2015 (Exh. DPU-28-12, at 2). The Department has reviewed NSTAR Electric's collection efforts, and we find them to be reasonable (Exh. DPU-28-12, at 2).

Eversource has demonstrated that both NSTAR Electric and WMECo have significant protected hardship account receivables balances that are over 360 days past due (Exhs. ES-DPH-1, at 146-150; ES-DPH-2 (East), Sch. DPH-24 (Rev. 3); ES-DPH-3 (East),

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151 NSTAR Electric notes that it began tracking hardship account balances and customer payments toward the balances after the Department's decision in D.P.U. 14-150 (Exhs. DPU-28-5; DPU-28-12, at 1).

WP DPH-24, at 1-2 (Rev. 3); ES-DPH-2 (West), Sch. DPH-24 (Rev. 3); ES-DPH-3 (West), WP DPH-24, at 1-2 (Rev. 3); DPU-28-7, Att.). To provide for the probability of recovery of these amounts in order to avoid an impairment loss, the Department will allow NSTAR Electric to recover its test year balance of protected hardship accounts receivable in the amount of $19,162,406, and WMECo to recover its test year balance of protected hardship accounts receivable in the amount of $4,337,928 (Exhs. ES-DPH-1, at 147; ES-DPH-3 (East), WP DPH-24, at 2 (Rev. 3); ES-DPH-3 (West), WP DPH-24, at 2 (Rev. 3)).

As noted above, the Companies proposed to amortize recovery of these balances over five years (Exhs. ES-DPH-1, at 147; ES-DPH-3 (East), WP DPH-24, at 1 (Rev. 3); Exh. ES-DPH-3 (West), WP DPH-24, at 1 (Rev. 3)). Amortization periods are determined based on a case-by-case review of the evidence and underlying evidence. Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 99 (2009); D.P.U. 93-223-B at 14; D.P.U. 84-145-A at 54. In this case, we consider the size of the balance to be recovered, the underlying facts giving rise to the accumulation of the balance, and the impact of recovery on ratepayers. Based on these considerations and the record in this case, the Department finds that five years is an appropriate amortization period. Amortizing $19,162,406 over five years produces an annual expense of $3,832,481 for NSTAR Electric (Exh. ES-DPH-3 (East), WP DPH-24, at 1 (Rev. 3). Amortizing $4,337,928 over five years produces an annual expense of $867,586 for WMECo (Exh. ES-DPH-3 (East), WP DPH-24, at 1 (Rev. 3)).

Going forward, Eversource shall continue to track the costs included in the balance of the Companies' hardship accounts allowed for recovery so that these costs are properly removed from bad debt expense. D.P.U. 10-70, at 221. Further, in its next rate case, Eversource shall provide information regarding the Companies' collection efforts relative to outstanding hardship account balances recovered through amortization since the end of the test year in this case. D.P.U. 15-155, at 252. In addition, WMECo shall credit through its RAAF any payments made by customers towards the outstanding hardship account balances recovered through the amortizations approved in the instant case. D.P.U. 15-155, at 252; D.P.U. 10-70, at 221. Finally, beginning on January 1, 2018, NSTAR Electric shall credit through its RAAF any payments made by customers towards the outstanding hardship account balances recovered through the amortizations approved in the instant case. D.P.U. 15-155, at 252; D.P.U. 10-70, at 221.[152]

O. Regulatory Assessments

1. Introduction

Eversource included in its base distribution cost of service the test year amount of regulatory assessments, adjusted to remove transmission-related expenses and out-of-period adjustments, as follows: (1) $7,389,986 for NSTAR Electric;[153] and (2) $1,267,327 for

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152 NSTAR Electric shall modify its Residential Assistance Adjustment Clause tariff accordingly.

153 This amount is comprised of the following three invoices received by NSTAR Electric during the test year: (1) the Attorney General's assessment of $841,804; (2) the Department's general assessment $4,321,231; and (3) the Department's Energy Trust Fund assessment of $2,226,951 (Exh. ES-DPH-2 (East), Sch. DPH-17 (Rev. 3)).

WMECo[154] (Exhs. ES-DPH-2 (East), Sch. DPH-17 (Rev. 3); ES-DPH-2 (West), Sch. DPH-17 (Rev. 3)). Eversource proposes to reduce NSTAR Electric's adjusted test year amount of regulatory assessments by $2,409,292 and to reduce WMECo's adjusted test year amount of regulatory assessments by $413,176, and it proposes to allocate these amounts from base distribution to basic service (see Exhs. ES-DPH-1, at 90-91; ES-DPH-2 (East), Sch. DPH-17 (Rev. 3); ES-DPH-2 (West), Sch. DPH-17 (Rev. 3)). Eversource determined the amount of regulatory assessments to assign to basic service based on the percentage of 2015 basic service revenues that are in 2015 total intrastate operating revenues, which calculates as 32.6 percent, and rounded up to 33 percent (Exhs. ES-DPH-1, at 91; ES-DPH-2 (East), Sch. DPH-17 (Rev. 3); ES-DPH-2 (West), Sch. DPH-17 (Rev. 3)).[155] Eversource also proposes that, for rates effective January 1, 2018, it will update the amount of regulatory assessments assigned to basic service based on the 2017 basic service revenues and 2017 intrastate operating revenues, as these amounts are expected to be known and measurable by the close of the record in this case (Exh. ES-DPH-1, at 91).[156]

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154 This amount is comprised of the following three invoices received by WMECo during the test year: (1) the Attorney General's assessment of $144,363; (2) the Department's general assessment of $741,059; and (3) the Department's Energy Trust Fund assessment of $381,905 (Exh. ES-DPH-2 (West), Sch. DPH-7 (Rev. 3)).

155 Eversource states that 2015 total intrastate operating revenues represent the most recent full year available (Exh. ES-DPH-1, at 91).

156 Eversource notes that regulatory assessments levied by the Department are annually allocated to each electric and gas company based on each company's proportionate share of total intrastate operating revenues, which include distribution revenues, and revenues from various reconciling rate mechanisms (Exh. ES-DPH-1, at 90).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that Eversource's proposal should be rejected, as it is neither fair nor consistent with cost causation principles (Attorney General Brief at 144). Specifically, she contends that singling out basic service customers for a rate increase based on the revenues they generate rather than the cost of serving their rate classes is arbitrary and unfair (Attorney General Brief at 144). The Attorney General claims that Eversource provided no evidence that 33 percent of the Attorney General's work or the Department's work, as represented by these assessments, is devoted to basic service matters (Attorney General Brief at 144). Moreover, she contends that Eversource's proposal "falsely assume[s]" that customers on competitive supply require absolutely no Department resources, when, she claims, those customers require significantly more resources than basic service customers (Attorney General Brief at 144-145).[157] For these reasons, the Attorney General

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[157] For instance, the Attorney General argues that the Department licenses all competitive supply companies in the Commonwealth and plays a significant role in their oversight (Attorney General Brief at 145, citing G.L. c. 164, §§ 1F, 102C(b); 220 CMR 11.05, 11.07; Interim Guidelines for Competitive Supply Investigations and Proceedings, D.P.U. 16-156-A (July 6, 2017). Further, she contends that the Department gathers data and maintains a website to compile the competitive supplier offers to retail customers, which she claims requires significant resources (Attorney General Brief at 144, citing Energy Switch Massachusetts, http://www.energyswitchma.gov). In addition, the Attorney General notes that the Department receives complaints regarding competitive suppliers from town officials and customer complaints through its consumer division, and she claims that these complaints requires significant Department resources (Attorney General Brief at 145, citing Initiatives to Improve the Retail Electric Competitive Supply Market, D.P.U. 14-140, Vote and Order Opening Investigation, at 3, 12 (December 11, 2014). Finally, she states that the Department adjudicates an increasing number of dockets concerning municipal aggregation plans (Attorney General Brief at 145, citing Town of Easton, D.P.U. 17-109 (June 30,

asserts that Eversource's proposal should be rejected, and that the Department should order the Companies to continue to allocate all regulatory assessment costs to all base distribution customers and to recover the costs through base distribution rates from all customers, using the general allocators that the Department "normally uses" (Attorney General Brief at 145-146).

b. Companies

Eversource argues that the Attorney General's contention that the Companies' proposal is unfair and inconsistent with cost causation principles is flawed (Companies Brief at 465). According to Eversource, the Attorney General fails to support with evidence or analysis her claims regarding the level of resources devoted by the Department to basic service (Companies Brief at 465). Similarly, Eversource contends that the Attorney General fails to rebut the Companies' calculations that support its allocation proposal (Companies Brief at 465, citing Exhs. ES-DPH-1, at 90-91; ES-DPH-2 (East), Sch. DPH-17 (Rev. 3); ES-DPH-2 (West), Sch. DPH-17 (Rev. 3). Eversource asserts that as a result of the Attorney General's failure to provide any support for her assertions, the Department should disregard her recommendation (Companies Brief at 466). Finally, Eversource states that competitive suppliers should be paying regulatory assessments in light of the resources expended by the Department on these suppliers and their customers (Companies Brief at 466, citing Exh. DPU-33-8). However, the Companies note that there currently exists no

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2017); City of Marlborough, D.P.U. 17-47 (April 20, 2017); Town of Billerica, D.P.U. 17-44 (April 20, 2017).

opportunity to charge such assessments to competitive suppliers (Companies Brief at 466, citing G.L. c. 24A, § 3).

3. Analysis and Findings

In general, a company's share of assessments made by the Department and other agencies is recognized as a component of its cost of service. D.P.U. 12-86, at 154-155; D.P.U. 85-137, at 83-85; South Egremont Water Company, D.P.U. 95-119/95-122, at 18 (1996); Westport Harbor Aqueduct Company, D.P.U. 93-142, at 6 (1993); Boston Edison Company, D.P.U. 160, at 48-49 (1980). The amount of assessments included in a company's cost of service must be known and measurable. D.P.U. 85-137, at 84-85; D.P.U. 95-119/95-122, at 18; D.P.U. 160, at 49.

Eversource included three regulatory assessments in its test-year amount. First, an annual assessment is made by the Commonwealth's Office of Consumer Affairs and Business Regulation on behalf of the Attorney General that is levied against each electric, water, gas, telephone, and telegraph company based on each company's proportionate share of total intrastate operating revenues. G.L. c. 24A, § 3. Second, the Department makes an annual general assessment against electric and gas companies under its jurisdictional control for the operation and general administration of the Department. G.L. c. 25, § 18. The general assessment is allocated based on each electric company's and gas company's proportionate share of total intrastate operating revenues. G.L. c. 25, § 18. Third, the Department makes an annual assessment to electric companies under its jurisdictional control that is credited to the Department's Energy Trust Fund and provides the Department with additional operating

funds for the regulation of electric companies. G.L. c. 25, § 18. The Energy Trust Fund assessment is allocated based on each electric company's proportionate share of total intrastate operating revenues. G.L. c. 25, § 18.[158] As an initial matter, we find that Eversource has properly calculated the Companies' adjusted test year amounts associated with these regulatory assessments, including removing amounts associated with transmission and accounting for out-of-period adjustments (Exhs. ES-DPH-1, at 90; ES-DPH-4 (East), Sch. DPH-17 (Rev. 3); ES-DPH-4 (West), Sch. DPH-17 (Rev. 3)).

Next, we address Eversource's proposal to decrease the Companies' adjusted test year amounts to reallocate 33 percent of the adjusted test year regulatory assessment amounts to basic service. The Department has found that basic service rates should include all costs of providing basic service to allow competitive suppliers a fair and reasonable opportunity to compete for basic service customers. See Provision of Default Service, D.T.E. 02-40-B at 14 (2003). These costs include all supplier-related wholesale costs, procurement-related wholesale costs, and direct retail costs, including bad debt. D.T.E. 02-40-B at 17.[159]

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158 The Department also makes an annual assessment to electric companies under its jurisdictional control for the costs associated with the Department's employees involved in the investigations of the preparation for and responses to storm and other emergency events by electric companies. Storm Trust Fund Assessment, D.P.U. 16-ASMT-3 (2016). Pursuant to G.L. c. 25, § 18, no electric company may list any Storm Trust Fund assessment as a recoverable expense in any rate proceeding before the Department. The Companies have appropriately removed the Storm Trust Fund assessment from their test year costs of service (Exhs. ES-DPH-2 (East), Sch. DPH-6 (Rev. 3) at 4; ES-DPH-2 (West), Sch. DPH-6 (Rev. 3) at 4).

159 The Department has distinguished direct retail costs from indirect retail costs, which are associated with services and activities that a distribution company provides to all of its customers alike (i.e., basic service and competitive supply). D.T.E. 02-40-B

Eversource has offered no evidence to demonstrate that regulatory assessments represent costs that should be specifically allocated to basic service. Moreover, even assuming that such costs were appropriate for specific allocation to basic service, Eversource has presented no evidence to establish a cost-based allocation of regulatory assessments to basic service. Rather, Eversource seeks to increase basic service rates based solely on a percentage of the Companies' total intrastate operating revenues related to basic service in 2015 (Exhs. ES-DPH-1, at 91; ES-DPH-2 (East), Sch. DPH-17 (Rev. 3); ES-DPH-2 (West), Sch. DPH-17 (Rev. 3)). While the statutory assessments are levied against jurisdictional electric and gas companies based on each company's proportionate share of intrastate revenues, we find that Eversource has offered no record evidence to justify why it is appropriate, or even necessary, to use intrastate operating revenues as a means to allocate regulatory assessments to basic service, particularly if the resulting allocations are not reflective of the costs of providing regulatory services to these customers.

Based on the above considerations, the Department declines to approve Eversource's proposal to allocate 33 percent of the adjusted test year amounts of regulatory assessments to basic service and, thus, remove $2,409,292 and $413,176 from the proposed costs of service of NSTAR Electric and WMECo, respectively. In light of this finding, the Department will retain all of the Companies' regulatory assessment expense in distribution rates. The effect

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at 17. The Department has determined that these services and activities are distribution-related, rather than basic service-related and, as such, should not be included in the calculation of basic service prices. D.T.E. 02-40-B at 17-18.

of this retention is provided in Schedule 2 of this Order for NSTAR Electric and WMECo, respectively.

P. Normalization of WMECo's Property Tax Deductions

1. Introduction

WMECo seeks to change the method it uses to account for property tax deductions from a flow-through method to a normalization method (Exhs. AG-19-55; AG-37-14). As of the end of the test year, WMECo states that it had an ADIT balance of $487,388,588, of which $11,134,250 is associated with property tax deductions (Exhs. ES-DPH-2 (West), Sch. 30 (Rev. 3); AG-37-14; RR-AG-15; RR-DPU-44). Eversource proposes to book the $11,134,250 in ADIT associated with property tax deductions as a regulatory asset[160] and to amortize the asset over five years (Exh. ES-DPH-2 (West), Sch. DPH-33, at 8 (Rev. 3)). As a result, WMECo proposes to increase its test year income tax expense associated with property tax accounting by $2,226,850 (Exh. ES-DPH-2 (West), Sch. DPH-33, at 8 (Rev. 3)).

When expenses or revenues recognized for income tax purposes differ from expenses or revenues recognized for ratemaking purposes, it is necessary for a company to account for these timing differences so that the total amount of expenses or revenues recognized for

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160 A regulatory asset is created when a regulatory agency, such as the Department, allows a company to record a cost for recovery in the future. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 10-54, at 318 n.235 (2010); NSTAR Electric Company, D.T.E. 03-47-A at 3 n.2 (2003); Western Massachusetts Electric Company, D.P.U. 94-8-CC (Phase I) at 11 n.13 (1994). The existence of a regulatory asset provides reasonable assurance of recovery of revenue at least equal to that cost within a reasonable, finite period. D.T.E. 03-47-A at 22; D.P.U. 94-8-CC (Phase I) at 11 n.13.

income tax purposes is equal to the total amount of expenses or revenues recognized for ratemaking purposes. D.T.E. 99-118, at 33; Essex County Gas Company, D.P.U. 87-59, at 27 (1987); 18 C.F.R. § 35.24(d)(2).

WMECo states that it experiences timing differences when it accelerates property tax deductions taken on its tax return in the current year by deducting up to eight and one-half months of those property tax payments made in the following year (RR-AG-15; RR-DPU-44). WMECo states that it currently uses flow-through accounting to address these temporary timing differences (Exh. AG-1-88). Under flow-through accounting, the timing differences produce tax savings for current customers that must be repaid by future customers (RR-DPU-43).

WMECo proposes to change the method it uses to account for property tax deductions from a flow-through method to a normalization method. Under the normalization method, a company calculates its income tax component as if the amounts of timing difference transactions recognized in each period for ratemaking purposes were also recognized in the same amounts, in the same periods, for income tax purposes. 18 C.F.R. § 35.24(d)(1). Normalization results in deferred income tax expense that is included in cost of service, with a corresponding increase in ADIT which is deducted from rate base. Oxford Water Company, D.P.U. 1219, at 2 (1982). Eversource states that WMECo currently uses normalization accounting for all book/tax differences except for the equity portion of AFUDC and property tax expense (Exhs. AG-1-88; AG-19-55; AG-37-14; Tr. 13, at 3128-3129;

Tr. 15, at 3130-3131).[161] Eversource further states that the proposed increase in WMECo's property tax expense in the instant case will be mitigated by an equally offsetting accounting entry of Statement of Financial Accounting Standards Number 109 ("FAS 109") ADIT,[162] which will reduce WMECo's rate base in future rate proceedings through the amortization of the regulatory asset (Exh. ES-DPH-2 (West), Sch. DPH-33, at 8 (Rev. 3); RR-DPU-45; Tr. 9, at 1837-1838; Tr. 15, at 3133)).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that Eversource has failed to provide any evidence or cite to any Department precedent to support its proposed adjustment to property tax expense (Attorney General Brief at 186). According to the Attorney General, there is no mention of the proposed change in accounting treatment in the Companies' initial filing (Attorney General Brief at 186-187). The Attorney General maintains that the Companies are seeking to retroactively address a problem that never existed and does not exist now (Attorney General Brief at 187). Accordingly, the Attorney General argues that WMECo's proposed property tax expense adjustment should be denied (Attorney General Brief at 186).

The Attorney General also argues that there is no evidence that WMECo used flow-through accounting for property taxes in its previous rate case (Attorney General Brief

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161 NSTAR Electric uses normalization accounting for all book/tax differences, including the equity portion of AFUDC and property tax expense (Exh. AG-1-88).

162 FAS 109 establishes financial accounting and reporting standards for the effects of income taxes, including the recognition and treatment of deferred taxes.

at 187, citing Exh. AG-37-14;[163] Tr. 13, at 2790; Attorney General Reply Brief at 36). In support of her position, the Attorney General maintains that WMECo did not flow-through any property tax deductions in its previous rate case, D.P.U. 10-70 (Attorney General Brief at 187, citing Tr. 13, at 2790). Further, the Attorney General argues that WMECo has failed to substantiate its claim that ADIT should be considered a regulatory asset or that recovery of such amounts from ratepayers is appropriate (Attorney General Reply Brief at 34-35). The Attorney General claims that, although the Companies make general reference on brief to a FAS 109-related "regulatory asset" and "deferred income taxes," Eversource has offered no evidence as to their actual existence or the amount related to property taxes (Attorney General Reply Brief at 35-36).

b. Companies

Eversource argues that the Department has full discretion to determine whether the use of normalization accounting is appropriate (Companies Brief at 491, citing RR-DPU-43). Eversource contends that it is appropriate for WMECo to change the method it uses to account for property tax deductions from a flow-through method to a normalization method because: (1) WMECo's property taxes are the last remaining flow-through item for WMECo, NSTAR Electric, and NSTAR Gas; (2) normalization provides for inter-generational equity in ratemaking, versus flow-through accounting that benefits current ratepayers at the expense of later generations of ratepayers; (3) without a consolidated accounting treatment, the Companies will be forced to apply a complex treatment involving

[163] The Attorney General's brief inadvertently refers to Exhibit AG-34-17.

estimates and allocations to maintain both accounting methods post-merger; and (4) the change from flow-through to normalization will result in a decrease to WMECo's rate base in the next base distribution rate proceeding (Companies Brief at 491, citing RR-DPU-43).

Eversource asserts that the Attorney General's arguments opposing its proposal are misleading and are based on a fundamental misunderstanding of the nature of the proposed adjustment and tax accounting (Companies Brief at 491; Companies Reply Brief at 131). With respect to the current accounting method used by WMECo, the Companies argue that the Attorney General fails to recognize that a flow-through of zero dollars in any given year (as occurred in the test year used in D.P.U. 10-70) does not mean that a company is not using flow-through accounting (Company Brief at 492; Companies Reply Brief at 133). Instead, the Companies argue that a flow-through of zero dollars in a given year only shows that the regulatory asset account and the corresponding ADIT account experienced no timing differences in that particular year (Company Brief at 492; Companies Reply Brief at 133).

Finally, Eversource contends that its proposal to implement normalized accounting for WMECo's property taxes, with the corresponding creation of a regulatory asset, is consistent with fundamental accounting rules and practices (Companies Reply Brief at 132, citing Exhs. ES-DPH-2, Sch. DPH-33, at 4 (West); ES-DPH-4, Sch. DPH-4 at 1 (West); AG-37-14; RR-AG-15; RR-DPU-44). The Companies maintain that under FAS 109, all book/tax differences must produce ADIT that is recorded on the balance sheet (Companies Brief at 491, citing RR-DPU-43; Companies Reply Brief at 132; citing D.T.E. 05-27, at 227). According to Eversource, accounting rules have required for decades that a FAS

109 regulatory asset be established for all flow-through items and that a failure to create such an asset would be a fundamental accounting error that would bar the Companies from issuing audited financial statements (Companies Reply Brief at 132).

3. Analysis and Findings

As described above, WMECo proposes to change the method it uses to account for property tax deductions from the flow-through method to the normalization method and to recover the remaining flow-through ADIT balance from ratepayers through the creation of a regulatory asset and an adjustment to test year property tax expense (Exhs. AG-1-88; AG-19-55; AG-37-14; Tr. 13, at 3128-3129; Tr. 15, at 3130-3131).[164] WMECo represents that it currently uses the flow-through accounting method for recording property tax deductions (Exhs. DPU-59-36; AG-1-88; AG-37-14; RR-AG-15). The Attorney General argues that the Companies have not shown that WMECo currently uses flow-through accounting and, therefore, have not shown that any ratemaking treatment of ADIT related to a change in accounting treatment is warranted (Attorney General Brief at 187, citing Exh. AG-37-14; Tr. 13, at 2790; Attorney General Reply Brief at 36).

Because any property tax deductions would be flowed through on an annual basis as the difference, either positive or negative, in the property tax deduction from one year to the next, that absence of a property tax deferral entry in the test year used in WMECo's previous

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164 Eversource's direct case on this issue consists of a single entry in its income tax calculations, with no narrative explanation (Exh. ES-DPH-2, Sch. DPH-33, at 8). By its own admission, Eversource did not go to "great length" to discuss the adjustments it was seeking in that entry (Tr. 13, at 2787). In the future, we expect companies seeking approval of proposals that have ratepayer impacts to present their requests in a more transparent manner.

rate case does not demonstrate one way or the other whether WMECo uses the flow-through method. The Department finds credible, however, WMECo's testimony that it currently uses the flow-through accounting method for recording property tax deductions and that the resulting timing differences have created deferred income taxes (Exhs. AG-1-88; AG-37-14; Tr. 13, at 2787-2789). As required under FAS 109, WMECo's accelerated deductions give rise to deferred income taxes (RR-AG-15; RR-DPU-45). As of the end of the test year, the Department finds that WMECo had a cumulative flow-through balance of $11,134,250 related to these timing differences for property tax deductions (Exh. AG-37-14; RR-AG-15; RR-DPU-44).

Utility companies have used normalization accounting for many years. See, e.g., Oxford Water Company, D.P.U. 1219, Interim Order at 1-2 (1982); Western Massachusetts Electric Company, D.P.U. 10779, at 2-3 (1954); Boston Edison Company, D.P.U. 10774, at 3-5 (1953). As described above, normalization accounting is designed to match the timing of recognition of income tax benefits or costs with the timing of recognition of the corresponding book expense or revenue. The normalization of temporary timing differences ensures that current and future ratepayers equitably share the tax benefits of property tax deductions. See Boston Edison Company, D.P.U. 18515, at 50-51 (1976); Boston Edison Company, D.P.U. 17795 at 4-5 (1974). The Department finds that WMECo's proposed use of normalization accounting for property tax differences is reasonable as it will avoid the need to use estimates and allocations to maintain two different accounting methods post-merger (Exh. DPU-59-36; RR-DPU-44). In addition, WMECo's use of normalization

accounting will enable WMECo, NSTAR Electric, and NSTAR Gas to use a consolidated accounting method (Exh. DPU-59-36). For these reasons, the Department will permit WMECo to employ the normalization accounting method for property tax deductions.

As noted above, WMECo had a cumulative flow-through balance of $11,134,250 in ADIT related to timing differences for property tax deductions as of the end of the test year (Exh. AG-37-14; RR-AG-15; RR-DPU-44). Eversource has requested recovery of this amount through the creation of a regulatory asset. Consistent with our findings above approving WMECo's change in accounting treatment, the Department will permit WMECo to create a regulatory asset in the amount of $11,134,250 and to recover these amounts from ratepayers as an adjustment to its test year income tax expense associated with property tax accounting. Because the regulatory asset will be amortized over a period of time, WMECo's ADIT balance will increase correspondingly, thereby reducing WMECo's rate base (Tr. 15, at 3132-3133).

With respect to the Companies' proposed amortization period, the Department considers the size of the balance to be recovered, the underlying facts giving rise to the accumulation of the balance, and the impact of recovery on ratepayers. D.P.U. 08-27, at 99; D.P.U. 93-223-B at 14; D.P.U. 84-145-A at 54. Based on these considerations and the record in this case, the Department finds that five years is an appropriate amortization period for WMECo's FAS 109 regulatory asset.[165] Amortizing $11,134,250 over five years produces an annual expense of $2,226,850 for WMECo. Based on the foregoing analysis,

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[165] The Department has previously found that a five-year amortization period for non-plant-related ADIT is reasonable. D.P.U. 15-155, at 258.

the Department approves Eversource's proposed adjustment to WMECo's income tax expense related to property taxes in the amount of $2,226,850.

Q. Pension and Post-Retirement Benefits Other than Pension Expense

1. Introduction

The Companies propose to consolidate their current pension adjustment mechanisms ("PAMs") in this proceeding (RR-DPU-51, Att. (a) at 108-111 (proposed M.D.P.U. No. 522)). As part of this proposal, Eversource proposes to collect all pension/post-retirement benefits other than pension ("PBOP") costs through the PAM (Exh. DPU-14-6).

NSTAR Electric's current PAM was approved by the Department in D.T.E. 03-47-A, and established separate, fully reconcilable, annual adjustment factors for NSTAR Electric (and NSTAR Gas) to recover the portion of the pension/PBOP costs not collected in base rates (Exh. DPU-14-6). Eversource states that NSTAR Electric currently has $31,490,920 of pension/PBOP costs embedded in base distribution rates (Exhs. ES-DPH-1, at 186; ES-DPH-5 (Rev. 1)).[166] Meanwhile, WMECo's PAM, which was approved by the Department in Western Massachusetts Electric Company, D.T.E. 06-55 (2006), already recovers all of its pension/PBOP costs.

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166 Eversource states that the $31,490,920 in pension/PBOP costs represents the base amount of approximately $32,609,000 of pension/PBOP costs initially included in base rates in D.T.E. 03-47, adjusted for changes due to NSTAR Electric's Simplified Incentive Plan ("SIP") and a final SIP adjustment factor of 109.47 percent, less the amount allocated to transmission based on the wages and salaries allocator of 11.79 percent (Exhs. ES-DPH-1, at 187-188; ES-DPH-3 (East), WP DPH-28, at 2 (Rev. 3)).

The Companies propose to collect all pension/PBOP expenses through the PAM for both NSTAR Electric and WMECo (Exh. DPU-14-6). Accordingly, Eversource proposes to transfer the pension/PBOP costs from NSTAR Electric's base distribution rates and collect these costs through the PAM (Exhs. ES-DPH-1, at 186-187; ES-DPH-2 (East), Sch. DPH-11, at 2 (Rev. 3); ES-DPH-2 (East), Sch. DPH-11, at 2 (Rev. 3); DPU-14-5 & Atts.; DPU-14-6; DPU-14-7). Thus, going forward, the amounts recovered through the PAM no longer will be reduced by an amount in base rates (Exh. DPU-14-6). No party commented on Eversource's proposal.

2. Analysis and Findings

The Department finds that the transfer of NSTAR Electric's pension/PBOP costs from base distribution rates to its PAM is consistent with the treatment approved for NSTAR Gas in D.P.U. 14-150, at 155. Therefore, the Department approves Eversource's proposal. At this time, the Department will not address any other provisions of the proposed tariff, M.D.P.U. No. 522. Instead, we will address any further issues in our subsequent Order addressing rate design issues.

R. Environmental Remediation Costs

1. Introduction

During the test year, NSTAR Electric booked $1,923,688 in environmental costs, and WMECo booked $281,618 in environmental costs (Exhs. AG-1-59, Atts. (a), (b)). A portion of these costs were associated with the remediation of former manufacturing gas plant ("MGP") sites that were owned and operated by its corporate predecessors (Exh. AG-1-2, Att. (a) at 21 (Supp. 1)). MGP plants produced gas from coal and other petroleum

processes, which resulted in byproducts that may pose risks to human health and the environment (Exh. AG-1-2, Att. (a) at 21 (Supp. 1)). See also Manufactured Gas Plants, D.P.U. 89-161, at 18-24 (1990).

In WMECo's previous rate case, the Department addressed environmental remediation costs at several MGP sites, including one owned by the former Easthampton Gas Company ("Easthampton Gas") and two sites owned by Amherst Gas Company ("Amherst Gas"). D.P.U. 10-70, at 176-185. In order to clarify WMECo's status as a potential liable party for these MGP sites, the Department directed WMECo to provide as part of its next Section 94 rate filing an explanation of its relationship to Amherst Gas and Easthampton Gas.[167] D.P.U. 10-70, at 182 n.91. No party commented on this issue.

2. Analysis and Findings

In order to promote expeditious remediation of contaminated sites, both the federal government and the Commonwealth of Massachusetts imposes joint and several liability, without regard to fault, for investigations and cleanup of any such site on any person who (1) generated, transported, or disposed of hazardous materials there, (2) owned or operated any such facility where the hazardous material was generated, stored, or disposed, or (3) simply owned the land (Exh. AG-1-2, Att. at 21 (Supp. 1)). See also D.P.U. 89-161,

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[167] Amherst Gas sold its electric operations to Western Counties Electric Company ("Western Counties"), another corporate predecessor of WMECo, in 1930, and discontinued gas operations in 1934. D.P.U. 10-70, at 182 n.91. Easthampton Gas sold its electric operations to Western Counties in 1930, and sold its remaining gas operations to Northampton Gas Light Company in 1935. D.P.U. 10-70, at 182 n.91. In view of WMECo's indirect association with the gas operations of these companies, the Department determined that further clarification was warranted.

at 6-9. Eversource reports that it has partial or full ownership responsibilities at hazardous waste sites, including those of former MGP facilities, and thus retains liabilities for environmental remediation costs at these locations (Exh. AG-1-2, Att. (a) at 21 (Supp. 1)). Thus, although WMECo failed to comply with the directives of D.P.U. 10-70, we are satisfied that WMECo never acquired an ownership interest in the gas operations of Amherst Gas or Easthampton Gas. Rather, the Department finds that the joint and several liability provisions of federal and state environmental laws places environmental remediation responsibilities associated with former MGP sites on WMECo.

S. Inflation Allowance

1. Introduction

Eversource proposes an inflation allowance of $2,832,290 for NSTAR Electric and $868,686 for WMECo (Exhs. ES-DPH-3 (East), WP DPH-22, at 1 (Rev. 3); ES-DPH-3 (West), WP DPH-22, at 1 (Rev. 3)).[168] To arrive at these proposed adjustments, Eversource first calculated a proposed inflation factor of 4.527 percent using the most recent forecast of the gross domestic product implicit price deflator ("GDPIPD") (as sourced from the Bureau of Economic Analysis of Moody's Analytics) from the midpoint of the test year to the

[168] In its initial filing, Eversource proposed an inflation allowance of $3,070,102 for NSTAR Electric and $942,355 for WMECo (Exhs. ES-DPH-1, at 134; ES-DPH-3 (East), WP DPH-22, at 1; ES-DPH-3 (West), WP DPH-22, at 1). Eversource subsequently revised its proposed inflation allowances based on updated expense reporting.

midpoint of the rate year (Exhs. ES-DPH-1, at 134; ES-DPH-3 (East), WP DPH-22, at 1 (Rev. 3); ES-DPH-3 (West), WP DPH-22, at 149-62 (Rev. 3)).[169]

Next, Eversource took NSTAR Electric's adjusted test year O&M expense of $273,888,542, and subtracted $211,324,149, which represents adjusted test year expenses associated with the various O&M expense categories for which Eversource seeks separate adjustments (Exhs. ES-DPH-1, at 134; ES-DPH-3 (East), WP DPH-22, at 1 (Rev. 3)). [170] Finally, Eversource multiplied the 4.527 percent inflation factor by $62,564,393 in adjusted test year residual O&M expenses to arrive at a proposed inflation allowance of $2,832,290 for NSTAR Electric (Exhs. ES-DPH-3 (East), WP DPH-22, at 1 (Rev. 3)).

Similarly, Eversource took WMECo's adjusted test year O&M expense of $59,758,644, and subtracted $40,569,643, which represents adjusted test year O&M expenses associated with the various categories for which Eversource seeks separate adjustments

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169 In its initial filing, Eversource calculated a proposed inflation factor of 4.870 percent using the change in GDPIPD from the midpoint of the test year to the midpoint of the rate year (Exhs. ES-DPH-1, at 133; ES-DPH-3 (East), WP DPH-22, at 1; ES-DPH-3 (West), WP DPH-22, at 1). Eversource subsequently updated its proposed inflation factor during the course of the proceedings.

170 Eversource seeks separate adjustments for the following NSTAR Electric expense categories: (1) postage expense; (2) uncollectible expense; (3) fee free payment processing; (4) dues and memberships; (5) employee benefits costs; (6) insurance expense and injuries and damages; (7) payroll expense; (8) variable compensation; (9) vegetation expense annualization; (10) vegetation management resiliency tree work pilot; (11) rate case expense; (12) regulatory assessments; (13) lease expense; (14) information systems expense adjustment; (15) amortization of GIS costs; (16) storm cost adjustment; and (17) storm fund adjustment (Exh. ES-DPH-3 (East), WP DPH-22, at 1 (Rev. 3)).

(Exhs. ES-DPH-1, at 134; ES-DPH-3 (West), WP DPH-22, at 1 (Rev. 3)).[171] Eversource then multiplied the 4.527 percent inflation factor by $19,189,000 in adjusted test year residual O&M expenses to arrive at a proposed inflation allowance of $868,686 for WMECo (Exh. ES-DPH-3 (West), WP DPH-22, at 1 (Rev. 3)).

2. Positions of the Parties

Eversource argues that its method of calculating an inflation allowance, including the use of GDPIPD, is consistent with Department precedent (Companies Brief at 225-226, citing D.P.U. 15-155, at 314; D.P.U. 15-80/81, at 188; D.P.U. 14-150, at 248; D.P.U. 13-75, at 251; D.P.U. 08-35, at 154-155; D.T.E. 02-24/25, at 184; D.P.U. 95-40, at 64; D.P.U. 92-250, at 97-98). Accordingly, Eversource asserts that the Department should approve its proposed inflation allowance adjustments to NSTAR Electric's and WMECo's costs of service (Companies Brief at 226). No other party commented on Eversource's proposed inflation allowances.

3. Analysis and Findings

The inflation allowance recognizes that known and inflationary pressures tend to affect a company's expenses in a manner that can be measured reasonably. D.T.E. 02-24/25, at 184; D.T.E. 01-56, at 71; D.T.E. 98-51, at 100-101; D.P.U. 96-50 (Phase I) at 112-113;

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171 Eversource seeks separate adjustments for the following WMECo expense categories: (1) postage expense; (2) uncollectible expense; (3) fee free payment processing; (4) dues and memberships; (5) employee benefits costs; (6) insurance expense and injuries and damages; (7) payroll expense; (8) variable compensation; (9) vegetation management resiliency tree work pilot; (10) rate case expense; (11) regulatory assessments; (12) lease expense; (13) information systems expense adjustment; (14) storm cost adjustment; and (15) storm fund adjustment (Exh. ES-DPH-3 (West), WP DPH-22, at 1 (Rev. 3)).

D.P.U. 95-40, at 64. The inflation allowance is intended to adjust certain O&M expenses for inflation where the expenses are heterogeneous in nature and include no single expense large enough to warrant specific focus and effort in adjusting. D.P.U. 1720, at 19-21; Commonwealth Electric Company, D.P.U. 956, at 40 (1982). The Department permits utilities to increase their test year residual O&M expense by an independently published price index from the midpoint of the test year to the midpoint of the rate year. D.P.U. 15-155, at 314-315; D.P.U. 08-35, at 154-155; D.T.E. 02-24/25, at 184; D.P.U. 95-40, at 64; D.P.U. 92-250, at 97-98. In order for the Department to allow a utility to recover an inflation adjustment, the utility must demonstrate that it has implemented cost-containment measures. D.P.U. 09-30, at 285; D.P.U. 08-35, at 154; D.T.E. 02-24/25, at 184; D.T.E. 01-56, at 71-72.

In the instant case, Eversource has demonstrated a number of cost-containment measures it has taken throughout the course of regular operations including the use of competitive solicitation processes for vendors and targeted programs designed to reduce healthcare expenses (Exhs. ES-MPS-1, at 8-11; DPU-13-20; DPU-21-20; DPU-45-27; AG-1-52). In addition, the Companies have demonstrated that they have taken reasonable measures to control property and liability insurance expense (Exh. ES-DPH-1, at 61-62). Eversource also has provided system-wide examples of cost reductions achieved through the merger approved in D.P.U. 10-170-B, including measures that reduced the residual O&M expenses that are subject to the proposed inflation allowance (Exhs. ES-DPH-4, Sch. 10; DPU-13-20). Based on these considerations, the Department finds that Eversource

demonstrated that it has implemented cost-containment measures sufficient to qualify it for an inflation allowance.

Eversource calculated its proposed inflation factor from the midpoint of the test year to the midpoint of the rate year, using the most recent GDPIPD as an inflation measure (Exh. ES-DPH-1, at 134). This calculation method and use of GDPIPD are consistent with Department precedent. D.P.U.15-155, at 315; D.P.U. 08-35, at 154-155; D.T.E. 02-24/25, at 184; D.P.U. 95-40, at 64; D.P.U. 92-250, at 97-98. Therefore, the Department concludes that Eversource has properly calculated an inflation factor of 4.527 percent (Exh. ES-DPH-3 (East), WP DPH-22, at 1, lines 49-62 (Rev. 3); ES-DPH-3 (West), WP DPH-22, at 1, lines 49-62 (Rev. 3)).

If an O&M expense has been adjusted or disallowed for ratemaking purposes such that the adjusted expense is representative of costs to be incurred in the year following new rates, the expense also is removed in its entirety from the inflation allowance. D.P.U. 09-39, at 322; D.T.E. 05-27, at 204; D.T.E. 02-24/25, at 184-185; Blackstone Gas Company, D.T.E. 01-50, at 19 (2001); D.P.U. 88-67 (Phase I) at 141; Commonwealth Gas Company, D.P.U. 87-122, at 82 (1987). Eversource has proposed adjustments to 17 expense categories for NSTAR Electric and 15 expense categories for WMECo (see nn.170, 171 above). The Department finds that Eversource has correctly excluded the O&M categories for which it seeks separate adjustments from the calculation of the inflation allowances. In addition, the Department has adjusted the Companies' expenses related to service company charges and

insurance policy distribution (see Sections VIII.B.3 and VIII.I.3 above). The effect of the Department's adjustments are shown below in Tables 1 and 2.

Based on the above, the Department finds that an inflation allowance adjustment equal to the most recent forecast of GDPIPD for the period proposed by the Companies, applied to NSTAR Electric's and WMECo's approved levels of residual O&M expense, is appropriate. As shown in Table 1, below, the approved inflation allowance for NSTAR Electric is $2,824,948 (Exh. ES-DPH-3 (East), WP DPH-22, at 1 (Rev. 3)). As shown in Table 2, below, the approved inflation allowance for WMECo is $867,630 (Exh. ES-DPH-3 (West), WP DPH-22, at 1 (Rev. 3)).

Table 1:

Test Year O&M Expense Per Books:	$273,888,542
Less Normalizing Adjustments:	
Postage Expense	$4,352,322
Uncollectibles Expense	$15,073,652
Fee Free Payment Processing	-
Dues and Memberships	$784,558
Employee Benefits Costs	$19,870,555
Insurance Expense And Injuries and Damages	$7,289,021
Payroll Expense	$119,525,370
Variable Compensation	$18,170,774
Vegetation Expense Annualization	$5,283,642
Vegetation Management Resiliency Tree Work Pilot	-
Rate Case Expense	-
Regulatory Assessments	$6,713,485
Lease Expense	$3,660,277
Information Systems Expense Adjustment	$6,100,492
Amortization of GIS Costs	-
Storm Cost Adjustment	-
Storm Fund Adjustment	$4,500,000
Total Company O&M Adjustments:	$211,324,149
Subtotal (Adjusted per Books Less Company Adjustments)	$62,564,393
Less DPU Excluded Expenses	
Eversource Service Company Charges	$3,778
Insurance Policy Distribution	$158,407
Total Excluded Test Year Expenses	$162,185
Residual O&M Expense	$62,402,208
Inflation Factor from Midpoint of Test Year to Midpoint of Rate Year:	4.527%
Inflation Allowance:	$2,824,948

Table 2:

Test Year O&M Expense Per Books:	$59,758,644
Less Company Adjusted Items:	
Postage Expense	$956,609
Uncollectibles Expense	$5,163,634
Fee Free Payment Processing	-
Dues and Memberships	$124,820
Employee Benefits Costs	$3,047,400
Insurance Expense And Injuries and Damages	$1,630,157
Payroll Expense	$23,173,030
Variable Compensation	$3,177,908
Vegetation Management Resiliency Tree Work Pilot	-
Rate Case Expense	-
Regulatory Assessments	$1,148,553
Lease Expense	$749,592
Information Systems Expense Adjustment	$1,397,941
Storm Cost Adjustment	-
Storm Fund Adjustment	-
Total Company O&M Adjustments:	$40,569,643
Subtotal (Adjusted per Books Less Company Adjustments)	$19,189,000
Less DPU Excluded Expenses	
Eversource Service Company Charges	$662
Insurance Policy Distribution	$22,675
Total Excluded Test Year Expenses	$23,337
Residual O&M Expense	$19,165,663
Inflation Factor from Midpoint of Test Year to Midpoint of Rate Year:	4.527%
Inflation Allowance:	$867,630

IX. PERFORMANCE-BASED RATEMAKING MECHANISM

A. Introduction

Eversource proposes to implement what it calls a "Grid-Wise Performance Plan," which has two components (Exh. ES-GWPP-1, at 9). First, the Companies propose to implement a PBR mechanism that would adjust base rates annually in accordance with a revenue cap formula (Exh. ES-GWPP-1, at 9). Second, the Companies propose to spend $400 million in incremental grid modernization-related capital investment over the next five years, commencing January 1, 2018 (Exh. ES-GWPP-1, at 9-10). The Companies' PBR proposal is addressed below. The Companies' proposed grid modernization investments are addressed in Section X.B below.

B. Companies PBR Proposal

1. Introduction

Eversource's proposed PBR uses a revenue cap formula to adjust distribution rates annually (Exh. ES-PBRM-1, at 5). Eversource states that it designed the proposed PBR to work in tandem with its proposed revenue decoupling mechanism (Exh. ES-PBRM-1, at 6). The PBR would adjust the base revenue requirement approved in this proceeding, which serves as the target revenue for the revenue decoupling mechanism, according to the following formula:

$$PBRAF_T = (GDPPI_{T-1} - X - CD) + [(Z + GMP)_T / \text{Base Revenue}_{T-1}], \text{ where}$$

$PBRAF_T$ is the adjustment to the annual revenue target;

$GDPPI_{T-1}$ is a price inflation index;

X is a productivity offset;

CD is a consumer dividend;

Z is an adjustment for exogenous costs (positive or negative);

GMP is an adjustment for additional incremental grid modernization investments; and

Base Revenue is the base distribution revenue requirement.

(Exhs. ES-PBRM-1, at 44; RR-DPU-51, Att. (a) at 329-334 (proposed M.D.P.U. No. 532)).

In addition, Eversource proposes to adopt an earnings sharing mechanism that would provide a credit to customers if earnings exceed the ROE approved in this proceeding by more than 200 basis points (Exhs. ES-GWPP-1, at 65; ES-PBRM-1, at 44). Each element of the Companies' proposed revenue cap formula and PBR mechanism are described in more detail below.

2. Formula Elements

a. Productivity Offset

Eversource proposes a productivity offset ("X factor") to be calculated as:

$X = (\%\Delta TFP_I - \%\Delta TFP_E) + (\%\Delta W_E - \%\Delta W_I)$, where

$\%\Delta TFP_I$ is the percentage change in electric distribution industry total factor productivity growth;

$\%\Delta TFP_E$ is the percentage change in economy wide total factor productivity growth;

$\%\Delta W_E$ is the percentage change in economy wide input price growth; and

$\%\Delta W_I$ is the percentage change in electric distribution industry input price growth.

(Exh. ES-PBRM-1, at 34-35, 40).

The X factor consists of the differential in expected productivity growth between the electric distribution industry and the overall economy, and the differential in expected input

price growth between the overall economy and the electric distribution industry (Exhs. ES-GWPP-1, at 46; ES-PBRM-1, at 34). To determine the proposed X factor, Eversource conducted a productivity study of U.S. electric distribution total factor productivity ("TFP") and input price growth over the period 2001 to 2015 (Exhs. ES-PBRM-1, at 46; ES-PBRM-2). Eversource used two different samples for its productivity study: (1) a sample of 67 electric distribution companies intended to represent the overall U.S. electric distribution industry ("nationwide LDCs"); and (2) a sample of 17 electric distribution companies intended to represent the distribution industry in the Northeast U.S. ("regional LDCs") (Exh. ES-PBRM-1, at 46). For economy wide TFP and input price growth the Companies used official U.S. government sources (Exh. ES-PBRM-1, at 46).[172]

TFP is defined as the ratio of total output to total input (Exh. ES-PBRM-1, at 30). Total output consists of all the services produced by the relevant unit of production (e.g., a firm or an industry) (Exh. ES-PBRM-1, at 30). Total input includes all resources used by the unit of production in providing those services (Exh. ES-PBRM-1, at 30). Eversource used number of customers as the sole productivity study output measure (Exh. ES-PBRM-1, at 68). For the input measure, Eversource constructed a quantity index of total input for each firm and each year based on individual labor, materials, and capital quantity indices (Exh. ES-PBRM-1, at 69-72).

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[172] The sources used by the Companies were FERC Form 1, Bureau of Labor Statistics Employment Cost Index and Consumer Price Index for all Urban Consumers, and the Bureau of Economic Analysis Gross Domestic Product Price Index and Federal Reserve Economic Data (Exh. ES-PBRM-1, at 69-72).

The results of the Companies' study indicate that, for the period 2001-2015, the average growth in productivity for the regional LDCs was equal to -0.41 percent, while the average productivity growth for the nationwide LDCs was equal to -0.46 percent (Exh. ES-PBRM-1, at 47-48). For the same period, the average input price growth for regional LDCs was equal to 4.10 percent, while the average input price growth for the nationwide LDCs was equal to 4.13 percent (Exh. ES-PBRM-1, at 47-48, 75-76). Eversource's productivity study indicates that the economy-wide average productivity growth during the 2001 to 2015 period was 0.92 percent, and the average input price growth was 2.95 percent (Exh. ES-PBRM-1, at 50).

Eversource calculated its proposed productivity offset using the productivity and input price growth indices for the nationwide LDCs rather than the regional LDCs (Exh. ES-PBRM-1, at 61). Inputting the results of the productivity study into the productivity formula, Eversource calculated a proposed productivity offset equal to -2.64 percent (RR-DPU-8).[173]

b. Inflation Index and Floor

Eversource proposes to base the price inflation index included in the revenue cap formula on the Gross Domestic Product Price Index ("GDP-PI") as measured by the U.S.

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[173] Eversource initially calculated a proposed productivity offset equal to -2.56 percent (Exhs. ES-GWPP-1, at 46; ES-PBRM-1, at 52, 61). During the course of the proceeding, the Companies corrected an error in the productivity study, resulting in an updated proposed productivity factor of -2.64 percent (RR-DPU-8).

Commerce Department (Exh. ES-GWPP-1, at 47).[174] Under the Companies' proposal, the inflation index would be calculated as the percentage change between the current year's GDP-PI and the prior year's GDP-PI (Exh. ES-GWPP-1, at 47). For each year, the GDP-PI would be calculated as the average of the most recent four quarterly measures of GDP-PI as of the second quarter of the year (Exh. ES-GWPP-1, at 47).[175] Additionally, Eversource proposes to include an inflation floor of one percent for the revenue cap formula (Exh. ES-GWPP-1, at 12, 47-48).

c. Consumer Dividend

Eversource proposes to implement a consumer dividend of 25 basis points, or 0.25 percent, when inflation exceeds two percent (Exhs. ES-GWPP-1, at 54; ES-PBRM-1, at 8, 60, 66-67). The Companies state that a consumer dividend is often included in first generation PBR plans to capture the increased productivity growth associated with the transition from cost of service ratemaking to incentive regulation (Exhs. ES-GWPP-1, at 49-50; ES-PBRM-1, at 54).

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174 The GDP-PI is a measure of the U.S. economy-wide inflation in the prices of final goods and services (Exhs. ES-PBRM-1, at 31-32, 34).

175 This information is published each September in the Survey of Current Business, a publication of the U.S. Commerce Department, Bureau of Economic Analysis. (Exh. ES-GWPP-1, at 47).

d. Grid Modernization Stretch Factor

Eversource states that its proposed commitment to spend $400 million in incremental grid modernization investments over five years represents an implicit stretch factor,[176] equal to approximately 1.08 percent (Exhs. ES-GWPP-1, at 53-56; ES-PBRM-1, at 54, 60). The Companies calculated an average annual revenue requirement associated with the grid modernization base commitment spending to arrive at a 1.08 percent implicit stretch factor (Exh. ES-GWPP-1, at 54).

e. Grid Modernization Plan Factor

As part of the proposed PBR formula, Eversource proposes to include an adjustment for incremental grid modernization investments outside of the grid modernization base commitment ("GMP factor") (Exhs. ES-GWPP-1, at 12, 18, 69; ES-PBRM-1, at 8). The Companies propose that the GMP factor will be set to zero unless and until the Department authorizes or requires grid modernization investment above the $400 million commitment proposed in this proceeding (Exhs. ES-GWPP-1, at 12, 18, 69; ES-PBRM-1, at 8). During the first five years of the PBR plan, should the Department, in this proceeding or in Grid Modernization, D.P.U. 15-122, authorize or require spending above this amount, the Companies propose to recover the associated revenue requirement through the GMP factor (Exhs. ES-GWPP-1, at 12, 18, 69; ES-PBRM-1, at 8).

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176 Eversource states that, while not an explicit part of the PBR formula, the grid modernization base commitment is an implicit stretch factor within the proposed PBR framework because the Companies will essentially absorb the revenue requirement associated with $400 million of grid modernization investment until the next base rate case (Exhs. ES-GWPP-1, at 53-56; ES-PBRM-1, at 5, 7-8).

f. Exogenous Cost Factor

The Companies propose to recover exogenous costs, which they define as positive or negative changes that are beyond the Companies' control and not reflected in either the GDP-PI or otherwise, in the PBR formula ("Z factor") (Exhs. ES-GWPP-1, at 12, 60; ES-PBRM-1, at 8, 44). The Companies propose to calculate the exogenous cost factor as a percentage of the previous year's base revenues. The factor would be zero unless an exogenous cost event occurs (Exhs. ES-GWPP-1, at 12, 60-62; ES-PBRM-1, at 44).

Eversource proposes that the following criteria must be met for exogenous cost recovery: (1) that the cost change is beyond Eversource's control; (2) that the change arises from a change in accounting requirements or regulatory, judicial, or legislative directives or enactments; (3) that the change is unique to the electric distribution industry as opposed to the general economy; and (4) that the change meets a threshold of "significance" for qualification (Exh. ES-GWPP-1, at 60-61).[177] Eversource proposes that the significance threshold for exogenous costs be set at $5 million for calendar year 2018 for NSTAR Electric and WMECo combined and, thereafter, be subject to annual adjustments based on changes in GDP-PI, as measured by the U.S. Commerce Department (Exh. ES-GWPP-1, at 62).

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[177] Eversource requests that the Department find that costs related to two potential future events will be eligible for exogenous cost recovery where the significance threshold is met: (1) costs related to incremental property taxes that arise from additional communities in the Companies' service area converting to the RCNLD valuation method; and (2) costs related to a FERC decision to modify the Companies' transmission tariffs in light of the consolidation of NSTAR Electric and WMECo into a single entity (Exh. ES-GWPP-1, at 63-64).

g. Earnings Sharing Mechanism

As part of the PBR, the Companies propose to adopt an asymmetrical earnings sharing mechanism ("ESM") with a deadband of 200 basis points (Exhs. ES-GWPP-1, at 12, 65-66; ES-PBRM-1, at 8). The proposed earnings sharing mechanism would trigger a sharing of earnings with customers on a 75/25 basis (i.e., 75 percent to shareholders, 25 percent to ratepayers) if and when the actual distribution ROE exceeds 200 basis points above the ROE authorized in this proceeding (Exh. ES-GWPP-1, at 65).[178] If and when the actual ROE exceeds 300 basis points above the ROE authorized in this proceeding, Eversource proposes to share earnings with customers on a 50/50 basis (Exh. ES-GWPP-1, at 65). For any year in which the ROE is above the deadband, the Companies propose that the percentage of earnings that is to be shared with customers be credited to customers in the succeeding year and that the impact of this prior year adjustment be excluded from the calculation of any subsequent year's sharing (Exh. ES-GWPP-1, at 66). The Companies acknowledge that any earnings sharing adjustment would be subject to a full investigation in an adjudicatory proceeding (Exh. ES-GWPP-1, at 67).

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178 The Companies propose that distribution ROE be calculated using distribution earnings available for common equity and the capital structure approved by the Department in this proceeding (Exh. ES-GWPP-1, at 67). The Companies propose that the calculation exclude incentive payments such as energy efficiency incentives, transition-incentive mitigation, and long-term contract remuneration. Additionally, the Companies propose that the calculation exclude any service-quality penalties as well as any amounts recognized in the current period resulting from regulatory or court settlements related to prior periods (Exh. ES-GWPP-1, at 67).

h. PBR Term

In the Companies' initial filing, the Companies did not specify a term for the PBR (Exhs. ES-GWPP-1, at 55; ES-PBRM-1, at 45, 54). During the course of the proceeding, Eversource proposed a five-year PBR term with an accompanying rate case moratorium, provided that Eversource may file for rate relief if the actual ROE falls more than 200 basis points below the ROE approved in this case (Exh. AG-33-8; Tr. 2, at 421-422).

i. Metrics

As described in Section X.B below, Eversource proposed a series of metrics to be used to monitor and evaluate the Companies' progress towards its grid modernization base commitment goals (Exh. ES-GMBC-1, at 132). The Companies did not, however, propose any separate metrics to track its performance under the PBR.

C. Positions of the Parties

1. Attorney General

The Attorney General argues that the Department should reject the proposed PBR. The Attorney General claims: (1) the PBR will not result in just and reasonable rates; (2) the PBR fails to meet the Department's requirements for implementing incentive-based ratemaking; and (3) that there are significant issues with multiple elements of the PBR (Attorney General Brief at 12-17, 20-21, 24-34; Attorney General Reply Brief at 77, 85-91).[179]

[179] TEC and WMIG explicitly adopted the Attorney General's arguments regarding the PBR (TEC and WMIG Reply Brief at 5-8). In addition to the Attorney General's arguments, TEC and WMIG claim that the PBR will not be understood by consumers

First, the Attorney General claims that the proposed PBR will impose unnecessary rate increases and, therefore, will not result in just and reasonable rates. Accordingly, the Attorney General argues that the Department must reject the PBR (Attorney General Reply Brief at 77). More specifically, the Attorney General argues that the proposed PBR is not incentive regulation but a cost recovery mechanism that guarantees Eversource $188 million in rate increases in the first four years (Attorney General Reply Brief at 77, 85). The Attorney General contends that the PBR will raise rates by 4.4 percent in 2019, 4.9 percent in 2020, 4.9 percent in 2021, and another 4.6 percent in 2022 (Attorney General Reply Brief at 77, citing Exh. DPU-40-8, Att.). The Attorney General claims that there is no need for these annual PBR rate increases because the Companies can and have earned appropriate returns under cost-of-service ratemaking (Attorney General Reply Brief at 5). In particular, the Attorney General argues that the Companies earned the highest returns on common equity in Massachusetts during 2013 and 2016 (Attorney General Brief at 2-3; Attorney General Reply Brief at 5).

In addition, the Attorney General argues that the Companies have numerous reconciling mechanisms and incentive programs in place that allow them to successfully operate in the changing dynamics of the electric utility market (Attorney General Reply Brief at 5). For example, the Attorney General maintains that, over the past four years, the Companies have received over $16 million a year in energy efficiency incentives (Attorney General Reply Brief at 5). Further, the Attorney General asserts that, with revenue

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and lacks the simplicity that the Department seeks when setting rate structures (TEC and WMIG Reply Brief at 6-8).

decoupling, other Massachusetts utilities have earned revenues sufficient to allow for long gaps between rate cases (Attorney General Reply Brief at 6).

Second, the Attorney General argues that the Companies have not met the Department's criteria for implementing for incentive-based ratemaking (Attorney General Brief at 10). Specifically, the Attorney General maintains that the proposed PBR focuses excessively on cost recovery, is not designed to achieve specific, measurable results, and will not lead to administrative cost efficiencies (Attorney General Brief at 10-12, 20, citing D.P.U. 96-50 (Phase I) at 242). The Attorney General asserts that the PBR, in conflict with Department precedent, is nearly exclusively focused on cost recovery (Attorney General Brief at 12, citing D.P.U. 96-50 (Phase I) at 242). The Attorney General posits that the Companies have presented the PBR proposal as a substitute for a cost recovery mechanism that addresses all of the Companies' capital spending (Attorney General Brief at 12-14; Attorney General Reply Brief at 85). The Attorney General argues that the Companies' admission that the proposed PBR is meant to replace a cost recovery mechanism shows that the PBR is excessively focused on cost recovery (Attorney General Brief at 12-13).

The Attorney General contends further that the proposed PBR lacks the specific, measurable metrics that Department precedent requires (Attorney General Brief at 12-14, citing D.P.U. 96-50 (Phase I) at 242). The Attorney General maintains that the Companies have not identified any targeted metrics to measure the PBR's success (Attorney General Brief at 14). While the Companies have presented general goals regarding advancing clean energy, cost efficiency, service quality, and grid modernization, the Attorney General

maintains that these goals are inadequate because they lack the performance targets or measures needed to evaluate the Companies' efforts (Attorney General Brief at 14-17).

In addition, the Attorney General argues that, although the Companies contend that the PBR will reduce regulatory costs, the Companies could not identify a single administrative filing that the PBR would eliminate (Attorney General Brief at 17, citing Tr. 3, at 539-540). Instead, the Attorney General claims that the PBR will increase the administrative burden through an annual PBR compliance filing (Attorney General Brief at 17, citing Tr. 3, at 531).

Third, the Attorney General argues that there are significant issues with multiple elements of the proposed PBR. With regard to the proposed earnings sharing mechanism, the Attorney General argues that the deadband is too large and the Companies will retain the majority of profits until the highest earnings levels (Attorney General Brief at 32). The Attorney General further argues that the earnings sharing mechanism's regressive structure, which gives the Companies a lower percentage of profits as earnings increase, will not benefit ratepayers (Attorney General Brief at 33). Because the Companies will share a lower percentage of profits as earnings increase, the Attorney General maintains that the Companies will have no incentive to take the risks required to attain the highest earnings levels (Attorney General Brief at 33). If the Department approves a PBR, the Attorney General recommends that the earnings sharing mechanism be modified so that the Companies' share of earnings starts lower and increases as both earnings and the Companies' risk increase (Attorney General Brief at 33).

With regard to the proposed term of the PBR, the Attorney General argues that the Department should bar the Companies from filing a rate case during the five-year term (Attorney General Reply Brief at 90-91). The Attorney General argues that if, as the Companies suggest, they can file a rate case whenever they choose, ratepayers would receive no benefit from the PBR (Attorney General Brief at 33-34; Attorney General Reply Brief at 90-91).

With regard to the X factor, the Attorney General argues that the Companies use a flawed TFP study to calculate the X factor (Attorney General Brief at 24-32). The Attorney General claims that the resulting X factor is too low and unprecedented (Attorney General Brief at 20-21, 24-26). In critiquing the Companies' TFP study, the Attorney General argues that the Companies' study should include not just capital costs and O&M expense, but also other labor and materials accounts, such as customer accounts, sales, and a portion of administrative and general expense (Attorney General Brief at 28, citing Exh. AG/DED-1, at 50, 53-54). Because the Companies did not consider these factors, the Attorney General argues that their analysis excludes major productivity improvements from technological advances (Attorney General Brief at 28-29, citing Exh. AG/DED-1, at 50, 55; Tr. 8, at 1523-1524).

The Attorney General also argues that the Companies' TFP study excludes certain peer utilities, preventing an accurate determination of the Companies' productivity (Attorney General Brief at 30). Further, the Attorney General claims that the Companies give

additional, unjustified weight to larger utilities, despite the fact that the TFP study already scales these utilities for size (Attorney General Brief at 30).

In addition, the Attorney General contends that, contrary to Department precedent, the Companies' TFP analysis relies solely on the number of customers, without accounting for peak demand (Attorney General Brief at 31, citing D.P.U. 96-50 (Phase I) at 277). The Attorney General asserts that using number of customers alone is inappropriate because it is not the sole driver of costs (Attorney General Brief at 31, citing AG/DED-1, at 59, 62-63; Tr. 3, at 494-496). Further, the Attorney General insists that the Companies' use of customer numbers as an output measure is inappropriate because the Companies provide distribution services, not customers (Attorney General Brief at 31, citing Exh. AG/DED-1, at 62-63).

Finally, the Attorney General claims that the Companies use an improper method to calculate their capital quantity index (Attorney General Brief at 31). The Attorney General asserts that because the Companies do not consider general plant or employ the more widely used geometric decay method, their analysis does not consider gradual depreciation, overstates capital inputs, and produces an inaccurately high degree of utility inefficiency (Attorney General Brief at 31, citing Exh. AG/DED-1, at 63-64). For all these reasons, the Attorney General maintains that the Companies' TFP analysis is limited and cannot be used to accurately determine Eversource's total productivity (Attorney General Brief at 28-31).

The Attorney General also argues that the negative X factor proposed by the Companies will guarantee unnecessary rate increases (Attorney General Brief at 20-21). In

particular, the Attorney General maintains that the proposed X factor will raise rates by more than 2.5 percent above inflation each year (Attorney General Brief at 20-21). According to the Attorney General, if approved by the Department, it would be the first negative (and by far the lowest) X factor used in North America (Attorney General Brief at 24-25). The Attorney General argues that the Companies have not shown that, over the past 15 years, negative productivity growth is common in the electric distribution industry (Attorney General Reply Brief at 86). Therefore, the Attorney General argues that a negative X factor, as proposed by the Companies, is unsupported by the record and should be rejected (Attorney General Brief at 20-21, 24-32; Attorney General Reply Brief at 86-90). If the Department implements a PBR for the Companies, which the Attorney General argues it should not, the Attorney General asserts that her analysis should be used to determine the X factor (Attorney General Brief at 32).

2. Acadia Center

Acadia Center argues that the Department should deny the proposed PBR and, instead, approve a capital cost recovery mechanism for the Companies (Acadia Center Brief at 13-14). Acadia Center asserts that the design of the proposed PBR is unprecedented and that every intervenor that addressed the issue has urged the Department to reject the proposed PBR (Acadia Center Brief at 13; Acadia Center Reply Brief at 2). Acadia Center also claims the proposed PBR is poorly designed and will not benefit ratepayers (Acadia Center Brief at 13). According to Acadia Center, the proposed PBR lacks the incentives or performance metrics needed to ensure that ratepayers will benefit (Acadia Center Brief at 13; Acadia

Center Reply Brief at 3-4). Instead, Acadia argues that the PBR's X factor, combined with an unjustified inflation floor, will guarantee annual rate increases without any requirement that ratepayers receive benefits (Acadia Center Brief at 13). Alternately, Acadia Center argues that a capital cost recovery mechanism will retain important ratepayer protections and Department oversight (Acadia Center Brief at 13-14).

3. Cape Light Compact

Cape Light Compact argues that the Companies have not satisfied Department precedent regarding PBRs (Cape Light Compact Brief at 45, citing D.P.U. 94-158, at 54, 57, 64-66). First, Cape Light Compact claims that the Companies have not shown that the proposed PBR is more likely to achieve the Department's ratemaking goals than cost of service regulation (Cape Light Compact Brief at 45). Cape Light Compact argues that the PBR will increase rates each year at a pace well above inflation (Cape Light Compact Brief at 46). Cape Light Compact also claims that these additional rate increases come without demonstrated benefits to customers (Cape Light Compact Brief at 45). According to Cape Light Compact, the proposed PBR puts the risk for capital projects on ratepayers, while the Companies receive most of the financial returns (Cape Light Compact Brief at 45). While the Companies expect certain efficiency gains, Cape Light Compact maintains that the proposed PBR does not deliver corresponding benefits to ratepayers (Cape Light Compact Brief at 46-47). Cape Light Compact also maintains that the Companies' assertion that the PBR is needed to make up for negative sales growth is not credible (Cape Light Compact Brief at 47). Further, Cape Light Compact argues that the Companies' sales have fallen

since 2005 and, as the Companies accept, revenue decoupling is designed to address this concern (Cape Light Compact Brief at 47, citing Exh. ES-GWPP-1, at 22-23).

Second, Cape Light Compact challenges the Companies' proposed X factor (Cape Light Compact Brief at 53). In particular, Cape Light Compact argues that the Companies' calculations cannot be relied upon because their TFP study is not sufficiently robust (Cape Light Compact Brief at 53-54). Cape Light Compact claims small changes to the analysis or sample produce drastic changes (Cape Light Compact Brief at 53-54). This volatility, according to Cape Light Compact, shows that the X factor is not reliable (Cape Light Compact Brief at 53-54). In addition, Cape Light Compact alleges that the reliability of the Companies' expert witness is in question because he has changed his analysis since he testified before another utility regulator in 2016 (Cape Light Compact Brief at 54, citing Exh. CLC-PLC-1, at 15 n.9).

If the Department accepts the proposed X factor, Cape Light Compact argues that it will lock in efficiency levels that have fallen and allow the Companies to keep the value from future efficiency improvements (Cape Light Compact Brief at 53). Cape Light Compact maintains that the Companies' improving efficiencies demonstrate that the rate increases from the proposed PBR are inappropriate (Cape Light Compact Brief at 53-55).

Third, Cape Light Compact argues that the proposed PBR should not have an inflation floor (Cape Light Compact Brief at 55). Cape Light Compact claims that this asymmetric proposal is unprecedented and puts additional inflationary risk on ratepayers (Cape Light Compact Brief at 55, citing Exhs. AG-DED-1, at 45; AG-28-5, Att. (a); Tr. 3, at 544

et seq.). Cape Light Compact posits that the proposed inflation floor is unfair to ratepayers and should be rejected because it protects the Companies with guaranteed revenues when inflation is low but provides no protection to ratepayers when inflation is high (Cape Light Compact Brief at 55-56).

Fourth, Cape Light Compact argues that the proposed PBR lacks needed performance metrics (Cape Light Compact Brief at 56, citing Exh. CLC-PLC-1, at 18). Specifically, Cape Light Compact claims that the PBR lacks specific metrics that will affect the Companies' revenues and, instead, only includes metrics that track spending without any link to performance (Cape Light Compact Brief at 56-57). Cape Light Compact argues that actual incentive mechanisms are needed to ensure progress towards the Companies' goals and benefits from the PBR (Cape Light Compact Brief at 57). Cape Light Compact further suggests that the Department should also establish performance metrics and penalties related to how well the Companies work with public agencies on issues such as equipment aesthetics, pole safety, the coordination of public-way construction, communication regarding service reliability and restoration, and land-use planning (Cape Light Compact Brief at 58-59).

Fifth, Cape Light Compact argues that the earnings sharing mechanism unfairly benefits the Companies (Cape Light Compact Brief at 59). Specifically, Cape Light Compact claims that the earnings sharing mechanism allows the Companies to retain all earnings in the proposed deadband and the majority of the earnings above the deadband (Cape Light Compact Brief at 59). Because the Companies will receive a smaller percentage of earnings at the highest levels of the earnings sharing mechanism, Cape Light Compact argues that the

earnings sharing mechanism gives the Companies little incentive to innovate and achieve efficiencies that benefit ratepayers (Cape Light Compact Brief at 58). Cape Light Compact urges the Department to adopt an earnings sharing mechanism that gives the majority of initial earnings to ratepayers and increases the Companies' percentage as earnings and the Companies' risk increases (Cape Light Compact Brief at 59).

Sixth, Cape Light Compact argues that the Department should adopt a five-year term for the PBR (Cape Light Compact Brief at 60). Cape Light Compact claims that this measure is necessary to maximize the Companies' incentives to be efficient and protect ratepayers (Cape Light Compact Brief at 60). To the extent the Department determines it is permitted by Section 94, Cape Light Compact maintains that the Department should review the Companies' rate schedules after five years and then extend the PBR term by an additional two years (Cape Light Compact Brief at 60-61).

4. CLF

CLF argues that the Department should reject the proposed PBR because it is not in the public interest (CLF Brief at 13-14). CLF claims that the proposed PBR is deeply flawed and will result in unreasonable rate increases without providing any incentive for the Companies to make efficient investments that serve the public interest (CLF Brief at 13-14). According to CLF, any argument that the annual rate increases are needed to address negative sales growth fails because the Companies have had negative sales growth since 2005, without a corresponding loss in revenues (CLF Brief at 18).

CLF makes three specific critiques of the proposed PBR formula (CLF Brief at 17). First, CLF argues that the deadband in the earnings sharing mechanism is too large and the sharing percentages skew towards the Companies (CLF Brief at 17). According to CLF, the earnings sharing mechanism gives the Companies a disproportionate share of the benefit, discouraging them from taking risks for the ratepayers' benefit (CLF Brief at 17).

Second, CLF argues that the Companies have not justified an inflation floor of one percent (CLF Brief at 17). CLF argues the inflation floor and lack of an inflation ceiling provide asymmetric benefits that favor the Companies (CLF Brief at 17).

Third, CLF argues that the proposed X factor is too low (CLF Brief at 17). CLF claims that it will increase rates faster than necessary, resulting in a windfall for the Companies (CLF Brief at 17).

5. DOER

DOER asserts that, although the PBR does not require the Companies to make any investments in the distribution system or grid modernization, the PBR will allow the Companies to collect an additional $507 million in revenues over five years (DOER Brief at 18). According to DOER, because the Companies would receive these additional revenues regardless of their actions, the Companies will have an incentive to keep hundreds of millions of dollars and not invest in the distribution system (DOER Brief at 19). DOER argues that, without explicit incentives or investment requirements, the PBR lacks the necessary regulatory oversight (DOER Brief at 19-20). In contrast, DOER maintains that while a capital tracker does not require investment, it would at least tie revenues to actual

investment, provide incentives to the Companies, and be less costly than the PBR (DOER Brief at 20-21; DOER Reply Brief at 7-9). For these reasons, DOER asserts that the Department should reject the PBR and implement a capital tracker to address the Companies' capital investments (DOER Brief at 21-22; DOER Reply Brief at 7-9).

Should the Department wish to implement incentive-based ratemaking, instead of a capital tracker, DOER argues that the Department should make two changes to the Companies' proposed PBR. First, DOER asserts that the annual PBR increase should only be a percentage of the base rates that the Department sets in this proceeding and not compound previous annual PBR increases (DOER Reply Brief at 10-12).

Second, DOER argues that the proposed PBR should be streamlined by eliminating the exogenous cost factor and the earnings sharing mechanism (DOER Reply Brief at 13). DOER claims that both of these variables could result in contested proceedings each year and add to the administrative burden (DOER Reply Brief at 13). According to DOER, eliminating the exogenous cost factor and earnings sharing mechanism would increase the PBR's efficiency (DOER Reply Brief at 13).

6. Sunrun and EFCA

Sunrun and EFCA argue that the Companies have failed to show that the proposed PBR will result in just and reasonable rates (Sunrun and EFCA Brief at 5). Sunrun and EFCA also maintain that the Companies have not shown that the PBR is more likely than current regulation to advance the goals of safe, reliable, and least cost energy service (Sunrun and EFCA Brief at 5, citing D.P.U. 96-50 (Phase I) at 241-242).

Sunrun and EFCA argue that the proposed PBR will put ratepayers at risk because it lacks performance metrics as required by Department precedent (Sunrun and EFCA Brief at 5, citing D.P.U. 96-50 (Phase I) at 241-242). Further, Sunrun and EFCA argue that ratepayers will be left without legitimate protection from questionable projects the Companies may undertake because the Companies claim that cost recovery could be withheld only if the Companies fundamentally neglect their obligations (Sunrun and EFCA Brief at 12).

Finally, Sunrun and EFCA dispute the Companies' claim that the proposed PBR will save $70 million by eliminating the need for capital cost recovery mechanisms (Sunrun and EFCA Brief at 5, citing Exhs. ES-PBRM-1, at 65; DPU-40-8; Tr. 2, at 421-423). According to Sunrun and EFCA, it is not plausible that the Companies will need capital cost recovery mechanisms because the Companies have not filed a rate case in years and have still earned a reasonable return (Sunrun and EFCA Brief at 5).

7. UMass

UMass argues that the Department should reject the PBR and, instead, approve a capital cost recovery mechanism for the Companies (UMass Brief at 3). UMass claims that the Companies have not demonstrated that a capital cost recovery mechanism is inadequate or, alternately, why a PBR is necessary to achieve the Companies' goals (UMass Brief at 3). UMass asserts that the Companies have admitted that, without the PBR, they have started grid modernization, provided top-tier service quality, implemented cost reductions, and made tremendous progress with productivity (UMass Brief at 10-11, citing Exh. ES-CAH-1, at 6;

Tr. 1, at 6, 66-68, 351-356, 391). UMass argues that these achievements demonstrate that a PBR is not necessary (UMass Brief at 3, 11).

Moreover, UMass argues that the proposed PBR is inappropriate because it places additional and unnecessary risk on ratepayers (UMass Brief at 4). Under a capital cost recovery mechanism, UMass argues that the Companies would have to fund their capital investments and then seek recovery by showing the prudence of those investments (UMass Brief at 4). UMass contends that this scenario forces the Companies to bear the initial risk of capital investments (UMass Brief at 4). Under the PBR, however, UMass argues that the Companies would receive upfront funding for capital projects and they would keep that funding regardless of a project's prudence (UMass Brief at 4). Therefore, UMass argues that the PBR attempts to shift the financial burden of an imprudent capital project from the Companies to ratepayers (UMass Brief at 4). While UMass maintains that future capital investment is necessary, it argues that the risk of the investments should fall on the Companies and not ratepayers (UMass Brief at 4-5).

8. Vote Solar

Vote Solar argues that Department should reject the proposed PBR because it lacks the performance metrics that are required by Department precedent for ratepayer protection (Vote Solar Brief at 12-13, citing Incentive Regulation, D.P.U. 94-158, at 34 (1995)). Vote Solar argues that the existing service quality metrics do not relieve the Companies of their obligation to adopt separate performance metrics related to the PBR (Vote Solar Reply Brief

at 6). According to Vote Solar, without the required metrics, the Companies have not met their burden to demonstrate that the PBR is in the public interest (Vote Solar Brief at 12-13).

With respect to the proposed X factor, Vote Solar argues that Eversource accepts that total output consists of all services that the Companies produce and, therefore, the Companies' reliance on customer count as the TFP study's output results in a skewed X factor (Vote Solar Brief at 6-7, citing Tr. 3, at 493-494, 497-489). Vote Solar asserts that while customer count is a convenient output choice, it underestimates the Companies' outputs and decreases the X factor because customer count is not a key driver of costs (Vote Solar Brief at 6-7). In addition, Vote Solar argues that Companies' X factor calculation is very volatile (Vote Solar Brief at 9-10). Vote Solar contends that the Companies' analysis shows significant year-to-year variation in productivity and the Companies have not shown that their selective averaging of data has addressed this volatility and produced a reliable X factor (Vote Solar Brief at 9-10, citing Exhs. VS-RB-Surrebuttal-1, at 10-11; AG/DED-1, at 64). Because the Companies' TFP study is not robust enough to be reliable, Vote Solar argues that the Department should not adopt the Companies' proposed X factor (Vote Solar Brief at 9-10).

If the Department implements a PBR, Vote Solar claims that its own analysis eliminates the volatility from the Companies' analysis (Vote Solar Brief at 12-13). Rather than using a TFP study, Vote Solar calculates an annual allowed revenue growth by using the average annual revenue growth from the utilities in the Companies' TFP study (Vote Solar Brief at 13, citing Exhs. VS-RB-1, at 33; DPU-VS-1-7). Vote Solar asserts that those

utilities had average annual revenue growth of 2.33 percent and, therefore, a reasonable X factor is an amount that when subtracted from inflation equals 2.33 percent (Vote Solar Brief at 15).

9. Companies

The Companies argue that the Department should approve its PBR, as proposed, as it will result in just and reasonable rates (Companies Reply Brief at 31-32). According to Eversource, its proposed PBR formula replicates the average cost trend for the electric distribution industry and no party has refuted its justification for the PBR (Companies Reply Brief at 31-32). Further, Eversource argues that no party has offered a viable alternative to the PBR as proposed (Companies Reply Brief at 31-32).

The Companies claim that the intervenors fail to address or misconstrue the revenue challenges that the Companies face (Companies Brief at 298-300, 306). For example, the Companies assert that, contrary to the intervenors' claims, revenue decoupling does not make the Companies whole for lost sales (Companies Brief at 298). According to the Companies, revenue decoupling only protects against a decline in sales to levels below test year sales (Companies Brief at 298). By contrast, the Companies contend that revenue decoupling does not restore lost sales growth (Companies Brief at 298-300, 306). The Companies argue that, in the past, growth in sales is what has allowed utilities to function without annual rate increases (Companies Brief at 300). Now, with declining sales and costs that grow faster than inflation, the Companies assert that annual PBR rate adjustments are essential (Companies Brief at 298-300).

Further, the Companies argue that, in recent years, they have been able to operate without annual rate increases only because of exceptional circumstances (Companies Brief at 303-308). For example, through mergers and non-merger-related efficiencies, the Companies claim to have had over $600 million in savings opportunities from 1999 through 2009 (Companies Brief at 304). The Companies maintain, however, that these types of savings opportunities are no longer available (Companies Brief at 304-305).[180] Even with these additional revenue sources, the Companies maintain that NSTAR Electric's actual ROE was only 9.44 percent in 2016, as compared to an authorized ROE of 10.5 percent and WMECo's actual ROE was only 5.6 percent, as compared to an authorized ROE of 9.6 percent (Companies Brief at 308).

According to the Companies, the proposed PBR and a capital cost recovery mechanism would each result in annual rate adjustments that would have a similar impact on ratepayers (Companies Brief at 297). Eversource argues, however, that a capital cost recovery mechanism would require the Companies to file at least one rate case during the next five years (Companies Brief at 297, 314-316, citing Exhs. DPU-19-3; DPU-40-8).

In addition, the Companies claim that the intervenors have overstated the financial impact of the PBR (Companies Brief at 314-316). Specifically, the Companies highlight

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[180] Eversource maintains that, from 2006 through 2012, NSTAR Electric was eligible for annual inflation-based adjustments under a rate settlement approved by the Department in D.T.E. 05-85 and, while some adjustments continued through 2012, these revenue opportunities are now gone (Companies Brief at 305). In addition, the Companies maintain that approximately $50 million in annual lost base revenues for NSTAR Electric will end when it adopts revenue decoupling in this proceeding (Companies Brief at 307).

DOER's mistaken claim that the PBR would result in $500 million in rate increases (Companies Brief at 315, citing DOER Brief at 4 n.15). The Companies assert that the $500 million cited by DOER are the five-year aggregate revenues under the PBR, not the sum of the annual rate increases (Companies Brief at 315). Further, the Companies argue that this revenue amount is roughly equivalent to the $498 million in revenues that would be collected if DOER's suggested capital cost recovery mechanism were approved (Companies Brief at 315, citing Exh. DPU-40-8). In addition, the Companies contend the Attorney General's claim that the PBR will result in annual adjustments of $188 million over five years is also overstated (Companies Brief at 315, citing Attorney General Brief at 21).

The Companies also claim that ratepayers will be protected under the PBR because the explicit and implicit stretch factors will require the Companies to perform better than the average utility (Companies Brief at 320). Specifically, Eversource maintains that, because the PBR operates under a revenue cap, the Companies will absorb the additional costs of new customers and these costs will act as an implicit stretch factor (Companies Brief at 36). Further, the Companies assert that, under the PBR, Eversource will continue to be a top-tier performer on service quality and electric reliability (Companies Brief at 321).

The Companies argue that the proposed PBR provides a more efficient regulatory approach than a capital cost recovery mechanism (Companies Brief at 332). Because the Companies have committed to a five-year stay-out period under the PBR, Eversource argues that the PBR will reduce administrative burden and rate case expense (Companies Brief at 317-318). With a decreased administrative burden, the Companies claim that the PBR will

create an environment with a greater focus on cost savings (Companies Brief at 334). By contrast, the Companies assert that a capital cost recovery mechanism imposes a far greater and more costly administrative burden than a PBR (Companies Brief at 332, citing D.P.U. 15-155, at 40). The Companies contend that the annual PBR rate adjustment filings will be much less complex and require substantially fewer resources than capital cost recovery filings (Companies Brief at 332).

Next, the Companies claim that they correctly calculated the proposed X factor (Companies Brief at 337-343, 347-360, 365-371). Eversource disputes the intervenors' claim that the proposed X factor is unlike any other X factor adopted in North America (Companies Brief at 337). The Companies assert that the jurisdictions that have adopted a higher X factor also have adopted capital cost recovery mechanisms or used higher industry inflation levels and, therefore, these factors are comparable to the Companies' all-inclusive PBR (Companies Brief at 337).[181]

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[181] For example, the Companies maintain that the Alberta Utilities Commission essentially implemented a negative X factor in 2016 because it approved a capital cost recovery mechanism on top of the X factor, and used industry inflation indices, instead of the lower economy wide inflation measure that the Companies employ (Companies Brief at 337, citing Tr. 3, at 499-500, 511; RR-DPU-7, at 7). In addition, the Companies argue that the British Columbia Public Utilities Commission, in effect, set a negative X factor, because the 0.93 percent X factor it allowed had only a 0.1 percent stretch factor and included a capital cost recovery mechanism that allowed rate changes from six to eight percent each year (Companies Brief at 337, citing Tr. 3, at 499-500, 511; RR-DPU-7, at 7). The Companies assert that, while the Ontario Energy Board set its X factor at zero, it used the higher industry inflation indices and allowed two supplemental capital cost recovery mechanisms (Companies Brief at 338, citing Report of the Ontario Energy Board (OEB), Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach at 18 (Oct. 18, 2012)). Finally, the Companies argue that the California Public Utilities

Further, Companies argue that the calculation of an X factor must consider the type of inflation used (Companies Brief at 349). Here, the Companies determined inflation based on the general economy, which they claim is appropriate because there are no widely reported measures of industry-specific inflation (Companies Brief at 348-350). Because they did not use a higher, industry-specific measure of inflation, the Companies argue that their proposed X factor appropriately includes adjustments to the industry input price growth and the industry specific TFP growth (Companies Brief at 349).

In addition, the Companies argue that customer count is the appropriate output to use to determine TFP growth (Companies Brief at 352-353, citing Exh. ES-PBRM-Reubuttal-1, at 29-31). For revenue-per-customer caps, the Companies claim that the output should reflect elements associated with revenue generation (Companies Brief at 353). Because rates essentially are determined by limits on the increase in revenue per customer over time, the Companies assert that customer count is the proper output (Companies Brief at 353). In fact, the Companies claim that using customer count as the output produces a more positive X factor than using kWh sales (i.e., -2.64 with customer number vs. -4.04 with kWh sales) (Companies Brief at 352, citing RR-DPU-7).

The Companies maintain that the alternative methods to calculate the X factor, as presented by intervenors, are flawed (Companies Brief at 353). For example, the Companies argue that Vote Solar's proposal to use historical revenue growth to calculate the X factor is

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Commission authorized Southern California Edison Corporation and Pacific Gas & Electric Company to implement annual adjustments in 2016 and 2017 that are similar in percentage terms to the adjustments the Companies seek under the PBR (Companies Brief at 338-339).

faulty because it does not take commodity revenues into account (Companies Brief at 353). Further, the Companies contend that historical revenue growth has never been used as a PBR output (Companies Brief at 353). Additionally, Eversource disputes Vote Solar's argument that the Companies' TFP study is not significantly robust (Companies Reply Brief at 43-44). While Vote Solar claims that the TFP study is too volatile, the Companies argue that the uncontested evidence shows that the TFP study results in an X factor that falls within a 95 percent confidence interval (Companies Reply Brief at 44, citing Tr. 3, at 506-507).

Further, the Companies argue that the time period of the TFP study (i.e., 2001 to 2015) is appropriate because earlier data are not reliable (Companies Reply Brief at 45-47, citing Tr. 3, at 647-648; RR-DPU-7). In earlier periods, the Companies claim that there was a direct correlation between electric usage and economic growth (Companies Reply Brief at 45-47, citing Tr. 3, at 647-648; RR-DPU-7). According to the Companies, however, post-2000 data show that energy efficiency efforts and other conservation measures have created a very wide divergence between electric usage and economic growth (Companies Reply Brief at 45-46, citing Tr. 3, at 647-648). Therefore, the Companies claim that pre-2001 data are unreliable to establish forward-looking rates (Companies Reply Brief at 45-47).

Moreover, the Companies argue that substantial evidence supports the adoption of the PBR, as proposed (Companies Brief at 343). According to the Companies, the Attorney General's PBR witness has no experience determining an X factor and this lack of experience was evident in the significant corrections he made to his calculations (Companies Brief

at 343, citing Exh. Sch. DED-4).[182] Further, the Companies criticize the sample size in the Attorney General's TFP study (Companies Brief at 355). The Companies argue that the Attorney General's witness, without justification, truncated the number of companies in Eversource's study (Companies Brief at 355). The Companies claim that removing such data from their study is a substantial flaw that undermines the Attorney General's entire analysis of the X factor (Companies Brief at 355). In addition, the Companies argue that the Department should give no weight to the Attorney General's claim that the Companies should have included Maine utilities in their study (Companies Brief at 355; Companies Reply Brief at 48). Eversource contends that the Attorney General presented no evidence to show that Maine utilities are peers to the Companies (Companies Brief at 355; Companies Reply Brief at 48).

The Companies also argue that the Attorney General's witness used an improper method (i.e., the geometric decay method) for determining capital input quantity (Companies Brief at 355-356; Companies Reply Brief at 49). The Companies claim that the Attorney General's witness did not have the data needed to properly use the geometric decay method, asserting that essential data were missing for more than 20 percent of the sample companies (Companies Brief at 356). Further, the Companies contend that the Attorney General's witness did not explain why excluding 20 percent of the companies from his sample did not compromise the analysis of capital input quantity (Companies Brief at 356).

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182 The Companies argue that, after correcting mistakes, the Attorney General's witness changed his calculation of the X factor from 0.73 percent to -1.36 percent (Companies Brief at 343).

Separately, Eversource disputes the Attorney General's argument that the method used by the Companies to determine capital input quantity (i.e., the one hoss shay method) does not account for the gradual depreciation of capital and leaves capital stock undepreciated until it is retired (Companies Brief at 368). According to Eversource, the Bureau of Labor Statistics ("BLS"), which is the federal agency that develops multi-factor productivity studies, uses a method that is similar to the method used by the Companies (Companies Brief at 368-370; Companies Reply Brief at 49). Additionally, the Companies dispute the Attorney General's claim that the Companies' expert has used the geometric decay method in previous testimony and studies (Companies Brief at 370, citing Exh. AG-10; Tr. 3, at 556, 564-565). Instead, the Companies assert that its witness used the one hoss shay method to determine capital input quantity in the cited study and testimony (Companies Brief at 370, citing Exhs. AG-6; AG-8; AG-10; Tr. 3, at 556, 563-575).

Additionally, Eversource disputes the Attorney General's claims regarding sample weighting in the Companies' TFP study (Companies Brief at 357). The Companies assert that they appropriately weighted the study companies by the number of customers each serves, which they maintain is consistent with their use of customer growth as the study's output measure (Companies Brief at 357-358). According to the Companies, using a simple average of the peer company's group average, as suggested by the Attorney General, would incorrectly give the same weight to small and large utilities even though small utilities are unlikely to be representative of the customer growth experienced by larger utilities like Eversource (Companies Brief at 358). The Companies further contend that using a simple

average inappropriately would give the ten smallest utilities in the study the same weight as the ten largest utilities, when the ten largest utilities serve over 18 times more customers (Companies Brief at 358-359). Therefore, the Companies argue that their use of sample weighting is correct (Companies Brief at 358-359).

Next, the Companies dispute the Attorney General's contention that a productivity analysis should include customer accounts, customer sales, and a portion of administrative and general expenses (Companies Brief at 359-360; Companies Reply Brief at 49). The Companies claim that these expenses include non-distribution costs; however, there is no dispute that a TFP study should include only distribution expenses (Companies Brief at 359; Companies Reply Brief at 49). By using these expenses, the Companies argue that the Attorney General's witness has "contaminated" his productivity analysis with non-distribution cost elements (Companies Brief at 360; Companies Reply Brief at 49).

The Companies argue that Attorney General's witness further distorted his productivity analysis by attributing 100 percent of general plant to distribution services (Companies Brief at 365-66, citing Exh. ES-PBRM-Rebuttal-1, at 44-45). The Companies claim that when the Attorney General's witness tried to correct this error, he again applied a higher percentage of general plant than intended to distribution services (Companies Brief at 366-367, citing Tr. 13, at 2694). Therefore, the Companies argue that the Attorney General's productivity analysis is not reliable (Companies Brief at 366-367).

The Companies dispute the Attorney General's claim that there is no record evidence showing negative productivity growth in the electric distribution industry over the last

15 years (Companies Reply Brief at 42-43). The Companies maintain that the Attorney General attempted to support her position by using the BLS utilities sector data (Companies Reply Brief at 42-43, citing Attorney General Reply Brief at 86). Eversource asserts, however, that the electric distribution industry and the utilities sector are distinct (Companies Reply Brief at 43). According to the Companies, the BLS utilities sector includes data for many industries such as natural gas, steam, water, sewage removal, electric generation, and electric transmission and, therefore, that data are not representative of the electric distribution industry (Companies Reply Brief at 43, citing Tr. 3, at 506-507). Conversely, the Companies argue that their TFP study presents the only reliable data regarding productivity growth in the electric distribution industry (Companies Reply Brief at 43).

Further, the Companies argue that there is no merit in the intervenors' critiques of the other elements of the PBR. For example, the Companies argue that the PBR is not excessively focused on cost recovery (Companies Brief at 322). Instead, Eversource argues that Department precedent fully intended incentive ratemaking to act as a substitute for cost of service ratemaking, which is, according to the Attorney General's own witness, a form of cost recovery (Companies Brief at 322, citing D.P.U. 94-158, at 42-43; Exh. ES-9).

The Companies also argue that an inflation floor of one percent is required to ensure the Companies have the necessary revenue support to implement required capital investments (Companies Brief at 34). Further, the Companies assert that the proposed consumer dividend of 25 basis points when inflation is greater than two percent is appropriate and shows the

Companies' commitment to give customers a tangible benefit in the PBR (Companies Brief at 36).

The Companies do not agree with DOER's position that the annual PBR rate adjustments only should be a percentage of the base rates set in this proceeding (Companies Reply Brief at 54). According to the Companies, the costs that drive the need for a PBR are cumulative and, therefore, the annual adjustments should be cumulative, as well (Companies Reply Brief at 54).

In addition, the Companies dismiss the Attorney General's and Cape Light Compact's arguments regarding extending the length of the stay-out period (Companies Brief at 372-373). The Companies assert that they have committed to a five-year stay-out period (Companies Brief at 372-373). The Companies argue that extending the stay-out period beyond five years is inappropriate because, in the past, stay-out periods in excess of five years have been problematic (Companies Brief at 372-373).

In addition, the Companies claim that the earnings sharing mechanism's current structure should not be changed, as suggested by the Attorney General and Cape Light Compact, because the mechanism will provide the correct incentives during the stay-out period (Companies Brief at 372-373). The Companies argue that their proposed deadband is narrower and more favorable to ratepayers than other earnings sharing mechanisms that the Department has approved (Companies Brief at 38, citing D.P.U. 96-50 (Phase I) at 326; D.T.E. 03-40, at 500; D.P.U. 05-27, at 405). Further, the Companies argue that DOER's recommendation to eliminate the earnings sharing mechanism and exogenous cost factor is

inappropriate because they are both basic and essential elements of the PBR (Companies Reply Brief at 55).

In response to intervenors' arguments regarding performance metrics to protect ratepayers during the term of the PBR, the Companies maintain that they will continue to be subject to the existing service qualities metrics with specific, measurable results (Companies Brief at 324-325). The Companies claim that the existing service quality metrics and the potential for service quality penalties address concerns regarding a lack of transparency under the PBR and ensure that there will be Department oversight throughout the PBR term (Companies Brief Reply at 42). Further, the Companies argue that the stretch factors within the PBR operate as measurable achievement indicators (Companies Brief at 325).

In sum, the Companies argue that their proposed PBR formula replicates the average cost trend for the electric distribution industry and will produce just and reasonable rates (Companies Reply Brief at 31-32). Eversource maintains the proposed PBR will provide the necessary revenues to address declining sales, while eliminating the significant administrative burden that would result from a capital cost recovery mechanism (Companies Brief at 297-300, 314-16, 332, 334). Further, the Companies assert that both the explicit and implicit stretch factors in the PBR will protect ratepayers and ensure that Companies perform at a high level (Companies Brief at 320). For these reasons, the Companies argue that the Department should approve the PBR as proposed (Companies Brief at 320).

D. Analysis and Findings

1. Introduction

In the sections below, we review our ratemaking authority and reaffirm that, pursuant to Section 94, the Department may implement PBR as an adjustment to cost of service/rate of return regulation. Further, we discuss the factors the Department has used to review incentive regulation proposals. Finally, we review the Companies' PBR, as proposed, to determine whether it is in the public interest and will result in just and reasonable rates.

2. Department Ratemaking Authority

Pursuant to Section 94, the Legislature has granted the Department extensive ratemaking authority over electric and local gas distribution companies. The Supreme Judicial Court has consistently found that the Department's authority to design and set rates is broad and substantial. E.g., Boston Real Estate Board v. Department of Public Utilities, 334 Mass. 477, 485 (1956). Because Section 94 authorizes the Department to regulate the rates, prices, and charges that electric and local gas distribution companies may collect, this authority includes the power to implement revenue adjustment mechanisms such as a PBR. See Boston Gas Company v. Department of Telecommunications and Energy, 436 Mass. 233, 234-235 (2002).

The Department is not compelled to use any particular method to establish rates, provided that the end result is not confiscatory (i.e., deprives a distribution company of the opportunity to realize a fair and reasonable return on its investment). Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 19 (1978). The Supreme Judicial Court has held that a basic principle of ratemaking is that "the [D]epartment is free to select

or reject a particular method as long as its choice does not have a confiscatory effect or is not otherwise illegal." American Hoechest Corporation v. Department of Public Utilities, 379 Mass. 408, 413 (1980), citing Massachusetts Electric Company v. Department of Public Utilities, 376 Mass. 294, 302 (1978).

In addition, G.L. c. 164, § 76 grants the Department broad supervision over electric and local gas distribution companies. Under G.L. c. 164, § 76, the Department has the authority to establish reasonable rules and regulations consistent with c. 164, as needed, to carry out its administration. D.P.U. 07 -50-B at 26-27. See also Cambridge Electric Light Company v. Department of Public Utilities, 363 Mass. 474, 494-496 (1973).

Although the Department traditionally has relied on cost of service/rate of return regulation to establish just and reasonable rates, there are many variations and adjustments in the specific application of this model to individual utilities as circumstances differed across companies and across time. D.P.U. 07-50, at 8. Over the years, many electric and local gas distribution companies subject to the Department's jurisdiction have operated under PBR or PBR-like plans. See e.g., D.T.E. 05-85; D.T.E. 05-27; D.T.E. 03-40; D.T.E. 01-56; D.T.E. 01-50; D.T.E. 99-47, at 4-14.

Consistent with the discussion above, the Department reaffirms that we may implement PBR as an adjustment to cost of service/rate of return regulation under the broad ratemaking authority granted to us by the Legislature under Section 94.[183] The standards by

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[183] In addition, pursuant to G.L. c. 164, § 1(E), the Department is authorized to promulgate rules and regulations to establish and require performance based rates for gas and electric distribution companies.

which the Department will review the Companies' specific PBR proposal are addressed below.

3. Evaluation Criteria for PBR

The Department must approach the setting of rates and charges in a manner that (1) meets our statutory obligation under Section 94 to ensure rates that are just and reasonable, not unjustly discriminatory, or unduly preferential, and (2) is consistent with long-standing ratemaking principles including fairness, equity, and continuity. D.P.U. 07-50, at 10-11. Further, the Department must establish rates in a manner that balances a number of these key principles to reflect and address the practical circumstances attendant to any individual company's rate case. D.P.U. 07-50-A at 28. The Department has implemented PBRs or PBR-like mechanisms when it has found that such regulatory methods would better satisfy our public policy goals and statutory obligations. See e.g., D.P.U. 96-50 (Phase I) at 261; D.P.U. 94-158, at 42-43; NYNEX Price Cap, D.P.U. 94-50, at 139 (1995).

As part of our generic investigation of incentive ratemaking in D.P.U. 94-158, the Department examined the criteria by which PBR proposals for electric and local gas distribution companies would be evaluated. D.P.U. 94-158, at 52-66. The Department found that, because incentive regulation acts as an alternative to traditional cost of service regulation, incentive proposals would be subject to the standard of review established by Section 94 which requires that rates be just and reasonable. D.P.U. 94-158, at 52. Further, the Department determined that a petitioner seeking approval of an incentive regulation proposal like PBR is required to demonstrate that its approach 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. D.P.U. 94-158, at 57. Finally, the Department stated that well-designed incentive mechanisms should provide utilities with greater incentives to reduce costs than currently exist under traditional cost of service regulation and should result in benefits to customers that are greater than would be present under current regulation. D.P.U. 94-158, at 57.

In addition to these criteria, the Department established a number of additional factors it would weigh in evaluating incentive proposals. D.P.U. 94-158, at 57. These factors provide that a well-designed incentive proposal should: (1) comply with Department regulations, unless accompanied by a request for a specific waiver; (2) be designed to serve as a vehicle to a more competitive environment and to improve the provision of monopoly services; (3) not result in reductions of safety, service reliability, or existing standards of customer service; (4) not focus excessively on cost recovery issues; (5) focus on comprehensive results; (6) be designed to achieve specific, measurable results; and (7) provide a more efficient regulatory approach, thus reducing regulatory and administrative costs. D.P.U. 94-158, at 58-64. The Department discusses these criteria and factors in the context of our evaluation of Eversource's PBR proposal in the subsections below.

4. Rationale for PBR

There is a fundamental evolution taking place in the way electricity is produced and consumed in Massachusetts. This evolution has been driven, in large part, by a number of

legislative and administration policy initiatives designed to address climate change and foster a clean energy economy through the promotion of energy efficiency, demand response, and distributed energy resources, and the procurement of long-term contracts for renewable energy. An Act Relative To Green Communities, St. 2008, c. 169 ("Green Communities Act"); An Act Establishing the Global Warming Solutions Act, St. 2008, c. 298 ("Global Warming Solutions Act"); An Act Relative to Competitively Priced Electricity in the Commonwealth, St. 2012, c. 209, § 36 ("Green Communities Act Expansion"); Global Warming Solutions Act, § 83; Green Communities Expansion Act, § 83A; Establishing an Integrated Climate Change Strategy for the Commonwealth, Executive Order No. 569, Office of the Governor, Commonwealth of Massachusetts (September 16, 2016). To varying degrees, this evolution is changing the operating environment for electric distribution companies in Massachusetts.

As described above, the Companies propose to implement PBR that would adjust rates annually in accordance with a revenue cap formula (Exh. ES-GWPP-1, at 9). The Companies maintain that, given specific changes that have taken place as a result of the Commonwealth's aggressive efforts to achieve clean energy goals, they no longer can operate effectively under cost of service regulation (Exh. ES-GWPP-1, at 19-25; Companies Brief at 298-300, 306). No longer able to retain sales growth revenues between rate cases after decoupling, the Companies maintain that PBR is essential for them to offset the effects of increasing operating and capital costs (Exh. ES GWPP-1, at 20; Tr. 2, at 413-415; Companies Brief at 298-300). And, unlike a capital cost recovery mechanism, Eversource

maintains that the proposed PBR is designed to provide it with strong incentives to control costs (Exh. ES-GWPP-1, at 11; DPU-19-2; DPU-19-3; DPU-19-10; DPU-19-22; DPU-24-18; DPU-44-2; AG-18-3; AG-18-4; AG-33-4; VS-1-1; Tr. 8, at 1518; Companies Brief at 16, 29, 318-319, 323, 332, 336).

Conversely, a number of intervenors argue that the Companies' proposed PBR is not in the public interest and should be rejected in its entirety (Attorney General Reply Brief at 77; Acadia Center Brief at 13-14; Cape Light Compact Brief at 45, 61-62; CLF Brief at13-14; DOER Brief at 21-22, Sunrun and EFCA Brief at 5; UMass Brief at 3; Vote Solar Brief at 12-13). The Attorney General argues that Eversource's proposed PBR is excessively focused on cost recovery in contravention of D.P.U. 94-158, at 58-64 (Attorney General Brief at 10-12, 20). In addition, intervenors claim that Eversource has operated very effectively in recent years and can continue to operate effectively under cost of service regulation (Attorney General Reply Brief at 5; Acadia Center Brief at 13-14; CLF Brief at 18; DOER Brief at 20-21, Sunrun and EFCA Brief at 5-7; UMass Brief at 3, 10-11; Vote Solar Brief at 12-13). Further, in lieu of PBR, intervenors maintain that a capital cost recovery mechanism would adequately address the challenges the Companies face as a result of the changing dynamics in the electric distribution industry (Attorney General Reply Brief at 38-39; Acadia Center Brief at 13-14; Acadia Center Reply Brief at 13; CLF Brief at 15; DOER Brief at 20-24; DOER Reply Brief at 7-9; NECEC Brief at 19-20, 23; Sunrun and EFCA Brief at 24; TEC and WMIG Brief at 8; UMass Brief at 3).

For the reasons discussed below, the Department finds that the Companies have demonstrated that they require an alternative to traditional cost of service/rate of return ratemaking. Further, the Department finds that, based on the evidence presented in this case, the Companies have demonstrated that PBR, as compared to a capital cost recovery mechanism, will provide them with greater incentives to reduce costs and will result in benefits to customers that are greater than would be present under current regulation.

Stakeholder efforts to pursue the Commonwealth's clean energy goals have been remarkably successful. For example, Massachusetts has earned the number one ranking for the seventh consecutive year in the American Council for an Energy-Efficient Economy's State Energy Efficiency Scorecard.[184] Eversource has demonstrated that a primary effect of the Commonwealth's clean energy efforts has been a decline in its levels of kWh sales (Exhs. ES-GWPP-1, at 23-24; Attachment DPU-19-3, at 3, 10; AG-18-15; SREF-1-4). Between 1995 and 2005, the Companies experienced average annual sales growth of 2.25 percent (Exhs. DPU-47-1; AG-18-15; SREF-1-4). From 2006 to 2016, however, the Companies experienced an average annual decline in sales of 0.44 percent (Exhs. Attachment DPU-19-3, at 3, 10; DPU-47-1; AG-18-15; SREF-1-4).

At the same time as its sales are declining, Eversource has shown that its distribution system is growing and that its capital and operating costs are increasing in ways that it has not experienced in the past (Exhs. ES-GWPP-1, at 19-22, 41, 74-75; DPU-47-1). Factors driving Eversource's increasing costs include: (1) system reliability improvements;

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184 See www.mass.gov/eea/pr-2017/massachusetts-named-most-energy-efficient-state.html.

(2) system resiliency improvements to address the effects of climate change; (3) distribution system changes to allow for two-way power flows; (4) cyber-security needs; and (5) mitigation of environmental impacts related to distribution infrastructure (Exh. ES-GWPP-1, at 19-20, 41-42, 74-75).

Between rate cases, electric distribution companies, such as Eversource, have traditionally relied on revenues from sales growth to fund capital investments that are intended to ensure safe and reliable service (Exh. DPU-19-19; Tr. 2, at 464-466). See, e.g., D.P.U. 15-155, at 22-23, 40; D.P.U. 13-90, at 35; D.P.U. 10-70, at 47. While revenue decoupling protects existing sales revenues,[185] it does not address the loss of sales growth revenues between rate cases, which Eversource has historically relied upon (Exh. DPU-19-19; Tr. 2, at 464-468).

In response to decoupling, the Department has allowed companies to adopt various capital cost recovery mechanisms in cases where a company has adequately demonstrated its need to recover incremental costs associated with capital expenditure programs between base distribution rate cases. D.P.U. 15-155, at 40, 51-54; D.P.U. 15-80 at 50; D.P.U. 10-55, at 121-122, 132-133; D.P.U. 09-39, at 79-80, 82; D.P.U. 09-30, at 133-134. Despite intervenors' assertions to the contrary, we find that Eversource has demonstrated that

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185 In 2008, the Department implemented revenue decoupling in order to remove the disincentive for local gas and electric distribution companies to invest in measures, such as energy efficiency, that reduced sales. D.P.U. 07-50-A at 4. The Department found that revenue decoupling: (1) aligns the financial interests of the companies with policy objectives regarding the efficient deployment of demand resources; and (2) ensures that the companies are not harmed by decreases in sales associated with any increased use of demand resources. D.P.U. 07-50-A at 31-32, 48-50.

declining sales, combined with lost sales growth has resulted in negative revenue impacts for the Companies (Exhs. ES-GWPP-1, at 11, 23-24; 40-41; DPU-19-3; DPU-24-4; AG-18-3; AG-21-7; Tr. 1, at 71-72).

For the reasons discussed above, we find that Eversource has demonstrated that a change is warranted in this case with respect to the Department's historical ratemaking approach (Exhs. DPU-19-2; DPU-19-9; DPU-19-10; DPU-19-19; DPU-24-18; DPU-24-23; DPU-44-2; DPU-47-1; AG-18-15, Att.; AG-28-6; Tr. 1, at 17-19; Tr. 4, at 789-792). The approach we adopt must address lost sales growth and allow Eversource to best meet its public service obligations in terms of providing safe, reliable, least-cost service to customers and ensure that the Commonwealth's clean energy goals are met. D.P.U. 94-158, at 57.

The Attorney General maintains that the Companies' PBR proposal is overly focused on cost recovery and, therefore, should be rejected (Attorney General Brief at 10-12, 20, citing D.P.U. 94-158). A PBR, like all ratemaking mechanisms, must have a certain focus on cost recovery. Here, the Department finds that a main focus of the proposed PBR is to allow the Companies to effectively meet their public service obligation and, therefore, is not overly focused on cost recovery.

As noted above, several intervenors suggest that a capital cost recovery mechanism may be an appropriate substitute for PBR in this case[186] (Attorney General Reply Brief at 38-39; Acadia Center Brief at 13-14; Acadia Center Reply Brief at 13; CLF Brief at 15;

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[186] As discussed in Section X.B.3 below, the Department has determined that it is in the public interest to remove the grid modernization base commitment investments from the PBR. Accordingly, the capital cost recovery mechanism we address here would be designed to recover capital investment costs unrelated to grid modernization.

DOER Brief at 20-24; DOER Reply Brief at 7-9; NECEC Brief at 19-20, 23; Sunrun and EFCA Brief at 24; TEC and WMIG Brief at 8; UMass Brief at 3). For the reasons discussed below, the Department finds that Eversource has demonstrated that a capital cost recovery mechanism would not be superior to PBR based on the facts and circumstances of this case.

With a capital cost recovery mechanism, the Companies have shown that they would file at least one (and possibly two) base rate cases over the next five years (Tr. 1, at 79-80; Tr. 2, at 368, 422, 424, 432, 448-449; Tr. 3, at 485-486). By comparison, the Companies have committed to refrain from filing a base rate case during the five-year term of the PBR (see Section IX.5.g below) (Exh. AG-33-8; Tr. 2, at 421-422). In addition, review of capital cost recovery mechanism filings can result in significant administrative burden and expense as compared to review of annual PBR filings, which should be less complex and require fewer resources. See, e.g., D.P.U. 15-155, at 36, 60, 86-89, 136. Accordingly, the Department finds that PBR will reduce administrative burden. Further, we find that PBR will reduce the potential for multiple rate cases where all distribution costs are updated (with the attendant rate case expense) (Tr. 3, at 634).

In addition, the Department finds that Eversource has demonstrated that PBR is superior to a capital cost recovery mechanism in terms of its ability to satisfy the Department's public policy goals and statutory obligations. Rather than directing its focus on specific capital investments, PBR will provide the Companies with greater incentives to be efficient and allow them to focus on developing innovative solutions in furtherance of the

Commonwealth's clean energy goals[187] (Exhs. ES-GWPP-1, at 9-10; DPU-19-2; Attachment DPU-19-3; DPU-19-10; DPU-19-9; DPU-19-22; DPU-24-18; DPU-44-2; AG-18-3; AG-18-4; AG-33-4; VS-1-1; Tr. 8, at 1518).

Finally, we are not persuaded by the Attorney General and DOER's arguments that the revenue stream generated by the PBR would be significantly higher than that of a capital cost recovery mechanism (Exhs. Attachment DPU-19-3, at 8-11; DPU-40-8; DPU-24-23; Tr. 2, at 422, 424). Instead, the Department finds that, after factoring in the number of likely base rate increases over a five-year period, a capital cost recovery mechanism and PBR would generate comparable revenue streams (Exhs. Attachment DPU-19-3, at 8-11; DPU-24-23; DPU-40-8; DPU-44-5; Tr. 2, at 422, 424).

Based on the findings above, the Department has determined that Eversource has demonstrated that PBR is more likely than current regulation to advance the Department's goals of safe, reliable, and least-cost energy service, while also promoting the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation. D.P.U. 94-158, at 57. In addition, the Department has determined that PBR will provide the Companies with greater incentives to reduce costs and should result in benefits to customers that are greater than would be present under current regulation. D.P.U. 94-158, at 57. Finally, the Department has determined that PBR will allow the Companies to focus on cost saving and innovation, which will enable initiatives designed to address climate

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187 As discussed in Section IX.D.h below, the Department intends to develop a number of PBR-specific metrics to measure the Companies' performance and the full range of benefits that will accrue under the PBR.

change and foster a clean energy economy, in furtherance of the Commonwealth's clean energy goals. Below, the Department addresses the PBR formula elements and whether the proposed formula, as a whole, appropriately balances ratepayer and shareholder risk and will result in just and reasonable rates.

5. PBR Formula Elements

a. Productivity Offset

i. Introduction

In the context of a PBR, a productivity offset, or X factor, is the difference between the differential in expected productivity growth between the electric-distribution industry and the overall economy and the differential in expected input price growth between the overall economy and the electric distribution industry (Exhs. ES-GWPP-1, at 46). In combination with the inflation factor, the X factor is designed to represent the expected unit cost performance of an average performing company in the industry (Exhs. ES-GWPP-1, at 46; ES-PBRM-1, at 45). As described above, Eversource calculated a proposed productivity offset in the instant case equal to -2.64 percent (RR-DPU-8). Although she does not argue on brief that the Department should adopt it, the Attorney General's witness calculates a productivity offset of -1.36 percent for her nationwide LDC sample and -0.95 percent for her regional LDC sample (Exh. AG/DED-Surrebuttal-1, Sch. DED-Surrebuttal-1, at 1).

The Attorney General maintains that the Companies' proposed X factor is lower than any X factor approved to date for a North American energy utility (Attorney General Brief at 24-27). Further, the Attorney General argues that Eversource's proposed productivity offset is unsupported by reliable measures of U.S. utility productivity growth (Attorney

General Brief at 24-27). The Companies counter that, while other jurisdictions may have approved X factors that are higher, these jurisdictions have also adopted capital cost recovery mechanisms or used industry inflation levels that, when taken into consideration, make the Companies' proposed X factor comparable (Companies Brief at 337). Further, regarding the measures of utility productivity cited by the Attorney General, Eversource argues that BLS data are not strictly limited to the electric distribution industry and, therefore, are not a useful measure of the Companies' productivity (Companies Reply Brief at 43).

The Attorney General notes that no other jurisdiction in North America has approved a negative X factor to date (Exh. AG/DED-1, at 47-48; Tr. 3, at 583-585). This fact does not, however, preclude the possibility of an X factor that is negative. In fact, other jurisdictions have acknowledged that an X factor may be positive or negative (Exh. VS-1-13, Att. (a) at 48). Whether an X factor is positive or negative is determined solely by the relationship between outputs and inputs in a given industry, and there is no reason to dismiss the possibility that the electric distribution industry may be in a period exhibiting changes that result in decreasing output given a similar or increasing level of inputs (see Exh. ES-PBRM-1, at 47). For these reasons, the Department cannot find that the proposed X factor is unreasonable merely because it is negative or lower than any productivity offset approved to date. Rather, in the sections below, the Department reviews the Companies' TFP study to determine whether it was conducted in a reasonable manner using appropriate assumptions.

ii. TFP Study Parameters

To determine the proposed X factor, Eversource conducted a productivity study of U.S. electric distribution TFP and input price growth over the period 2001 to 2015 (Exhs. ES-PBRM-1, at 46; ES-PBRM-2). Eversource considered two different samples for its TFP study: (1) a sample of 67 nationwide LDCs intended to represent the overall U.S. electric distribution industry; and (2) a sample of 17 regional LDCs intended to represent the distribution industry in the Northeast U.S. (Exh. ES-PBRM-1, at 46). As described below, Eversource ultimately used the nationwide sample for its TFP study (Exh. ES-PBRM-1, at 61).

The Attorney General contends that both the nationwide and regional LDC samples selected by the Companies exclude certain relevant peer utilities and, therefore, result in a flawed analysis with questionable reliance on a peer average that does not represent the Companies' own productivity or that of comparable peers (Attorney General Brief at 30). Eversource counters that the utilities cited by the Attorney General are not relevant peer utilities to the Companies (Companies Brief at 355; Companies Reply Brief at 48). Eversource further maintains that the nationwide LDC sample has been used in other TFP studies and is robust because it represents 75 percent of electric distribution customers in the country (Exh. ES-PBRM-1, at 68; Tr. 3, at 562-563, 635; Tr. 8, at 1483-1485).

Because it represents a significant portion (i.e., 75 percent) of electric distribution customers in the country and is sufficiently robust, the Department is persuaded that the Companies' sample of 67 nationwide utilities is reasonably representative of the U.S.

distribution industry and is a reliable basis to establish TFP (Exh. ES-PBRM-1, at 61; Tr. 8, at 1483-1485). With regard to the regional LDC sample, the Companies selected 17 out of 43 available investor owned utilities to represent the electric distribution industry in the northeast United States, which represents 40 percent of investor owned LDCs in the region (Exhs. ES-PBRM-1, at 46, 77; DPU-40-4, Att.). The regional LDC sample contains seven Eversource and National Grid operating companies, which raises some concerns about sample endogeneity (Exh. DPU-24-16).

Eversource calculated industry TFP over the period 2001 to 2015 (Exhs. ES-PBRM-1, at 47-51, 61). Vote Solar argues that this 15-year time period is too short, resulting in a TFP study that is not robust (Vote Solar Brief at 10). The Companies maintain that significant changes in the electric distribution industry render earlier data unreliable and, therefore, data from 2001 to 2015 are most indicative of future productivity expectations (Exh. ES-PBRM-1, at 62; Tr. 3, at 508-509, 642-646).

As Eversource acknowledges, longer time periods generally are better indicators of future expectations and use of a full data set will ensure robust, reliable results (Tr. 3, at 642-646). The Department is persuaded, however, that, in the instant case, the benefit of using more recent data from 2001 to 2015 to incorporate non-trivial industry changes (as discussed in greater detail below) outweighs possible sacrifices to the study's robustness inherent with the use of a shorter time period.

iii. TFP Study Execution/Components; Input Price and Productivity Differentials

Eversource's proposed X factor includes two components: (1) an input price differential, which calculates the average annual difference in input price growth between the overall economy and the electric distribution industry from 2001 to 2015; and (2) a productivity differential, which calculates the average annual difference in productivity growth between the electric distribution industry and the overall economy from 2001 to 2015 (Exh. ES-PBRM-1, at 27, n. 25). The input price and productivity differentials are intended to reflect the average annual difference in productivity and input price growth between the electric distribution industry and the overall economy from 2001 to 2015. Considered jointly, these differentials are meant to reflect the average annual increase in industry unit costs (Exhs. ES-GWPP-1, at 46; ES-PBRM-1, at 28).[188]

The sum of the differentials serves as a proxy for the growth in per unit costs that a particular company should have experienced from 2001 to 2015, if it were an average performing company (Exhs. ES-GWPP-1, at 46; ES-PBRM-1, at 28, 46). A company that achieved lower-than-average growth in unit costs during this period would have the opportunity to earn additional profits (Exh. ES-PBRM-1, at 46). Conversely, a company whose growth in unit costs exceeded the average might realize lower-than-anticipated profits (Exh. ES-PBRM-1, at 46).

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188 For companies operating in a competitive market, the prices charged for a product or service are determined by the prices of the inputs used to produce the product or service, adjusted for any productivity gains exhibited in combining those inputs to produce the product or service (Exh. ES-PBRM-1, at 28).

The Department must first determine whether it is more appropriate to base Eversource's historic input price and productivity growth differentials on the historic productivity and input price growth indices of either regional or nationwide LDCs. With respect to input price growth, Eversource's TFP study indicates that, between 2001 and 2015, regional LDCs experienced an average annual input price growth rate of 4.10 percent, while nationwide LDC input prices grew at an average annual rate of 4.13 percent (Exh. ES-PBRM-1, at 47-48). With respect to productivity growth, Eversource's TFP study indicates that, between 2001 and 2015, regional LDCs experienced an average annual productivity growth of -0.41 percent, while nationwide LDCs experienced an average annual productivity growth of -0.46 percent (Exh. ES-PBRM-1, at 47-48). Given the small difference between the regional and nationwide growth rates in each instance and the substantial presence of Eversource and National Grid operating companies in the regional sample which could result in sample endogeneity, we find that use of nationwide LDC input price growth and nationwide LDC productivity growth will maintain a high degree of statistical reliability and preserve the function of the input price and productivity growth rates as true industry-wide averages (Exhs. ES-PBRM-1, at 30, n.30; DPU-24-16).

Next, the Department addresses the appropriate output measure to use in the calculation of average annual productivity growth. As described above, Eversource calculated annual productivity growth using TFP, which is defined as the ratio of total output to total input (Exh. ES-PBRM-1, at 30; Tr. 3, at 487-489). Annual gains or losses in productivity are measured as the percentage change in TFP, which is calculated as the

percentage change in total output less the percentage change in total input (Exh. ES-PBRM-1, at 30-31).

Traditionally, the Department has approved TFP studies that use both customer count and a measure of sales (i.e., kWh sales) as output measures. See D.P.U. 96-50 (Phase I) at 275-278; D.T.E. 03-40, at 476. Eversource used number of customers as the sole output measure for its TFP study (Exh. ES-PBRM-1, at 30; Tr. 3, at 491). Several intervenors maintain that the Companies' use of number of customers as the sole output measure is problematic because total output consists of all of the products and services produced by the relevant firm or industry (Attorney General Brief at 31; Vote Solar Brief at 6-7).

The Department has previously expressed concern with the use of number of customers as the sole indicator of LDC output growth. D.P.U. 07-50-A at 48-49; D.P.U. 96-50 (Phase I) at 275-276.[189] As Eversource recognizes, while the number of customers is a driver of the costs needed to operate gas or electric distribution systems, it does not capture all of the reasons for changes in costs associated with providing distribution services (Exh. ES-PBRM-1, at 49; Tr. 3, at 495). D.P.U. 07-50-A at 48-49. For example, a distribution company may make capital expenditures to replace existing assets and the magnitude of capital replacement required has little or no correlation with levels of customer

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189 Certain economists have concluded that number of customers is an appropriate output measure in determining the productivity offset for a revenue-per-customer PBR, because the number of customers directly affects a utility company's revenues (Exhs. ES-PBRM-1, at 36-38; ES-PBRM-Rebuttal-1, at 31 n.44; Tr. 3, at 626-631; RR-DPU-6, Att. at 129-130). The Companies have not, however, proposed a revenue-per-customer PBR. Instead, the Companies propose a revenue cap PBR where the annual revenues resulting from any PBR adjustments are unrelated to changes in the number of customers (Exhs. ES-PBRM-1, at 39-40).

growth (Exh. ES-PBRM-1, at 49; Tr. 3, at 494-495, 633-634). D.P.U. 07-50-A at 48-49. Instead, these capital expenditures are influenced by factors such as the age of the assets, changes in technology, past patterns of customer growth and increases in the load to serve (Exh. ES-PBRM-1, at 49; D.P.U. 07-50-A at 48-49.

Because of significant changes in the electric distribution utility industry, use of kWh sales as an alternate output measure may also be flawed. In particular, successful energy efficiency programs have led to decreased energy consumption, which has resulted in decreased kWh sales for electric distribution utilities (Exh. ES-GWPP-1, at 21-26; Tr. 1, at 32, 71; Tr. 5, at 986; Tr. 8, at 1474, 1538). D.P.U. 07-50-A at 3, 6. In addition, the introduction of a growing amount of distributed energy resources into the distribution system decreases kWh sales (Exh. ES-GWPP-1, at 22, 25-26). In this current environment, electric distribution utilities may exhibit kWh sales data that are unrelated to distribution system investments or other customer service inputs (see Tr. 3, at 494-495, 633-634).

Given the discussion above, the Department concludes that both output measures used in traditional TFP studies (i.e., kWh sales and customer count) present challenges. The record does not contain the data necessary to allow us to consider a non-traditional output measure. In these circumstances, the Department finds that Eversource has demonstrated that customer count is a reasonably reliable TFP output measure as it is less affected than kWh sales by the industry changes discussed above (Exh. ES-GWPP-1, at 21-26; Tr. 1, at 32, 71; Tr. 5, at 986; Tr. 8, at 1474, 1538). D.P.U. 07-50-A at 3, 6. Going forward, any distribution company conducting a TFP study should consider and present data regarding

alternative or non-traditional output measures that are designed to capture all of the products and services it provides.

The Attorney General raises several other issues with respect to the execution of Eversource's TFP study. First, the Attorney General argues that the Companies' inputs should include not only labor and materials costs booked to distribution O&M expense but also an allocated portion of labor and materials costs associated with customer accounts, sales, administrative and general expenses, and general plant (Attorney General Brief at 28-30). The Companies counter that these accounts should not be included because they contain non-distribution expenses (Companies Brief at 359-360; Companies Reply Brief at 49). As the adjustments affect the distribution revenue requirement, the Department finds that it is not appropriate to include any non-distribution cost elements in the input index.

The Attorney General also argues that Eversource used an improper method to calculate the capital quantity index; specifically it used the one hoss shay method rather than the geometric decay method (Attorney General Brief at 31).[190] The Attorney General contends that a geometric decay method is more appropriate here because it considers gradual depreciation of capital, whereas the one hoss shay method does not (Attorney General Brief at 31). Alternately, the Companies maintain that the one hoss shay method is consistent with the method that the BLS uses to develop multifactor productivity studies (Companies Brief at 368-370; Companies Reply Brief at 49). Further, the Companies claim that the Attorney

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[190] The one hoss shay method assumes that the flow of services received for capital is constant at full productive efficiency up until its retirement, whereas the geometric decay method assumes that the productivity of an asset decreases at a constant percentage rate (Tr. 3, at 554-555, 569).

General's calculation of the capital quantity index using the geometric decay method is unreliable because she excluded data from more than 20 percent of the sample companies (Companies Brief at 356, 370-371).

While the gradual depreciation of capital assets is necessary for accounting and cost recovery purposes, a capital asset's contribution to a company's productivity remains relatively constant until it is retired (Tr. 3, at 554-558). As Eversource correctly notes, the BLS relies on a method similar to the one hoss shay method for its multifactor productivity studies (Exh. ES-PBRM-1, at 69; Tr. 3, at 554-558). For these reasons, the Department finds that Eversource's use of the one hoss shay method to calculate the capital quantity index is appropriate.

Finally, the Attorney General raises concerns about the method used by Eversource to calculate the industry productivity growth rate (Attorney General Brief at 30). Once Eversource determined the quantity of output and the quantities and total prices of total input for each firm and each year, it used these data to calculate the industry productivity growth rate (Exh. ES-PBRM-1, at 73; ES-PBRM-2). In calculating the industry average annual productivity growth, Eversource weighted each company's TFP by its relative number of customers (Exh. ES-PBRM-1, at 73). The Attorney General argues that weighting the companies by their relative number of customers is inappropriate because the TFP estimates are already scaled for size given that productivity is a relative measure comparing a utility's inputs to its outputs (Attorney General Brief at 30). Even if such weighting is found to have a legitimate basis, the Attorney General asserts that Eversource's actual adjustment is both

limited and selective (Attorney General Brief at 30). Specifically, the Attorney General claims that there are a number of differences between utilities that could affect the productivity estimates (e.g., regulatory environment, geography, service territory characteristics) and that only adjusting for size without adjusting for all other possible factors results in a weighted average that is selective and arbitrary (Attorney General Brief at 30-31). Eversource maintains that weighting for size is necessary given that the output measure is number of customers (Companies Brief at 358). Without such weighting, the Companies contend that the ten largest firms (which serve 45.3 percent of the customers in the study) have the same weight as the ten smallest firms (which serve 2.5 percent of the customers in the study) (Companies Brief at 358-359). Because the output measure is number of customers, the Department finds that weighting to account for utility size may result in more representative industry-average TFP data. Accordingly, the Department concludes that the Companies' weighting of TFP estimates is appropriate.

Based on the findings above, the Department has determined that that Eversource's input price differential of -1.29 percent and productivity growth differential of -1.35 percent were determined in a reasonable manner.

iv. Conclusion

In the sections above, the Department has determined that the Companies' TFP study was conducted in a reasonable manner using appropriate data and assumptions. Accordingly, the Department has determined that the resulting input price differential of -1.29 percent and productivity growth differential of -1.35 percent were determined in a reasonable manner.

Accordingly, the Department will use these inputs to calculate an appropriate productivity offset for the Companies.

Eversource maintains that the proposed X factor of -2.64 percent would allow it to absorb the $400 million grid modernization base commitment investment (Companies Brief at 36, 403). The average annual revenue requirement associated with the $400 million base commitment investment is represented by an implicit stretch factor of 1.08 percent (Exhs. ES-GWPP-1, at 54; ES-PBRM-1, at 60; AG-21-2, Att. at 1; Tr. 2, at 240-242; Tr. 8, at 1553-1559, 1595-1597; Companies Brief at 403). To the extent that the Department determines it is appropriate to remove the grid modernization base commitment from the PBR, the Companies maintain that they would not object to making the 1.08 percent explicit and removing it from the X factor (Exhs. ES-GWPP-1, at 54; ES-PBRM-1, at 60; AG-21-2, Att. at 1; Tr. 2, at 240-242; Tr. 8, at 1553-1559, 1595-1597; Companies Brief at 403).

For reasons discussed in Section X.B.3 below, the Department has determined that it is in the public interest to remove the proposed grid modernization base commitment investments from the PBR. Accordingly, the Department will reduce Eversource's proposed X factor by 1.08 percent, representing the estimated revenue requirement associated with the $400 million grid modernization base commitment investment (Exhs. ES-GWPP-1, at 54; ES-PBRM-1, at 60; AG-21-2, Att. at 1; Tr. 2, at 240-242; Tr. 8, at 1553-1559, 1595-1597; Companies Brief at 403). Accordingly, the Department approves an X factor of -1.56 percent.

b. Inflation Index and Floor

In D.P.U. 94-50, at 141, the Department found that the GDP-PI is the most accurate and relevant measure of output price changes for the bundle of goods and services whose TFP growth is measured by the BLS. In addition, the Department found that GDP-PI is: (1) readily available; (2) more stable than other inflation measures; and (3) maintained on a timely basis. D.P.U. 94-50, at 141. In the instant proceeding, no party disputes that the GDP-PI is an appropriate measure for inflation in a revenue cap PBR formula. Accordingly, the Department approves the Companies' use of GDP-PI as an inflation index in the PBR formula.

As described above, Eversource proposes to include an inflation floor of one percent in the revenue cap formula, meaning that if inflation drops below one percent, the Companies would fix the inflation component of the PBR formula at one percent (Exh. ES-GWPP-1, at 12, 47-48). The Attorney General, Cape Light Compact, and CLF argue that the proposed inflation floor is unprecedented and unjustified (Attorney General Brief at 21; Cape Light Compact Brief at 55-56; CLF Brief at 17). The Companies concede that there are no other examples of incentive regulation plans that include a floor on inflation (Tr. 3, at 544). Eversource's primary justification for its proposed inflation floor stems from its commitment to spend $400 million over five years on grid modernization investments (Exhs. ES-GWPP-1, at 47-48; DPU-24-6; DPU-44-4; DPU-44-5, AG-28-6; Tr. 2, at 314). However, as discussed in Section X.B.3 below, the Department has determined that it is in the public interest to address the grid modernization base commitment investments outside of the PBR.

Based on the foregoing, the Department finds that the Companies have not demonstrated that an inflation floor is a necessary or reasonable component of its PBR formula. Accordingly, the inflation component of the PBR formula shall strictly reflect GDP-PI, as outlined above.

c. Consumer Dividend

The consumer dividend is intended to reflect expected future gains in productivity due to the move from cost of service regulation to incentive regulation. D.P.U. 96-50 (Phase I) at 165-166, 280. As a deduction to the PBR adjustment, the consumer dividend is designed to allow ratepayers to share in these aforementioned gains (Exh. ES-GWPP-1, at 56). In the instant proceeding, Eversource proposes to apply a consumer dividend of 25 basis points (or 0.25 percent) when inflation exceeds two percent (Exhs. ES-GWPP-1, at 54; ES-PBRM-1, at 8, 60, 66-67). No party addressed this particular component of the Companies' PBR proposal on brief.

The Companies acknowledge that the determination of a consumer dividend is largely subjective and that there is a lack of quantitative, empirical basis for establishing its magnitude (Exhs. ES-GWPP-1, at 55; ES-PBRM-1, at 55; DPU-19-21). Although the Department has previously approved consumer dividends greater than 25 basis points, we recognize that Eversource's recent ratemaking history includes a series of rate freezes for both NSTAR Electric and WMECo (Merger Settlement at Art. II (3)). D.P.U. 96-50 (Phase I) at 281; D.P.U. 05-85 Settlement, at Art. II. Accordingly, it is reasonable to expect that Eversource's future gains in productivity may be somewhat lower than would be

expected in a move from pure cost of service regulation to PBR (Exhs. ES-GWPP-1, at 56-57; DPU-19-21).

The Companies submit that the consumer dividend represents an explicit, tangible customer benefit in the PBR (Exhs. ES-GWPP-1, at 49, 56; ES-PBRM-1, at 66-67). We agree. Accordingly, in order to ensure that an appropriate share of the benefits of future gains in productivity will accrue to ratepayers, the Companies shall include in the PBR formula a consumer divided of 25 basis points (or .25 percent) when inflation exceeds two percent.

d. Grid Modernization Plan Factor

Eversource proposes to include a GMP factor in its PBR formula. The GMP factor would be used to recover approved: (1) investments in grid modernization above the $400 million base commitment proposed in this proceeding; and (2) incremental grid modernization investments proposed in D.P.U. 15-122 (Exhs. ES-GWPP-1, at 12, 18, 69; ES-PBRM-1, at 8; DPU-24-8). As discussed in Section X.B.3 below, the Department has determined that the Companies' grid modernization plan investments will be addressed outside of the proposed PBR mechanism. Accordingly, the Companies shall remove the proposed GMP factor from the PBR formula.

e. Exogenous Cost Factor

In D.P.U. 94-158, at 62, the Department recognized there may be exogenous costs, both positive and negative, that are beyond the control of a company and, because the company is subject to a stay-out provision, may be appropriate to recover (or return) through the PBR. The Department has defined exogenous costs as positive or negative cost changes

actually beyond the Company's control and not reflected in the GDP-PI. D.P.U. 94-50, at 172-173. These include, but are not limited to, incremental costs resulting from: (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. D.P.U. 96-50 (Phase I) at 291; D.P.U. 94-50, at 173. The Department has cautioned against expansion of these categories to a broader range. D.P.U. 96-50 (Phase I) at 290-291; D.P.U. 94-158, at 61-62.

In the instant proceeding, Eversource proposes to adopt a definition of exogenous costs that is consistent with the definition adopted by the Department in D.P.U. 94-50. Accordingly, the Department finds that the Companies' proposed definition of exogenous costs is appropriate.

In order to avoid costly regulatory process over minimal dollars, the Department has found that exogenous cost recovery must be subject to a significance threshold that is noncumulative (i.e., exogenous costs cannot be lumped together into a single total for purposes of determining whether the threshold has been met). D.T.E. 01-56, at 22-23; D.T.E. 99-19, at 26; D.P.U. 96-50 (Phase I) at 292-293; D.P.U. 94-50, at 173. The significance threshold is determined based on a percentage of the company's total operating revenues, taking into account the term of the PBR insofar as the effects that inflation will have on the threshold in the later years of the PBR. D.T.E. 01-56, at 11-14; D.P.U. 98-128, at 57.

Eversource has proposed an exogenous cost significance threshold of $5 million for the combined entity of NSTAR Electric and WMECo for calendar year 2018, subject to annual adjustments thereafter based on changes in GDP-PI (Exh. ES-GWPP-1, at 62). Although the Department must consider the facts and circumstances of each case, in several prior cases, the Department has found that an exogenous cost significance threshold was reasonable where it was equal to a multiple of 0.001253 times a company's total operating revenues. D.T.E. 05-27, at 396; D.T.E. 03-40, at 491; D.T.E. 01-56, at 22-26; D.P.U. 98-128, at 53-56. [191]

On a consolidated basis, Eversource's total test year operating revenues were $3,249,892,540 (see Exhs. ES-DPH-2 (East), Sch. DPH-5, at 1 (Rev. 3); ES-DPH-2 (West), Sch. DPH-5, at 1 (Rev. 3)).[192,193] Consistent with our prior precedent and the facts of this case, the Department finds that $5 million is a reasonable exogenous cost significance threshold for the Companies that have total operating revenues of $3,249,892,540 and that are implementing a multi-year PBR plan of the overall design approved herein.

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191 In support of its proposal, the Companies maintain that the Department recently approved an exogenous cost significance threshold of 0.003212 times a company's total annual distribution revenues (Exh. ES-GWPP-1, at 61, citing D.P.U. 12-25). Although Bay State Gas Company proposed to adopt a significance threshold based on the above calculation, the Department declined to adopt the expense adjustment factor at issue and, therefore, did not address the reasonableness of the proposed exogenous cost significance threshold in that case. D.P.U. 12-25, at 331-334.

192 NSTAR Electric's and WMECo's total operating revenues for the test year were $2,769,893,671 and $479,998,869, respectively (Exhs. ES-DPH-2 (East), Sch. DPH-5, at 1 (Rev. 3); ES-DPH-2 (West), Sch. DPH-5, at 1 (Rev. 3)).

193 Multiplying Eversource's consolidated operating revenues of $3,249,892,540 by a factor of 0.001253 equals $4,072,115.

In addition, the Companies have proposed that the exogenous cost significance threshold be subject to annual adjustments based on changes in GDP-PI as measured by the U.S. Commerce Department (Exh. ES-GWPP-1, at 62). The Department is satisfied that this proposal appropriately takes into account the effects that inflation will have on the threshold in the later years of the PBR. D.T.E. 01-56, at 11-14; D.P.U. 98-128, at 57. Accordingly, we set the Companies' threshold for exogenous cost recovery at $5 million for each individual event in calendar year 2018, subject to annual adjustments thereafter based on changes in GDP-PI as measured by the U.S. Commerce Department. Based on the foregoing analysis, the Department approves the Companies' proposed exogenous cost factor as a component of the PBR formula.

Exogenous cost recovery requires that a company provide supporting documentation and rationale to the Department for a determination as to the appropriateness of the proposed exogenous cost. D.T.E. 99-19, at 25; D.P.U. 98-128, at 55; D.T.E. 98-31, at 17-18. Additionally, any company seeking recovery of an exogenous cost bears the burden of demonstrating the propriety of the exogenous cost and that the proposed exogenous cost change has not been incorporated into the GDP-PI. D.P.U. 96-50 (Phase I) at 292-293; D.P.U. 94-50, at 171. For these reasons, the Department will not prejudge the qualification of any future events as exogenous costs (e.g., an adverse ruling on a municipal property tax issue and any future transmission formula rate changes mandated by FERC). Instead, at the time it seeks exogenous cost recovery, Eversource must demonstrate that the event meets both the definition and threshold for exogenous costs approved herein.

f. Earnings Sharing Mechanism

The Department has found that earnings sharing mechanisms may be integral components of incentive regulation plans. D.P.U. 94-50, at 197, n. 116. Specifically, the Department has found that earnings sharing mechanisms provide an important backstop to the uncertainty associated with setting the productivity factor. D.P.U. 96-50 (Phase I) at 325; D.P.U. 94-50, at 197.

The Companies propose to implement an asymmetrical earnings sharing mechanism with a deadband of 200 basis points (Exhs. ES-GWPP-1, at 12, 65-66; ES-PBRM-1, at 8). Under the Companies' proposal, earnings would be shared with ratepayers on a 75/25 basis (i.e., 75 percent to shareholders, 25 percent to ratepayers) if and when the calculated distribution ROE exceeds the ROE authorized in this proceeding by 200 basis points (Exh. ES-GWPP-1, at 65). If and when the calculated ROE exceeds the ROE authorized in this case by more than 300 basis points, Eversource proposes to share earnings with ratepayers on a 50/50 basis (Exh. ES-GWPP-1, at 65). For any year in which the ROE is above the deadband, the Companies propose to credit the percentage of earnings to be shared to customers in the succeeding year and exclude the impact of this adjustment in calculating any earnings sharing for the subsequent year (Exh. ES-GWPP-1, at 66).

The Attorney General argues that the proposed earnings sharing deadband of 200 basis points is too large and could result in outcomes where ratepayers see little to no benefits from the PBR (Attorney General Brief at 32). In addition, the Attorney General and Cape Light Compact argue that the design of the Companies' proposed earnings sharing

mechanism gives too much upside earnings potential to the Companies and too little potential benefit for customers (Attorney General Brief at 32-33; Cape Light Compact Brief at 59).

An earnings sharing mechanism offers an important protection for ratepayers in the event that expenses increase at a rate much lower than the revenue increases generated by the PBR (Tr. 2, at 435-436; Tr. 3 at 643). See D.P.U. 10-70, at 8 n.3; D.P.U. 05-27, at 404-405. For this reason, the Department finds that there is a significant benefit to implementing an earnings sharing mechanism as part of the PBR adopted in this case. However, as discussed below, the Department finds that certain modifications to the Companies' proposed earnings sharing mechanism are necessary in order to appropriately balance the risks to shareholders and ratepayers under the PBR.

As noted above, the Companies propose to adopt a deadband of 200 basis points (Exhs. ES-GWPP-1, at 12, 65-66; ES-PBRM-1, at 8). The Department has previously approved earnings sharing mechanisms with deadbands of 200 basis points or greater. D.T.E. 05-27, at 405; D.T.E. 03-40, at 500; D.P.U. 96-50 (Phase I) at 326. Here, with the changes to the tiered structure and earnings percentages discussed below, the Department finds that a 200-basis point deadband is both consistent with Department treatment of such mechanisms in the past and is reasonable to apply in this instance.

The Department finds that a 200-basis point deadband will provide the Companies with a strong incentive to pursue savings. However, in order to appropriately balance shareholder and ratepayer risk under the PBR as designed, the Department finds that the benefits of any earnings above the deadband must inure largely to ratepayers. Accordingly,

we find that a mechanism that shares earnings with ratepayers on a 75/25 basis above the 200-basis point deadband (i.e., 75 percent to ratepayers and 25 percent to shareholders) is appropriate in this case. This ratio will provide the Companies both adequate incentives to pursue savings and also protect ratepayers from an unforeseen financial windfall for the Companies as a result of the implementation of the PBR.

Finally, the Department declines to adopt a tiered structure as proposed by the Companies. As the Companies' witness acknowledged, a tiered sharing structure can create perverse cost containment incentives at the margin that can encourage misreporting or changes in spending (Tr. 8, at 1515). The Department finds that a non-tiered earnings sharing mechanism will resolve any concerns regarding incentives at the margin and achieve the goals of simplicity and administrative efficiency.

In conclusion, the Department finds that the Companies' PBR shall include an earnings sharing mechanism that sets a 200 basis points deadband above the Companies' authorized ROE. If the Companies' earned distribution ROE falls within or below the deadband, there will be no sharing. If the Companies' earned distribution ROE exceeds the deadband, shareholders and ratepayers will share earnings 25 percent and 75 percent, respectively.

g. PBR Term

Eversource's initial PBR proposal did not provide for an explicit term or stay-out provision (see Exhs. ES-GWPP-1; ES-PBRM-1). Instead, the Companies maintained that the PBR was designed to operate for "the long term" (Exhs. DPU-24-1; DPU-47-1; AG-33-8;

Tr. 2, at 421). During the course of the proceeding, Eversource proposed to adopt a PBR five-year term and associated stay-out provision where the Companies would have the ability to file for rate relief if the actual ROE falls more than 200 basis points below the ROE approved in this proceeding (Exh. AG-33-8; Tr. 1, at 421-422).

Intervenors argue that the Department should bar the Companies from filing a rate case during the five-year term (Attorney General Reply Brief at 90-91; Cape Light Compact Brief at 60). They argue that if the Companies are allowed to file a rate case during the five-year term, then ratepayers would receive little benefit or protection from the PBR (Attorney General Brief at 33-34; Attorney General Reply Brief at 90-91; Cape Light Compact Brief at 60).

The Department has found that a well-designed PBR should be of sufficient duration to give the plan enough time to achieve its goals and to provide utilities with the appropriate economic incentives and certainty to follow through with medium- and long-term strategic business decisions. D.P.U. 96-50 (Phase I) at 320; D.P.U. 94-158, at 66; D.P.U. 94-50, at 272. The Companies acknowledge that a stay-out provision is one of the ways to ensure strong incentives for cost containment (Exhs. DPU-24-1; DPU-47-1; AG-33-8; Tr. 2, at 421). In addition, the Department has stated that one benefit of incentive regulation is a reduction in regulatory and administrative costs. D.P.U. 96-50 (Phase I) at 320; D.P.U. 94-158, at 64.

Previous PBR plans approved by the Department have had terms of five years or longer. See, e.g., D.T.E. 01-56, at 10; D.P.U. 96-50 (Phase I) at 320. In the instant case,

the Department finds that a five-year term will give the plan enough time to achieve its goals and will provide the Companies with the appropriate economic incentives for cost containment and long-term planning. Further, we find that a five-year term will establish an appropriate interval over which to review the Companies performance over the initial term of the PBR.[194]

As noted above, a stay-out provision provides an important benefit to ratepayers as it will ensure that there are strong incentives for cost containment under the PBR. Accordingly, the Department will adopt a stay-out provision in conjunction with the five-year term. The Department declines to adopt Eversource's proposal to allow an explicit off-ramp where the Companies earned ROE is more than 200 basis points below the ROE approved in this case. The Department finds that such provision would not be in the public interest as it would undermine the intent of a defined PBR term and would not provide the proper incentives for cost containment and long-term planning, and would not ensure a reduction of regulatory and administrative costs.

Although we do not approve an explicit off-ramp provision, the Department notes that extraordinary economic circumstances have always been a recognized basis for any gas or electric company to petition the Department for changes in tariffed rates. D.T.E. 03-40, at 497 n.263, citing D.T.E. 98-128, at 56; D.T.E. 98-31, at 18. This review is consistent

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194 Section 94 provides that electric distribution companies shall file rate schedules no less than every five years. The Companies maintain that Section 94 does not specify that such schedules must be designed to allow for an increase in base rates and, therefore, the Department may allow a PBR with a term of longer than five years (Exh. DPU-47-1, at 2).

with G.L. c. 164, § 93 and Section 94 and with the general requirement that rates must be just and reasonable. D.T.E. 03-40, at 497 n.263. Statute, of course, governs and, where need be, supersedes any regulatory arrangement prescribed by the Department. D.T.E. 98-27, at 14-21. Nonetheless, the Department fully expects that the Companies will not file a base rate case during the term of the PBR and that any rate relief sought under Section 94 would be of last resort. Should the Companies seek to change base rates before the end of the PBR term, that action would be a significant consideration in that Section 94 proceeding and would likely have a negative effect on the Companies' resulting ROE, based on the Department's standard for establishing ROE.

For the reasons discussed above, the Department finds that the Companies' PBR shall operate for a five-year term starting January 1, 2018. Additionally, absent a showing of extraordinary economic circumstances, the Companies shall not file a proceeding under Section 94 that seeks to change base rates prior to the end of the PBR term.

h. Metrics

As discussed above, the Companies have demonstrated that the electric distribution industry is rapidly changing and that PBR is the appropriate ratemaking model to allow them to adapt to this change. The Department must find, however, that the PBR we approve in this proceeding will result in just and reasonable rates. G.L. c. 164, § 94; D.P.U. 96-50 (Phase I) at 242; D.P.U 94-158, at 52-66. One factor that the Department considers in reaching this determination is the extent to which the PBR is designed to advance policy and other Department objectives to ensure that ratepayer benefits will result. D.P.U. 96-50

(Phase I) at 242. In this regard, the Department has determined that a PBR (1) should be designed to achieve specific, measurable results, and (2) should identify, where appropriate, measurable performance indicators and targets that are not unduly subject to miscalculation or manipulation. D.P.U. 94-158, at 63-64. The Department has further found that broader performance indicators are preferred, and should be tied to the stated goals of a program and consistent with the Department's regulatory goals. D.P.U. 94-158, at 63-64. Finally, the Department has determined that a well-designed PBR should present a timetable for program implementation and specific milestones for program tracking and evaluation. D.P.U. 94-158, at 64-65.

Here, intervenors argue that the Companies' proposed PBR lacks specific, measurable metrics to measure the success of the PBR (Attorney General Brief at 14; Cape Light Compact Brief at 56-57; Sunrun and EFCA Brief at 9; Vote Solar Brief at 12-13). Eversource maintains that PBR-specific metrics are not necessary because the Department's existing service quality metrics, with the related potential for penalties, will continue to apply to the Companies during the term of the PBR (Companies Brief at 325-326). In addition, the Companies argue that specific PBR-related metrics are not necessary because the increased efficiency that will result from the PBR is a measurable achievement that is already contained within the PBR formula in the form of the consumer dividend (Companies Brief at 324-325; Companies Reply Brief at 40-42).

Eversource's proposed metrics solely relate to spending for the grid modernization base commitment and do not contain any measurable performance indicators or targets to

assess the Companies' performance or the benefits achieved under the PBR (Exhs. ES-GMBC-1, at 132; ES-GMBC-3; AG-18-26; DPU-41-7; Tr. 12, at 2387-2388). As discussed in Section X.B.3 below, the Department has determined that it is in the public interest to remove the grid modernization investments from the PBR and the Department will address the establishment of appropriate metrics designed to advance the Department's grid modernization objectives as part of our forthcoming Order in D.P.U. 15-122.

As recognized by the Companies, the Department's service quality metrics (and associated penalties) will remain in place during the term of the PBR.[195] The Department will continue to rely on these rigorous service quality metrics to gauge whether sufficient investment is occurring on the Companies' distribution system to maintain the reliability of electric service to customers. See, e.g., Revised Service Quality Guidelines, D.P.U. 12-120-D (2015). The service quality metrics and consumer dividend do not, however, capture the full range of benefits that the Companies maintain, and that the Department expects will accrue from implementation of the PBR.

The Companies argue the PBR is designed to operate as a mechanism for maintaining alignment between costs and revenues so that they can continue to operate their system in support of the Commonwealth's clean energy goals, including the provision of safe, reliable and resilient electric service with a minimal environmental impact (Companies Reply Brief at 12). The Department found above that PBR should result in benefits to ratepayers

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195 The Department notes that the maximum service quality penalty that can be assessed against the Companies grows as the Companies' annual revenues for distribution and transmission operations increase. G.L. c. 164, § 1*I*.

because, among other reasons, it will allow Eversource the flexibility to focus on cost saving and innovation to meet the Commonwealth's clean energy goals. In exchange for this flexibility, the Department finds that it is appropriate to establish PBR-specific metrics to measure the Companies' performance and gauge the extent to which these critical policy benefits accrue.

Eversource had demonstrated that its costs are increasing due to several changes in the electric distribution industry including: (1) the need to rebuild the distribution system to allow for reliable two-way power flows; (2) the need to improve system resiliency to withstand climate-change impacts; (3) the emergence of a greater need for cybersecurity; (4) an increased need to minimize environmental effects from distribution infrastructure; (5) incorporating the emergence of digital technology and consumer engagement in energy consumption; and (6) recruiting and retaining a non-traditionally skilled workforce (Exh. DPU-19-3, Att.). Through the adoption of the PBR, the Department recognizes Eversource requires the degree of flexibility to adapt to these changes.

Accordingly, in order to measure the full range of benefits that will accrue under the PBR, the Department finds that it is appropriate to establish a set of broad performance metrics in the following three categories that are tied to the goals of the PBR and consistent with the Department's regulatory objectives: (1) improvements to customer service/engagement; (2) reductions in system peak; and (3) strategic planning for climate adaptation.

The Department acknowledges that the evidentiary record in this case is not sufficient

to establish final performance metrics and benchmarks at this time. In this Order, the Department will establish the categories in which the metrics will be developed. After input from the Companies and intervenors, the Department will adopt final metrics and benchmarks in a compliance phase of this proceeding.[196]

The metrics that the Department establishes in this proceeding will be used for reporting purposes and to determine whether the PBR is working as designed and providing benefits to ratepayers. Going forward, the Department intends to consider whether it may be appropriate to establish incentives or otherwise tie earnings under the PBR to performance metric outcomes.

First, the Companies shall develop metrics and appropriate benchmarks to measure improvement in the level of customer satisfaction and customer engagement. The Department has often recognized the importance of customer satisfaction and its direct alignment with ratepayer interests. See D.P.U. 12-120-D at 56; D.P.U. 12-25 at 161; D.P.U. 10-55, at 253-254; D.P.U. 12-120; D.P.U. 04-116-C at 16-17. Under the PBR, the Companies will have the ability to focus their customer engagement to adjust to the changing energy market. As the Companies note, customers are becoming more active participants in how they get their power and manage their electricity consumption (Exh. DPU-19-3, Att.). For example, the Companies must change to adapt to customers that are more reliant on mobile applications and devices (see Exh. DPU-19-13).

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196 As discussed further below, the Companies will be required to submit a compliance filing containing proposed metrics and benchmarks consistent with the categories and design criteria established in this Order. The Department will investigate the proposed metrics in a compliance phase of this proceeding.

When developing the proposed customer satisfaction/engagement metrics, the Companies must consider customers both who are producers and consumers of electricity. In addition, the Companies shall establish a baseline associated with those metrics in order to measure improvements over the term of the PBR.[197] Regarding customer satisfaction, the metrics should be designed to account for factors outside of the Companies' control, such as commodity prices or weather. To control for these types of outside variables, the Department finds that it is appropriate for a third party to benchmark the Companies' performance relative to their utility peers.

Second, the Companies shall develop a metric and appropriate benchmark to measure reductions in peak system demand. System peak demand is the primary driving force in the cost of electric supply and the need for new generation, transmission, and distribution investments.[198] D.P.U. 12-76-B at 10-12. Customers benefit from reductions in sales and peak demand through lower capacity and commodity prices (i.e., lower bills). See e.g.,

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197 Examples of ways the Companies may seek to improve customer satisfaction/engagement include, but are not limited to: (1) investments in technologies such as billing and tracking systems to improve customer access to information; (2) improved mobile device and digital communication support; and (3) improvements in distributed energy resource interconnections (Exh. DPU-19-13). Further, notwithstanding the findings of this Order, the Companies may consider in these efforts to improve customer satisfaction for inclusion within the context of the PBR, including, but not limited to various payment program options, dispute resolutions, and opportunities for community engagement.

198 According to the State of Charge Report, during 2013 to 2015 the top one percent of most expensive hours accounted for eight percent of customers' annual spending on electricity. The top ten percent of hours during these years, on average, accounted for 40 percent of annual electricity spending (Exh. ES-GMBC-6, at 5-6).

Three-Year Plans Order, D.P.U. 15-160 through D.P.U. 15-169 at 93 (2016); Order on Bill Impacts, D.P.U. 08-50-D at 11 (2012).

In designing the system peak demand metric, the Companies must create a structure that is weather normalized and appropriately anchored in measureable parameters that are within the Companies' control. The Companies should set baseline reductions during peak event conditions, rather than a year-to-year reduction.[199] In addition to weather normalizing, the target should recognize the historical trends in system peak demand and account for year-to-year variances over the five-year term of the PBR.[200] There are many additional functions within the Companies' control that affect peak demand (e.g., theft, line loss, upgrading standard technology, employing time of use rates, demand response, energy efficiency, energy storage, Volt/VAR optimization). The Companies should consider all aspects of their business (e.g., traditional capital investment, grid modernization investment, energy efficiency, behind the meter generation) to set a single overarching demand target. However, the Companies should identify a separate benchmark to allow for identification of the portion of the overall demand target that is enabled by investments under the PBR.

Finally, the Companies shall develop metrics and appropriate benchmarks to measure progress towards climate adaptation and greenhouse gas reductions. The Global Warming

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199 Peak events, which are often weather dependent, are not comparable on a year-to-year basis (see Tr. 1, at 138-139).

200 The Department notes that despite a record hot summer in New England in 2016, the Companies' system peak demand in 2016 was six percent less than the peak experienced ten years earlier in 2006 (i.e., 4,958 MW in 2006 as compared to 4,653 MW in 2016) (Exh. DPU-19-3, Attachment DPU-19-3, at 3).

Solutions Act mandates the following reductions in greenhouse gas emissions: (1) ten to 25 percent from 1990 levels by 2020; and (2) at least 80 percent of 1990 levels by 2050. G.L. c. 21N, § 4(a). The Department must consider reasonably foreseeable climate change impacts, including additional greenhouse gas emissions, when considering and issuing administrative approvals or decisions. G.L. c. 30, § 61. Further, Governor Baker's Executive Order 569 requires each agency to develop a climate adaptation plan to assess the potential risk to critical infrastructure assets from natural disasters and climate change. On both bases, the Companies are obligated to make progress towards climate adaptation and greenhouse gas reductions. Accordingly, the Department finds that establishment of metrics to measure progress towards climate adaptation and greenhouse gas reductions is reasonable and appropriate.

The Companies are responsible for providing a safe and reliable electric system. In order to develop the climate adaptation metric, the Companies must conduct their own climate adaptation study to identify those areas under the Companies' control that are most vulnerable to climate change and could jeopardize system reliability. The Department finds that requiring the Companies to develop a climate adaptation plan is within the Companies' control, in line with current emergency response planning, and in the public interest. Further, we find that this process will help guide future infrastructure investments and advance the Commonwealth's clean energy goals. Therefore, the Department directs the Companies to develop a climate adaptation plan for their assets, including an assessment of the potential risk to these assets from climate change (e.g., risks to the underground system

from sea level rise, emergency response plans for severe weather, etc.).

As part of the climate adaptation plan, the Companies shall assess the estimated carbon emissions from their existing assets. After the completion of the plan, the Companies shall propose a greenhouse gas reduction target. The proposed target shall be based solely on assets under the control of the Companies.

Within 90 days of the date of this Order, the Companies shall, consistent with above the directives, submit: (1) proposed customer satisfaction/engagement metrics and benchmarks, including a third party benchmark to measure the level of customer satisfaction/engagement over the term of the PBR; (2) a proposed system peak demand reduction metric and benchmark to measure reductions of demand during peak events from current levels; and (3) a proposed climate adaptation plan designed to inventory and address the Companies' at risk assets and the emissions from those assets. The results of the climate adaption plan will be used to develop future metrics and benchmarks to measure the Companies' progress towards climate adaptation and greenhouse gas reductions.

E. Conclusion

In the sections above, the Department has reviewed the Companies' proposed PBR and has found that it is more likely than current regulation to advance the Department's traditional goals of safe, reliable, and least-cost service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation. In addition, the Department has found that the proposed PBR will provide Eversource with greater incentives to reduce costs than currently exist and should result in

benefits to customers that are greater than would be present under current regulation. Further, the Department has found that the proposed PBR better satisfies our public policy goals and statutory obligations, including promotion of the Commonwealth's clean energy goals and mandates.

With the modifications to the PBR formula required herein, the Department finds that the PBR appropriately balances ratepayer and shareholder risk and will result in just and reasonable rates pursuant to G.L. c. 164, § 94. Accordingly, the Department approves Eversource's proposed PBR, subject to the modifications required herein.

Eversource shall submit an annual PBR compliance filing, including all information and supporting schedules necessary for the Department to review the proposed PBR adjustment for the subsequent rate year. Such information shall include the results and supporting calculations of the PBR adjustment factor formula, descriptions and accounting of any exogenous events, and an earnings sharing credit calculation for the year two years prior to the rate adjustment. In addition, Eversource shall file revised summary rate tables reflecting the impact of applying the base rate changes provided in the PBR compliance filing. Eversource is directed to submit its annual PBR compliance filing on or before September 15th each year, commencing in 2018 and continuing for the five-year term of the PBR. Consistent with our findings in Section IX.D.5.g above, the PBR shall continue in

effect for a total of five consecutive years starting January 1, 2018, with the last adjustment taking effect on January 1, 2022.[201]

X. GRID MODERNIZATION PROPOSAL

A. Introduction

The Department seeks to encourage electric distribution companies to adopt grid modernization technologies and practices that will enhance the reliability of electricity service, reduce costs of operating the electric grid, mitigate price increases and volatility for customers, and empower customers to adopt new electricity technologies and better manage their electricity use. Modernization of the Electric Grid, D.P.U. 12-76-A at 1 (2013). The Department has defined grid modernization as functions that fall within four broad objectives: (1) reducing the effects of outages; (2) optimizing demand, which includes reducing system and customer costs; (3) integrating distributed resources; and (4) improving workforce and asset management. Modernization of the Electric Grid, D.P.U. 12-76-B at 9 (2014).

The Department directed each electric distribution company to submit a ten-year grid modernization plan designed to make measurable progress towards each of these four objectives as well as a short term investment plan addressing the specific initiatives that they expect to undertake in the first five years of the plan. D.P.U. 12-76-B at 15-16; Modernization of the Electric Grid, D.P.U. 12-76-C (2014). The Companies filed their grid modernization plan, including a short-term investment plan, on August 19, 2015. The Department docketed the Companies' grid modernization plan filing as D.P.U. 15-122.

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[201] Because the earning sharing adjustment lags the PBR adjustment by one year, the last earning sharing adjustment would take effect on January 1, 2024.

The Companies also included $400 million in investments in grid modernization technologies as part of their PBR proposal in the instant case. Specifically, the Companies commit to absorb the revenue requirement associated with $400 million of grid modernization investments ("grid modernization base commitment") through the PBR until their next base rate case (Exhs. ES-GWPP-1, at 9-10; ES-GMBC-1, at 10, 22, 51-52 (Table ES-GMBC-2)). These base commitment investments include certain investments proposed as part of the grid modernization plan in D.P.U. 15-122, as well as additional investments in expanded automation and customer tools for distributed energy resource integration, an electric storage pilot, and electric vehicle make-ready infrastructure (Exhs. ES-GWPP-1, at 17-18; ES-GMBC-1, at 14-15).

On February 3, 2017, the Companies filed a revised grid modernization plan in D.P.U. 15-122 to remove from consideration in that docket any grid modernization investments also proposed in the instant proceeding.[202] The Companies refer to the remaining investments in D.P.U. 15-122 as their "incremental grid modernization plan." Together, the grid modernization base commitment investments (as presented in D.P.U. 17-05) and the incremental grid modernization plan investments (as presented in the revised plan in D.P.U. 15-122) encompass the entirety of the Companies' grid modernization plan. The Department addresses the Companies' grid modernization base commitment proposal in D.P.U. 17-05 in the sections below.

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202 The Department determined that review of the grid modernization base commitment in the instant case was reasonable and would not adversely impact resolution of the grid modernization docket in D.P.U. 15-122. D.P.U. 17-05, Interlocutory Order at 11 (February 23, 2017).

B. Grid Modernization Base Commitment

1. Companies Proposal

Eversource proposes a total five-year spending target of $400 million for grid modernization investments in two broad categories: (1) distribution network systems operations; and (2) customer engagement and enablement (Exhs. ES-GMBC-1, at 52; ES-GMBC-2, at 9-10). The Companies state that the investments in these two categories are foundational investments needed to implement other aspects of grid modernization (Exh. ES-GMBC-1, at 13).

The Companies propose to undertake four initiatives in the distribution network systems operations category: (1) a distribution network systems operator initiative, which includes investments of $44 million in distribution management systems ("DMS"), advanced system load flow, and Volt/VAR optimization; (2) an automation initiative, which includes investments of $84 million in automated feeder reconfiguration, urban underground automation, and adaptive protection; (3) a foundation technology for DMS and automation initiative, which consists of investments of $111 million in foundational technology for DMS and automation including advanced sensing technology, remove fault indicators, and communications network; and (4) an energy storage initiative, which includes investments of $100 million for research and demonstrations (Exhs. ES-GMBC-1, at 52; ES-GMBC-2, at 9-10).[203] The Companies propose to undertake two initiatives in the customer engagement and enablement category: (1) a distributed energy resource integration initiative which

[203] The Companies' energy storage proposal is addressed in Section X.C below.

includes investments of $15 million for customer tools; and (2) an electric vehicle research and demonstration projects initiative which includes investments of $45 million for development of electric vehicle charging infrastructure and vehicle conversions (Exh. ES-GMBC-2, at 9-10).[204]

The Companies do not propose to recover their grid modernization base commitment investments through a separate short term capital cost recovery mechanism as described in D.P.U. 12-76-B at 22-25. Rather, they propose to absorb the revenue requirement associated with the $400 million in grid modernization base commitment investment through their proposed PBR, until their next base rate case (Exh. ES-GWPP-1, at 9, 14, 53-54). As described in Section IX.B.d above, the Companies state that the commitment to spend $400 million in incremental grid modernization investments over five years represents an implicit deduction from the annual revenues collected through the proposed PBR mechanism, or an implicit stretch factor of 1.08 percent on an average annual basis (Exh. ES-GWPP-1, at 14, 53-54).[205] The Companies state that if they are unable to meet the $400 million spending commitment, they will "return" the unspent dollars to ratepayers through a mechanism to be established in their next base rate proceeding (Tr. 2, at 270-273, 301-302).

The Companies request that the Department: (1) pre-approve the proposed grid modernization base commitment categories as reasonable and appropriate and, therefore, any

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204 The Companies' electric vehicle proposal is addressed in Section X.D, below.

205 The Companies calculated the stretch factor based on the total revenue requirement associated with the grid modernization base commitment investment over the five-year term, equal to approximately $160 million (Exh. AG-21-2, Att. at 1).

investments in these categories would be eligible for inclusion in rate base in the Companies' next base rate proceeding;[206] and (2) find that the overall proposed spending target and amounts allocated to each of the investment categories are reasonable (Exh. ES-GMBC-1, at 20-21). The Companies propose that investment could shift between categories as they gain experience in implementing their grid modernization plan, with any modifications subject to Department review and approval (Exh. ES-GMBC-1, at 20-21; Tr. 2, at 270-273, 301-302).

The Companies propose to track 14 metrics for the six grid modernization initiatives (Exhs. ES-GMBC-1, at 11, 132-135; ES-GMBC-3; DPU-41-7 (Supp.)). The 14 metrics include company-specific implementation metrics and customer benefit sub-metrics (Exh. ES-GMBC-3).[207] The Companies state that the proposed metrics are not tied to specific grid modernization outcomes. Instead, the Companies state that the proposed metrics will track progress milestones, spending parameters, and other indicators to monitor and evaluate progress on the grid modernization base commitment (Exhs. ES-GMBC-1, at 132, 134-135; ES-GWPP-1, at 13; ES-CAH-1, at 13, 18). During the course of the investigation, intervenors identified several additional performance metrics for consideration, including statewide metrics (see, e.g., Exhs. ME-1, at 71; DPU-41-7 (Supp.); RR-AC-2, Att.;

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206 The Companies do not request that the Department pre-approve specific investments (Exh. ES-GMBC-1, at 20). The Companies acknowledge that all grid modernization base commitment investments would remain subject to a prudence review in the Companies' next rate case (Exh. ES-GMBC-1, at 20, citing D.P.U. 12-76-B at 22-25).

207 Within the 14 proposed metrics, there are 35 distinct implementation and customer benefit sub-metrics (Exh. ES-GMBC-3; RR-DPU-2, Att.).

RR-CLF-2, Att.).[208] The Department also sought comment on several additional metrics (Exh. DPU-41-7 (Supp.); RR-DPU-2, Att.).[209]

The Companies propose to submit information to the Department on its grid modernization base commitment in their annual PBR compliance filing (Exh. ES-GMBC-1, at 21). The Companies state that this annual grid modernization base commitment report will include information on program expenditures in relation to authorized budget amounts, the Companies' progress in developing the anticipated investments and other performance data in conformance with the metrics approved by the Department in this proceeding to demonstrate that the Companies are meeting its commitments (Exh. ES-GMBC-1, at 21-22).

Finally, the Companies propose to implement a grid modernization stakeholder process to present and discuss the Companies' performance on implementing the grid modernization base commitment (Exh. ES-GWPP-1, at 19; RR-DPU-24). The Companies propose to conduct an annual stakeholder meeting in the second quarter of each year (RR-DPU-24).[210] After the stakeholder meeting, the Companies propose to refine the draft grid modernization base commitment report and circulate the revised draft to stakeholders for comment (RR-DPU-24). The Companies propose to compile comments from stakeholders

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208 Intervenors proposed a total of 60 additional metrics (RR-AC-2, Att.; RR-CLF-2, Att.).

209 Record Request DPU-2 contains a comprehensive list of all metrics proposed in this proceeding.

210 At the annual stakeholder meeting, Eversource proposes to present stakeholders with the prior year's performance results, the outlook for the next year, and a preliminary draft of the annual grid modernization base commitment report (RR-DPU-24).

and, to the extent feasible, incorporate input from stakeholders in each final annual grid modernization base commitment report to be filed with the Department with the PBR compliance filing (RR-DPU-24).

2. Positions of the Parties

a. Intervenors

i. Inclusion of Base Commitment in PBR

The Attorney General, Cape Light Compact, CLF, DOER, and UMass maintain that under the PBR, there are no assurances that the Companies will make the proposed grid modernization base commitment investments or that they will invest in initiatives that are cost effective or beneficial to ratepayers (Attorney General Reply Brief at 92; Cape Light Compact Brief at 50-51; CLF Brief at 16, 27-28; DOER Brief at 18-20; UMass Brief at 9). The Attorney General argues that pre-approval of the grid modernization base commitment investments may allow the Companies to collect revenues through the PBR without making the proposed investments if the business case analysis for the investments is not successful (Attorney General Reply Brief at 92). Further, NECEC asserts that there are no financial consequences to the Companies if they fail to make the grid modernization investments (NECEC Brief at 22).

UMass argues that, under the PBR, ratepayers bear more of the upfront risk of grid modernization investments than shareholders (UMass Brief at 4-5). The Attorney General and CLF assert that the PBR provides no connection between cost recovery and performance as the grid modernization base commitment is not tied to any quantitative improvements in

service reliability, resiliency, energy efficiency, environmental benefits, or resource diversity (Attorney General Brief at 4, 38-39; CLF Brief at 22).

Several intervenors urge the Department to require the Companies to recover eligible costs associated with the grid modernization base commitment through a capital cost tracker as set forth in D.P.U. 12-76-B (Acadia Center Brief at 13-14; Choice Energy Brief at 25-27; CLF Brief at 51; DOER Brief at 20-24; NECEC Brief at 19-26; RESA Brief at 35-38). Acadia Center, Choice Energy, CLF, DOER, NECEC, and RESA argue that a capital cost tracker will provide the Companies with timely recovery of grid modernization costs, while retaining important ratepayer protections and Department oversight (Acadia Center Brief at 13-14; Choice Energy Brief at 25-27; CLF Brief at 51; DOER Brief at 20-24; NECEC Brief at 19-26; RESA Brief at 35-38). Additionally, DOER asserts that a capital cost tracker is superior to a PBR because it: (1) provides better incentives for the Companies to control costs; (2) provides additional transparency and accountability; (3) is less expensive; and (4) ties cost recovery directly to investments made (DOER Brief at 20-24). DOER recommends that any pre-authorized recovery of grid modernization costs through a capital cost tracker should be limited to some period of less than five years so that cost estimates remain current (DOER Brief at 24-26). Further, DOER maintains that, in determining the appropriate time period for pre-approval, the Department should strike an appropriate balance between creating administrative efficiencies and ensuring the most cost-effective investment outcomes (DOER Brief at 24-26).

In order to implement a grid modernization capital cost tracker, NECEC supports an approach that converts the implicit grid modernization stretch factor to an explicit stretch factor and removes it from the PBR (NECEC Brief at 24-26, citing Tr. 2, at 263-269; Tr. 8, at 1552-1563; Tr. 10, at 1966-1984, 2058-2063). NECEC asserts this method would allow the Companies to separate recovery of their grid modernization investments from the PBR without affecting their ability to collect sufficient revenues under the PBR (NECEC Brief at 24-26, citing Tr. 2, at 263-269; Tr. 8, at 1552-1563; Tr. 10, at 1966-1984, 2058-2063). NECEC further maintains that this method would provide appropriate opportunities for stakeholder involvement and Department oversight (NECEC Brief at 24-26). Finally, NECEC argues that the Department should convert the Companies' spending commitment targets into spending caps to provide flexibility for changing circumstances and to reduce the Companies' incentive to make investments based on ratemaking treatment rather than need (NECEC Brief at 24-26, citing Tr. 2, at 263-269; Tr. 8, at 1552-1563; Tr. 10, at 1966-1984, 2058-2063).

ii. D.P.U. 12-76 Requirements

Several intervenors assert that the Companies' grid modernization base commitment proposal does not comply with various directives in D.P.U. 12-76 (Attorney General Brief at 36-38; Acadia Center Brief at 14-16; Cape Light Compact Brief at 21; CLF Brief at 13, 19-23; NECEC Brief at 36-37; Sunrun and EFCA Brief at 8; UMass Brief at 7-10). The Attorney General argues that Eversource's grid modernization base commitment proposal does not qualify for targeted cost recovery under D.P.U. 12-76-B because it does not include

a plan to fully deploy advance metering functionality (Attorney General Brief at 36-38). Additionally, Cape Light Compact maintains that the Companies' proposal is deficient because it is not grounded in customer engagement, customer markets, or the full range of distributed energy resources beyond distributed generation as required by D.P.U. 12-76-B (Cape Light Compact Brief at 19).

iii. Business Case Analysis

Numerous intervenors argue that the grid modernization base commitment investments are not eligible for pre-approval or targeted cost recovery because the Companies did not provide a supporting business case analysis as required by D.P.U. 12-76-C (Attorney General Brief at 5-6, 36-39; Acadia Center Brief at 16; AIM Brief at 3; Cape Light Compact Brief at 23-24; CLF Brief at 21; DOER Brief at 28; RESA Brief at 30; Sunrun and EFCA Brief at 4-6, 9-11; TEC and WMIG Brief at 11-15; UMass Brief at 10). Without a business case analysis, Cape Light Compact and DOER assert that the Department and stakeholders cannot perform an appropriate assessment of the effects of the grid modernization base commitment on ratepayers (Cape Light Compact Brief at 15; DOER Brief at 28-31).

According to Acadia Center, the lack of detail on costs and benefits prevents the Department and stakeholders from adequately reviewing the proposed grid modernization cost categories (Acadia Center Brief at 16). Cape Light Compact asserts that the grid modernization base commitment budgets are based solely on internal top-down allocations rather than vendor quotes or costs from similar projects or studies (Cape Light Compact Brief at 16). As a consequence, Cape Light Compact maintains that the Companies have not

shown that the grid modernization base commitment investments are reasonable or a good value for ratepayers (Cape Light Compact Brief at 16). UMass maintains that the Companies have presented scant evidence of when customers will experience benefits or whether such benefits are sufficient to warrant the grid modernization base commitment investments (UMass Brief at 9-10). NECEC asserts that the Companies failed to perform a benefit cost analysis for the proposed grid modernization investments that would reduce the risk and uncertainty to customers (NECEC Brief at 21). Acadia Center argues that the Companies fail to provide any evidence that specific benefits (i.e., increased reliability, increased levels of distributed energy resource installation, reduced greenhouse gas emissions) would accrue from the proposed grid modernization base commitment investments (Acadia Center Brief at 15).

CLF and Sunrun and EFCA contend that the Companies do not adequately define the proposed grid modernization base commitment expenditures, show how they arrived at the proposed expenditures, or provide support that the proposed cost categories and total expenditures within the cost categories are correct (CLF Brief at 22; Sunrun and EFCA Brief at 10). Further, CLF and Sunrun and EFCA maintain that the Companies have not provided adequate information about costs and benefits to allow them the flexibility to shift spending between investment categories (CLF Brief at 27-28; Sunrun and EFCA Brief at 10).

Acadia Center, NECEC, Sunrun and EFCA, and UMass argue that, without a showing that benefits will accrue to ratepayers through the proposed investments, the Department should not pre-approve the grid modernization base commitment (Acadia Center

Brief at 15; NECEC Brief at 21; Sunrun and EFCA Brief at 6; UMass Brief at 9-10). Finally, Cape Light Compact and NECEC assert that the Department should not pre-approve the Companies' proposed grid modernization investments as the base commitment does not constitute a ten-year plan for progress toward the Department's grid modernization objectives or provide information on how these investments will support a roadmap to a modern electric grid (Cape Light Compact Brief at 21-23; NECEC Brief at 38).

iv. Business as Usual

Several intervenors characterize the Companies' proposed grid modernization base commitment investments as business as usual expenditures that are necessary to provide safe and reliable service, but are not transformative and do not constitute grid modernization as provided in D.P.U. 12-76-B (Attorney General Brief at 39-40; Cape Light Compact Brief at 52; CLF Brief at 23; Sunrun and EFCA Brief at 10). CLF maintains that the Companies' characterization of the grid modernization base commitment investments as foundational suggests that they are business as usual investments rather than transformative investments as described in D.P.U. 12-76-B (CLF Brief at 22-23). Similarly, UMass contends that the grid modernization base commitment investments are necessary capital projects that should be undertaken as good utility practice without the need for a PBR (UMass Brief at 12).

Likewise, Cape Light Compact maintains that Eversource should not be allowed to spend grid modernization base commitment dollars on investments that are core to the Companies' utility functions (e.g., automated billing system upgrades, remote fault circuit indicators, urban underground system automation) given such investments already should

have been made or will become obsolete once advanced metering functionality is deployed (Cape Light Compact Brief at 16-18). Further, Sunrun and EFCA maintain that the Companies admit they lack any basis for distinguishing grid modernization base commitment investments from (1) investments they would make anyway in the normal course of business; or (2) investments they would charge to interconnecting customers as system modifications through the interconnection process (Sunrun and EFCA Brief at 10, citing Tr. 15, at 3148-3149; RR-SREF-2).

v. Metrics

Various parties argue that the Companies' proposed grid modernization base commitment performance metrics are inadequate (Attorney General Brief at 55-56; Cape Light Compact Brief at 13, 19, 22-23; CLF Brief at 16-17; DOER Brief at 35-36; NECEC Brief at 14, 35-36). The Attorney General, CLF, and NECEC maintain that the proposed performance metrics are not designed to measure progress towards achievement of the Department's grid modernization objectives (Attorney General Brief at 55-56; CLF Brief at 16-17; NECEC Brief at 14, 35-36). Similarly, Cape Light Compact and DOER argue that the Companies failed to provide a description of the process used to develop the proposed metrics, the common definitions and formulas employed, and an explanation of how each metric relates to grid modernization objectives as required by D.P.U. 12-76-B (Cape Light Compact Brief at 13, 19, 22-23; DOER Brief at 35-36).

Acadia Center, Cape Light Compact, NECEC, and RESA claim that the Companies inappropriately excluded metrics that measure outcomes that may not be within the

Companies' direct control (Acadia Center Brief at 20, 22; Acadia Center Reply Brief at 7; Cape Light Compact Reply Brief at 13; NECEC Brief at 22, n.10; RESA Brief at 36). Regardless of whether the Department sets targets or performance incentives associated with such metrics, Acadia Center and Cape Light Compact contend that tracking metrics that measure outcomes outside of the Companies control will allow evaluation of grid modernization progress and provide insight on future optimization of the electric system (Acadia Brief at 22; Acadia Reply Brief at 7-8; Cape Light Compact Reply Brief at 13). Finally, Acadia Center and DOER argue that Eversource's proposal fails to include broad, outcome-based statewide metrics as required by D.P.U. 12-76-B (Acadia Center Brief at 3, 6, 19-23; DOER Brief at 35-36).

With respect to the incentive regulation evaluation criteria established in D.P.U. 94-158 and D.P.U. 96-50 (Phase I), the Attorney General and Vote Solar assert that the Companies' proposed metrics fail to: (1) incorporate well-defined, measurable indicators; (2) include clear objectives, consistently applied incentives, and an equitable sharing of potential risks and benefits between customers and shareholders; and (3) outline how performance will be tracked and evaluated over time by company management and other interested parties (Attorney General Brief at 11-12; Vote Solar Brief at 12-14; Vote Solar Reply Brief at 5-8). In addition, the Attorney General, Cape Light Compact, NECEC, and Sunrun and EFCA assert that the Companies' proposed metrics are not designed to achieve specific, measurable results or to identify, where appropriate, measurable performance indicators and targets as required by D.P.U. 96-50 (Phase I) at 242-243 (Attorney General

Brief at 10, 12, 14-17; Cape Light Compact Brief at 56-59; NECEC Brief at 14; Sunrun and EFCA Brief at 8).

Additionally, Cape Light Compact maintains that the Companies' proposal is deficient because it fails to include metrics that provide financial penalties where performance is not met (Cape Light Compact Brief at 19). Cape Light Compact and Vote Solar also argue that the Companies' proposed performance metrics are too narrow in scope and are not tied to incentives that are large enough to drive improvements to meet the Department's criteria for evaluating PBR proposals (Cape Light Compact Brief at 56; Vote Solar Brief at 13).

vi. Stakeholder Process

The Attorney General and several other intervenors recommend improvements to the proposed stakeholder process in areas such as stakeholder identification and notification, advance access to written materials, timing of and response to written stakeholder comments, and the frequency and timing of stakeholder meetings (Attorney General Brief at 60; Acadia Center Brief at 19; CLF Brief at 53; NECEC Brief at 36). The Attorney General also maintains that the Department should hold a public hearing and establish a comment period for the Companies' annual grid modernization base commitment report (Attorney General Brief at 61).

Additionally, AIM recommends that the Department adopt a formal stakeholder process, similar to the process employed by the Energy Efficiency Advisory Council, which, according to AIM, would create transparency in how the Companies spend ratepayer money on grid modernization and also allow grid modernization projects to be considered in a wider

context (AIM Brief at 3-4). Finally, TEC and WMIG recommend that the Companies create a separate working group for C&I customers (TEC and WMIG Brief at 9-11).

b. Companies

i. Inclusion of Base Commitment in PBR

The Companies maintain that the Department should approve the foundational investment component of their grid modernization base commitment proposal without alteration (Companies Reply Brief at 68). The Companies argue that the Department is not precluded from approving a grid modernization plan that does not include advanced metering functionality (Companies Reply Brief at 64-67). Further, the Companies argue that substantial benefits will result from keeping the grid modernization base commitment proposal as a component of the PBR with the applicable procedural timeline (Companies Reply Brief at 63). Finally, the Companies maintain that the grid modernization objectives identified by the Department in D.P.U. 12-76 can be accomplished, in part, by the base commitment proposal (Companies Reply Brief at 64-65).

The Companies assert that, while the proposed PBR will create the most incentives for control of grid modernization base commitment costs, they are not opposed to recovery of these costs through a capital cost tracker (Companies Brief at 402-403). The Companies maintain that recovery of the grid modernization base commitment investments through a capital cost tracker outside of base rates is financially equivalent to the removal of a 1.08 percent explicit stretch factor from the PBR (Tr. 8, at 1555-1561). Finally, the Companies assert that the Department should not establish a preauthorization timeframe of less than five years, as suggested by DOER, because the grid modernization base

commitment provides sufficient transparency and oversight, as well as protections against cost estimates becoming out of date (Companies Brief at 402-403).

ii. D.P.U. 12-76 Requirements

The Companies argue that their proposal meets the grid modernization objectives outlined in D.P.U. 12-76 (Companies Brief at 374-376). In particular, the Companies contend that their grid modernization base commitment proposal facilitates the incremental grid modernization plan investments proposed in D.P.U. 15-122 and lays the foundation for future grid modernization investments (Companies Brief at 374-376). Further, the Companies claim that their proposal is consistent with D.P.U. 12-76-B in that it acknowledges that advanced metering functionality may not be justified in the short term, instead requiring a longer-term investment plan (Companies Brief at 374-376). In addition, the Companies argue that their proposal removes the risk of overcommitting to a single end-state investment path if the market shifts course (Companies Brief at 377-378).

The Companies maintain that the various intervenor arguments regarding the lack of an overarching grid modernization strategy, the failure to value distributed generation as a resource, and the risk of future obsolescence of grid modernization base commitment investments, are attempts to distract the Department from the substance of the Companies' proposal and to expand the grid modernization path set forth by the Department (Companies Brief at 395). Eversource also maintains that its grid modernization base commitment proposal is in line with the Department's vision for grid modernization (Companies Brief at 395). Further, the Companies contend that the Department has the authority to approve

grid modernization proposals in addition to the grid modernization plan proposals mandated in D.P.U. 12-76-B (Companies Brief at 380). Finally, with respect to suggestions that the Companies should revise and refile their grid modernization proposal, the Companies argue that this would not change their determination as to the appropriate investments for their distribution system, the appropriate methods to measure the implementation of these investments, or the Companies' position on advanced metering functionality (Companies Reply Brief at 68).

iii. Business Case Analysis

Responding to arguments concerning the lack of a comprehensive business case analysis, the Companies argue that they have presented an analysis similar to the business case analysis required by D.P.U. 12-76 or have committed to perform additional analysis where required (Companies Brief at 378-379, citing Tr. 7, at 1383; Exhs. ES-GMBC-2; AG-18-6). The Companies argue that its grid modernization base commitment proposal includes a plan to evaluate all of its components using a business case analysis or provides the details of any analysis that has already been performed (Companies Brief at 378-379, citing Exhs. DPU-30-17; DPU-49-1; DPU-49-2; DPU-49-3; DPU-49-4; DPU-57-7; AG-32-3; AG-23-15; Tr. 7, at 1325, 1327-1328).

iv. Business as Usual

The Companies maintain that the grid modernization base commitment proposal includes foundational investments to facilitate their incremental grid modernization proposal in D.P.U. 15-122 and lays the foundation for future grid modernization (Companies Brief at 377). Further, the Companies contend that these foundational investments are not business

as usual as they are incremental (i.e., either new types of technology or an increased level of investment relative to current investment practices) and will accelerate the Companies' progress in achieving the Department's grid modernization objectives in D.P.U. 12-76-B (Companies Brief at 377-378).

v. Metrics

The Companies maintain that their proposed metrics are not designed to secure specific outcomes or to achieve an envisioned end state, but to provide information and insight into the Companies' grid modernization activities and to monitor and evaluate the Companies progress towards its base commitment goals (Companies Brief at 103-105). The Companies assert that the proposed metrics are calibrated to provide transparency and clarity regarding their progress on execution of the grid modernization base commitment and to gauge the direct impact to customers of the grid modernization base commitment investments (Companies Brief at 103).

Further, the Companies argue that their proposed metrics are appropriate for measuring progress with respect to the grid modernization base commitment (Companies Brief at 105). The Companies maintain that they used appropriate design criteria to develop the proposed metrics (i.e., whether the metric is objectively measurable, whether the metric contains a starting point or baseline from which the Companies will be able to measure progress, and whether the metric is within the Companies' control and related to the grid modernization base commitment) (Companies Brief at 105, 326-327; Tr. 10, at 2094). In addition, the Companies assert that 14 additional metrics proposed by the intervenors also

meet these design criteria and, therefore, merit Department consideration (Companies Brief at 106, 326, citing Exh. DPU-41-7 (Supp.)).[211]

The Companies argue that, contrary to the intervenors' contentions, it is not appropriate to adopt metrics that pertain to the grid modernization objectives outlined in D.P.U. 12-76 (Companies Brief at 327-330, 407, 410, 417 418; Companies Reply Brief at 82, 91-92). Specifically, the Companies maintain that the Department's directives on metrics in D.P.U. 12-76-B apply to a grid modernization model that includes targeted cost recovery of a short term investment plan; whereas, in the present proceeding, the Companies developed the metrics to measure performance under a PBR (Companies Reply Brief at 91-92). The Companies contend that their failure to meet the grid modernization base commitment could serve as a basis for the Department to terminate the PBR and, therefore, the Companies argue that measuring performance using metrics outside of the Companies control would have consequences that were not considered in D.P.U. 12-76 (Companies Reply Brief at 92).

Finally, the Companies argue that an important goal of the PBR is to provide the Companies with the resources they need to undertake the foundational investments necessary to enable the Department's grid modernization objectives (Companies Brief at 326). The Companies contend that, consistent with Department precedent regarding incentive regulation, their proposed grid modernization performance metrics are appropriately designed to measure

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[211] The Companies maintain that three of the ten metrics proposed by Acadia Center and four of the six metrics proposed by CLF are appropriate to track for informational purposes (Companies Brief at 390, citing RR-CLF-2; RR-AC-2).

the achievement of this goal (Companies Brief at 323-324, 326, citing D.P.U. 94-158). The Companies assert that the proposed metrics provide measurable performance indicators and targets to evaluate progress on the grid modernization base commitment and goals of the PBR (Companies Brief at 105, 331, citing Exh. ES-GMBC-1, at 134).

vi. Stakeholder Process

The Companies do not oppose adoption of the Attorney General's recommendations to create a more robust stakeholder process, but state that amendments to the stakeholder process are not a basis for rejecting the grid modernization base commitment proposal (Companies Brief at 394). In addition, the Companies maintain that the level of coordination needed to develop the statewide three-year energy efficiency plans is not the same as the level of coordination needed for the grid modernization base commitment and, therefore, they oppose the creation of a stakeholder process modeled after the Energy Efficiency Advisory Council (Companies Brief at 414-415).

3. Analysis and Findings

The Department's review of the Companies' proposed grid modernization investments, including the base commitment proposal in the instant case, is guided by the grid modernization objectives outlined in D.P.U. 12-76. These objectives include: (1) reducing the effects of outages; (2) optimizing demand, which includes reducing system and customer costs; (3) integrating distributed resources; and (4) improving workforce and asset management. D.P.U. 12-76-B at 9. Progress toward meeting these objectives will enable customers to realize the benefits of grid modernization and advance policy goals and

statutory mandates regarding energy efficiency, renewable energy resources, demand response, electricity storage, microgrids, and electric vehicles. D.P.U. 12-76-B at 9.

In the instant proceeding, the Companies maintain that the investments proposed as part of the grid modernization base commitment will serve as foundational, first-step initiatives to enable the long-term achievement of the Department's grid modernization objectives (Exhs. ES-GMBC-1, at 17; DPU-42-1). The Companies state that the proposed base commitment investments are intended to be consistent with the Department's grid modernization objectives, with a particular emphasis on technologies and investments that achieve multiple grid modernization objectives (Exh. ES-GMBC-1, at 47-48).

In addressing cost recovery of grid modernization investments, the Department seeks to align an electric distribution company's investment priorities with the interests and needs of its customers. D.P.U. 12-76-A at 27. To achieve these results, the Department identified a capital cost tracker as the appropriate mechanism through which the electric distribution companies would recover eligible grid modernization costs. D.P.U. 12-76-B at 22-23. The Department concluded that a capital cost tracker would reduce a company's risk associated with grid modernization investments, while avoiding the significant disadvantages of a future-test-year ratemaking approach. D.P.U. 12-76-B at 22-23.

As described above, the Companies cost recovery proposal for the grid modernization base commitment investments is different from the mechanism envisioned in D.P.U. 12-76. Instead of a capital cost tracker, the Companies propose to spend $400 million in incremental grid modernization capital investments over five years and to absorb the revenue requirement

associated with these investments through the PBR until their next rate case (Exh. ES-GWPP-1, at 9-14).

Intervenors expressed various concerns with the inclusion of the grid modernization base commitment in the PBR. For example, the Attorney General, Cape Light Compact, CLF, DOER, NECEC, and UMass maintained that there are no assurances that the Companies will make the proposed investments and no financial penalties if they do not (Attorney General Reply Brief at 92; Cape Light Compact Brief at 50-51; CLF Brief at 16, 27-28; DOER Brief at 18-20; NECEC Brief at 22; UMass Brief at 9). Further, UMass contends that, even if the Companies refund to ratepayers any unspent portion of the $400 million commitment, ratepayers bear greater upfront risks than shareholders by including these investments in the PBR (UMass Brief at 4-5). Acadia Center, CLF, DOER, and NECEC assert that a capital cost tracker is more appropriate than the PBR to recover any approved grid modernization spending (Acadia Center Brief at 13-14; CLF Brief at 51; DOER Brief at 20-24; NECEC Brief at 19-26). Acadia Center, Choice Energy, CLF, DOER, NECEC, and RESA argue that a capital cost tracker approach would allow cost recovery for eligible grid modernization investments in a manner that also provides appropriate opportunities for stakeholder involvement and Department oversight (Acadia Center Brief at 13-14; Choice Energy Brief at 25-27; CLF Brief at 51; DOER Brief at 20-24; NECEC Brief at 19-26; RESA Brief at 35-38). As part of implementing this approach, NECEC maintains that the Department should convert the Companies' spending commitment targets into spending caps, asserting that this would provide flexibility to address changing

circumstances and would reduce the Companies' incentive to make investments based on ratemaking treatment instead of need (NECEC Brief at 24-26).

The Companies maintain that there is sufficient evidence to support inclusion of their grid modernization base commitment in the PBR (Companies Brief at 373, 403). Nonetheless, the Companies do not oppose recovery of their grid modernization investments through a capital cost tracker and the associated adjustments to the X factor needed to remove the grid modernization investments from the PBR (Companies Brief at 403; RR-DPU-3; Tr. 2, at 252-268).

For the reasons discussed below, the Department finds that it is not in the public interest to include the grid modernization base commitment investments as part of the PBR. Instead, we will address the substance of the Companies' proposed grid modernization investments, including cost recovery, as part of our forthcoming Order in the Companies' grid modernization proceeding, D.P.U. 15-122.[212] As discussed in Section IX.D.5.a above, the Department has made an appropriate adjustment to the Companies' PBR formula to remove the stretch factor associated with the proposed $400 million base commitment investment.

At the outset, the Department appreciates Eversource's commitment to address the significant changes that will increase the amount of distributed energy resources on its distribution system and its proposed grid modernization base commitment under the PBR as

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[212] Notwithstanding our findings here regarding removal of the grid modernization base commitment investments from the PBR, the Department addresses the Companies' storage and electric vehicle proposals in the Sections X.C and X.D below.

means to address these changes (Exh. ES-GMBC-Rebuttal at 5). Eversource's proposal acknowledges that modernization of the electric grid is a complex and long-term endeavor. The Companies state that their grid modernization base commitment proposal is not designed to achieve an end-state vision of the modern electric grid but is merely a first-step grid modernization enablement plan (Exh. ES-GMBC-1, at 132). The Companies recognize that additional learning is required to ensure optimal solutions for grid modernization (Exhs. ES-GMBC-1, at 46-47; NECEC-4-1).

As several intervenors note, there is significant uncertainty regarding implementation of the Companies' grid modernization base commitment (Attorney General Brief at 4; Attorney General Reply Brief at 92; Cape Light Compact Brief at 15, 50-51; CLF Brief at 16, 27-28; DOER Brief at 18-20, 28-31; UMass Brief at 9). In particular, there is uncertainty surrounding the projected costs and anticipated benefits of many of the proposed grid modernization investment (Exhs. DPU-43-6; DPU-43-7; DPU-43-10; AG-18-19; AG-18-20; AG-32-2; Tr. 2, at 377). The Department agrees with the Companies that a certain amount of uncertainty is inherent when planning for future deployments of technology (Companies Brief at 383).[213] Given this uncertainty, however, it is essential that the

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[213] In D.P.U. 12-76, the Department anticipated some uncertainty with regard to costs, savings, and benefits for planned grid modernization investments. In particular, we acknowledged that electric distribution companies and stakeholders may have difficulty in evaluating unquantifiable benefits across companies. D.P.U. 12-76-C at 25. Further, the Department recognized uncertainty in estimating quantifiable benefit variables as well. D.P.U. 12-76-C at 22. To address this uncertainty, the Department directed the electric distribution companies to present costs and benefits at a level of granularity that strikes an appropriate balance between enabling review of

Department establish a robust regulatory review and stakeholder process for the grid modernization investments. Such process will ensure that the investments will be implemented in a manner that achieves measurable, cost-effective progress towards our grid modernization objectives and will provide the necessary confidence that the investments will result in benefits to customers that justify the costs.

Eversource proposes to address the uncertainty in its proposal, through a project screening and stakeholder process, with periodic reporting to the Department (Companies Brief at 378-379; Exhs. ES-GMBC-Rebuttal at 22; DPU-60-8). Through the project screening and stakeholder processes, the Companies maintain that they will not invest in any project until the costs and benefits are better understood (Exhs. ES-GMBC-1, at 87; DPU-29-1). The intervenors maintain that the process proposed by the Companies does not provide sufficient assurances that benefits to ratepayers will accrue (Attorney General Brief at 4, 38-39; Attorney General Reply Brief at 92; Cape Light Compact Brief at 50-51; CLF Brief at 16, 22, 27-28; DOER Brief at 18-20; UMass Brief at 9). As discussed further below, the Department finds that removing the grid modernization investments from the PBR will facilitate the necessary Department oversight and stakeholder input regarding the grid modernization investments (Tr. 2, at 252, 370-371; RR-DPU-3).

With the inclusion of grid modernization investments in the PBR, the Companies' primary focus would be on a commitment to undertake capital investments to meet a pre-determined $400 million spending target. However well intentioned, the Department

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the proposed investments while reflecting the relatively high-level nature of the plans and the uncertainty inherent in planning estimates. D.P.U. 12-76-C at 38.

finds that the Companies' commitment to a pre-determined amount of grid modernization spending over the next five years is misplaced. Instead of a commitment to spend, the Companies must focus on a commitment to achieve the greatest benefit from their grid modernization investments (see Tr. 2, at 328). The Department finds that this shift in focus can be best achieved by removing the grid modernization base commitment from the PBR.

The Attorney General and CLF opine that because the Companies' grid modernization base commitment is included in the PBR, there are no ties between the investment and any quantitative improvements in service reliability, resiliency, energy efficiency, environmental benefits or resource diversity (Attorney General Brief at 4, 38-39; CLF Brief at 22). Eversource accepts that its proposed metrics are primarily designed to measure performance under the PBR (Companies Reply Brief at 91-92). Nonetheless, the Companies maintain that they have proposed to adopt a number of metrics that are designed to provide information regarding their grid modernization investment activities and measure progress towards their grid modernization base commitment goals (Exhs. ES-CAH-1, at 7; ES-GWPP-1, at 19; ES-GMBC-1, at 132, 135; ES-GMBC-2, at 74; ES-GMBC-3, at 1-6).

The Department finds that more robust metrics are needed to adequately measure the Companies' progress toward achieving the Department's grid modernization objectives.[214]

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[214] In D.P.U. 12-76-B at 30-34, the Department directed the electric distribution companies to include as part of their grid modernization plans, proposed metrics to measure progress towards achieving the Department's four grid modernization objectives. The Department directed the distribution companies to propose two types of company-specific metrics: (1) infrastructure metrics that track the implementation of grid modernization technologies and systems; and (2) performance metrics that measure progress towards the objectives of grid modernization. D.P.U. 12-76-B

By removing the grid modernization base commitment from the PBR, the Department will be able to comprehensively address grid modernization performance metrics for all distribution companies in a consistent manner.

Finally, we find that by removing the Companies' proposed grid modernization base commitment investments from the proposed PBR and reviewing the same in the context of the D.P.U. 15-122 proceeding affords the Department the ability to address all of the Companies' proposed grid modernization investments together (i.e., the proposed base commitment investments in D.P.U. 17-05 together with the remaining investments in D.P.U. 15-122). On that basis, the Department will be better able to assess issues that affect grid modernization as a whole. For instance, investments which are arguably business as usual are relevant to the definition of what constitutes grid modernization for cost recovery purposes and these issues are more appropriately considered in the context of a review of the Companies' complete grid modernization plan. In addition, the Department will be better able to address how the Companies' complete grid modernization plan complies with the Department's grid modernization objectives, including the Companies' approach to achieving advanced metering functionality.

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at 30. In addition, the Department directed the distribution companies to jointly propose statewide metrics and identified 15 specific statewide metrics for the distribution companies to consider adopting as part of their grid modernization plans. D.P.U. 12-76-B at 30-32. Although the Companies maintain that they are willing to adopt certain of the statewide metrics, the Companies proposed metrics do not include any of the joint statewide performance metrics developed pursuant to D.P.U. 12-76-B (Exh. ES-GMBC-3; RR-DPU-2, Att.).

Therefore, with the exception of the energy storage and electric vehicle proposals addressed below, the Department declines to make any findings in this case regarding pre-approval of the proposed budgets or investments included in the grid modernization base commitment. Rather, for the reasons stated above, the Department will address these issues in our forthcoming Order in D.P.U. 15-122.[215]

In the future, as we gain experience with grid modernization, it may be appropriate to include grid modernization investments together with other capital investments in a PBR. However, given our expectations that grid modernization will evolve substantially over the next five years, the Department finds that a more robust review of grid modernization investments than can be afforded by including these investments in the PBR is necessary in the short term. Accordingly, based on the above, the Department finds that it is in the public interest to address the Companies' proposed grid modernization base commitment investments outside of the PBR.

Consistent with this finding, the Department will address the structure of the grid modernization regulatory review process in the context of our review of the proposed grid modernization investments in our forthcoming Order in D.P.U. 15-122. In that Order, the Department intends to establish an appropriate cost recovery mechanism for eligible grid modernization investments that, to the extent practicable, will be consistent for all electric distribution companies. In addition, the Department intends to establish a uniform grid

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[215] In reaching these findings, the Department will rely on the relevant portion of the record in the instant case as well as the evidentiary record in the Companies' grid modernization proceeding, D.P.U. 15-122.

modernization stakeholder process for all electric distribution companies. Finally, the Department will address more robust grid modernization performance metrics. In all, the Department finds that this process will ensure that the Companies' investments will be aligned with the Department's grid modernization objectives and will provide benefits to customers.

C. Energy Storage Demonstration Program

1. Companies Proposal

a. Introduction

The Companies propose to invest $100 million over five years on an energy storage demonstration program to investigate the ability of energy storage facilities: (1) to provide distribution reliability; and (2) to address power quality and voltage stability issues arising from the deployment of intermittent distributed energy resources on their distribution system (Exh. ES-GMBC-1, at 70-74). The Companies have identified four projects in the following locations: Martha's Vineyard, Wellfleet, New Bedford and Pittsfield (Exh. ES-GMBC-1, at 71-72). Eversource anticipates that the four projects under consideration will exhaust the entire $100 million budget; however, if costs decline, Eversource proposes to identify additional projects to meet its total grid modernization base commitment (Exh. ES-GMBC-1, at 90).

The Companies state that final determination of what projects will be undertaken will be based on a three-phase feasibility analysis that will be conducted for each potential location (Exhs. ES-GMBC-1, at 87; DPU-29-1). In the initial phase of the feasibility analyses, the Companies state that they will: (1) further define the system challenges faced

by each location; (2) create a conceptual system design; and (3) refine preliminary estimates of each project's costs and benefits (Exh. DPU-29-1). In the second phase of the feasibility analyses, the Companies state that they will complete a more detailed engineering evaluation to: (1) better define system needs and identify the storage systems that would meet these needs; and (2) further refine each project's costs and benefits (Exh. DPU-29-1). Finally, in the third phase of the feasibility analyses, the Companies state that they will create a detailed cost and schedule analyses that will form the basis for the decisions to proceed (Exh. DPU-29-1). For projects that proceed beyond the third phase of analysis, the Companies state that they will (1) finalize engineering designs, cost estimates, and schedules, and (2) pursue the permits and approvals necessary to site and complete the projects (Exh. DPU-29-1).

Eversource states that it will meet with stakeholders annually as part of the proposed stakeholder process described above, to discuss the Companies' progress in identifying the energy storage projects that they expect to deploy (Exh. DPU-30-17, at 1, RR-DPU-24 & Att.). The Companies state that they will provide sufficient information to allow stakeholders to understand the Companies' decision-making process in this regard (Exh. DPU-30-17, at 1, RR-DPU-24 & Att.). In addition, the Companies state that they will notify the Department of the projects selected for deployment as part of the annual grid modernization base commitment report filings (Exhs. ES-GMBC-1, at 89, DPU-30-17, at 1-2).

The Companies state that for each project that is implemented, they will complete a project development evaluation within twelve months of the project's commercial operation

date (Exh. ES-GMBC-1, at 85).[216] Finally, the Companies state that they will complete a project operations evaluation within 24 months after completion of the project (Exhs. ES-GMBC-1, at 85-86; ES-GMBC-7).[217]

b. Proposed Projects

i. Martha's Vineyard

Martha's Vineyard currently is served by four undersea distribution cables and five 2.5 megawatt ("MW") emergency diesel generators (Exh. ES-GMBC-1, at 78). The Companies propose a two-phase approach to deploy energy storage on the island in order to investigate how this technology can be used to: (1) avoid the need to upgrade or add undersea cables; (2) replace diesel generators; and (3) integrate additional distributed energy resources (Exh. ES-GMBC-1, at 79-80). The Companies state that the cost estimates for the Martha's Vineyard location were developed by a consultant who designed the preliminary system specifications based on a power-flow study of the distribution system in the area (Exh. ES-GMBC-1, at 80-81).

During the first phase of the demonstration project, the Companies propose to deploy, at an estimated cost of $10 million to $15 million, a 5.0 MW storage facility to test the ability of this technology to replace two of the five emergency diesel generators (Exhs. ES-GMBC-1, at 80; ES-GMBC-7, at 2). The Companies expect that deployment of

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216 The Companies state that the project development evaluation will review the siting and permitting process, the engineering and design process, the commercial strategies employed, the construction process, and the operational turnover process (Exh. ES-GMBC-1, at 85).

217 The Companies state that the project operations evaluation will be used to determine whether each project fulfilled its intended functions (Exh. ES-GMBC-1, at 85-86).

the phase one facility will occur in late 2018 or early 2019 (Exh. ES-GMBC-1, at 80). During the second phase of the demonstration project, the Companies propose to deploy, at an estimated cost of $20 million to $30 million, a 10 MW storage facility to test the ability of this technology to: (1) replace the remaining three emergency diesel generators; and (2) further defer the need to upgrade the existing undersea cables or construct additional cables (Exhs. ES-GMBC-1, at 80; ES-GMBC-7, at 3). The Companies expect that deployment of the phase two facility will occur in 2022 (Exh. ES-GMBC-1, at 80)

ii. Wellfleet

The Wellfleet substation serves customers located on outer Cape Cod (Exh. ES-GMBC-1, at 81). Currently, a single 115 kV line and a backup 23 kV line from the Orleans substation serve the Wellfleet substation (Exh. ES-GMBC-1, at 81). The Companies state that in scenarios where they lose use of the 115 kV line, the 23 kV backup line has insufficient capacity to fully meet demand without exceeding the specified load flow limit and subjecting customers to unacceptably low voltage (Exh. ES-GMBC-1, at 81). Based on an analysis provided by a third-party consultant, the Companies propose to deploy, at an estimated cost of $35 million to $45 million, a 12 MW energy storage facility at the Wellfleet substation to test how this technology can be used to provide capacity when the Companies lose use of the 115 kV line (Exh. ES-GMBC-1, at 81-82).[218] The Companies expect that deployment of this facility will occur in 2020 or 2021 (Exh. ES-GMBC-1, at 82).

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[218] The Companies state that the consultant who designed the preliminary system specifications, developed the costs estimates based on a power-flow study of the distribution system in the area (Exh ES-GMBC-1, at 82).

iii. New Bedford

The Companies state that the Business Drive substation in New Bedford currently is experiencing power quality issues (e.g., intermittent short outages, transient voltage dip, and surge conditions) that affect certain C&I customers served by the substation (Exh. ES-GMBC-1, at 82). Based on a preliminary evaluation, the Companies are considering deploying, at an estimated cost of $10 million to $15 million, a 6.0 MW energy storage facility at this New Bedford substation to test how this technology can be used to address the identified power quality issues (Exh. ES-GMBC-1, at 82-83). The Companies state that this project is in the early stages of development and that they expect to have further developed cost estimates upon completion of a detailed analysis of the project by a third-party consultant (Exh. ES-GMBC-1, at 83).

iv. Pittsfield

The Companies state that the Partridge Road substation in Pittsfield has a large amount of distributed energy resources connected to its circuits that cause momentary fluctuations in voltage (Exh. ES-GMBC-1, at 83-84). Based on their preliminary evaluation, the Companies are considering deployment, at an estimated cost of $10 million to $15 million, of a 6.0 MW energy storage facility at the Partridge Road substation to test how this technology can be used to address the identified power quality issues and better integrate distributed energy resources (Exh. ES-GMBC-1, at 83-84). Like the New Bedford project, the Companies state that this project in the early stages of development and that they expect to have further developed cost estimates upon completion of a detailed analysis of the project by a third-party consultant (Exh. ES-GMBC-1, at 83-84).

2. Positions of the Parties

a. Intervenors

A number of intervenors recommend that the Department either reject or significantly modify the Companies' energy storage proposal (Attorney General Brief at 40-43; Attorney General Reply Brief at 92-94; Acadia Center Brief at 14-18; Cape Light Compact Brief at 24-39; Cape Light Compact Reply Brief at 6-7; Choice Energy Brief at 25-27; CLF Brief at 49-51; DOER Brief at 32-33; DOER Reply Brief at 17-18; NECEC Brief at 26; NECEC Reply Brief at 5-8; Sunrun and EFCA Brief at 15-16; Sunrun and EFCA Reply Brief at 6-7; RESA Brief at 35-38; RESA Reply Brief at 8-9; TEC and WMIG Brief at 18-19). The Attorney General, Acadia Center, Cape Light Compact, CLF, and DOER maintain that the Companies did not provide sufficient information for the Department to determine whether the proposed storage projects will benefit ratepayers and are in the public interest (Attorney General Brief at 41-42 Attorney General Reply Brief at 92-94; Acadia Center Brief at 15-16; Cape Light Compact Brief at 35-38; Cape Light Compact Reply Brief at 6-7; CLF Brief at 50-51; DOER Brief at 32-33; DOER Reply Brief at 17-18;). The Attorney General argues that, while the Companies commit to providing detailed cost estimates before proceeding with each storage project, Eversource makes no comparable commitment to provide detailed project benefits (Attorney General Brief at 41-42; Attorney General Reply Brief at 92-94). In addition, the Attorney General maintains that the Companies' likely share of the statewide energy storage targets to be established by DOER is approximately $200 million and 350 MW (Attorney General Brief at 42). The Attorney General asserts that it is not reasonable for the Companies to spend half of that amount on demonstration projects for only

30 to 40 MW of storage, with no assurance of customer benefit or operational success (Attorney General Brief at 41; Attorney General Reply Brief at 92-94).

Cape Light Compact, Choice Energy, and RESA argue that Eversource's storage proposal is contrary to state and federal laws and policies (Cape Light Compact Brief at 25-31; Cape Light Compact Reply Brief at 6-7; Choice Energy Brief at 25-27; Choice Energy Reply Brief at 10-12; RESA Brief at 36-38; RESA Reply Brief at 8-9). In particular, Cape Light Compact asserts that the proposal is contrary to the provisions of G.L. c. 164, Acts of 1997 ("Restructuring Act") related to the exercise of vertical market power by distribution companies (Cape Light Compact Brief at 25-27; Cape Light Compact Reply Brief at 6-7). Specifically, Cape Light Compact argues that, because Eversource would control both the energy provided by the storage facilities and the delivery of that energy to customers, the project would vertically integrate energy resources with the distribution system, in contravention of the Restructuring Act (Cape Light Compact Brief at 25-28; Cape Light Compact Reply Brief at 6-7). Further, Cape Light Compact argues that Eversource could use its position as a monopoly distribution service provider to gain advantage over competitive entities (e.g., it could use one of the proposed energy storage sites to favor the Companies' own solar projects) (Cape Light Compact Brief at 29-31, 33-34; Cape Light Compact Reply Brief at 6-7). RESA argues that the Companies' proposal is not a plan to integrate distributed energy resources; instead it is a plan to develop a market resource (RESA Brief at 35-36; RESA Reply Brief at 8-9).

Cape Light Compact and RESA also assert that the proposal is in direct conflict with evolving federal energy market policy geared at facilitating the participation of storage and other distributed energy resources in the wholesale electricity markets (Cape Light Compact Brief at 25-26; Cape Light Compact Reply Brief at 6-7; RESA Brief at 36-37; RESA Reply Brief at 8-9).[219] Cape Light Compact and RESA contend that the Companies seek to participate in the wholesale markets in direct competition with third-party providers, in a manner that exceeds the services lawfully provided by a distribution company (Cape Light Compact Brief at 26-27; Cape Light Compact Reply Brief at 6-7; RESA Brief at 37; RESA Reply Brief at 8-9).

Cape Light Compact, NECEC, and RESA argue that the energy storage proposal is deficient because it excludes or does not facilitate participation by third-party-owned energy storage, which could provide distribution reliability functions (Cape Light Compact Brief at 28-31; Cape Light Compact Reply Brief at 6-7; NECEC Brief at 26-33; NECEC Reply Brief at 5-8; RESA Brief at 35-38; RESA Reply Brief at 8-9). Further, RESA asserts that, in D.P.U. 12-76- at 33, the Department found that distributed energy resources such as storage would be developed by third parties and not distribution companies (RESA Brief at 36; RESA Reply Brief at 8-9). In addition, Cape Light Compact and NECEC contend that the proposal would not remove existing barriers to customer investment in storage systems or to third-party investment in aggregated, customer-sited storage solutions (Cape Light

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[219] Cape Light Compact and RESA cite a notice of proposed rulemaking issued by FERC: Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, Notice of Proposed Rulemaking, 157 FERC ¶ 61,121 (November 17, 2016) ("FERC NOPR").

Compact Brief at 28-31; Cape Light Compact Reply Brief at 6-7; NECEC Brief at 26-31; NECEC Reply Brief at 5-8). NECEC recommends that the Department require the Companies to file a revised proposal that incorporates customer and third-party owner of energy storage assets (NECEC Brief at 26: NECEC Reply Brief at 5-8).

NECEC further argues that the Companies' energy storage proposal is not designed to demonstrate the relative costs and benefits of different business models and uses for energy storage and, therefore, the Companies are missing an important opportunity to test approaches that could unlock future energy storage development in the Commonwealth (NECEC Brief at 26-30; NECEC Reply Brief at 5-8). Accordingly, NECEC asserts that the Department should direct the Companies to refocus their energy storage proposal in order to test diverse business models that support energy storage development rather than deploying utility-owned storage assets, including third-party ownership of energy storage assets (NECEC Brief at 26-27; NECEC Reply Brief at 5-8).

Acadia Center argues that, to ensure progress towards grid modernization and a clean energy future, the Department should permit the Companies' to implement only one of the four proposed storage projects and add a second project that would use a competitive solicitation to procure clean resources (Acadia Center Brief at 17-18). CLF argues that, given the importance of energy storage to the achievement of the Commonwealth's energy and climate goals, the Department should direct the Companies to file a stand-alone, comprehensive energy storage integration plan (CLF Brief at 49-51). DOER maintains that, while it conceptually supports the inclusion of energy storage in the Companies' grid

modernization plan, the Department should require the Companies to submit a compliance filing that includes a comprehensive analysis of the costs and benefits of the proposed storage projects (DOER Brief at 31-33; DOER Reply Brief at 18). Sunrun and EFCA argue that the Department should direct the Companies to implement the proposed storage program but should not pre-approve recovery of costs until the Companies provide cost-effectiveness and business cases analyses (Sunrun and EFCA Brief at 15-16; Sunrun and EFCA Reply Brief at 6-7). TEC and WMIG argue that the Companies' have not shown that the proposed energy storage investments are prudent or beneficial to ratepayers, or minimize the risk of stranded costs (TEC and WMIG Brief at 18-20).

b. Companies

The Companies argue that their energy storage proposal will help foster the market for energy storage in Massachusetts, while enabling the Companies to obtain real-time operating data that will be critical in evaluating future energy storage deployments (Companies Brief at 77-78). The Companies maintain that energy storage provides an opportunity to fundamentally change the way they plan for and deliver electricity to customers (Companies Brief at 83). The Companies assert that their proposal will result in standard protocols to evaluate the installation of energy storage systems in locations that are challenged to integrate additional distributed energy resources or facing transmission or distribution upgrades (Companies Brief at 78). Accordingly, the Companies maintain that their proposal meets the Department's grid modernization objectives of integrating distributed energy resources and improving workforce and asset management (Companies Brief at 77).

The Companies argue that they selected the potential storage project locations in order to demonstrate the ability of energy storage to: (1) offset new upgrades to their distribution system; (2) eliminate the use of aging diesel generators that produce greenhouse gas emissions; and (3) address intermittency and smooth voltage from distributed energy resource installations (Companies Brief at 381-382). The Companies further maintain that the proposed projects are designed to be implemented in two phases in order to prioritize the projects with the longest critical path schedules and allow the Companies to incorporate the lessons learned from the initial projects into the analyses of the second phase projects (Companies Brief at 384-385).

In response to arguments that additional analysis is required before Department approval, the Companies assert that their proposed three-phase feasibility analysis process will: (1) refine the design and cost estimates associated with the projects; and (2) identify and evaluate both quantifiable benefits (e.g., avoided transmission or distribution costs) and difficult to quantify benefits (e.g., benefits related to integration of distributed energy resources or enhancement of local power quality reliability) (Companies Brief at 379-382; Companies Reply Brief at 76). The Companies maintain that this feasibility analysis will ensure that the necessary information to assess the cost effectiveness or business case for each project is available prior to construction (Companies Reply Brief at 77-78). Further, the Companies contend that the projects will not move forward until the level of detail on costs and benefits is sufficient for their internal review process and that the Department will retain oversight of program expenditures, including pre- and post-construction cost variances

(Companies Brief at 384; Companies Reply Brief at 76). The Companies assert that benefits associated with grid modernization are difficult to measure and that lack of data concerning these new technologies should not be grounds for rejecting the proposal (Companies Brief at 383, 404).

In response to the arguments regarding conflict with state and federal laws and policies, the Companies assert that their proposed energy storage demonstration program is not designed to act as a generation asset. Instead, the Companies maintain that the proposed energy storage projects are designed, among other things, to integrate distributed energy resources in locations where such integration is becoming cost prohibitive (Companies Brief at 396; Companies Reply Brief at 81). In addition, the Companies argue that Section 9 of an Act to Promote Energy Diversity, Acts of 2016, c. 188 ("Energy Diversity Act") explicitly excludes "an energy storage system procured by a distribution company for support in delivering energy services to end users" from the definition of "generation facility" (Companies Reply Brief at 80).

Finally, the Companies assert that any arguments that they are attempting to use energy storage to the disadvantage of other market participants, are without merit (Companies Brief at 396; Companies Reply Brief at 81). The Companies maintain that their proposal will not preclude third-party energy storage opportunities (Companies Brief at 395-396). Instead, the Companies argue that their proposal to explore utility-owned storage in the instant case, together with their proposal to explore non-utility-owned storage as part of their demand reduction demonstration project in D.P.U. 16-178, will allow Eversource to compare these

models when considering the future use of energy storage on its distribution system (Companies Brief at 395-396; Companies Reply Brief at 79). The Companies contend that their proposal to test utility-owned storage first, and then to use this experience to evaluate commercial models later, is appropriate for technology at this early stage of development (Companies Reply Brief at 79).

3. Analysis and Findings

a. Introduction

Eversource states that its proposed energy storage demonstration program is intended to foster the market for energy storage in the Commonwealth by enabling the Companies to (1) obtain real–time data on the operation of energy storage facilities, and (2) develop a model for the deployment of such facilities in the future (Exh. ES-GMBC-1, at 70). The Companies propose to implement the demonstration program in two stages (Companies Brief at 384-385). The first stage includes: (1) phase one of the Martha's Vineyard project, in which the Companies propose to deploy an energy storage facility in late 2018 or early 2019; and (2) the Wellfleet project, in which the Companies propose to deploy an energy storage facility in late 2020 or 2021 (Exh. ES-GMBC-1, at 78-82). The second stage of the demonstration program includes: (1) phase two of the Martha's Vineyard project, in which the Companies expect to deploy an energy storage facility in 2022; (2) the New Bedford project; and (3) the Pittsfield project. The Companies did not specify proposed deployment dates for either the New Bedford project or the Pittsfield project (Exh. ES-GMBC-1, at 82-84). The Companies maintain that they designed the demonstration program to be

implemented in stages in order to allow them to incorporate lessons learned from the first stage projects into the analysis of the second stage projects (Companies Brief at 384-385).

The Companies request that the Department pre-authorize the entire proposed energy storage demonstration program as reasonable and appropriate and, therefore, any investments in energy storage under the program would be eligible for inclusion in rate base in the Companies' next base rate proceeding (Exh. ES-GMBC-1, at 20).[220] In addition, the Companies request that the Department find that the proposed $100 million budget for the energy storage demonstration program is reasonable (Exh. ES-GMBC-1, at 20).

Intervenors raise several concerns about the proposed energy storage demonstration program. In particular, the Attorney General, Acadia Center, Cape Light Compact, Choice Energy, CLF, DOER, NECEC, RESA, and TEC and WMIG argue that the Companies have provided insufficient information regarding the costs and likely benefits of the proposed demonstration projects to determine whether they are in the public interest (Attorney General Brief at 40-43; Attorney General Reply Brief at 92-94; Acadia Center Brief at 14-18; Cape Light Compact Brief at 24-39; Cape Light Compact Reply Brief at 6-7; Choice Energy Brief at 25-27; CLF Brief at 49-51; DOER Brief at 32-33; DOER Reply Brief at 17-18; NECEC Brief at 26; NECEC Reply Brief at 5-8; RESA Brief at 35-38; RESA Reply Brief at 8-9; TEC and WMIG Brief at 18-19). In addition, Acadia Center, Cape Light Compact, CLF,

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220 The Companies state, however, that they are not requesting that the Department pre-authorize the specific energy storage projects identified in their filing (Exh. ES-GMBC-1, at 20). Instead, the Companies request that the Department find that the Companies' decision to invest in the energy storage demonstration program is reasonable (Exh. ES-GMBC-1, at 20).

Choice Energy, NECEC and RESA argue that the Companies proposal is contrary to state and federal laws and policies, the Department's grid modernization directives, or the Commonwealth's energy and climate goals (Acadia Center Brief at 17-18; Cape Light Compact Brief at 25-31; Cape Light Compact Reply Brief at 6-7; CLF Brief at 49-51; Choice Energy Brief at 26-27; NECEC Brief at 26-27; NECEC Reply Brief at 5-8; RESA Brief at 35-38; RESA Reply Brief at 8-9).

In NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 16-178 (2017),[221] the Department summarized the factors it considers when evaluating a proposed demonstration project. In evaluating the Companies' proposed energy storage demonstration program, the Department will consider the following criteria: (1) the consistency of the proposed demonstration program with applicable laws, policies, and precedent; (2) the reasonableness of the size, scope, and scale of the proposed projects in relation to the likely benefits to be achieved; (3) the adequacy of the proposed performance metrics and evaluation plans; and (4) bill impacts to customers. See D.P.U. 16-178, at 16.

b. Consistency with Applicable Laws, Policies, and Precedent

Cape Light Compact, Choice Energy, and RESA assert that Eversource's proposed energy storage demonstration program is in contravention to state and federal laws and policies related to distribution company ownership of energy storage facilities and the potential for the exercise of vertical market power (Cape Light Compact Brief at 25-31; Cape

[221] In D.P.U. 16-178, at 42-43, the Department approved, as part of the three-year energy efficiency plans, Eversource's proposal to implement demand reduction demonstration offerings for large C&I customers in four areas: (1) battery storage; (2) thermal storage; (3) software and controls; and (4) active demand response.

Light Compact Reply Brief at 6-7; Choice Energy Brief at 26-27; RESA Brief at 35-38; RESA Reply Brief at 8-9). With respect to state law, Section 8 of the Energy Diversity Act permits utility-owned energy storage provided that the energy storage system will "(i) reduce the emission of greenhouse gases; (ii) reduce demand for peak electrical generation; (iii) defer or substitute for an investment in generation, transmission, or distribution assets; or (iv) improve the reliable operation of the electrical transmission or distribution grid."[222] Further, Section 9 of the Energy Diversity Act amended the definition of "generation facility" contained in G.L. c. 164 § 1 to exclude "energy storage system procured by a distribution company for support in delivering energy services to end users." Because the primary objectives of the Companies' proposed demonstration program are to test how energy storage facilities can (1) serve as non-wires alternatives to providing distribution reliability, and (2) address power quality issues arising from the deployment of intermittent distributed energy resources, the Department finds that the program meets the legal requirements of the Energy Diversity Act regarding distribution company ownership of energy storage assets.

With respect to state energy policy objectives, in 2015, the Commonwealth instituted an Energy Storage Initiative, the objective of which is to establish an energy storage market structure to leverage the potential benefits of energy storage at the wholesale, local distribution, and customer levels (Exh. ES-GMBC-6, at 4). The State of Charge Report, which DOER issued as part of the Energy Storage Initiative, identifies several potential

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[222] Among other things, the Energy Diversity Act promotes the use of energy storage in the Commonwealth.

applications for energy storage facilities.[223] Two of these applications relate to the potential for such facilities to (1) serve as a non-wires alternative to investments in transmission and distribution infrastructure, and (2) address power quality and reverse power flow issues that arise from the increased deployment of distributed energy resources (Exh. ES-GMBC-6, at 84, 90). Accordingly, the Department finds that the proposed energy storage demonstration program, with its specified objectives, is consistent with the energy policy objectives of the Commonwealth.

The Department notes that federal policies regarding energy storage are currently under review, including policies regarding the participation of energy storage in organized wholesale electricity markets, which is the subject of Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, Notice of Proposed Rulemaking, 157 FERC ¶ 61,121 (November 17, 2016) ("FERC NOPR"). The Department recognizes that the Companies likely will participate in, and receive revenues from, the wholesale markets through the operation of any deployed energy storage resources, although the Companies state that participation in the wholesale markets is not the objective of the proposed program (Exh. DPU-29-13; Tr. 8 at 1677). The Department will continue to monitor the development of federal policies regarding energy storage, including the FERC NOPR; however, we find that nothing raised by the intervenors leads us to conclude that the proposed energy storage demonstration program is in

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223 DOER issued the State of Charge report on September 16, 2016. The full title of the report is "State of Charge: Massachusetts Energy Storage Initiative Study" (Exh. ES-GMBC-6).

contravention of any federal laws or policies related to distribution company ownership of energy storage.

Finally, in D.P.U. 12-76-B at 9, the Department stated that distribution companies could propose research, development and deployment efforts that test the ability of emerging technologies to meet the Department's grid modernization objectives. The Department finds that the proposed energy storage demonstration program is consistent with the grid modernization objectives of integrating distributed resources and improving asset management.

c. Size, Scope and Scale

i. Introduction

The Department requires distribution companies to fully support proposed pilot programs or demonstration offerings with detailed program descriptions to allow the Department and stakeholders to evaluate the reasonableness of the size, scope, and scale of the proposals in relation to the benefits to be achieved. D.P.U. 16-178, at 30; Fitchburg Gas and Electric Light Company, D.P.U. 16-184, at 11 (2017). In the absence of cost-effectiveness screenings, the Department requires detailed program descriptions and appropriate analyses to support the potential of the proposals to deliver net benefits in the future. D.P.U. 16-178, at 30; D.P.U. 16-184, at 11.

In the instant proceeding, several intervenors assert that the Companies failed to provide sufficient detail regarding program costs and benefits for the Department to determine whether the Companies' proposed energy storage demonstration program is reasonable and in the best interest of ratepayers (Attorney General Brief at 41-42; Attorney

General Reply Brief at 92-94; Acadia Center Brief at 15-16; CLF Brief at 51; DOER Brief at 32-33; DOER Reply Brief at 17-18; TEC and WMIG Brief at 18-19). In consideration of these arguments, the Department addresses the reasonableness of the size, scope and scale of each of the proposed projects below.

ii. Stage One Projects

(A) Martha's Vineyard (Phase One)

In phase one of the Martha's Vineyard project, the Companies propose to deploy, in late 2018 or early 2019, a 5.0 MW energy storage facility to test the ability of such a facility to replace two of the five diesel generators that currently serve the island, at an estimated cost of $10 million to $15 million (Exh. ES-GMBC-1, at 80; Exh. ES-GMBC-7, at 2). For the phase one Martha's Vineyard project, the Companies provided a detailed conceptual design report that includes: (1) a description of the electrical system that serves the island; (2) a summary of the historic performance of the undersea cables and diesel generators that serve the island; (3) a modeling of the future electrical loading on the island; (4) an analysis of the project's technical feasibility; (5) a proposed deployment approach and schedule; (6) estimated project costs; and (7) an analysis of the anticipated benefits associated with the deferral of investments in additional undersea cables and the retirement of diesel generators (Exh. AG-32-3. Att. (b) (confidential)). Cost estimates for Martha's Vineyard were based on prices provided by external consultants from analysis of industry costs for projects of this size (Exh. AG-23-13)

As noted above, the intervenors maintain that the Companies have not provided sufficient information regarding the costs and likely benefits of the proposed demonstration

projects (Attorney General Brief at 41-42; Attorney General Reply Brief at 92-94; Acadia Center Brief at 15-16; CLF Brief at 51; DOER Brief at 32-33; DOER Reply Brief at 17-18; TEC and WMIG Brief at 18-19). After review, the Department finds that the Companies have provided a sufficiently detailed description of phase one of the proposed Martha's Vineyard project, including cost estimates and analysis, to support the likely potential of this project to deliver net benefits in the future (Exhs. AG-23-13; AG-32-3, Att. (b) (confidential)).[224]

Further, the Department finds that the Companies have demonstrated that phase one of the proposed Martha's Vineyard project will likely generate benefits in the following areas: (1) benefits related to the retirement of diesel generators (and associated greenhouse gas emissions); (2) data and insight into the costs of integrating distributed energy resources before and after deployment of storage; (3) reliability through improved voltage regulation; (4) contingency planning; and (5) peak load reduction (Exhs. ES-GMBC-1, at 79-80; ES-GMBC-2, at 56-57; ES-GMBC-7, at 2; AG-32-3, Att. (b)). In addition, the Companies have identified Martha's Vineyard as a location where they have potential capacity needs in accordance with established reliability criteria and, therefore, have shown that phase one of the proposed Martha's Vineyard project could serve as non-wires alternative to defer upgrades to, or avoid construction of, an additional undersea cable (Exhs. DPU-29-12; AG-32-4; SREF-1-20). For these reasons, the Department finds that the Companies have

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224 The Companies state that the initial feasibility analysis for Martha's Vineyard phase one will be complete in the fourth quarter 2017 (Exh. DPU-30-17).

demonstrated that phase one of the Martha's Vineyard project is reasonable in size, scope, and scale in relation to the likely benefits to be achieved.[225]

(B) Wellfleet

For the Wellfleet project, the Companies propose to deploy a 12.0 MW energy storage facility to test its ability to provide capacity when the Companies lose use of the 115 kV line that serves the Wellfleet substation. The Companies propose to deploy this facility in late 2020 or 2021, at an estimated cost of $35 million to $40 million (Exh. ES-GMBC-1, at 81-82). The Companies provided a conceptual design report for the Wellfleet project that includes: (1) a description of the electrical system in the area served by the Wellfleet substation; (2) a summary of the historic performance of the electric system that serves the area; (3) a modeling of the future electrical loading in the area; (4) an analysis of the project's technical feasibility; (5) a proposed deployment approach and schedule; (6) estimated costs; and (7) an analysis of the anticipated benefits associated with the deferral of investments in additional transmission and distribution infrastructure (Exh. AG-32-3, Att. (c) (confidential)). Similar to the Martha's Vineyard phase one project, the primary objective of the proposed Wellfleet project is to demonstrate how utility owned and operated energy

[225] The Department notes that the conceptual design report is first phase of a three-phase feasibility analysis (Exhs. ES-GMBC-1, at 87; DPU-29-1, at 3-4). The later phases of this analysis will include engineering evaluations that will form the basis for the Companies' decision of whether to proceed with the project (Exh. DPU-29-1, at 3-4; AG-9-7). It should go without saying that if the later phases of this feasibility analysis do not support the prudence of the project the Companies should refrain from further implementation.

storage can be deployed to defer or avoid the need to upgrade existing transmission and distribution facilities (Exh. ES-GMBC-1, at 81).[226]

The Department finds that the Companies have provided a sufficiently detailed description of the Wellfleet project, including cost estimates and analysis, to support the likely potential of this project to deliver net benefits in the future (Exhs. AG-23-13; AG-32-3, Att. (c) (confidential)). In particular, the Department finds that the Companies have demonstrated that the Wellfleet project will likely generate benefits in the following areas: (1) data and insight into the costs of integrating distributed energy resources before and after deployment of storage; (2) reliability through improved voltage regulation; and (3) contingency planning (Exhs. ES-GMBC-1, at 81; ES-GMBC-2, at 57-58; ES-GMBC-7, at 3; AG-32-3, Att. (c) (confidential)). Further, like Martha's Vineyard, the Companies have identified Wellfleet as a location where they have potential capacity needs in accordance with established reliability criteria and, therefore, have shown that the Wellfleet project could serve as an alternative to the siting of an additional transmission line (Exhs. DPU-29-12; SREF-1-20).[227] For these reasons, the Department finds that the Companies have

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[226] The Companies state their initial feasibility analysis for Wellfleet will be complete in the fourth quarter 2017 (Exh. DPU-30-17).

[227] The Companies notes that this location is in or near environmentally sensitive areas that would make siting, permitting, and constructing a traditional project challenging (Exh. SREF-1-20).

demonstrated that the Wellfleet project is reasonable in size, scope, and scale in relation to the likely benefits to be achieved.[228]

iii. Stage Two Projects

The Companies propose to implement the New Bedford and Pittsfield projects, and phase two of the Martha's Vineyard project, in the second stage of the demonstration program (Companies Brief at 384). The Companies state that they designed the proposed energy storage demonstration program in this manner in order to allow them to incorporate lessons learned from the initial projects into the analyses of the second phase of projects (Companies Brief at 384-385).

The Companies' analysis of the costs and potential benefits of the New Bedford and Pittsfield demonstration projects consists of a vendor presentation that includes: (1) current distributed generation capacity and penetration at these sites; (2) a high-level analysis of current and future reverse powerflow; and (3) a brief overview and analysis of possible mitigation of reverse powerflow achieved by energy storage (Exh. AG-32-3, Att. (a) (confidential)). Because these projects are in the earliest phases of development, the cost estimates for these projects are based only on the estimated costs of the Martha's Vineyard phase one and Wellfleet projects (Exh. AG-23-13).

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228 Like phase one of the Martha's Vineyard project, the Department notes that the conceptual design report is first phase of a three-phase feasibility analysis for Wellfleet (Exhs. ES-GMBC-1, at 87; DPU-29-1, at 3-4). Should the later phases of this feasibility analysis not support the prudence of the project the Companies should refrain from further implementation.

The Department finds that the information provided by the Companies regarding costs and likely benefits of the New Bedford and Pittsfield projects is not sufficient to analyze the size, scope, and scale. While these projects may ultimately be appropriate for implementation, they need to be further along in the development process before the Department can make such an assessment.[229]

With respect to phase two of the Martha's Vineyard project, the Companies plan to install a second, larger energy-storage system capable of providing 10 MW of power and 64 MWh of energy. The Companies estimate that the phase two project could be deployed in 2022, at an estimated cost of $20 million to $30 million (Exh. ES-GMBC-1, at 80).

The second phase of the proposed Martha's Vineyard project will target the same opportunities and customer benefits as the phase one project, but on a larger scale (Exhs. ES-GMBC-2, at 56-57; AG-23-13). Accordingly, the success or failure of the phase one project will determine whether it is reasonable to invest in phase two. For this reason, the Department is unable to assess the reasonableness of the size scope and scale of the phase two Martha's Vineyard project until the Companies have implemented and evaluated phase one of the project.

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229 The Companies maintain that the New Bedford and Pittsfield sites were selected based on opportunities to bring benefits to customers through enhanced power quality and integration of additional intermittent renewable resources in areas with existing distributed energy resources (Exh. ES-GMBC-1, at 72). The phase one demonstration projects discussed above will provide similar information that should be used by the Companies in their phase two project selection process (Exhs. SREF-1-19; SREF-1-20).

iv. Third-Party Participation

Cape Light Compact, NECEC, and RESA argue that the Companies' energy storage proposal is deficient because it does not include participation by third-party owned energy storage (Cape Light Compact Brief at 25-31; Cape Light Compact Reply Brief at 6-7; NECEC Brief at 26; NECEC Reply Brief at 5-8; RESA Brief at 35-38; RESA Reply Brief at 8-9). The Companies respond that their proposal does not preclude third-party energy storage opportunities and that will they explore non-utility owned storage as part of the demand reduction demonstration project in D.P.U. 16-178 (Companies Brief at 395-396; Companies Reply Brief at 79).

In its State of Charge Report, DOER indicates that it will establish specific targets for utility ownership of energy storage (Exh. ES-GMBC-6, at 104). As part of the State of Charge Report, DOER analyzed several business models to evaluate how the economics of energy storage may vary by asset ownership, market involvement, and location (Exh. ES-GMBC-6, at 18-20). These models include energy storage systems that are (1) owned and operated by the electric distribution companies, (2) owned and operated by third party merchants, and (3) located behind customer meters (Exh. ES-GMBC-6, at 18-20). The State of Charge Report provides that, when the distribution company can dispatch these behind-the-meter systems, the systems can be used to address renewable integration and distribution upgrade deferral (Exh. ES-GMBC-6, at 168).

As noted by Eversource, the Department has recently approved demonstration projects incorporating third-party ownership of storage in D.P.U. 16-178, at 42-44.[230] However, we find that there may be additional benefits to evaluating how utility owned storage and third-party owned storage could work in tandem. As discussed in Section X.B.3 above, the Department intends to establish a grid modernization stakeholder process in D.P.U. 15-122. As part of this process, the Companies and stakeholders should consider the full range of energy storage business models for demonstration project design.

d. Evaluation Plan & Performance Metrics

For any proposed demonstration program, the Department requires that a company present a detailed evaluation plan for gathering and analyzing data in a timely manner to inform the development and/or refinement of broad-scale programs and/or initiatives. D.P.U. 16-178, at 35. Eversource proposes to complete a project-specific development evaluation within twelve months of each project's commercial operations date that will consider "customary performance indicators for infrastructure construction projects," including the cost and schedule performance of the project (Exh. ES-GMBC-7, at 1). This evaluation will assess the following areas of the project development process to identify the maturity of the process and highlight areas for future improvements in the process: (1) siting and permitting; (2) engineering and design; (3) commercial strategies; (4) construction; and (5) operational turnovers (Exhs. ES-GMBC-3, at 4; ES-GMBC-7, at 2). Finally, the

230 Eversource's demand reduction demonstration program will test the ability of large C&I customers to use storage technology to reduce their usage during peak load hours. D.P.U. 16-178, at 31-33.

Companies propose to conduct a project-specific operations evaluation, to be completed within 24 months of the completion of each project, that will: (1) report the basic operational performance information related to the project; and (2) assess the extent to which the project's performance met or exceeded the specified use cases (i.e., the hypotheses the project was intended to test) (Exhs. ES-GMBC-3, at 4; ES-GMBC-7, at 1-2). Based on our review, the Department finds that the Companies have presented a reasonable evaluation plan for the phase one Martha's Vineyard project and the Wellfleet project.[231]

Finally, with respect to performance metrics for the energy storage demonstration program, the Companies propose to adopt certain metrics that measure the progress of their projects and evaluations (Exh. ES-GMBC-3, at 4). As discussed in Section X.B.3 above, the Department will discuss the sufficiency of these metrics as part of our forthcoming Order in D.P.U. 15-122.

e. Bill Impacts

The Department examines the bill impacts that customers would experience as a result of the proposed storage demonstration project to assess the reasonableness of the associated costs. The Companies have submitted a bill impact analysis allowing the Department to analyze increases to all Eversource customer rate classes (Exh. LI-1-3 & Att. (a); RR-DPU-50, Att. (e) at Exhibit ES-RDP-2 (ALT1), Schedule RDP-9 (East) & (West); RR-DPU-50, Att. (f) at Exhibit ES-RDP-3 (ALT1), Schedule RDP-3 (East) & (West); RR-DPU-50, Att. (j) at Exhibit ES-RDP-7 (ALT1), Schedule RDP-5). After review, the

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231 The Department anticipates that this evaluation plan may evolve somewhat over time based on feedback from stakeholders.

Department finds that, on balance, the bill impacts resulting from the phase one Martha's Vineyard project and the Wellfleet project are reasonable and the potential benefits of these proposed storage demonstration projects justify the costs to customers.

f. Conclusion

In the sections above, the Department has found that the Companies' proposed energy storage pilot program is consistent with applicable laws, policies and precedent. In addition, the Department has found that the phase one Martha's Vineyard project and the Wellfleet project are reasonable in size, scope, and scale in relation to the likely benefits to be achieved. The Department has found that the evaluation plan for these two demonstration projects is reasonable. Finally, the Department has found that the bill impacts resulting from the phase one Martha's Vineyard and Wellfleet energy storage demonstration projects are reasonable. Accordingly, the Department approves a budget not to exceed $15 million for phase one of the Martha's Vineyard project and a budget not to exceed $40 million for the Wellfleet project. (Exh. ES-GMBC-1, at 80, 82). As discussed in Section X.B.3 above, the Department will establish a cost recovery mechanism for eligible grid modernization investments, including energy storage demonstration projects, in our forthcoming Order in D.P.U. 15-122.

Because our approval here is based on a determination of the size, scope, and scale of the specific projects in relation to the likely benefits to be achieved, the Companies cannot allocate any unspent funds to other efforts. At the time the Companies seek final cost recovery of any energy storage demonstration program costs for the Martha's Vineyard phase

one and Wellfleet projects, they bear the burden of demonstrating the appropriateness and prudence of all spending or be subject to disallowance of such costs.

Finally, given their early stage of development, the Department has found that the information provided by the Companies regarding costs and likely benefits of the New Bedford, Pittsfield, and phase two Martha's Vineyard projects is not sufficient to analyze the size, scope, and scale of these projects. Accordingly, the Department is unable to review these projects at this time.

D. Electric Vehicle Proposal

1. Companies Proposal

The Companies propose to spend $45 million on an electric vehicle ("EV") infrastructure program as part of their proposed grid modernization investments (Exh. ES-GMBC-1, at 114). The proposed EV infrastructure program includes two primary components: (1) increased investment in long dwell-time EV charging make-ready infrastructure in public and workplace settings and at multi-unit dwellings ("MUDs"); and (2) increased market education and outreach targeting potential car buyers in the Companies' service territories (Exhs. ES-GMBC-1, at 90-113; ES-GMBC-2, at 70-72).[232] The Companies also seek the flexibility to use an unspecified portion of the proposed EV infrastructure program funds to electrify their bucket trucks with electric power take off

[232] The Companies' proposed $45 million budget, which is included as part of the $400 million grid modernization base commitment, does not include costs related to O&M and marketing (Exh. ES-GMBC-3, at 114, Table ES-GMBC-3, EV Program Cost).

technology ("ePTO") if potential site hosts are slow to respond to the Companies' marketing efforts (Exhs. ES-GMB-1, at 114, 125-126; ES-GMBC-2, at 72).

The Companies divide the proposed EV infrastructure program into two phases: Phase I will extend from January 1, 2018 through December 31, 2019; and Phase II will extend from January 1, 2020 through December 31, 2022 (Exh. AG-23-9). Over the course of five years, the Companies plan to support the deployment of up to 72 direct charging ("DC") fast charging ports at 36 charging sites,[233] and up to 3,955 Level II charging ports at 452 charging sites,[234] throughout the Companies' service territories (Exh. DPU-55-20).[235]

The Companies plan to support the deployment of EV charging ports by installing electrical equipment and components necessary to connect EV chargers to the Companies' distribution system (Exh. ES-GMBC-1, at 91, 116-117). The Companies propose to install the "Eversource-side Infrastructure", and to contract with third-party electrical contractors to install behind the meter "Participant-side Infrastructure" (Exhs. ES-GMBC-1 at 91, 116-119; ES-GMBC-2, at 70). Specifically, the EV infrastructure that the Companies are proposing to install and own includes the following: (1) distribution primary lateral service feed; (2) necessary transformer and transformer pad; (3) new service meter; (4) new service panel;

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233 DC fast chargers use direct current and are the fastest method for charging an EV (Exh. ES-GMBC-1, at 97).

234 Level II 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 (Exh. ES-GMBC-1, at 97).

235 The Companies revised their charging port and site estimates several times throughout the proceeding (Exhs. ES-GMBC-2, at 71; ES-GMBC-3, at 6; AG-23-15). The amounts listed are the latest estimate given by the Companies.

and (5) associated conduit and conductor necessary to connect each piece of equipment (Exh. ES-GMBC-1, at 91). The Companies do not propose to spend any EV program funds on EV chargers (Exh. ES-GMBC-1, at 90-91, 116).

The Companies plan to target multi-unit dwellings, including apartment complexes, places of employment and other long-dwell-time locations such as universities and hospitals, and public parking spaces for installation of Level II charging stations and high travel density locations for DC fast chargers (Exh. ES-GMBC-1, at 107-109, 120-121). The Companies also propose to deploy up to ten percent of the EV charging infrastructure in environmental justice ("EJ") communities and to provide rebates for the cost of the EV chargers located in these communities (Exh. ES-GMBC-1, at 111-112).[236] The Companies propose a two-part evaluation plan to be applied to the two phases of the proposed program (Exh. ES-GMBC-1, at 127-129).

During the first two years of the EV program, the Companies will focus and conduct evaluations on the acceleration of EV adoption in Massachusetts by developing the marketing, customer education, and outreach strategies, and validating the process for deployment of electric vehicles (Exh. ES-GMBC-1, at 127; see also Exh. DOER-3-11). During the next

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[236] 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. The Companies propose to select EJ communities that meet two of the following three criteria established by the Massachusetts Executive Office of Energy and Environmental Affairs: (1) 25 percent or more of the population in the communities must earn 65 percent or less than the Massachusetts median household income; (2) 25 percent of more of the population in the communities must identify as a race other than white; and (3) 25 percent of households lack a person over the age of 14 who speaks only English or speaks English very well (Exh. ES-GMBC-1, at 111).

three years the Companies expect to evaluate the make-ready infrastructure to be established for installation and use of the charging stations (Exh. ES-GMBC-1, at 128). Specifically, the Companies will collect data regarding EV driver enrollment, rates by site and charger type, price of kWh and use of kWh by price, charging load profiles, and load impacts (Exh. ES-GMBC-1, at 128-129). The Companies also propose six performance metrics to evaluate the implementation and customer benefits of the proposed EV infrastructure program (Exh. ES-GMBC-3, at 6).[237]

The Companies' proposed marketing plan includes two components: (1) site host recruitment; and (2) customer education (Tr. 7, at 1448-1449). The Companies indicate that the two primary outreach channels for recruiting site hosts for this program will be through existing account executives and through EV infrastructure providers (Exh. ES-GMBC-1, at 121).

2. Standard of Review

On August 4, 2014, the Department issued an Order on its jurisdiction over EV charging and electric distribution company involvement in EV charging. Electric Vehicles, D.P.U. 13-182-A (2014). In its Order, the Department determined that charging

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[237] The proposed performance metrics include: (1) total number of "make ready" sites developed (i.e., 130 in Phase I and 375 in Phase II); (2) ten percent capital invested in DC fast charging sites; (3) ten percent capital invested in EJ communities; (4) annually report utilization of EV charging stations separately for Level II chargers and DC fast chargers (measured in annual kWh per port); (5) annually report the percentage of Eversource residential customers within the range of an Eversource "make ready" site constructed as part of the grid modernization base commitment (i.e., report percentage within 20-mile range and within 40-mile range); and (6) annually collect and report available data on plug-in EV adoption and CO_2 emissions reductions (Exh. ES-GMBC-3, at 6).

infrastructure is defined as Electric Vehicle Supply Equipment ("EVSE"). EVSE is the charging station and the connector or cord that supplies the electricity to the EV. The Department has determined that EVSE is not a distribution facility within the meaning of G.L. c. 164. D.P.U. 13-182-A at 6. Therefore, the ownership or operation of EVSE does not transform an entity that otherwise is not a distribution company into a distribution company. D.P.U. 13-182-A at 6. The Department also 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.

In relation to electric distribution company involvement in electric vehicle charging, the Department determined that it would not allow recovery of costs for distribution company ownership or operation of EVSE for new investments going forward, with a few exceptions. First, distribution companies are allowed to recover the cost of EVSE ownership and operation for their own vehicle fleet charging and employee vehicle charging. D.P.U. 13-182-A at 13. Second, the Department determined that it may grant cost recovery for distribution company EVSE ownership and operation in response to a company proposal. For Department approval and allowance of cost recovery, any such 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.

Further, the Department allows and encourages investment in, and cost recovery for, research, development, and deployment efforts ("RD&D") related to EVs, EVSE, and EV charging as part of a distribution company's RD&D proposal in its grid modernization plan, or as a separate, approved pilot. D.P.U. 13-182-A at 13, citing Modernization of the Electric Grid, D.P.U. 12-76-B at 27-30 (2014). The Department will apply this three-part standard to any cost recovery proposal related to EVs, EVSE, and EV charging, including RD&D investments.

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

The Companies maintain that the proposed EV infrastructure program will help accelerate EV charging infrastructure development within their service territories, encourage EV purchases, and contribute to greenhouse gas emissions reduction in the Commonwealth (Exh. ES-GMBC-2, at 66-69; Companies Brief at 97-100, citing e.g., Exh. ES-GMBC-1, at 94-95). Several intervenors generally support the proposed EV infrastructure program as it will help meet the Commonwealth's goal contained in the Global Warming Solutions Act ("GWSA")[238] and support the campaign of the Executive Office of Energy and Environmental Affairs ("EEA") to encourage zero emissions vehicles ("ZEVs") via a commitment for 300,000 ZEVs registered in Massachusetts by 2025 (Charge Point Brief at 6; CLF Brief at 38-40; Mass. Energy and the Sierra Club Brief at 11-12). The Department finds that the Companies' proposal to invest in "make-ready infrastructure" will lower the investment barriers to ownership of EVSE (Exh. ES-GMBC-1, at 95). Further, the

[238] An Act Establishing the Global Warming Solutions Act. St. 2008, c. 298.

anticipated expansion of the network of charging stations as a result of the Companies' EV infrastructure proposal will assist the Commonwealth in meeting its GWSA goals by encouraging EV purchases (Exh. ES-GMBC-1, at 92). Therefore, the Department finds that the Companies' proposed EV infrastructure program is in the public interest.

Second, the Companies propose to proactively recruit site hosts in order to promote and accelerate the construction of EV charging sites (Exh. ES-GMBC-2, at 68). A few intervenors contend that the Companies' proposal will help lower the technical and financial barriers to the installation of EV chargers, as the construction of EV charging sites is more costly and more technically challenging than the installation of EV chargers themselves (Charge Point Brief at 7; CLF Brief at 35-37; Mass. Energy and the Sierra Club Brief at 10-11). Further, Mass. Energy and the Sierra Club assert that the proposed program is likely to: (1) improve the efficiency, reliability, and flexibility of the grid, including the ability to integrate renewable resources; (2) provide equitable deployment of services; and (3) stimulate innovation and competition in EV service providers (Mass. Energy and the Sierra Club Brief at 11-12).

The Department finds that the Companies' proactive approach of recruiting site hosts and reducing the cost of infrastructure for investors likely will help facilitate the construction of EV charging sites (Exh. ES-GMBC-2, at 68). Further, the Department finds that the Companies' proposed EV infrastructure 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.

Finally, the Companies propose to construct interconnection infrastructure up to the point of the EV chargers (Exh. ES-GMBC-1, at 91). A few intervenors contend that the proposed EV infrastructure program will significantly lower cost barriers for site hosts without limiting the site hosts' ability to choose EV charger vendors (Charge Point Brief at 7-8; CLF Brief at 37-38; Mass. Energy and the Sierra Club Brief at 11). The Department finds that the Companies do not propose to participate in the competitive EV charger market (Exh. ES-GMBC-1, at 91). The Department further finds that the Companies' proposed EV infrastructure program likely will help to boost the market size for the competitive EV charger suppliers as the proposal is designed to achieve an economy of scale (Exh. AG-GLB-1, at 64, lines 1-5). As such, the Department determines that the Companies' proposed EV infrastructure program does not hinder the development of the competitive EV charging market. Therefore, the Department finds that the Companies' EV charging proposal meets the three criteria set forth in D.P.U. 13-182-A. Although the Companies' proposal meets the standards set forth in D.P.U. 13-182-A, there are specific components of the proposal that merit further examination.

4. Additional Issues for Examination

a. Introduction

The intervenors have raised a number of issues regarding the Companies' proposed EV infrastructure program. First, several intervenors assert that the Department should conduct a separate statewide investigation into certain specific issues related to distribution company involvement in EV charging (Attorney General Brief at 44-54; Attorney General Reply Brief at 95-100; Charge Point Brief at 10-11; Charge Point Reply Brief at 6-7; DOER

Brief at 34-35; DOER Reply Brief at 16-17; Mass. Energy and the Sierra Club Reply Brief at 7). Further, intervenors raise issues relating to: (1) program evaluation and metrics; (2) behind-the-meter infrastructure; (3) program modifications and additions, such as time of use ("TOU") rate design, demand response issues, and site host issues; (4) electrification of the Companies' bucket trucks; (5) criteria relating to EJ communities; and (6) communities taking competitive electricity supply (Attorney General Brief at 48-52; Attorney General Reply Brief at 98-99; Acadia Center Brief at 18; Cape Light Compact Brief at 40, 43; Cape Light Compact Reply Brief at 8; Charge Point Brief at 8-14; Charge Point Reply Brief at 2-4; CLF Brief at 40-46, 47-48; DOER Reply Brief at 17; Mass. Energy and the Sierra Club Brief at 12-22; Mass. Energy and the Sierra Club Reply Brief at 5-6, 8-15). In addition, the Department finds it appropriate to address the issues of marketing and education. Finally, in order to assess the reasonableness of the associated costs of the proposed EV infrastructure program in relation to the benefits to be achieved, the Department will consider bill impacts.

b. Separate and Statewide Process

i. Positions of the Parties

(A) Intervenors

The Attorney General suggests that the Department open a separate proceeding to develop a statewide plan on utility involvement in EV charging infrastructure in order to address such issues as the scope of utility involvement, the appropriate number of utility supported EV chargers, utility ownership of infrastructure upgrades behind the meter, cost recovery, and evaluation metrics (Attorney General Brief at 44-54). The Attorney General

maintains that D.P.U. 13-182-A and G.L. c. 25A, § 16 ("the ZEV Act")[239] do not address these issues or provide any direction as to what should be included in a proposal for a utility-supported EV infrastructure program (Attorney General Brief at 47; Attorney General Reply Brief at 95-96). The Attorney General recommends that the Department require the Companies to establish joint working group meetings with National Grid to allow stakeholder input on common issues, or that the Department open a separate docket for this purpose (Attorney General Brief at 53-54; Attorney General Reply Brief at 100).[240]

Charge Point maintains that the Department should not delay the proposed EV infrastructure program, but should address rate design issues separately (Charge Point Brief at 10-11; Charge Point Reply Brief at 6-7). Charge Point recommends that the Department retain oversight of the proposed EV infrastructure program and allow for more rigorous stakeholder review in a formal setting in place of a separate proceeding (Charge Point Brief at 10-13; Charge Point Reply Brief at 5-7). According to Charge Point, the market-driven approach in the Companies' proposal for site host selection means that a site host's business proposition will determine site selection; therefore, there is no need to coordinate EV charging locations, except for DC fast charging stations (Charge Point Reply Brief at 6). CLF similarly argues that the Companies should provide more details on site host selection criteria, and should coordinate with other companies and stakeholders (CLF Brief at 43).

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239 An Act Promoting Zero Emission Vehicle Adoption, St. 2016, c 448.

240 National Grid's electric vehicle market development program is under review by the Department in D.P.U. 17-13.

DOER agrees with the Attorney General that statewide coordination is necessary for issues like TOU EV charging rate design (DOER Brief at 34-35; DOER Reply Brief at 16-17). DOER is concerned that if the utility companies do not coordinate EV charging sites, they may not locate sites efficiently (DOER Brief at 35). Finally, Mass. Energy and the Sierra Club support the Attorney General's suggestion to open a separate docket for EV rate design issues, but cautions against delaying the implementation of the Companies' proposed EV infrastructure program (Mass. Energy and the Sierra Club Reply Brief at 7).

(B) Companies

The Companies argue that D.P.U. 13-182-A and the ZEV Act already have addressed concerns regarding utility participation in the EV charging market, and delaying the implementation of the Companies' EV program by opening a new proceeding would not help achieve the state's goal in EV deployment (Companies Brief at 386-387; Companies Reply Brief at 69, 73-74, 96). The Companies also maintain that the joint working group and mid-point program evaluation suggested by the intervenors are unnecessary since the Companies have proposed annual stakeholder meetings and are already in routine contact with National Grid on EVs (Companies Brief at 389, 413-414).

ii. Analysis and Findings

In D.P.U. 13-182-A, the Department has addressed the role of distribution companies in the EV charging market. Simply stated, a distribution company may own EV infrastructure only if its proposal is in the public interest, meets a need regarding the advancement of EVs in the Commonwealth that is not likely to be met by the competitive EV charging market, and does not hinder the development of the competitive EV charging

market. D.P.U. 13-182-A at 13. Further, a distribution company may design and propose its own EV programs, including an RD&D proposal in its grid modernization plan or as a separate, approved pilot, as long as the proposals meet the three criteria set forth above. D.P.U. 13-182-A at 13. In this proceeding, the Department will not prescribe further elements beyond the current scope of the Companies' proposed EV program because of the nascent stage of the EV charging market in the Commonwealth. Further, as discussed above, the Department anticipates addressing issues that require a broad statewide consideration as part of our forthcoming Order in the grid modernization proceedings in D.P.U. 15-122. Therefore, the Department declines to adopt the Attorney General's recommendation to open a new proceeding to address these issues.

Several intervenors suggest that the Department require the Companies to coordinate with other distribution companies and with state and regional programs on EV infrastructure program design, EV rate design issues and EV demand response (Attorney General Brief at 53-54; Attorney General Reply Brief at 100; Charge Point Brief at 12-13; Charge Point Reply Brief at 5; CLF Brief at 43; DOER Reply Brief at 16). The Department encourages the Companies to coordinate with other distribution companies as well as with state and regional EV initiatives, in order to make the best use of available resources to advance EV charging infrastructure development in the Commonwealth.

Further, as described in Section X.B.3, above, the Department intends to establish a uniform grid modernization stakeholder process in our forthcoming Order in D.P.U. 15-122. However the Companies' EV infrastructure proposal was not introduced in D.P.U. 15-122.

Rather, the proposal was first presented as a component of the grid modernization base commitment included in this filing. Therefore, to the extent a formal stakeholder process is necessary for EVs the Department will establish a process separate from the grid modernization stakeholder process. In the meantime, however, the Department endorses the Companies' proposed stakeholder process and, rather than delaying EV infrastructure program implementation by opening a formal stakeholder proceeding, the Department directs the Companies to include the EV charging coordination issues in their annual stakeholder meetings. The Department also directs the Companies to coordinate with stakeholders on the selection of site locations, especially DC fast charging sites, and site host selection criteria (see Exh. ME-1-3, Att.).

c. Evaluation Plan and Performance Metrics

i. Positions of the Parties

(A) Intervenors

The Attorney General argues that the six proposed EV program performance metrics are not sufficient, and suggests that the Department include all of the performance metrics recommended by the intervenors (Attorney General Brief at 57-58, citing Exh. DPU-41-7 & Att. (Supp.)). The Attorney General also recommends conducting a formal mid-point program evaluation at the end of the third year (Attorney General Brief at 53). Mass. Energy and the Sierra Club suggest that the Department formalize data reporting on EV programs with a set of required data items (Mass. Energy and the Sierra Club Brief at 23; Mass. Energy and the Sierra Club Reply Brief at 15-16).

(B) Companies

The Companies agree to formalize data reporting as suggested by the intervenors (Companies Brief at 413; Companies Reply Brief at 74). The Companies are amenable to including metrics suggested by the intervenors, but maintain that these metrics need to be objectively measureable, contain a starting point or baseline from which the Companies will be able to measure progress, and measure performance that is within the Companies' control (Companies Reply Brief at 91).

ii. Analysis and Findings

As identified above, the Companies have developed a two-part evaluation plan that is specific to the EV program (Exh. ES-GMBC-1, at 127). The Department recognizes the value of the information that the Companies propose to provide through the development and operations evaluation described above. A systematic collection and analysis of information to document the impact of the EV program in terms of costs and benefits is necessary to improve the effectiveness of the investment.

Due to the as of yet untested nature of the Companies' EV infrastructure program, Eversource has proposed a robust two-part evaluation plan. The first phase will focus on providing information on potential for site host deployment, while the second phase will focus on evaluating data from actual deployments (Exh. ES-GMBC-1, at 127-129). The Department finds that the Companies' proposed data collection practices and the two-phased evaluation plan are reasonable. The Department will solicit stakeholder input on the results of the Companies' evaluations in order to review the recommendations and data of the evaluated projects and whether adjustments need to be made going forward. The Department

directs the Companies to solicit such input at future EV stakeholder meetings and collect and submit any comments from stakeholders to the Department.

d. Behind-the-Meter Infrastructure

i. Positions of the Parties

(A) Attorney General

The Attorney General argues that the Department should maintain the traditional boundary in asset ownership between utility companies and customers, and that owning behind-the-meter assets is not a requirement for utility companies to support EV charging (Attorney General Brief at 48-50). The Attorney General further contends that the Companies have not provided enough evidence to show that behind-the-meter asset ownership is necessary, and that utility ownership models relating to EV infrastructure should be consistent among utility companies in Massachusetts (Attorney General Reply Brief at 98-99).

(B) Companies

The Companies argue that not allowing utility companies to own behind-the-meter infrastructure would put the EV charging market back to the status quo where the competitive market is unwilling to invest in EV charging stations due to the lack of EV purchases, and drivers are unwilling to purchase EVs due to the lack of charging stations (Companies Brief at 387-388, Companies Reply Brief at 72-73). The Companies further contend that its EV proposal should be evaluated on its merits pursuant to the standard of review set forth in D.P.U. 13-182-A, and that this standard does not require matching proposals from all electric distribution companies (Companies Reply Brief at 73).

ii. Analysis and Findings

The demarcation point between a distribution company's system and a customer's wiring system is known as the service point. The service point is "the point of connection between the facilities of the serving utility and the premises wiring." National Electrical Code, Art. 100 (Definitions). Based on this definition, it is reasonable to expect that the meter typically could be considered the demarcation between the supply/utility side and the load/customer side of the typical electric service set-up.[241]

Under the Companies' proposed EV infrastructure program, Eversource would invest in infrastructure beyond the meter up to the charging station, specifically for the service panel and the associated conduit and conductor necessary to connect each piece of equipment (Exh. ES-GMBC-1, at 91; Tr. 1, at 202). The Department does not prescribe the service point, but instead relies on the engineering judgment of the utility. For example, under prior circumstances, gas and electric companies have provided tariffed water heating service where the company owned the water heater located on the customer's premises. See, e.g., Eastern

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[241] In a typical electric service set-up, the service point line of demarcation actually is further on the supply side than the meter. For overhead service, the service point is at the point of attachment of the utility's service at the premises. The customer is responsible for the wiring from this point of attachment to the meter and beyond the meter on the load side (NSTAR Electric Information and Requirements for Electric Service, Art. 409, Sketch 7, available at https://www.eversource.com/Content/docs/default-source/pdfs/ema-information_requirements_for_electric_service.pdf?sfvrsn=2; Tr. 1, at 201). For underground service, the point of attachment would be a terminal box, handhole, or padmount transformer, depending on the configuration, located on the customer's premises. The customer is responsible for the wiring from this point of attachment to the meter and beyond the meter on the load side (NSTAR Electric Information and Requirements for Electric Service, Arts. 415 and 417, Sketch 8; Tr. 1, at 201). For both overhead and underground service connections, the utility owns the meter.

Edison Company, D.P.U. 92-148, at 37-38 (1992) (water heating service is part of rate H-2); Boston Edison Company, D.P.U. 85-266-A/D.P.U. 85-271-A at 239-240 (1986 (rate R-6 governs residential water heating service). Also, Account 371, "installations on customers' premises," expressly provides for recording the cost of equipment installed on the customer-side of the meter when the utility incurs such costs and when the utility retains title to and assumes full responsibility for maintenance and replacement of such property. 220 CMR 51.01(1), Uniform System of Accounts For Electric Companies; 18 CFR, Part 101, Uniform System of Accounts Prescribed For Public Utilities and licensees Subject to the Provisions of the Federal power Act, Account 371.

The Companies' proposed EV infrastructure program is intended to lower the investment barrier faced by customers regarding infrastructure needed for ownership of charging stations (Exh. ES-GMBC-1, at 91-95). The Department finds that, based on the current status of EV charging station deployment, lowering the investment barrier is an apparent necessity. Considering the demonstrative nature of the Companies' EV proposal, the Department finds that the Companies' proposal to own the infrastructure behind the meter, excluding the EV charger, is reasonable.

e. Program Modifications and Additions

i. Introduction

A number of intervenors express general support for the Companies' EV proposal and assert that it meets the three criteria set forth in D.P.U. 13-182-A, but suggest some modifications and additions including TOU rate design, demand response, MUDs and

workplace charging, site host pricing disclosure, and Level I charging[242] (Acadia Center Brief at 18; Charge Point Brief at 6-7; CLF Brief at 33-34; Mass. Energy and the Sierra Club Brief at 12; Mass. Energy and the Sierra Club Reply Brief at 5-6; NECEC Brief at 34).[243]

ii. TOU Rate Design and Demand Response

(A) Positions of the Parties

(1) Intervenors

A few intervenors argue that the Companies' proposal should include TOU and other rate design incentives to encourage efficient charging behavior and demand response (Acadia Center Brief at 18; Cape Light Compact Brief at 40; Charge Point Brief at 8-9; CLF Brief at 40-42; Mass. Energy and the Sierra Club Brief at 15-16). Further, Charge Point suggests that the Companies should require site hosts to install EV chargers with smart or connected technologies to avoid additional utility meter investments (Charge Point Brief at 8-9). DOER suggests a phased approach where the Companies would collect data and information for TOU rate design during Phase I, and implement the TOU rates during Phase II (DOER Reply Brief at 17). Mass. Energy and the Sierra Club argue that the Companies have failed to utilize experience gained in their EV Pilot with smart charging to inform their proposed EV program (Mass. Energy and the Sierra Club Brief at 15-16).

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242 Level I charging involves plugging the EV into a typical 110-volt household outlet and may require nearly a full day or more to fully charge existing EVs, depending on battery capacity (Exh. ES-GMBC-1, at 97).

243 TEC and WMIG urge the Department to reject the Companies' proposal for lack of a cost benefit analysis as required by D.P.U. 12-76-B (TEC/WMIG Brief at 18-19). The Department's analysis here focuses on compliance with the criteria set forth in D.P.U. 13-182-A and not D.P.U. 12-76-B.

Some intervenors assert that the Department should require the Companies to exclude demand charges or propose alternatives to demand charges (CLF Brief at 40-42; Mass. Energy and the Sierra Club Brief at 14; Mass. Energy and the Sierra Club Reply Brief at 8-13). Charge Point also suggests that the Companies develop a residential charging program with a TOU component, and a pilot for DC fast charging with an alternative to demand charges (Charge Point Brief at 13-14).

(2) Companies

The Companies maintain that it is premature to deploy TOU rate design in their proposed EV program because the Companies currently do not have the ability to process real time data from TOU and demand response (Companies Brief at 399, citing Tr. 7, at 1429; Companies Reply Brief at 96). In addition, the Companies contend that EV charging could create a secondary peak if the standard TOU rate design is applied, and therefore a different TOU rate is needed for EV charging, which requires collection of charging data after the EV charging infrastructure is built (Companies Brief at 399-400; Companies Reply Brief at 96-97).

The Companies claim that they allow site hosts the flexibility to select the EV chargers that best suit their needs, level of sophistication, and objectives, rather than requiring smart chargers, striking a balance between costs and benefits for ratepayers (Companies Brief at 400). The Companies further argue that EV demand response may not provide system benefits to the Companies' ratepayers at this time, and investment in EV demand response is premature (Companies Brief at 400-401). The Companies also note that

EV drivers at public charging stations are not in a position to shop around because their primary objective at these charging stations is to recharge the vehicle and complete their travel (Companies Brief at 401). Further, the Companies argue that load management issues at these sites could create dissatisfaction among EV drivers and discourage further EV adoption (Companies Brief at 401). The Companies believe that the additional costs associated with the design and administration of demand response would reduce the funding available to build EV charging infrastructure and decrease the number of sites that the Companies are able to facilitate in EJ communities (Companies Brief at 401-402).

The Companies argue that Charge Point's proposed residential EV infrastructure program and tariff pilot for DC fast charging are beyond the scope of this proceeding, but the Companies are willing to discuss these issues at the proposed stakeholder meetings (Companies Brief at 409; Companies Reply Brief at 94).

(B) 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 the majority of the societal benefits related to EV infrastructure deployment. The Department recognizes that the Companies need time to collect data and information from the site hosts before they are able to design and implement effective rate design and EV demand response programs. The initial goal of the Companies' proposed EV infrastructure program is to recruit site hosts and build infrastructure to support EV charging sites (Exh. ES-GMBC-2, at 70-71). Without site hosts, the Companies will not be able to collect data or develop effective rate design and

EV demand response programs (Exh. ME-1-9, Atts. (a), (b)). The Department directs the Companies, as they select site hosts, to collect EV charging data that they can use to develop TOU rates and a potential EV demand response pilot program (Exh. ES-GMBC-1, at 127-129).

The Department anticipates that the Companies will work closely with stakeholders during this process of data collection, information gathering, rate design, and EV demand response program design. Specifically, the Department finds that data collection is essential in the development of EV charging TOU rates, alternative demand charges, and potential demand response pilot programs. See Order Adopting Policy Framework for Time Varying Rates, D.P.U. 14-04-C at 7-8 (2014).

In addition, the Companies should make investments in a manner that does not lead to stranded costs. D.P.U. 15-122, Exh. AG-3-8(a), Att. To that end, the Companies shall consider 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 (Exh. ES-GMBC-Rebuttal at 32). D.P.U. 15-122, Exh. AG-3-8(a), Att.

Charge Point suggests that the Department direct the Companies to require smart chargers (Charge Point Initial Brief at 8-9). The Department will not require the Companies to determine the type of EV chargers that the site hosts may install, so as to avoid interfering with the competitive EV charger market. However, given the importance of future EV rate design and EV demand response programs, the Companies shall establish terms of agreements with site hosts regarding the Companies' collection of interval charging data.

The data collected will be necessary for the Companies' analysis of potential EV charging TOU rates and EV demand response pilot program design. The EV chargers chosen by site hosts should have the capability of transmitting interval charging data to the Companies (Exhs. ES-GMBC-1, at 128-129; ES-GMBC-Rebuttal at 32).

Charge Point also recommends that the Companies consider a residential EV demand response program (Charge Point Brief at 13). The Department's review in this proceeding is limited to the Companies' proposal. The Department declines to expand the scope of this proceeding to include residential EV charging; however, the Companies could use their stakeholder process to consider developing separate EV infrastructure programs that will bring further value to ratepayers in the future.

iii. Site Host Issues

(A) Positions of Parties

(1) Intervenors

Charge Point maintains that the Department has no jurisdiction over site hosts' charging terms and pricing, but agrees that site hosts should disclose their pricing plan (Charge Point Reply Brief at 2-3). CLF argues that some sites may accept Level I charging better than Level II and therefore the Companies' proposal should include EV infrastructure investments for Level I charging (CLF Brief at 44). Charge Point, however, agrees with the Companies decision to exclude Level I charging because of its long charging time and inability to enable smart charging (Charge Point Reply Brief at 4).

Mass. Energy and the Sierra Club state that the Companies' proposal appropriately targets site host locations such as MUDs and workplaces with long dwell time and frequent

visitors (Mass. Energy and the Sierra Club Brief at 12). However, Mass. Energy and the Sierra Club suggest that the Department require the Companies to put a cap on the number of sites that drivers do not regularly visit, in order to ensure that the majority of the Companies' investments are made in locations that will enable regular access to EV charging sites to encourage EV ownership (Mass. Energy and the Sierra Club Brief at 18-20; Mass. Energy and the Sierra Club Reply Brief at 13-14). Mass. Energy and the Sierra Club further suggest that since the funding for the EV infrastructure ultimately comes from ratepayers, the Department should require site hosts to disclose their pricing plan to ensure that Department-approved distribution rates, especially demand charges, are not directly passed through to EV drivers (Mass. Energy and the Sierra Club Brief at 14).

(2) Companies

The Companies maintain that their study does not identify Level I charging as a barrier to EV adoption and therefore it is more appropriate to focus on Level II charging and DC fast charging outside single family homes (Companies Brief at 402). The Companies recognize that sites like MUDs and workplaces are important to EV adoption, but argue that they should not impose a cap, nor limit on the type of site hosts, because the Companies require the flexibility to foster sufficient program participation (Companies Brief at 413).

(B) Analysis and Findings

The Companies propose to target site hosts 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, MUDs, and workplaces (Exh. ES-GMBC-2, at 71). The Department finds that MUDs and workplaces are important EV charging locations because

they provide EV owners with regular access to EV charging, and, therefore, encourage EV purchases (Exh. CP-MKW-4, at 4-5). Mass. Energy and the Sierra Club suggest that the Department cap the Companies' investment in infrastructure at sites that EV drivers do not regularly visit (Mass. Energy and the Sierra Club Brief at 18-19; Mass. Energy and the Sierra Club Reply Brief at 13-14). The Department declines to adopt this suggestion because we find that imposing such a cap would be arbitrary and could hinder the development of the EV charging market at this initial phase.

In consideration of the public interest, the Companies' proposed EV infrastructure program must demonstrate benefits for all ratepayers. The success of the proposed EV infrastructure 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 those site hosts who serve the public at large. The Department directs the Companies to prioritize the selection of Level II 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 MUDs parking areas that the public can access, including offices, colleges, universities, and government properties; and (3) workplaces and MUDs parking areas.

iv. Bucket Truck Electrification

(A) Positions of Parties

(1) Intervenors

The Attorney General argues that the Companies' proposal does not include any transparent threshold or criteria for making the decision to electrify the Companies' bucket trucks, and that the absence of a cap on spending in bucket truck electrification could lead to insufficient spending in public EV charging infrastructure (Attorney General Brief at 51-52; Attorney General Reply Brief at 99). Several intervenors do not support EV program funding for the Companies' bucket truck electrification, contending that the proposed cost recovery mechanism is inappropriate (Acadia Center Brief at 18; Cape Light Compact Brief at 40; CLF Brief at 47-48; Mass. Energy and the Sierra Club Brief at 22). They argue that bucket truck electrification is a part of the Companies' normal O&M, and using EV program funds to recover those costs would serve as a disincentive for the Companies to vigorously recruit site hosts (Acadia Center Brief at 18; Cape Light Compact Brief at 40; CLF Brief at 47-48; Mass. Energy and the Sierra Club Brief at 22).

(2) Companies

The Companies claim that D.P.U. 13-182-A permits cost recovery for bucket truck electrification, but they are not opposed to treating these investments as traditional capital investments (Companies Brief at 388; Companies Reply Brief at 74). The Companies maintain that they have proposed performance metrics and a process to solicit stakeholder input before investing in bucket truck electrification, although the decision would ultimately be the Companies' (Companies Brief at 388; Companies Reply Brief at 75). The Companies

contend that electrifying five bucket trucks per year over five years as part of the EV infrastructure program is not unreasonable and helps meet the Companies' spending commitment as a function of the PBRM stretch factor (Companies Brief at 388-389; Companies Reply Brief at 75-76).

(B) Analysis and Findings

The Department has held that distribution companies may recover the cost of EVSE ownership and operation for their own vehicle fleet charging and employee vehicle charging. D.P.U. 13-182-A at 13. In this context, "vehicle fleet charging and employee vehicle charging" has no other meaning than the charging of "electric vehicles." Further, vehicle charging, not the vehicles themselves, fall within this category. The Department finds that the best use of the proposed EV infrastructure program funds is in the advancement of the deployment of EV charging stations, and not in the electrification of the Companies' bucket trucks. The Companies may undertake this type of investment through their traditional capital additions process, apart from the proposed EV infrastructure program.

v. EJ Communities and Communities on Competitive Supply

(A) Positions of Parties

(1) Intervenors

Acadia Center suggests that the Companies pair charging stations in EJ communities with efforts to make EVs affordable for residents of those communities, such as dedicated state programs supporting low income residents' purchase of EVs (Acadia Center Brief at 18, citing Exh. AC-ML-1, at 41). Mass. Energy and the Sierra Club disagree, and argue that

the Department should not require the Companies to support EV purchases (Mass. Energy and the Sierra Club Reply Brief at 5-6).

Further, Mass. Energy and the Sierra Club, along with CLF, argue that the Companies' proposal to require two of the three state EJ community criteria as the basis for site selection is not reasonable, and will limit the number of EJ communities that participate in the proposed program and exclude almost all EJ communities in Western Massachusetts (CLF Brief at 45-46; Mass. Energy and the Sierra Club Brief at 20-21; Mass. Energy and the Sierra Club Reply Brief at 15). They also suggest that the Companies' proposal should set a minimum investment level in EJ communities instead of the proposed maximum of ten percent (CLF Brief at 45; Mass. Energy and the Sierra Club Brief at 20-21).

Cape Light Compact argues that the Department should ensure that the Companies do not make EV program participation contingent upon enrollment in basic service, and ensure that the Companies do not discriminate against communities on competitive supply and municipal aggregation (Cape Light Compact Brief at 43; Cape Light Compact Reply Brief at 8).

(2) Companies

The Companies argue that, based on the EEA map regarding EJ communities, many communities in Eastern Massachusetts meet only one criterion, which could skew the site selection leading to inequitable deployment (Companies Brief at 398-399; Companies Reply Brief at 74). The Companies suggest that they could require one EJ community criterion in Western Massachusetts, and still require two EJ community criteria in Eastern Massachusetts,

and they clarify that ten percent is their target for installations in the EJ communities, not a cap (Companies Brief at 398-399; Companies Reply Brief at 74).

(B) Analysis and Findings

The Department finds the Companies' proposed adjustment to the EJ community selection criteria reasonable, and directs the Companies to apply one EJ community criterion in Western Massachusetts and two EJ community criteria in Eastern Massachusetts. Further, the Department finds that the Companies have provided sufficient clarification that the ten percent deployment is their target in the EJ communities, not a cap (Companies Brief at 398-399; Companies Reply Brief at 74). The Department directs the Companies to update the stakeholders regularly on their progress in EJ community EV charging site host recruitment through the annual stakeholder meetings.

Given the existence of other state and regional programs targeting EV purchases, including a pilot program currently being planned by DOER, the Department is not persuaded that additional directives are necessary at this time to support low income residents' purchase of EVs.[244] Therefore, the Department declines to adopt Acadia Center's suggestion. Further, the Department finds that the Companies do not include enrollment in basic service as a requirement for site host selection (Exh. ES-GMBC-1, at 119-121). Therefore, the Department declines to adopt Cape Light Compact's suggestion.

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[244] The Department does not exclude investments in EVs made under a separate statutory requirement (e.g., G.L. c. 25, § 19(c), 21(a)).

f. Marketing and Education

As discussed above, the primary goal of the Companies' proposed EV infrastructure program is to recruit site hosts and to build the infrastructure necessary for site hosts to install EV chargers. Accordingly, the Department finds that the proposal for site host recruitment is reasonable in order to achieve this goal.

With the exception of costs related to site host recruitment, the Companies' proposed $45 million budget does not include costs related to O&M or customer education and marketing, which, in total, the Companies estimate will cost approximately $10 million dollars (Exhs. ES-GMBC-3, at 114, Table ES-GMBC-3, EV Program Cost; AG-23-15; LI-1-5, Att.). With respect to customer education marketing, the Companies indicate that they are seeking to develop broad awareness about the benefits of EVs and will target potential EV drivers in the Companies' service territory (Exh. ES-GMBC-1 at 124). The Companies submit that, while not directly addressed by D.P.U. 13-182 or the ZEV Act, the proposed customer education and marketing plan is in the public interest (Exhs. DPU-27-1; DPU-55-2).

The Companies have acknowledged that there is potential overlap between their proposed customer education marketing plan and the existing state-wide EV customer education initiatives (Exh. ES-GMBC-1, at 101; Tr. 7, at 1446). In addition, the Companies have provided few details to support the reasonableness of any proposed spending on customer education and marketing to potential EV drivers (see Exh. ES-GMBC-1 at 123-124; Tr. 7 at 1448-1449). For these reasons, the Department finds that the Companies' proposed

customer education marketing plan is not appropriate for inclusion as part of the proposed EV infrastructure program.

g. Budget and Bill Impacts

The Companies propose to spend $45 million on the EV infrastructure program as part of their proposed grid modernization base commitment investments (Exhs. ES-GMBC-1, at 114; ES-GMBC-2, at 66; AG-23-15, Att.). In the sections above, the Department has found that the Companies proposed EV program is in the public interest, will advance EV policy in the Commonwealth that is not likely to be met by the competitive EV market, and does not hinder the development of the competitive EV charging market. Accordingly, the Department finds that the Companies have demonstrated that the proposed distribution infrastructure, beyond the meter infrastructure, and other capitalized costs associated with the EV infrastructure program and totaling $45 million are reasonable in relation to the likely benefits to be achieved.

In order to assess the reasonableness of the associated costs to customers, the Department must examine the bill impacts that customers would experience as a result of the proposed EV infrastructure program. The Companies have submitted a bill impact analysis allowing the Department to analyze increases to all Eversource customer rate classes (RR-DPU-50, Att. (e) at Exhibit ES-RDP-2 (ALT1), Sch. RDP-9 (East) & (West); RR-DPU-50, Att. (f) at Exhibit ES-RDP-3 (ALT1), Schedule RDP-3 (East) & (West); RR-DPU-50, Att. (j) at Exhibit ES-RDP-7 (ALT1), Schedule RDP-5). The Department specifically reviewed the impacts based on the capitalization of the $45 million proposed

budget for the EV infrastructure program (Exhs. ES-GMBC-2, at 66; AG-23-15; LI-1-5, Att. (a); LI-1-15). After review, the Department finds that, on balance, the bill impacts resulting from the EV infrastructure proposals are reasonable and, the potential benefits of the proposed EV infrastructure program, discussed above, justify the cost to customers.

Based on the above, the Department approves a budget of $45 million dollars for the proposed EV program. The Companies may not allocate any unspent funds to other efforts (e.g., energy storage). At the time the Companies seek final cost recovery for any EV program expenditures, the Companies bear the burden of demonstrating the appropriateness and prudence of all spending or will be subject to disallowance of such costs. As discussed in Section X.B.3 above, the Department will establish a cost recovery mechanism for eligible grid modernization investments, including EV infrastructure program, in our forthcoming Order in D.P.U. 15-122.

5. Conclusion

The Department finds the Companies proposed EV infrastructure program meets the standards laid out in D.P.U. 13-182-A as it: (1) is in the public interest; (2) meets a need regarding the advancement of EVs in the Commonwealth that is not likely to be met by the competitive EV market; and (3) does not hinder the development of the competitive EV charging market. Further, the Department finds that the Companies have demonstrated that their proposed expenditures of $45 million on the EV infrastructure program are reasonable in relation to the likely benefits to be achieved. In addition, the Department has reviewed the

associated bill impacts from the EV infrastructure program and finds them to be reasonable and in light of the potential benefits of the proposed EV infrastructure program.

Based on the above, the Department approves the proposed EV infrastructure program budget, with an associated budget not to exceed $45 million. The Department finds that the Companies' proposed customer education marketing plan is not appropriate for inclusion in the proposed EV infrastructure program.

So as not to delay program implementation, the Department declines to open a separate proceeding to address specific issues related to distribution company involvement in EV charging at this time. Rather, the Department encourages the Companies to coordinate the EV infrastructure program with other distribution companies and state and regional EV initiatives, and include issues such as rate design and demand response in the stakeholder meetings. The Department directs the Companies to collect EV charging data, as site hosts are selected, that can be used to develop TOU rates and a potential EV demand response pilot program. The Department will not restrict EV charging locations, but directs the Companies to give priority to site locations that are publicly accessible, and to apply one EJ community criterion in Western Massachusetts and two EJ community criteria in Eastern Massachusetts when selecting EJ community charging sites.

Finally, the Companies' EV infrastructure program is intended to increase the availability of charging stations in order to lower the barriers to EV ownership. The Department finds the Companies proposed investment in infrastructure to be a reasonable means of achieving this goal. Investments to electrify the Companies' fleet or their bucket

trucks may be made, where prudent, through the Companies' capital additions process, not through the EV infrastructure program.

E. Conclusion

The Department has determined that grid modernization is vital for maintaining and improving the reliability of the electric system and offers potential savings to customers. D.P.U. 12-76 at 1-2. The Department remains committed to ensuring that our electric distribution companies implement appropriate grid modernization technologies and practices to enhance reliability, reduce costs, empower customers to better manage usage, and support a cleaner, more efficient electric system. D.P.U. 12-76 at 5-6.

In the sections above, the Department approves the first stage of the Companies' energy storage demonstration program. These investments should not only enable the market for energy storage in Massachusetts but also provide data that will be critical in evaluating future energy storage deployments as part of Massachusetts' clean energy future. The Department also approves the Companies' electric vehicle demonstration program. These infrastructure investments will help accelerate electric vehicle charging infrastructure development in Massachusetts, encourage electric vehicle purchases, and contribute to greenhouse gas emissions reductions in the Commonwealth. Finally, for the reasons discussed above, the Department has determined that it is in the public interest to remove the Companies' proposed grid modernization base commitment investments from the PBR and, instead, address these proposals in a comprehensive manner in our forthcoming Order in D.P.U. 15-122.

As a final matter, we note that on October 6, 2017, the Companies, TEC, WMIG, and AIM submitted to the Department for approval a Joint Stipulation Agreement ("Joint Stipulation") they entered into in order to resolve certain issues related to momentary outages (Joint Stipulation at 4). The Joint Stipulation outlines the structure for a C&I working group to address momentary outages experienced by certain, very large C&I customers (Joint Stipulation at 1-4).

The Attorney General, UMass, and Cape Light Compact submitted comments in response to the Joint Stipulation. UMass supports approval of the Joint Stipulation because momentary outages have been a continuing problem for UMass (UMass Comments at 1-2). Conversely, the Attorney General maintains that the Joint Stipulation raises issues of transparency, costs, and impact on non-C&I customers (Attorney General Comments at 2).[245] Cape Light Compact urges the Department not to approve the Joint Stipulation because it is inconsistent with the public interest as it: (1) directs funds contributed by all ratepayers to specific circuits that benefit only certain customers; and (2) establishes a private forum for one customer group to the exclusion of other stakeholders (Cape Light Compact Comments at 2-4).

The Joint Stipulation provides that "[s]hould the Department reject the [grid modernization base commitment], in whole or in part, the [Companies'] obligations under this Joint Stipulation shall be null and void" (Joint Stipulation at 1). Given the timing of the filing of the Joint Stipulation after the close of the record and our decision to remove the grid

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[245] The Attorney General also notes that the Joint Stipulation was filed, without a motion, after the close of evidentiary hearings (Attorney General Comments at 2).

modernization base commitment investments from the PBR, the Department will not review or approve the Joint Stipulation here. Nonetheless, we fully expect that the Companies will work equally and equitably with all interested stakeholders to address the myriad of issues that may arise as we work towards meeting our grid modernization goals.

XI. COMPANIES' FEE FREE PROPOSAL

A. Introduction

Eversource proposes to implement a credit/debit card payment system (hereinafter "fee free") that will allow customers to pay their bills electronically without incurring a transaction fee (Exhs. ES-PMC-1, at 5; ES-DPH-1, at 50). Eversource states that the fee free payment system is necessary to accommodate changing customer expectations and preferences regarding their payment options (Exh. ES-PMC-1, at 5).

Currently, Eversource customers who choose to pay their bills using a credit or debit card incur a transaction fee of $2.25,[246] paid directly to a third-party payment processing agent (Exhs. ES-PMC-1, at 7; ES-DPH-1, at 50, 52). The Companies' proposal is based on an agreement between ESC (acting as agent for both NSTAR Electric and WMECo) and SpeedPay Inc. ("SPI"), a third-party vendor selected to administer the program following a RFP process (Exhs. ES-PMC-1, at 10-15; ES-PMC-3; ES-PMC-4; ES-DPH-1, at 51). Under the agreement, SPI would offer credit/debit card transactions to Eversource customers without charging a transaction fee, and the transaction costs would be charged to the

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[246] In the test year, NSTAR Electric customers paid a transaction fee of $3.95 and WMECo customers paid a transaction fee of $3.50; however, the fee was reduced to $2.25 for both customer groups in September 2016 (Exhs. ES-PMC-1, at 5, 19; DPU-13-2; DPU-13-3).

Companies (Exh. ES-PMC-1, at 7).[247] Eversource proposes to recover these costs from all customers through base distribution rates (Exhs. ES-PMC-1, at 7; ES-DPH-1, at 51-52).

The Companies estimate the total cost of the fee free proposal to be approximately $30 million over the next five years, or approximately $6 million per year (Exhs. ES-DPH-1, at 52, 54; ES-DPH-2 (East), Sch. DPH-9 (Rev. 3); ES-DPH-2 (West), Sch. DPH-9 (Rev. 3)). To determine the estimated program cost, Eversource multiplied the anticipated number of transactions over the five-year period by the expected cost per transaction provided by SPI in response to the Companies' RFP (Exh. ES-DPH-1, at 54). Further, in deriving this cost estimate, the Companies assumed that 30 percent of Eversource customers will migrate to the fee free option from other payments options by year five of the program (Exhs. ES-PMC-1, at 14, 15; DPU-13-9).[248]

The Companies propose to allocate the $6 million annual cost between NSTAR Electric and WMECo based on each company's number of customers, which results in an allocation of 85 percent to NSTAR Electric and 15 percent to WMECo (Exhs. ES-DPH-1, at 53, 54; ES-DPH-2 (East), Sch. DPH-9 (Rev. 2); ES-DPH-2 (West), Sch. DPH-9

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247 The cost for the Companies would be a per-transaction amount subject to change over the term of the agreement with SPI, depending on specified parameters such as the number of transactions completed and the dollar value of transactions (Exh. ES-DPH-1, at 52).

248 The Companies did not initially propose any cost savings associated with customers who migrate to the fee free proposal. During the course of the proceeding, Eversource acknowledged that there would be some savings as customers migrated from other payment methods (primarily paying by check and direct debit) toward using credit or debit cards (Exh. AG-37-12). Specifically, the Companies estimated annual savings of $52,891 and $9,738 for NSTAR Electric and WMECo, respectively (Exhs. DPU-48-6; AG-37-12).

(Rev. 2)). Thus, Eversource's proposed revenue requirement includes $5,093,091 and $906,909 in costs associated with the fee free proposal, allocated to NSTAR Electric and WMECo, respectively (Exhs. ES-DPH-2 (East), Schs. DPH-6, at 1, DPH-9 (Rev. 3); ES-DPH-2 (West), Schs. DPH-6, at 1, DPH-9 (Rev. 3)).

For ratemaking purposes, the Companies propose to establish a reserve funded through the annual $6 million contribution collected through distribution rates, and to charge the actual amounts paid by the Companies to SPI against the reserve fund, so that the balance of the fund represents the difference between the amount collected through distribution rates and the amounts actually paid over the course of the agreement with SPI (Exh. ES-DPH-1, at 53). The Companies propose to amortize any over- or under-collection at the time of their next base rate proceeding (Exh. ES-DPH-1, at 53).

Finally, to minimize customer confusion, the Companies request that the Department also approve implementation of the fee free credit/debit card payment program for customers of NSTAR Gas (Exh. ES-PMC-1, at 19). The Companies seek authorization to defer the actual transaction costs incurred on behalf of gas customers until NSTAR Gas' next base rate proceeding, at which point the deferred costs would be amortized (Exh. ES-PMC-1, at 18-19).

B. Positions of the Parties

1. Attorney General

The Attorney General argues that the Department should reject Eversource's proposed fee free program because it is not "free," but in fact is one of the most expensive of the various methods that customers can use to pay their bills (Attorney General Brief at 138;

Attorney General Reply Brief at 37). The Attorney General submits that paying by credit or debit card is currently the most expensive payment method available to customers, and will continue to be the most expensive method even if the fee free program is implemented (Attorney General Brief at 139). Moreover, the Attorney General contends that customers who do not pay their bills with a credit or debit card will be forced to subsidize those that do,[249] and that recuperating costs from all customers through base rates is inconsistent with the Companies' obligation to provide least-cost service to customers (Attorney General Brief at 138, 139).

Additionally, the Attorney General contends that the fee free program may actually harm customers who pay their bill by credit card, since credit card interest rates typically range between 13 and 25 percent, and such interest payments would more than offset any benefit received from paying their bills fee free (Attorney General Brief at 140, citing Tr. 6, at 1064). Rather than implementing the fee free proposal, the Attorney General asserts, the Companies should instead encourage customers to use online bank payments or automated clearing house ("ACH") payments, both of which are less costly options (Attorney General Brief at 140, citing Exhs. DPU-13-2; DPU-13-3; AG-54-3, at 2).

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[249] The Attorney General claims that, based on the Companies' projections, all customers will pay for the program but only 30 percent of customers are expected to use it (Attorney General Brief at 140, citing Exh. ES-PMC-1, at 14-15, 30; Attorney General Reply Brief at 37).

The Attorney General also contends that the reported program costs and proposed cost savings[250] associated with customer migration are not known and measurable as they rest on "uncertainties compounded by speculation" (Attorney General Brief at 141-142; Attorney General Reply Brief at 37-38). In particular, the Attorney General claims the Companies do not know how many customers ultimately will take advantage of the program, or the actual amount of the per-customer transaction fee, or what any offsetting savings will be (Attorney General Brief at 142, citing Tr. 13, at 2774-2776). For these reasons, the Attorney General asserts that the Department should reduce the revenue requirements for NSTAR Electric and WMECo by $5,040,200 and $897,171, respectively (Attorney General Brief at 142).

Finally, regarding the Companies' request to defer the fee free program costs for NSTAR Gas, the Attorney General contends that this request violates due process because NSTAR Gas, its customers, and other stakeholders are not parties to this proceeding (Attorney General Brief at 141; Attorney General Reply Brief at 37 n. 14). Therefore, the Attorney General argues the Department should reject Eversource's request for a deferral, and she recommends that the Department direct NSTAR Gas to submit a separate filing to request approval of a fee free program (Attorney General Brief at 141).

2. Cape Light Compact

Cape Light Compact argues that Eversource's proposal to recover $6 million per year for the fee free program is "not appropriate" (Cape Light Compact Brief at 78). Cape Light

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[250] The Attorney General notes that the Companies included in the revenue requirements minor offsetting cost savings related to the migration of customers to payment by credit or debit card from other payment methods (Attorney General Brief at 142).

Compact contends that the proposed cost of the program is not known and measurable and that the Companies have not properly taken into account offsetting savings from customer migration from other forms of payment (Cape Light Compact Brief at 79). Cape Light Compact supports the Attorney General's recommendation to eliminate from Eversource's revenue requirement the Companies' proposed pro forma adjustments for the fee free proposal (Cape Light Compact Brief at 79).

3. Low Income Network

The Low Income Network argues that the Companies' proposal to accept credit and debit card payments without charging a fee presents possible risks for low-income customers (Low Income Network Brief at 10). In particular, the Low Income Network contends that low-income customers may resort to these payment options and ultimately pay interest, penalties, and late fees if their credit card balances are not paid in full each month, or face overdraft fees on debit card use (Low Income Network Brief at 10). According to the Low Income Network, low-income customers are substantially more likely than other residential customers to make payments by credit or debit card (Low Income Network Brief at 10). Low-income customers, however, choose a credit/debit card not as a convenience but because they are "cash-poor" or wish to avoid service termination (Low Income Network Brief at 10-11).

While the Low Income Network does not strictly oppose the fee free program, it asserts that as a condition of any approval, the Department must order the Companies to conduct extra training for customer service representatives so that whenever credit/debit card

payment options are being discussed with low-income customers, representatives can inform such customers of payment plan arrangements, the arrearage management program, and protections against service termination for customers that are seriously ill, elderly, or have infants in the household (Low Income Network Brief at 12). The Low Income Network also recommends that the Department direct the Companies to make available information about payment locations by including a list of locations on Eversource's website, through bill messages, bill "envelope stuffers," and via calls with customer service representatives when appropriate (Low Income Network Brief at 13). Finally, the Low Income Network recommends that the Department direct the Companies to report back to the Department within six months of the final Order on efforts to expand the number of locations where customers can make in-person payments without incurring any fee (Low Income Network Brief at 13).[251]

4. Companies

Eversource argues that its current policy of charging customers a transaction cost of $2.25 who pay their electric bills with a credit or debit card has led to customer dissatisfaction (Companies Brief at 192, citing Exh. ES-DPH-1, at 50). Specifically, Eversource notes that the Companies have experienced numerous customer service complaints regarding the customer-side fees (Companies Brief at 552, citing Tr. 6, at 1084). The Companies contend that by implementing a fee free credit/debit card payment option they can

[251] As noted below, currently some walk-in locations charge a nominal amount for in-person bill payments (Exhs. DPU-13-3; DPU-13-13).

align Eversource's service offerings with customer experience in the marketplace and improve customer satisfaction (Companies Brief at 192, 554, citing Exh. ES-DPH-1, at 50-51). According to Eversource, its commitment to excellent customer service is driving the Companies' proposal, and the fee free program will enable the Company to "catch up" to other industries with payment methods that align with customer expectations (Companies Brief at 137, 142, 146, 194, 553; Companies Reply Brief at 134).[252] Because of this emphasis on customer satisfaction, Eversource disagrees with the Attorney General that instead of the fee free proposal, the Companies should encourage customers to use online bank payments or ACH payments (Companies Brief at 553). Rather, Eversource claims that national J.D. Power customer surveys, as well as Eversource's own experience with customer complaints, indicate that customers are more satisfied when they can pay their electric bills using a credit card with no fee (Companies Reply Brief at 134, citing Exhs. DPU-13-10; DPU-48-6; AG-54-4; AG-54-5; Tr. 6, at 1049, 1052, 1094-1095). Further, the Companies contend that in response to internal satisfaction surveys related to billing and payment matters, approximately seven percent of the negative complaints received from customers relate to dissatisfaction with credit card fees currently charged (Companies Reply Brief at 135, citing Exh. DPU-13-16).[253]

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[252] For example, the Companies offer an analogy related to parking meters and note that one "used to carry coins [...] to come into Cambridge, into Boston [...] to feed the meter" but that now it is possible to pay for parking using one's phone (Companies Brief at 553, citing Tr. 6, at 1051).

[253] The Companies claim that a focus on customer satisfaction is what led the Department to consider imposing service quality-related penalties based on the results of customer

Regarding the issue of cross-subsidization raised by the Attorney General, the Companies counter that many aspects of Eversource's customer service activities are included in the cost of service, despite not being used by all customers in any given year, such as the Companies' call center (Companies Brief at 551, citing Exh. DPU-13-10). Further, the Companies insist that while not all customers may take advantage of fee free credit/debit payment option, it is wholly reasonable to provide the program and to socialize the associated costs across all customers (Companies Brief at 552, citing Exh. DPU-13-10). Eversource also notes that because the fee free program would be available to all customers, it is consistent with the principle of cost causation (Companies Brief at 555).

Moreover, Eversource maintains that the cost of the proposed fee free program is based on reasonable assumptions regarding customer migration and, because the Companies used a competitive RFP process, the proposal is consistent with the provision of least-cost service (Companies Brief at 192, 193, 554). In this regard, the Companies claim that the Attorney General misunderstands the cost of the fee free program, and that the annual bill impact amounts to an average of $4.32 per customer (Companies Brief at 552-553). In addition, Eversource contends that offering the fee free program costs less than owning and maintaining an in-person payment center, such as a business office (Companies Brief at 553).

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satisfaction surveys (Companies Reply Brief at 134). Eversource notes that while the Department ultimately decided against imposing such penalties, the Department maintained the requirement to improve customer satisfaction (Companies Reply Brief at 134, citing Order Adopting Revised Service Quality Standards, D.P.U. 12-120-D, at 10 (2015)).

In response to claims that the fee free program costs are not known and measurable, Eversource notes that the proposal constitutes the best possible estimation, with adoption rates based on the experience of industry leaders, and that the costs are fully reconcilable (Companies Brief at 556; Companies Reply Brief at 135). Eversource also contends that while, any cost savings associated with the program are speculative and difficult to quantify, the lack of easily quantifiable savings is not, in and of itself, sufficient reason to justify disallowing the fee free program (Companies Brief at 559; Companies Reply Brief at 136).

Further, with respect to the proposed ratemaking treatment sought by the Companies, they claim that because the customer migration trend is expected to be steep over the first five years, a "different" ratemaking approach (i.e., establishing a reserve fund) is necessary (Companies Brief at 194). As such, the Companies contend that the proposal is designed to provide customers with the full benefit of the lowest cost per transaction, while also providing appropriate ratemaking treatment for transitioning the associated costs into base rates in the future once a more representative level of expense is known (Companies Brief at 194, 558). In this regard, Eversource explains that it initially considered establishing a representative level of costs into base rates as part of the instant filing, but the level of uncertainty and risk in estimating a known and measurable amount was "significant" (Companies Brief at 557; Companies Reply Brief at 135). Eversource claims it also have considered a separate cost recovery mechanism outside of base rates, but ultimately determined that option to be administratively inefficient (Companies Brief at 557; Companies Reply Brief at 135).

Eversource contends that if the Department determines that the current proposal or projected adoption rate is too high or too costly, the Companies would be amenable to a reduced annual budget (Eversource does not offer an alternative annual amount) for the fee free program, subject to the same true up method initially proposed (Companies Reply Brief at 136). Eversource argues that while this would accomplish the same objective from a cost recovery perspective, it could result in a larger future increase to reconcile an under recovery if the annual contribution to the reserve fund is too low (Companies Reply Brief at 136).

Finally, Eversource contends that if the fee free proposal is approved, the Companies will require an implementation period of approximately six months to make system changes to accommodate the new payment offering (Companies Brief at 138 n.35). According to Eversource, the cost to NSTAR Gas will be significant on an annual basis, assuming customer participation rates are as robust as the Companies anticipate (Companies Brief at 138 n.35). Therefore, Eversource requests that the Department approve implementation of the fee free program for both electric and gas customers, and authorize the Companies to defer the actual transaction costs incurred on behalf of gas customers for amortization in rates in the next rate case (Companies Brief at 138 n.35).

C. Analysis and Findings

Eversource proposes to implement a fee free credit/debit card payment program that allows customers to pay their electric bills via credit or debit card without incurring the third-party transaction fee of $2.25 (Exhs. ES-PMC-1, at 5, 7; ES-DPH-1, at 50, 52). The Companies estimate the cost of the program to be $30 million over five years, or $6 million

annually, and propose to recover the cost from all customers through base distribution rates (Exhs. ES-PMC-1, at 7, 15; ES-DPH-1, at 51-52, 54; ES-DPH-2 (East), Sch. DPH-9 (Rev. 3); ES-DPH-2 (West), Sch. DPH-9 (Rev. 3); AG-19-14; Tr. 6, at 1079).

The Attorney General and Cape Light Compact both argue that the program should be rejected as the costs associated with the fee free proposal are not known and measurable, but instead are based on assumptions that are speculative at best (Attorney General Brief at 142; Cape Light Compact Brief at 79). As a threshold matter, proposed adjustments to test year expenses based on estimates typically are not allowed. D.T.E. 98-51, at 62; D.P.U. 92-210, at 83; Dedham Water Company, D.P.U. 849, at 32-34 (1982). However, irrespective of whether Eversource has provided sufficient and reliable cost information to support the fee free program as a known and measurable change to the Companies' costs of service, the Department is not persuaded that the proposal, on the whole, is in the best interest of ratepayers.

In particular, we find that the estimated annual cost of the fee free proposal is disproportionate to the combined cost of all other payment options. During the test year, NSTAR Electric incurred approximately $1.2 million in costs to process all types of payments, and WMECo incurred $172,773 in costs to process all types of payments (Exhs. AG-37-8; AG-37-9; Tr. 6, at 1086). At an annual cost of $6 million, the fee free program would not only be the most expensive of all payment options, but the cost of processing credit and debit card transactions fee free would eclipse the total cost of

processing all other payment types by almost 450 percent (Exhs. AG-37-8; AG-37-9; Tr. 6, at 1086-1087).

Further, we find that the proposal will result in costs being borne by a vast majority of customers who are unlikely to take advantage of the fee free program. In this regard, the record shows that during the test year only approximately 1.64 percent of NSTAR Electric customers chose to pay their bill by credit/debit card and only 3.40 percent of WMECo customers chose to pay by credit/debit card (Exhs. DPU-13-2; DPU-13-3; Tr. 6, at 1062). Yet, under the Companies' proposal, all customers would be responsible for the program's cost, even those who choose to pay their bills by another method. Thus, even assuming that Eversource's estimate of 30 percent customer migration to the fee free option proves accurate, 70 percent of customers would be subsidizing the cost for the convenience of the remaining 30 percent of the Companies' customers. Thus, on its surface, the Companies' proposal is inconsistent with established cost-causation principles in ratemaking. Bay State Gas Company, D.T.E./D.P.U. 06-36, at 41 (2007); D.P.U. 96-50 (Phase I) at 133-134.

Moreover, we are not persuaded by Eversource's reference to other customer service activities, such as the call center, where costs are borne by all customers through the cost of service, but not used by all customers (Companies Brief at 551-552). While Eversource is correct that all customers pay for call centers through base distribution rates despite not always using them, the comparison is misplaced because a customer call center is a necessary business expense for a distribution utility with no comparable low-cost alternative. On the other hand, with respect to the proposed fee free payment option, the record shows that

customers have several low-cost, and even no-cost, payment options (Exhs. DPU-13-2; DPU-13-3; Tr. 6, at 1081). For example, customers may pay their bills by mailing a check and paying the cost of a first class stamp, or they may pay in person, which can be free or cost a nominal amount (i.e., $1.00 or $1.50), depending on the location (Exhs. DPU-13-2; DPU-13-3). In addition, customers can use no-cost electronic payment options such as on-line bank payments, ACH (both one-time and recurring) payments, and mobile payments (Exhs. DPU-13-2; DPU-13-3; Tr. 6, at 1081).

Eversource defends its proposal by emphasizing that the fee free proposal is necessary to increase customer satisfaction (Companies Brief at 194, 553). In this regard, the Companies point to customer satisfaction surveys wherein customers expressed displeasure with having to pay a transaction fee when choosing to pay by credit or debit card (Exhs. DPU-13-16; AG-54-4; Tr. 6, at 1094). However, the record shows that in one of the referenced surveys, the percentage of customers that expressed discontent with credit card convenience fees was roughly equal to the percentage of customers who also expressed dissatisfaction because their electric rates are too high (Exh. AG-54-4; Tr. 6, at 1097-1098). While the Department recognizes the importance of maintaining customer satisfaction by offering convenient payment options to customers, we find that the fee free proposal fails to strike an appropriate balance between this objective and the Companies' obligation to provide least-cost service to all of their customers. The estimated annual cost of $6 million associated with the fee free proposal is simply too costly to adhere to the standard of

least-cost service.[254] Further, we are not convinced that the fee free proposal is necessary as a means to "catch up" with other payment services available to customers in the market (Exh. ES-PMC-1, at 6, 34; Tr. 6, at 1051; see also n.252 above).[255]

Finally, we turn to the Low Income Network's concern about low-income customers paying high interest rates for credit card payments if the fee free proposal were to be approved. The Companies concede that credit card companies can charge high interest rates, often in the range of 13 to 25 percent (Tr. 6, at 1064). It stands to reason that these penalties can create a financial hardship for any customer who fails to pay his/her electric bill, but especially a low-income customer. Further, the Department recognizes that a fee free credit/debit card payment option could dissuade some low-income customers from choosing to take advantage of other options, such as the arrearage forgiveness programs, payment plan arrangements, and various customer protections (Tr. 6, at 1066-1067).

Based on the above considerations, we conclude that Eversource's fee free proposal, on the whole, is not in the best interest of ratepayers. Therefore, the Department declines to

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254 We note that if the Companies' customer migration assumptions are valid, the annual cost of the fee free program presumably would eventually surpass $6 million as a 30 percent adoption rate continues into the future (Exhs. DPU-13-9, Att.; DPU-13-12, Att.).

255 As noted above in n.252, the Companies analogize the fee free proposal to paying for parking meters via a smartphone rather than with coins (Companies Brief at 553; Tr. 6, at 1051). However, in the parking meter analogy, the customer parking his/her car is paying for his/her own convenience in both scenarios - the cost has not changed, merely the mode of payment. A more apt analogy that adheres to the theme of parking meters would be a proposal where parking meters became "free," but property or automotive taxes are increased for everyone to pay for the cost. Under this scenario, we would expect there to be opposition from those who would be paying for a service that they may not use.

approve the proposal. Accordingly, the Department will remove $5,040,200 from NSTAR Electric's cost of service[256] and $897,171 from WMECo's cost of service.[257] Finally, in light of this decision, we need not specifically address the Companies' proposal to implement the fee free proposal for NSTAR Gas customers, though we do recognize that the Companies' proposal to do so in this proceeding raises important due process concerns.

XII. PROPERTY TAX COST RECOVERY PROPOSAL

A. Introduction

Eversource states that WMECo has incurred $8,314,371 in incremental property taxes from 2012 through 2015 as a result of the City of Springfield's adoption of the RCNLD valuation method (Exh. AG-44-1, Att. (a); Tr. 9, at 1840-1841, 1867-1868; RR-DPU-31). WMECo has withheld paying the incremental property tax levied by Springfield (Exh. DPU-39-7 & Att.; Tr. 9, at 1874-1875). Eversource states that WMECo sought abatements from Springfield for the incremental tax amounts levied in 2012 through 2015, but the requests were denied (Exhs. ES-DPH-1, at 192; DPU-39-6, at 2-3 & Att. (a)). Thereafter, WMECo appealed the abatement decisions to the Massachusetts Appellate Tax Board ("Appellate Tax Board") and those appeals still are pending (Exhs. ES-DPH-1, at 192; DPU-39-6, at 3 & Att. (a); Tr. 9, at 1860).[258] Eversource states that if the Appellate Tax

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256 $5,093,091 less savings of $52,891 = $5,040,200 (see n.248 above).

257 $906,909 less savings of $9,738 = $897,171 (see n.248 above).

258 On December 16, 2009, the Appellate Tax Board issued a ruling approving the City of Boston Board of Assessors' adoption of the RCNLD valuation method for assessing utility property. Boston Gas Company v. The Board of Assessors of Boston, Docket No. F275055, F275056 (December 16, 2009). Boston Gas Company appealed the

Board denies these appeals, WMECo will seek relief with the Massachusetts Court of Appeals (Exh. ES-DPH-1, at 192).

Pursuant to Article II (5) of the Merger Settlement (see Section V.A above), WMECo may seek recovery of incremental property taxes incurred during the rate freeze (i.e., January 1, 2012 through December 31, 2015) associated with the adoption of the RCNLD valuation method, provided that the incremental expense meets the minimum annual threshold for exogenous costs.[259] The Merger Settlement is silent with respect to the method to be used to recover exogenous costs.

B. Companies Proposal

Eversource seeks to recover the aforementioned $8,314,371 in incremental property taxes that WMECo incurred from 2012 through 2015 as an exogenous cost pursuant to the Merger Settlement (Exhs. ES-DPH-1, at 189, AG-44-1, Att. (a); Tr. 9, at 1840-1841, 1867-1868; RR-DPU-31). WMECo proposes to recover these costs, amortized over five years, pursuant to a new Municipal Property Tax Adjustment ("MPTA") tariff

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ruling to the Supreme Judicial Court, which upheld the Appellate Tax Board's decision and determined that the valuation method used by Boston was reasonable. Boston Gas Company v. Board of Assessors, 458 Mass. 715, 729, 739-740 (2011). The Supreme Judicial Court then remanded the matter to the Appellate Tax Board for further findings. On April 21, 2011, the Appellate Tax Board issued a final ruling in the matter denying Boston Gas Company's appeal of the property tax valuation of the City of Boston Board of Assessors. Boston Gas Company v. The Board of Assessors of Boston, Docket No. F275055, F275056 (April 21, 2011).

259 Pursuant to the Merger Settlement, the dollar threshold for qualification as an exogenous factor in any calendar year covered by the Merger Settlement shall be determined by multiplying the total distribution revenues of that year by a factor of 0.003212 (Merger Settlement at Art. II (5)).

(Exhs. ES-DPH-1, at 190, RR-DPU-51, Att. (a) at 336-338 (proposed M.D.P.U. No. 534)).[260] WMECo further proposes that any abatements associated with the incremental taxes subject to exogenous cost recovery will be credited to ratepayers through the MPTA (Tr. 9, at 1844, 1865, 1872; RR-DPU-51, Att. (a) at 336-338 (proposed M.D.P.U. No. 534)).

C. Positions of the Parties

1. Attorney General

The Attorney General does not contest WMECo's eligibility to recover the incremental property taxes incurred during the rate freeze that result from Springfield's use of the RCNLD valuation method (Attorney General Brief at 190). The Attorney General argues, however, that the claimed amounts should be reduced to reflect income tax deductions (Attorney General Brief at 191). Specifically, the Attorney General maintains that the Companies' proposal does not capture the state and federal tax benefits WMECo would receive after it deducts the amounts from its income taxes (Attorney General Brief at 190).

2. TEC and WMIG

TEC and WMIG credit Eversource for vigorously challenging municipal efforts to use the RCNLD valuation method (TEC and WMIG Brief at 16). TEC and WMIG maintain, however, that they have concerns about allowing WMECo to recover the incremental

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[260] WMECo sought to recover an additional $1,991,983 through the MPTA, representing incremental property taxes assessed by Springfield in 2016 (Exh. AG-1-44, Att. (a); Tr. 9, at 1840-1841, 1867-1868; RR-DPU-31). WMECo sought a deferral of these amounts in a separate proceeding, Western Massachusetts Electric Company, D.P.U. 16-107. On November 30, 2017, the Department denied WMECo's request for a deferral. D.P.U. 16-107 (November 30, 2017). Accordingly, WMECo is not eligible to recover these amounts.

property taxes while it still has a pending appeal challenging these taxes (TEC and WMIG Brief at 16). Specifically, TEC and WMIG assert that if WMECo is allowed to recover these costs while an appeal is pending, the Companies would no longer have a financial incentive to aggressively challenge the use of the RCNLD valuation method (TEC and WMIG Brief at 16-18).

3. Companies

The Companies argue that the incremental property taxes at issue far exceed the threshold for recovery in the Merger Settlement (Exh. ES-DPH-1, at 189). Further, Eversource notes that the Attorney General does not contest that WMECo is eligible to recover incremental property taxes incurred during the rate freeze arising from the use of the RCNLD valuation method (Companies Brief at 502).

Eversource argues that the Attorney General's request to reduce WMECo's recovery of incremental property tax expense based on tax benefits is flawed (Companies Brief at 502). Specifically, Eversource maintains that any revenues received through the recovery of exogenous costs would be subject to taxation and WMECo's property tax expense is a deduction already (Companies Brief at 502). Therefore, the Companies maintain that reducing recovery, as the Attorney General suggests, would only prevent WMECo from receiving the full amount of exogenous costs to which it is entitled (Companies Brief at 502).

D. Analysis and Findings

The Merger Settlement provides that, if certain conditions are met, WMECo may seek recovery of incremental RCNLD-related property taxes incurred during the rate freeze as exogenous costs (Merger Settlement at Art. II (5)). At the close of the record in this case,

Eversource's appeals to the Appellate Tax Board of Springfield's denials of its tax abatement requests were pending (Exh. ES-DPH-1, at 192; DPU-39-6, at 3 & Att. (a); Tr. 9, at 1860). If such appeals are unsuccessful, Eversource states that it will appeal further to the Massachusetts Court of Appeals (Exh. ES-DPH-1, at 192). There is no timeline for resolution of the appeals.

The Department is unable to now assess whether at the end of the appeals process there will be any incremental taxes and, if there are, whether the amount will be above the annual threshold subject to recovery from ratepayers as exogenous costs.[261] Accordingly, the Department cannot consider Eversource's request for recovery of WMECo's incremental property taxes as an exogenous cost at this time. This finding is consistent with the treatment of NSTAR Gas' similar request for exogenous cost recovery in its last base rate proceeding. D.P.U. 14-150, at 280-281.

Once all appeals are exhausted, WMECo may file a petition seeking exogenous cost recovery of any incremental property tax assessed using the RCNLD valuation method from 2012 through the year ending December 31, 2015. D.P.U. 14-150, at 281. At that time, the Department and any parties to the proceeding will have an opportunity to investigate the proposal to determine whether the costs satisfy the thresholds and other requirements in the

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261 Eversource maintains that WMECo has incurred $8,314,371 in incremental property taxes associated with Springfield's use of the RCNLD valuation method during the applicable period (Exhs. ES-DPH-1, at 189, AG-44-1, Att. (a); Tr. 9, at 1840-1841, 1867-1868; RR-DPU-31). The Appellate Tax Board or an appellate court could, however, determine that the amount of incremental taxes owed by WMECo is different than the amount sought.

Merger Settlement for exogenous cost recovery and are otherwise recoverable from ratepayers. D.P.U. 14-150, at 281.[262]

Having found that WMECo's request for exogenous cost recovery is not ripe for consideration at this time, the Department disallows Eversource's proposed MPTA tariff, M.D.P.U. No 534. The Department will consider a request to establish an MPTA tariff as part of any future petition seeking exogenous cost recovery under the Merger Settlement.

XIII. STORM COST RECOVERY MECHANISM

A. Current Storm Funds and Storm Cost Recovery Filings

1. NSTAR Electric

In Boston Edison Company, D.P.U./D.T.E. 96-23 (1998), the Department approved a restructuring settlement that, among other things, established a storm fund for Boston Edison Company. The Department allowed Boston Edison Company to access the storm fund when the incremental O&M expense of a storm exceeded $1.0 million. D.P.U./D.T.E. 96-23, at 81-83. The settlement required Boston Edison Company to prefund the storm fund at $8.0 million and, whenever storm costs were paid from the fund, restore the fund balance to $8.0 million, up to a maximum of $3.0 million per year. D.P.U./D.T.E. 96-23, at 81-83. In D.T.E. 05-85, at 7-8, 13, 33, the Department approved the proposed merger that formed

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[262] Although the Merger Settlement allows Eversource to seek recovery of incremental tax amounts associated with the RCNLD valuation method, the Merger Settlement makes no provision for the recovery of ancillary costs such as accrued interest or litigation expenses. Therefore, interest and litigation costs are not eligible for recovery as exogenous costs under the provisions of the Merger Settlement. D.P.U. 14-150, at 278-279.

the corporate entity known as NSTAR Electric,[263] increased the amount in the storm fund to $13.5 million, and increased the annual replenishment amount to a maximum of $4.5 million per year.

Pursuant to its storm fund mechanism, NSTAR Electric filed for, and the Department approved, the recovery of costs associated with two storms that occurred in 2011 ((“Tropical Storm Irene”) and an October 29, 2011 snowstorm (“October Snowstorm”)) over a five-year period (2014 through 2018) with interest at the prime rate (Exh. ES-DPH-1, at 126). See also NSTAR Electric Company, D.P.U. 13-52, at 106-107. As a result, NSTAR Electric currently recovers approximately $8.0 million annually, and will do so through the end of 2018 (Exh. ES-DPH-1, at 126, citing NSTAR Electric Company, D.P.U. 16-172, Exh. NSTAR-BKR-13) (2016)). Further, NSTAR Electric has filed with the Department for approval to recover costs through the storm fund of approximately (1) $109.8 million for eight storms that occurred between 2012 through 2015, and (2) $11.1 million for two storms that occurred in February 2016. NSTAR Electric Company, D.P.U. 16-74, Exh. EVER-LML-1-SUMMARY (Rev. 3); NSTAR Electric Company, D.P.U. 17-51, Exh. EVER-LML-1-SUMMARY.[264]

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263 Pursuant to the settlement agreement approved in D.T.E. 05-85, at 7, 33, Boston Edison, Cambridge Electric Light Company, Commonwealth Electric Company, and Canal Electric Company merged into a single corporate entity known as NSTAR Electric.

264 Both D.P.U. 16-74 and D.P.U. 17-51 are currently pending before the Department.

2. WMECo

In D.T.E. 06-55, the Department approved the establishment of a storm fund reserve to pay for incremental O&M costs associated with any individual major storm event with incremental O&M costs over $300,000. D.T.E. 06-55, at 7. The Department required WMECo to prefund the storm fund with $300,000, and to accrue an additional $300,000 per year to the storm fund. D.T.E. 06-55, at 7. In D.P.U. 10-70, at 192, the Department approved increasing the annual funding level to $575,000. D.P.U. 10-70, at 192. The Department also approved an annual reconciliation of the storm fund through the storm recovery reserve cost adjustment ("SRRCA") factor. D.P.U. 10-70, at 203 & February 17, 2017 Compliance Filing (2011). Further, the Department allowed WMECo to amortize recovery of a $15,307,551 deficit balance over five years outside of base distribution rates and to establish a symmetrical cap of $3.0 million on the storm fund. D.P.U. 10-70, at 193, 198. In instances where the funds exceed the cap, the Department required WMECo to return the excess amount to ratepayers and, in instances where the fund had a deficiency in excess of the cap, the Department allowed WMECo to propose a method to recover the deficiency in excess of the cap. D.P.U. 10-70, at 199. Further, the Department approved the use of a carrying charge at the customer deposit rate on the storm fund monthly balance. D.P.U. 10-70, at 201.

Pursuant to D.P.U. 10-70, WMECo has subsequently filed six annual petitions to the Department for reconciliation of the storm fund through the SRRCA and approval of its storm recovery adjustment factor ("SRAF"). In Western Massachusetts Electric Company,

D.P.U. 11-102/11-102-A (2014), WMECo sought recovery of $24,557,641 in storm-related costs for the period January 2008 through September 2011. The Department approved recovery of most of these costs but denied recovery of $622,202, which included costs for t-shirts, video and radio commercials, insurance, storm bonuses, and $448,919 of non-incremental capitalized wages. D.P.U. 11-102/11-102-A at 42-50, 68, 84-88, 103.[265] In Western Massachusetts Electric Company, D.P.U. 13-135, at 2 (2016), WMECo petitioned the Department for recovery of $27,109,008 in storm-related costs for the October Snowstorm and for Hurricane Sandy. The Department approved cost recovery for most of these costs, but denied WMECo $563,069 in capital labor costs. Western Massachusetts Electric Company, D.P.U. 13-135-A at 21-24 (2014).[266] Additionally, WMECo has three other storm filings pending before the Department.[267]

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[265] For the calendar year 2012, in which there were no new storms, WMECo filed and the Department approved the reconciliation of WMECo's annual SRRCA factor. Western Massachusetts Electric Company, D.P.U. 12-90 (2012).

[266] The Department found that WMECo's method for calculating total capital labor costs overstated non-incremental labor costs, and that WMECo should have assigned a portion of these costs to contractor labor costs. D.P.U. 13-135-A at 21-24. The Department further found that WMECo failed to demonstrate it had taken reasonable and prudent steps to bill Verizon, and conditionally disallowed 50 percent of vegetation management costs. D.P.U. 13-135-A at 44-45. WMECo has submitted a motion for reconsideration of the Department's findings related to vegetation management, which is under Department review in D.P.U. 13-135.

[267] The following investigations are pending before the Department: (1) Western Massachusetts Electric Company, D.P.U. 14-126 (2014), in which WMECo experienced no new storms but seeks reconciliation of its SRAF; (2) Western Massachusetts Electric Company, D.P.U. 15-149 (2015), in which the WMECo filed for approval for recovery of $3,882,229 in costs associated with a July 2014 thunderstorm and November 2014 snowstorm; and (3) Western Massachusetts Electric

B. Companies Storm Fund Proposal

1. Storm Fund Mechanism

Eversource proposes to consolidate the storm fund mechanism for NSTAR Electric and WMECo for storm costs incurred on and after January 1, 2018, and to recover future qualifying storm-related costs pursuant to a new tariff (Exh. ES-DPH-1, at 110-111; RR-DPU-51, Att. (a) at 122-123 (proposed M.D.P.U. No. 524)). Eversource states that it largely modeled the storm fund components after the mechanism approved in D.P.U. 15-155, with some modifications (Exhs. ES-CAH-1, at 25; ES-DPH-1, at 111).[268]

First, as noted, Eversource proposes to continue storm fund operations of NSTAR Electric and WMECo in a consolidated storm fund for storm costs incurred on and after January1, 2018 (Exh. ES-DPH-1, at 111-112). Second, Eversource proposes that any single storm in which Eversource incurs $1.2 million in incremental O&M cost will be eligible for recovery through the storm fund (Exh. ES-DPH-1, at 112, 115). Eversource calculated the proposed threshold by increasing NSTAR Electric's $1.0 million threshold by the cumulative inflation change based on the gross GDP-PI from the U.S. Bureau of Economic Analysis

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Company, D.P.U. 16-179 (2016), in which WMECo experienced no new storms but seeks reconciliation of its SRAF. The Department approved these three filings subject to further investigation. D.P.U. 14-126, at 5; D.P.U. 15-149, at 5; D.P.U. 16-179, at 5.

268 In addition to proposed storm fund components that are similar to those approved in D.P.U. 15-155, Eversource seeks approval to recover carrying charges for storms that exceed the proposed $30.0 million cap inclusion within the storm fund, to establish a replenishment factor if the combination of any deferral balance and/or the balance of the storm fund exceeds $75.0 million, and to recover lean-in costs related to the costs of pre-staging resources when a storm event fails to materialize (Exhs. ES-DPH-1, at 113, 120-124). We address these issues in detail below.

from January 1, 2005 through December 31, 2016, resulting in an increase to the qualifying threshold from $1.0 million to $1.2 million (Exh. ES-DPH-1, at 115).[269] Given that the Companies plan to legally consolidate operations effective January 1, 2018, Eversource proposes that a single $1.2 million threshold apply to NSTAR Electric and WMECo's consolidated storm fund mechanism (Exh. ES-DPH-1, at 115).[270]

Third, Eversource proposes to recover the $1.2 million threshold amount through base distribution rates for a representative number of storms (Exh. ES-DPH-1, at 124). Based on a normalized level of three major storm events per year, Eversource proposes to recover a total of $3.6 million annually through base distribution rates (Exhs. ES-DPH-1, at 125; ES-DPH-2, Sch. DPH-21, at 3, 4 (East); ES-DPH-2, Sch. DPH-21, at 3, 4 (West)). Eversource proposes to allocate the $3.6 million annual amount to NSTAR Electric and WMECo on an 80/20 split, respectively (Exh. ES-DPH-1, at 125).[271] Accordingly, Eversource proposes that NSTAR Electric recover $2.88 million annually in base distribution

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269 Eversource states that it used the same method approved by the Department in D.P.U. 15-155 to calculate its proposed qualifying storm event threshold (Exh. ES-DPH-1, at 114).

270 Eversource proposes that its $1.2 million threshold would replace the current threshold for storm cost recovery of $300,000 and $1.0 million for WMECo and NSTAR Electric, respectively (Exh. ES-DPH-1, at 112).

271 Eversource states that it determined this proposed base distribution rate allocation by the ratio of NSTAR Electric storm costs and WMECo storm costs to the total net incremental storm costs incurred from February 2010 through February 2016 (Exhs. ES-DPH-1, at 125; ES-DPH-2, Sch. DPH-21, at 4 (East); ES-DPH-2, Sch. DPH-21, at 4 (West)).

rates, and WMECo recover $720,000 annually in base distribution rates (Exh. ES-DPH-1, at 126).

Fourth, Eversource proposes to include an annual contribution to the storm fund through base distribution rates in the consolidated amount of $10.0 million (Exh. ES-DPH-1, at 112; see Exh. ES-DPH-2, Sch. DPH-21, at 2, lines 59, 60 (East)). Eversource asserts that its current total storm fund allowance of $5.075 million annually is insufficient based on the total actual net cost of 21 storm fund eligible events experienced since 2010 (Exh. ES-DPH-1, at 110, 115).[272] Eversource states that it applied the same method approved for National Grid in D.P.U. 15-155 to determine a new level of base distribution rate contributions for storm fund eligible events (Exh. ES-DPH-1, at 117). In calculating the proposed base distribution rate contribution, Eversource excluded the costs related to the two largest storm events from total costs incurred during the six-year period from February 2010 through February 2016 (Exh. ES-DPH-1, at 117). Next, Eversource took the $96.0 million in rounded storm costs that resulted from removing the two largest storm events ($187.0 million in net incremental storm costs minus $92.0 million) and divided by 77 (the number of months between February 2010 through the end of the test year of June 30, 2016) to determine an average monthly incremental O&M storm fund eligible cost of approximately $1.2 million (Exhs. ES-DPH-1, at 117; ES-DPH-2, Sch. DPH-21, at 2 (East); ES-DPH-2, Sch. DPH-21, at 2 (West)). Eversource then multiplied the resulting $1.2 million average

[272] The $5.075 million total consists of $4.5 million per year for NSTAR Electric (collected through base distribution rates) and $575,000 per year for WMECo (collected through the SRRCA) (Exh. ES-DPH-1, at 110, 115).

monthly storm fund eligible cost by twelve months to derive an average annual incremental O&M storm fund eligible cost of approximately $15.0 million (Exh. ES-DPH-1, at 117). Eversource proposes, however, a $10.0 million annual storm fund contribution in base distribution rates, which it states is consistent with the amount the Department approved for National Grid (Exh. ES-DPH-1, at 117-118, citing D.P.U. 15-155, at 79). Eversource proposes to collect the $10.0 million annual storm fund contribution in base distribution rates from NSTAR Electric and WMECo ratepayers on an 80/20 basis, respectively, collecting annually $8.0 million in NSTAR Electric's base distribution rates and $2.0 million in WMECo's distribution rates (Exhs. ES-DPH-1, at 118; ES-DPH-1, at 117; ES-DPH-2, Sch. DPH-21, at 2 (East); ES-DPH-2, Sch. DPH-21, at 2 (West)).[273]

Fifth, Eversource proposes a symmetrical cap of $30.0 million on the storm fund's balance to trigger either a customer refund for an over-recovery balance that exceeds the cap, or a customer charge for an under-recovery balance that exceeds the cap (Exh. ES-DPH-1, at 112, 121). Eversource seeks to accrue interest at the prime rate on the storm fund balance commencing at the start date of the storm event (Exh. ES-DPH-1, at 112-113, 121). Eversource asserts that its proposal to apply the $30.0 million storm fund cap is consistent

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[273] Eversource determined the proposed 80/20 split by the ratio of NSTAR Electric storm costs and WMECo storm costs to total net incremental storm costs between February 2010 and February 2016 (Exhs. ES-DPH-1, at 118; ES-DPH-1, at 117; ES-DPH-2, Sch. DPH-21, at 2 (East); ES-DPH-2, Sch. DPH-21, at 2 (West)). This represents an annual increase of $3.5 million over current levels for NSTAR Electric and an annual increase of $2.0 million over current levels for WMECo (Exhs. ES-DPH-1, at 118; ES-DPH-2, Sch. DPH-21, at 1 (East); ES-DPH-2, Sch. DPH-21, at 1 (West)).

with Department's directives in D.P.U. 15-155 (Exh. ES-DPH-1, at 121).[274] In addition, Eversource proposes to accrue carrying charges for those storms that exceed the $30.0 million cap beginning at the start of the storm event (Exh. ES-DPH-1, at 121).

Sixth, Eversource proposes that if the combination of the cost for storms in excess of $30.0 million and the storm fund balance exceed $75.0 million (i.e., the total sum of all single storms in excess of $30.0 million and/or the balance in the storm fund exceeds $75.0 million), it may file for an annual replenishment amount, pending a prudence review by the Department (Exh. ES-DPH-1, at 123). Eversource asserts that this would enable it to reduce the outstanding, unrecovered storm balance, minimize carrying charges, and mitigate bill impacts that would accompany the pancaking effect of significant storm cost recovery (Exhs. ES-DPH-1, at 113, 123; DPU-2-19).

Finally, Eversource proposes that it be allowed to recover "lean-in" costs from the storm fund in the event that an anticipated emergency response plan ("ERP") event does not materialize (Exh. ES-DPH-1, at 113, 123-124). Lean-in costs are defined as costs incurred in response to anticipated Type 3 or greater ERP events to mobilize and pre-stage third-party contractors (Exh. ES-DPH-1, at 113,123-124).[275] Eversource proposes cost recovery for all

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274 In D.P.U. 15-155, at 82, the Department approved a $30.0 million symmetrical cap for National Grid's storm fund mechanism.

275 The ERP applies to emergency events caused by any hazard or threat that results in, or could result in, a major disruption of the electrical service to Eversource customers. NSTAR Electric Company/Western Massachusetts Electric Company, D.P.U. 17-ERP-10, ERP at 13 (2017). An emergency event is defined as a Type 3 ("moderate regional event"), Type 2 ("serious regional event"), or Type 1 ("full scale

lean-in costs regardless of whether the actual magnitude and cost of storm is above or below the $1.2 million storm fund threshold (Exh. ES-DPH-1, at 113). Eversource requests that lean-in cost recovery accrue carrying charges at the prime rate beginning at the date of the storm event (Exh. ES-DPH-1, at 120-121). Eversource proposes that the following five criteria be met for recovery of lean-in costs: (1) Eversource's Incident Commander determines that circumstances warrant activation of the ERP;[276] (2) pre-staging of external-crew resources is anticipated as part of the ERP activation to facilitate the efficient restoration of service to potentially affected customers; (3) pre-staging of external-crew resources will require Eversource to incur incremental cost due to the circumstances at hand; (4) Eversource provides written notice to the Department informing the Department: (a) of the activation of the ERP; (b) that the event classification declared is a Type 3 or greater (i.e., Type 3, Type 2, or Type 1); and (c) that the Eversource is commencing efforts to procure and pre-stage external crews to address oncoming storm conditions; and (5) the total incremental costs actually incurred by Eversource falls below the $1.2 million threshold for storm-fund eligibility due to the fact that actual storm conditions did not develop as anticipated, thereby obviating a full response by the Eversource under the ERP requirements (Exh. ES-CAH-1, at 29).

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catastrophic event") (Exh. DPU-2-1, Att. at 1-3). See also D.P.U. 17-ERP-10, ERP at 21-23.

276 Eversource states that whenever a significant incident capable of causing interruptions to electric service is anticipated to occur, or occurs, the Incident Commander is responsible for analyzing the expected severity and complexity of the incident, with the collaboration and input of the Section Chiefs (Exh. DPU-2-1, at 1).

2. Outstanding Storm Fund Balance

Eversource proposes to collect all unrecovered storm costs incurred prior to January 1, 2018 through separate reconciling charges for NSTAR Electric customers and WMECo customers (Exh. ES-DPH-1, at 128; RR-DPU-51, Att. (a) at 116-121 (proposed M.D.P.U. Nos. 116E, 1054C). As part of its revised rate design proposal, the Companies propose that, effective January 1, 2019, storm costs will be recovered from all customers in both the Eastern and Western Massachusetts territories through a consolidated charge (RR-DPU-51, Att. (a) at 123 (proposed M.D.P.U. No. 524)). The Department will address the proposed change to recovery of storm costs through a consolidated charge effective January 1, 2019, in our subsequent Order addressing rate design issues.

Eversource proposes to recover the approximate $105.0 million storm fund balance for NSTAR Electric (from storms that have occurred since 2011) over a five-year period beginning January 1, 2018,[277] with interest accruing at the prime rate from the date of the storm event (Exhs. ES-DPH-1, at 129; DPU-30-8).[278] Eversource states that NSTAR Electric is currently recovering approximately $8.0 million annually with interest at the prime rate over a period of five years (2014 through 2018) associated with two storm events in

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277 Eversource initially estimated NSTAR Electric's storm fund deficit to be approximately $100.0 million but, as of March 31, 2017, Eversource estimates NSTAR Electric's storm fund deficit to be approximately $105.0 million (Exhs. ES-DPH-1, at 129; DPU-30-8).

278 Eversource estimates that, at NSTAR Electric's current rate of storm fund replenishment of $4.5 million through base distribution rates, it would take approximately 22 years to replenish its storm fund deficit assuming no additional storms (Exh. ES-DPH-1, at 129).

2011 (Tropical Storm Irene and the October Snowstorm) (Exh. ES-DPH-1, at 126).[279] Since 2011, Eversource states that NSTAR Electric has incurred a total of $125.0 million of incremental storm fund eligible storm costs for ten storm events (between 2012 and 2016) and that costs for these storms have been offset somewhat by recovery in base distribution rates of $4.5 million annually (Exh. ES-DPH-1, at 126, 127 (Table DPH-1), 129). As of March 31, 2017, however, NSTAR Electric calculates a storm fund deficit of approximately $105.0 million (Exh. DPU-30-8).[280] Eversource states that, assuming the Department approves storm fund cost recovery as proposed, NSTAR Electric's total unrecovered storm fund balance would take ten years to recover (2012 through 2022) (Exhs. ES-DPH-1, at 129).[281] Absent changes to the storm fund, Eversource estimates NSTAR Electric's current total annual revenue recovery rate associated with its outstanding storm fund balance

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279 NSTAR Electric sought to recover a total of $37,963,558, consisting of $22,830,603 for Tropical Storm Irene and $15,132,955 for the October Snowstorm. D.P.U. 13-52, at 1. The Department approved recovery of $34,201,144 in storm-related costs. D.P.U. 13-52, at 106-107 & Stamp Approved Compliance Filing (January 2, 2014).

280 Eversource notes that it experienced three storm events over the current $1.0 million threshold for NSTAR Electric in 2017 (Exh. DPU-30-8). Consistent with Eversource's proposal for recovering 2017 outstanding storm fund eligible costs at the current threshold (discussed in detail below) Eversource proposes to recover these additional storm costs through NSTAR Electric's current storm fund mechanism as a unique rate for NSTAR Electric customers (see Exhs. ES-DPH-1, at 128; DPU-30-8).

281 This assumes that NSTAR Electric continue to recover approximately $8.0 million per year towards these costs through the end of 2018 pursuant to the Department's Order in D.P.U. 13-52, and no additional storm events occur (Exh. ES-DPH-1, at 130).

to be approximately $31.0 million (Exhs. ES-DPH-1, at 130; ES-DPH-5, at line 27 (East)).[282]

For WMECo, Eversource proposes to continue with WMECo's current storm cost recovery annually through the SRRCA at the current level until WMECo fully recovers the total outstanding balance of storm costs as of December 31, 2017 (Exh. ES-DPH-1, at 131). Eversource states that WMECo has been recovering its major storm costs on a more "real time" basis than NSTAR Electric (Exh. ES-DPH-1, at 127). Eversource states that WMECo currently has a rate in place through its SRRCA to recover storm costs approved for recovery in D.P.U. 11-102/11-102-A and D.P.U. 13-135, and for storms currently pending review before the Department in Western Massachusetts Electric Company, D.P.U. 15-149 (2015) (Exh. ES-DPH-1, at 127-128). Eversource proposes recovery of WMECo's outstanding storm balance as of January 1, 2018 at the level currently recovered in the SRRCA until the cost are fully recovered, unless additional significant storms occur in 2017 with costs that raise the balance to a level that it would not be recovered in five years (Exh. ES-DPH-1, at 130-131). In this instance Eversource proposes to amortize WMECo's storm fund balance over five years (Exh. ES-DPH-1, at 131). Eversource projects that, assuming no additional storms events occur and the level of recovery continues at current levels, the outstanding balance for these WMECo storms will be fully recovered by December 31, 2019

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[282] This amount is subject to the final determination of recoverable storm costs for: (1) storm costs sought for recovery in D.P.U. 16-74; (2) Winter Storm Lexi and Winter Storm Mars, for which NSTAR Electric is seeking recovery in D.P.U. 17-51; and (3) any additional storms that may occur prior to new rates going into effect January 1, 2018 (Exh. ES-DPH-1, at 130).

(Exh. ES-DPH-1, at 128). If the level of recovery exceeds five years, Eversource then proposes that WMECo recover the unrecovered balance over five years beginning in 2018 (Exh. ES-DPH-1, at 131).

C. Positions of the Parties

1. Attorney General

The Attorney General raises arguments regarding (1) the recovery of deferred costs through a replenishment factor, (2) recovery of carrying charges in a replenishment factor for storms in which Eversource incurs over $30.0 million in incremental O&M costs, which are not eligible for recovery through the storm fund, (3) recovery of lean-in costs, and (4) the proposed recovery of the outstanding storm cost balance. The Attorney General did not comment on the other aspects of the Companies' storm fund proposal.

First, the Attorney General asserts that Eversource should not be allowed to recover deferred costs for single storms in excess of $30.0 million through the proposed annual replenishment factor as a means to reduce the deferred storm fund balance (Attorney General Brief at 179). The Attorney General contends that the Department has not previously allowed electric distribution companies to recover deferred storm costs through a replenishment factor (Attorney General Brief at 179). Rather, the Attorney General states that the Department recently allowed National Grid to petition the Department for a replenishment factor only for storm costs that are eligible for storm fund recovery (Attorney General Brief at 179, citing D.P.U. 15-155, at 82). Finally, the Attorney General argues that denial of recovery of these deferred costs through a replenishment factor would not result in unlawful confiscation, because Eversource can seek recovery of individual storm

events with incremental O&M costs that exceed $30.0 million in its next base distribution rate case (Attorney General Brief at 179-180, citing Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 10 (1978); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 15-155-A at 15 (2017); D.P.U. 15-155, at 82).

Next, the Attorney General argues that carrying charges for deferred amounts that are not eligible for storm fund recovery should not be collected in the replenishment factor (Attorney General Brief at 180). The Attorney General asserts that the Department allows for collection of carrying charges for storm fund eligible events only, not for outlier storms for which incremental O&M costs exceed $30.0 million (Attorney General Brief at 180, citing D.P.U. 15-155-A at 15-16; D.P.U. 15-155, at 82-84). The Attorney General further argues that Eversource will not be harmed by not collecting carrying charges for outlier storms where incremental O&M costs exceed $30.0 million because the Companies can seek a prudence review of these storm costs between rate cases and can seek recovery of carrying costs in those reviews (Attorney General Brief at 181; citing D.P.U. 15-155-A at 15-16; D.P.U. 15-155 at 82). In addition, the Attorney General argues that Eversource can seek carrying costs in a Department prudence review of any outlier storm (Attorney General Brief at 181).

Additionally, the Attorney General contends that the Department should reject Eversource's request to recover lean-in costs associated with pre-staging crews through its storm fund for predicted ERP Type 3 or greater storm events that do not qualify for storm fund recovery (Attorney General Brief at 181). The Attorney General argues that, because

Eversource could neither identify when lean-in costs last occurred nor identify the dollar magnitude of any such costs, these costs are not extraordinary and do not require special recovery through the storm fund (Attorney General Brief at 182). Further, the Attorney General asserts that a Department approval to recover lean-in costs would create an incentive for Eversource to needlessly incur and inflate these costs (Attorney General Brief at 182).

Finally, the Attorney General recommends that the Department deny NSTAR Electric cost recovery for any purported storm fund under-recovery as well as any additional storms that may occur prior to new rates becoming effective on January 1, 2018 (Attorney General Brief at 183, citing Exh. ES-DPH-1, at 128). The Attorney General argues that Eversource provided no supporting evidence that it incurred $124,766,641 in incremental maintenance O&M costs for ten storms (Attorney General Brief at 182, citing Exh. ES-DPH-1, at 127 (Table DPH-1)). The Attorney General asserts that costs must be verifiable to be considered reasonable and prudent (Attorney General Brief at 183, citing Massachusetts Institute of Technology v. Department of Public Utilities, 425 Mass 856, 871-872 (1997)). Further, the Attorney General argues that Eversource presented certain storm costs in D.P.U. 16-74 and D.P.U. 17-51, which are currently pending prudence review (Attorney General Brief at 183). According to the Attorney General, Eversource acknowledged that the Department's review of D.P.U. 16-74 and D.P.U. 17-51 could affect the amount NSTAR Electric seeks for recovery from ratepayers for any under-recovery (Attorney General Brief at 183, citing Exhs. ES-DPH-1, at 127 (Table DPH-1); ES-DPH-5 (East); DPU-16-6).

2. Companies

Eversource disputes the Attorney General's argument that deferred costs for single storms greater than $30.0 million and associated carrying charges should be ineligible for recovery through replenishment factor (Companies Brief at 480, 482). Eversource states that the Attorney General did not cite to a Department standard that supported her contention that deferred costs are ineligible for recovery through the replenishment factor (Companies Brief at 480). In this regard, Eversource asserts that, in D.P.U. 15-155, the Department did not prohibit or otherwise indicate that deferred costs on storms over $30.0 million were ineligible for cost recovery through the replenishment factor (Companies Brief at 480). Further, Eversource argues that, absent a replenishment factor as proposed, multiple storms of significant magnitude could trigger the filing of a base distribution rate case (Companies Brief at 481). Thus, Eversource asserts that if recovery of multiple extraordinary storms is postponed, it would exacerbate bill impacts by pancaking (1) additional carrying charges that will accrue on the unrecovered balance, and (2) the base distribution rate increase that will result from the rate case (Companies Brief at 481, citing Exhs. ES-DPH-1, at 122; DPU-2-19; DPU-2-20; Tr. 5, at 1015). Eversource maintains that to avoid these negative impacts and maintain rate continuity, it should be allowed to recover these costs, subject to a prudence review and reconciliation, on an accelerated basis (Companies Brief at 481, citing Exhs. ES-DPH-1, at 122; Companies Reply Brief, App. C at 14, citing Exhs. DPU-2-19; DPU-2-20).

Eversource also argues that the Department has previously allowed the implementation of a replenishment factor where it benefits customers to reduce outstanding balances of storm costs developed over time due to the layering of storm events (Companies Brief at 481, citing Exh. DPU-2-19; Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 13-59 (2013)). Further, Eversource contends that the Attorney General's recommendation to not allow a replenishment factor is contrary to the Department's goals in D.P.U. 15-155 to reduce interest costs paid by customers (Companies Brief at 482, citing D.P.U. 15-155, at 84; Companies Reply Brief, App. C at 14). In this regard, Eversource argues that holding unrecovered costs on the balance sheet for an extended period would be a concern to credit rating agencies (Companies Brief at 482, citing Tr. 5, at 1017). As such, Eversource asserts that a credit downgrade could ultimately lead to higher capital costs that would ultimately be passed on to ratepayers (Companies Brief at 482).

Additionally, Eversource claims that the Department has previously decided that carrying charges are allowed on deferred storms, starting at the date of the storm event (Companies Brief at 482). According to Eversource, regardless of the magnitude of the storm event, the Companies still incur those costs and have a right to recover carrying charges on the incurred costs from the date of the storm event (Companies Brief at 482).

Next, Eversource asserts that the Attorney General's argument to reject Eversource's proposal to recover lean-in costs is baseless (Companies Brief at 483). Eversource notes that the Department has consistently placed a strong emphasis on pre-staging of external crews in preparation for a large storm, and has levied penalties for deficient response of such storms

(Companies Brief at 483; Companies Reply Brief, App. C at 15). Thus, Eversource contends that recovery of lean-in costs is consistent with the Department's storm response priorities (Companies Brief at 484, citing DPU-16-1; Companies Reply Brief, App. C at 15). Further, Eversource asserts that its lean-in proposal is consistent with recovery mechanisms in effect for two of the Companies' regional affiliates, CL&P and Public Service Company of New Hampshire (Companies Brief at 484, citing Exh. DPU-2-7; Companies Reply Brief, App. C at 15).

Eversource also argues that the Attorney General's contention that allowing the Companies to recover lean-in costs would improperly serve as an incentive to incur and inflate such costs is baseless (Companies Brief at 484-485). Eversource counters that, as lean-in costs are proposed for recovery through the storm fund, the Companies still would need to demonstrate that such costs were prudently incurred (Companies Brief at 485, citing Exhs. ES-DPH-1, at 124; DPU-2-10). Further, Eversource asserts that the incurrence of pre-staging lean-in costs for large-scale storm events that do not materialize is relatively rare (Companies Brief at 484, citing DPU-2-8; Tr. 5, at 992-1002). Eversource explains that there were no lean-in costs in the test year and, as a result, it does not have such costs currently embedded in base distribution rates (Companies Brief at 484, citing Exh. DPU-2-11, Tr. 5 at 997, 1005-1006). Should the Department approve collection of lean-in costs through the storm fund, however, Eversource commits to track such costs separately in order to demonstrate prudency of cost incurrence and eligibility pursuant to its

proposal on this matter (Companies Brief at 484, citing Tr. 5, at 1002-1004; Companies Reply Brief, App. C at 15).

Finally, Eversource asserts that the Department should disregard the Attorney General's arguments to reject the proposal to recover through base distribution rates NSTAR Electric's unrecovered storm balance (Companies Brief at 485). Eversource contends that the Attorney General's argument misstates the nature of the proposal (Companies Brief at 485). Eversource explains that it is not seeking Department approval in this proceeding of the storm costs at issue in D.P.U. 16-74 and D.P.U. 17-51, nor is Eversource seeking a determination of prudence regarding the incurrence of those costs (Companies Brief at 486; Companies Reply Brief, App. C at 15). Rather, Eversource asserts that under its proposal when the amount of storm costs is ultimately approved in D.P.U. 16-74 and D.P.U. 17-51, those costs will be recovered in accordance with the recovery parameters set in this case, i.e., over a period of five years beginning January 1, 2018 with interest at the prime rate from the date of the storm event (Companies Brief at 486). Further, Eversource notes that it is not seeking to recover storm costs related to other storm events that occur prior to January 1, 2018, without a prudence review (Companies Brief at 486-487). Eversource states that under its proposal it would begin recovery of the approved outstanding storm cost balance, and then amend the mechanism at a later date after any outstanding storms that occur prior to January 1, 2018 have been filed for review (Companies Brief at 487, citing Exh. DPU-50-1; Tr. 9, at 1817-1819).

D. Analysis and Findings

1. Introduction

The Department's primary objective for allowing a storm fund is to levelize storm restoration costs of major storms on ratepayers. D.P.U. 13-90, at 13, citing D.P.U. 10-70, at 201-202; D.P.U. 09-39, at 206; D.P.U. 15-155, at 73. The Department has recognized that the use of storm funds may shift the burden of cost recovery disproportionately to ratepayers without providing commensurate benefits. D.P.U. 13-90, at 13. As such, the Department has put all electric distribution companies on notice that if they seek continuation of a storm fund in their next base distribution rate case, they must demonstrate why the continuation of a storm fund is in the best interest of ratepayers D.P.U. 13-90, at 14-15.

2. Continuation of the Storm Fund

a. Introduction

The Department has devoted significant time and resources to the improvement of each electric utility's storm response. As a result, storm response requirements are now more formalized, more comprehensive, and more rigorous. See, e.g., G.L. c. 164, § 1J; 220 CMR 19.03 (setting forth standards for the acceptable performance for emergency preparation and restoration of service for electric and gas companies); NSTAR Electric Company, D.P.U. 11-85-B/11-119-B at 141 (2012) (imposing penalties for company's failure to timely respond to emergency wires-down calls and communicate effectively with municipal officials and customers); Western Massachusetts Electric Company, D.P.U. 11-119-C at 71-72, (2012) (imposing penalties for company's failure to restore service to its customers in a safe and reasonably prompt manner). In order to meet these requirements, electric

distribution companies are expected to properly prepare for and implement storm response measures that restore power safely and expeditiously. These obligations require Eversource to devote substantial resources to achieving the desired results. Further, as recent history indicates, the frequency and severity of major storm events has increased (see, e.g., Exhs. ES-DPH-2, Sch. DPH-21, at 2 (East); DPU-2-24, Att. (b) (outlining 21 major storm events between February 2010 and February 2016)). Not surprisingly, the costs of responding to those events have increased as well.

We acknowledge that NSTAR Electric's current storm fund mechanism has not provided the desired balance between cost recovery and rate stability. Specifically, the overall number of NSTAR Electric's major storm events in the past six years contributed to a large storm fund deficit that expanded even further due to the accumulation of a significant amount in carrying charges.[283] The number and magnitude of these storms could not have been anticipated when NSTAR Electric's storm fund mechanism was developed. As a result, without a storm fund mechanism, it is unlikely that during this time frame NSTAR Electric

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[283] As noted above, NSTAR Electric's storm fund balance since 2011 is $105.0 million (Exhs. ES-DPH-1, at 129; DPU-30-8). This includes related carrying charges. In the six years between 2011 through 2016, NSTAR Electric incurred a total of approximately $12.1 million in storm fund related carrying charges (Exh. DPU-50-1, Att. (a) at 2). For 2017, storm fund related carrying charges total approximately $4.1 million (Exh. DPU-50-1, Att. (a) at 2). In total, from 2011 through 2017, NSTAR Electric will have incurred approximately $16.2 million in carrying charges related to 14 outstanding storm fund events (ten storms currently under review in D.P.U. 16-74, two storms currently under review in D.P.U. 17-51, and Tropical Storm Irene and the October Snowstorm, which the Department reviewed in D.P.U. 13-52) (Exh. DPU-50-1, Att. (a) at 2). From January 2018 through December 2022, the total carrying charges associated with these same 14 storms is approximately $10.7 million (Exh. DPU-50-1, Att. (a) at 3).

could have absorbed these costs without filing a base distribution rate case, or even multiple rate cases, which could have resulted in an increase in rates to ratepayers for distribution costs other than storm fund costs.[284] Therefore, we find that, if properly structured, allowing NSTAR Electric and WMECo to continue to operate a storm fund can provide for adequate recovery of storm costs from customers in a manner that is designed to create rate stability. Moreover, because NSTAR Electric and WMECo plan to legally consolidate effective January 1, 2018, and based on the findings discussed below, we allow the Companies' storm fund to operate on a consolidated basis (see Exh. ES-DPH-1, at 115). See also D.P.U. 15-155, at 75-78.

b. Storm Fund Threshold

NSTAR Electric and WMECo each currently have separate storm fund thresholds. For NSTAR Electric, storms with incremental O&M expenses that exceed $1.0 million are eligible for storm fund cost recovery. NSTAR Electric recovers all incremental O&M storm costs, including the $1.0 million deductible (Exh. ES-DPH-1, at 114; Tr. 5, at 1017). WMECo currently has a $300,000 threshold for storm fund eligibility (Exh. ES-DPH-1, at 114). Unlike NSTAR Electric, however, the first $300,000 does not qualify for storm fund cost recovery; rather, WMECo recovers only the amounts above the $300,000 threshold through the storm fund (Exh. ES-DPH-1, at 114; see Tr. 5, at 1019). In addition to the previously noted increase in frequency and magnitude of storms, it also stands to reason that

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284 We note that WMECo's annual recovery through the SCCRA has allowed it to more timely recovery storm costs, which has provided it with greater rate stability (see Exh. ES-DPH-1, at 130-131).

overall storm restoration costs have increased since 2010. Thus, we find that it is appropriate to increase the cost-per-storm threshold to reflect the general increase in costs and to prevent including more routine future storms in the storm fund.

Here, Eversource proposes that a storm fund eligible event must meet a $1.2 million incremental O&M cost threshold, and that any costs falling below $1.2 million are not eligible for recovery through the storm fund (see Exh. ES-DPH-1, at 114-115). The Attorney General did not address Eversource's proposed storm fund threshold proposal.

The Department has reviewed the record and considered Eversource's derivation of the proposed $1.2 million cost-per-storm threshold (Exhs. ES-DPH-1, at 114-115; DPU-2-6). Specifically, Eversource adjusted its storm fund threshold by applying to the current threshold amount for NSTAR Electric's a cumulative inflation change factor based on application of the GDP-PI from the U.S. Bureau of Economic Analysis (Exh. ES-DPH-1, at 114).[285] The Department finds that this method is consistent with that approved in D.P.U. 15-155, at 77. Further, we find that the $1.2 million threshold for the consolidated storm fund represents an appropriate cost distinction between events that require a response using resources that are contemplated in base rates and those events that are larger in nature and involve resources beyond the level provided in base rates. As such, we approve

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[285] Eversource proposes only to adjust NSTAR Electric's deductible for inflation to establish the new threshold for the consolidated storm fund going forward and to eliminate WMECo's deductible as part of the conversion to a single storm fund (Exh. DPU-2-6). Thus, storms affecting only the western part of Massachusetts may not meet the threshold for storm-fund recovery as was the case in the past with WMECo's current threshold of $300,000 (Exh. DPU-2-6).

Eversource's proposal to apply a $1.2 million threshold to determine eligibility for storm fund recovery.

c. Annual O&M Expense

In D.P.U. 15-155, at 80, the Department determined that, given that the frequency of storm events varies significantly each year, the test year level of O&M costs associated with storm events were not necessarily representative of National Grid's future costs. Accordingly, we normalized the level of base distribution rate recovery to derive a more representative amount of the O&M expense associated with storm events. D.P.U. 15-155, at 80. Based on that evaluation, the Department determined that three storms represented a normalized number of annual storm-fund eligible events. D.P.U. 15-155, at 80.

Consistent with this determination, Eversource proposes to include for recovery in base distribution rates three storm fund eligible events per year, based on the proposed $1.2 million cost-per-storm threshold (Exh. ES-DPH-1, at 124-125). Eversource, therefore, proposes to include $3.6 million annually in base distribution rates to recover a representative level of the storm fund threshold that occurs each year ($1.2 million cost-per-storm threshold amount multiplied by three storm fund eligible storms per year) (Exhs. ES-DPH-1, at 125; ES-DPH-2, Sch. DPH-21, at 4 (East); ES-DPH-2, Sch.DPH-21, at 4 (West)).[286] Eversource proposes to allocate the $3.6 million annual amount to NSTAR Electric and WMECo on an 80/20 split, respectively (Exh. ES-DPH-1, at 125). Accordingly, using an 80/20 allocation

[286] Based on an average of 21 storms over a seven-year period (February 2010 – February 2016) during which these storms occurred (see Exh. ES-DPH-2, at 2 (East)).

of storm costs, Eversource proposes that NSTAR Electric annually collect $2.88 million in base distribution rates, and WMECo annually collect $720,000 in base distribution rates (Exhs. ES-DPH-2, Sch. DPH-21, at 4 (East); ES-DPH-2, Sch. DPH-21, at 4 (West)). The Attorney General did not address Eversource's proposal on this matter.

As the frequency and magnitude of storm events has varied significantly year-to-year, the Department recognizes that the test year level of O&M costs in base distribution rates is not necessarily representative of the Companies' future costs. Therefore, as in D.P.U. 15-155, at 80-81, we find it necessary to normalize the level of base distribution rate recovery to derive a more representative threshold amount for O&M expenses associated with storm events. The Department finds that Eversource's proposed annual collection of $3.6 million in base distribution rates, based upon recovery for three storm fund qualifying events per year and applying the $1.2 million cost-per-storm threshold, is reasonable and consistent with the method approved in D.P.U. 15-155, and, therefore, is approved. Further, the Department finds that Eversource's proposed 80/20 allocation ratio of the $3.6 million in base distribution rates is a reasonable cost allocation based on documented historical storm-fund eligible storm costs (Exhs. ES-DPH-1, at 125; ES-DPH-2, Sch. DPH-21, at 3, 4 (East); ES-DPH-2, Sch. DPH-21, at 3, 4 (West)). Therefore, the Department approves the 80/20 cost allocation of the $3.6 million annual O&M expense in base distribution rates ($2.88 million annually for NSTAR Electric and $720,000 annually for WMECo).

d. Annual Storm Fund Contributions Collected Through Base Distribution Rates

In aggregate, Eversource currently collects $5.075 million per year in annual base distribution rate contributions to the storm fund. Eversource proposes to increase the aggregate annual base distribution rate contribution to the storm fund by $4.925 million to $10.0 million (Exhs. ES-DPH-1, at 112, 116-118). Eversource states that the current annual storm fund contribution of $5.075 million is insufficient as compared to actual storm cost experienced for 21 storms in the six-year period since 2010 (Exh. ES-DPH-1, at 115-116). The Attorney General did not address the proposed annual storm fund collection amount.

A storm fund is intended to provide a level of rate stability for customers, but only if it actually allows for recovery of storm costs over time without requiring a change to customer rates. D.P.U. 15-155, at 78. As evidenced by the increased frequency and magnitude of storm fund eligible events since 2010, and the projected storm deficit balance if the current storm fund contribution and number and magnitude of storms remained the same, the current storm fund annual contribution of $5.075 million has proven to be insufficient to maintain rate stability (Exhs. ES-DPH-1, at 129; DPU-30-8). See, e.g., D.P.U. 15-155, at 178; D.P.U. 13-85, at 101, 106; D.P.U. 13-59. Thus, we conclude that an increase in the annual base distribution rate contribution to the storm fund is warranted.

Here, the Department seeks to establish a new annual contribution amount that would permit the Companies to recover storms costs over time without generating a surplus or

deficit balance in the storm fund that would exceed the proposed symmetrical cap.[287] We recognize the uncertainty in achieving this result given the unpredictable nature of weather in general, and storm fund qualifying events in particular. Further, we acknowledge that, while major historical storm events provide some perspective upon which to predict the possible frequency and magnitude of future storms, it is by no means sufficiently predictive with any real degree of certainty to definitively plan for future storm events. Notwithstanding these considerations, however, we conclude that, in the absence of better predictive information of future events, Eversource's storm fund history is instructive in the context of developing elements of a new storm fund.

The Department has reviewed the record supporting the proposed annual storm fund contribution by Eversource (see, e.g., Exhs. ES-DPH-1, at 116-119; DPU-2-26). In its review, the Department considered the number of storm fund qualifying storms that have occurred in the six-year period between 2010 and 2016, and storm fund qualifying storms in the test year (Exhs. ES-DPH-2, Sch. DPH-21, at 2 (East); ES-DPH-2, Sch. DPH-21, at 2 (West)). We also considered the individual storms during these time periods that were so extraordinarily high that they should be considered statistical outliers, and reviewed the storms that would not have been eligible for storm fund recovery had the $1.2 million cost-per-storm threshold been in effect (Exhs. ES-DPH-2, Sch. DPH-21, at 2 (East);

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287 The symmetrical cap is discussed in further detail below.

ES-DPH-2, Sch. DPH-21, at 2 (West)).[288] Additionally, we reviewed the calculation applied by Eversource as the basis to establish its proposed $10.0 million storm fund contribution amount, which we determine is consistent with the method approved in D.P.U. 15-155.[289] Based on these considerations, we find that Eversource's proposal to set the annual storm fund contribution at $10.0 million is reasonable and appropriate and will provide sufficient funds to levelize the rate impact for major storms that are eligible for cost recovery through the storm fund and decrease the likelihood that the storm fund will attain a large deficiency balance. Further, we find that Eversource's proposed allocation collection of the $10.0 million annual storm fund amount on an 80/20 allocation ratio ($8.0 million for NSTAR Electric and $2.0 million for WMECo) is a reasonable cost allocation ratio and is consistent with the ratio approved above for the annual O&M expense. Accordingly, we also approve this aspect of Eversource's proposal.

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288 We agree that it was appropriate for Eversource to remove approximately $92 million of combined incremental O&M expense from two extraordinary storms (October Snowstorm and Blizzard Nemo) that occurred in the six-year period between February 2010 and February 2016 in calculating its proposed annual storm fund contribution (see Exhs. ES-DPH-1, at 117; ES-DPH-2, Sch. DPH-21, at 2 (East); ES-DPH-2, Sch. DPH-21, at 2 (West)).

289 The Department acknowledges that Eversource's method for calculating its proposed annual storm fund contribution is consistent with that approved in D.P.U. 15-155 and, mathematically, produces an annual storm fund contribution of approximately $15.0 million (Exh. ES-DPH-1, at 115). The Department further acknowledges Eversource's proposal for a $10.0 million annual storm fund (as opposed to $15.0 million as produced mathematically) is an effort to maintain relative consistency with the $10.5 million annual storm fund contribution in base distribution rates approved by the Department for National Grid in D.P.U. 15-155 (see Exh. ES-DPH-1, at 117-118).

e. Storm Fund Cap

Neither NSTAR Electric nor WMECo currently has a storm fund cap in their current, respective storm funds. Eversource states that, in an effort to maintain consistency with the storm fund approved in D.P.U. 15-155, it proposes to implement a symmetrical storm fund cap of $30.0 million, which is the amount that the Department approved for National Grid (Exhs. ES-DPH-1, at 121, citing D.P.U. 15-155, at 82; DPU-2-4). Eversource states that, due to the uncertainty of future storms and storm fund activity, it ultimately decided to maintain consistency with the Department's decision in D.P.U. 15-155 for this aspect of storm fund design (Exh. DPU-2-4).

In D.P.U. 15-155, at 82, the Department found that a symmetrical cap of $30.0 million on the storm fund balance was appropriate to minimize the potential for frequent rate changes (either positive or negative), and to realign the risks associated with storm cost recovery to protect ratepayers' interest. As a general matter, there is an uncertainty regarding the frequency and magnitude of the storms that could affect the Eversource service territory. For this reason, and in an effort to prevent the storm fund from falling into a significant deficit as a result of a single major storm event, we find it appropriate to exclude from storm fund eligibility any single storm event that exceeds $30.0 million in incremental costs (exclusive of costs for which Verizon is responsible under a joint operating agreement). Consistent with the Department's finding in D.P.U. 15-155-A at 18, Eversource has the option to seek a deferral of storm costs that exceed $30.0 million until its next base distribution rate case. Alternatively, Eversource may seek cost recovery

for storms in excess of $30.0 million through the exogenous cost provision of the PBR mechanism approved in this proceeding (see Section IX.D.5.e above).

f. Carrying Charges

Eversource seeks to accrue interest for storm fund eligible events at the prime rate commencing at the start date for the storm event (Exh. ES-DPH-1, at 112-113, 121). Eversource also proposes to accrue interest at the prime rate beginning on the date of the storm event on the deferred incremental costs of storms in excess of the $30.0 million cap (Exh. ES-DPH-1, at 112-113, 120-121).

In D.P.U. 15-155-A at 15-16, the Department allowed for accrual of interest (at the prime rate) for storm events that are eligible for recovery under the storm fund to begin at the time that the costs are incurred.[290] The Department made this finding to ensure that the accrual of interest provides for adequate recovery of storm costs from customers in a manner that is designed to create rate stability. See D.P.U. 15-155-A at 15. We see no reason to depart from that finding in the instant case. Therefore, we decline to accept Eversource's proposal and instead approve the accrual of interest at the prime rate beginning at the time the costs are incurred for storm events that are eligible for recovery under the storm fund (i.e., storms with incremental O&M costs above the $1.2 million cost-per-storm threshold,

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290 In D.P.U. 15-155-A, at 15-16, the phrase "at the time that costs are incurred," means the date upon which National Grid was billed for storm cost recovery. In other words, the Department allowed National Grid to begin accruing interest on storm fund eligible events pursuant to the storm fund on the date National Grid incurred costs as a result of billing. Such accrual is consistent with the operation of National Grid's storm fund that was in place prior to the Department's Order in D.P.U. 15-155. See D.P.U. 15-155-A at 15-16.

but below $30.0 million). Similar to the Department's directives in D.P.U. 15-155-A, Eversource may begin to accrue carrying charges at the prime rate for storm fund eligible events when it is billed for storm cost recovery.

In D.P.U. 15-155, while National Grid sought in its initial proposal to have the Department apply the weighted average cost of capital for carrying charges associated with storms both in the storm fund and for those storms in excess of the storm fund, the Department declined to address the issue of whether to allow carrying charges for a storm event where the incremental O&M expense exceeds $30.0 million. D.P.U. 15-155, at 82, 84. Similarly, in reconsidering storm fund issues in that proceeding, the Department determined it appropriate only to address individual storm events with incremental O&M costs that exceed $30 million with respect to the permissive "may" found in the Order at 82 to mean that a company has the option to seek a deferral if it chooses to file for one. D.P.U. 15-155-A at 18. Further, consistent with our findings with respect to storm fund-eligible costs, the Company may seek, in between rate cases, a prudence review of storm costs associated with any storm event where incremental O&M costs exceed $30 million. D.P.U. 15-155-A at 18.

Here, the Companies question as to carrying charges for storms that exceed $30.0 million. To that end, the Department clarifies that it will consider the recovery of carrying charges for such large scale storms only after it has had an opportunity to fully investigate the circumstances surrounding the incurrence of the costs to which the carrying charges are proposed to be applied. Thus, the propriety of recovering carrying charges for

storms in excess of $30.0 million will be determined when the Companies file with the Department for storm cost recovery.

In such a filing, the Department will seek to verify that the costs were prudently incurred, and fully compliant with the Companies' obligations to restore service, consistent with G.L. c. 164, §§ 1J, 85B, 76, 220 CMR 19.00 et seq., and Final Revised Emergency Response Plan Guidelines for Electric Companies, D.P.U. 14-72-A (2015). In such a review, the Department will expect the Companies to show that they have met all performance standards for emergency preparation and restoration of service, including restoring service to customers in a safe and reasonably prompt manner during a qualifying emergency event where widespread outages have occurred due to storms or other causes beyond the control of the Companies. The Companies will be expected to show contact with and prioritization of power restoration for customers with documented needs, designated and maintained communications and communication protocols with local emergency management officials and relevant regulatory agencies, provisions for adequate staffing and deployment and any necessary mutual aid preparations, and the proper identification of additional supplies and equipment during such an emergency event. If the Department determines that a material deficiency exists in the emergency response plan or the Companies' implementation of its emergency response plan, the Department may deny the recovery of all, or any part of, the service restoration costs, commensurate with the degree and impact of the service outage. G.L. c. 164, § 85B.

g. Replenishment Factor

Eversource proposes that if the combination of the single storm deferral balance exceeds $75.0 million (i.e., the total sum of all single storms in excess of $30.0 million exceeds $75.0 million and/or the balance in the storm fund exceeds $75.0 million), it may file for a "replenishment" factor to reduce the outstanding unrecovered storm fund balance, and minimize carrying charges (Exh. ES-DPH-1, at 123). The Companies further assert that there is Department precedent for a replenishment factor in D.P.U. 13-59 (Company Brief at 481, citing D.P.U. 13-59). The Attorney General asserts that the Department has not previously allowed for a replenishment factor for costs outside of the storm fund (Attorney General Brief at 179). Moreover, she argues that, consistent with D.P.U. 15-155, Eversource may seek cost recovery of individual storms with incremental storms in excess of $30.0 million in its next base distribution rate case (Attorney General Brief at 180).

The Department's Order in D.P.U. 13-59, at 11, allowed for the replenishment of an existing storm fund deficit resulting from 14 extraordinary storms that occurred three years prior to the replenishment factor request. In other words, the replenishment request approved in D.P.U. 13-59 was based on a specific storm fund deficit amount resulting from specific historical storms. Conversely, in the instant proceeding, Eversource seeks pre-authorization to request replenishment of a storm fund deferral balance that may or may not occur in the future (see Exh. ES-DPH-1, at 113). Nevertheless, the Department is not convinced that pre-authorizing Eversource to file for replenishment recovery (albeit pending Department prudence review) based upon a pre-defined deferral balance is definitively in the

best interest of ratepayers. Rather than authorizing the Companies to file a replenishment factor, the Companies may seek cost recovery through the exogenous cost provision of the PBR (pending a prudence review) provided that the combination of any single storm in excess of $30.0 million and balance of the storm fund exceed $75.0 million.

h. Lean-In Costs

Eversource proposes to recover lean-in costs associated with pre-staging crews for forecasted Type 3 and greater ERP storm preparation activities regardless of whether such storms come to fruition (Exh. ES-DPH-1, at 113,123-124). Eversource states that, in the test year there were no pre-staging (i.e., lean-in) expenses for anticipated storm fund qualifying events that did not materialize (Exh. DPU-2-8).[291] Further, Eversource states that it is relatively infrequent that forecasted large scale storm events do not end up materializing (Exh. DPU-2-8). Additionally, Eversource could not identify specific storms and estimated lean-in costs over the past five years because it does not currently track lean-in costs separately from overall storm costs (Exh. DPU-2-11). In the absence of historical lean-in cost documentation, Eversource provided a hypothetical example of the types and magnitude of lean-in costs for a storm event (Exh. DPU-2-11, Att.).

The Department concludes that, based upon the lack of actual, historical lean-in cost documentation showing that the Companies pre-staged third-party contractors but no storm ultimately materialized, there is an insufficient basis upon which to approve lean-in cost recovery. There is no evidence upon which to determine that lean-in costs may be

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[291] Eversource applies the terms “pre-staging costs” and “lean-in costs” interchangeably (Tr. 5, at 994).

sufficiently significant to warrant consideration of recovery of these costs. Because of the high degree of uncertainty regarding these costs, the Department is not persuaded they are an appropriate part of the storm fund. Based on the foregoing, the Department rejects Eversource's proposal to recover lean-in costs through the storm fund. The Department may, however, in a future base distribution rate proceeding, consider allowing these costs for recovery through the storm fund if Eversource can provide sufficient documentation of the type and level of costs incurred.

3. Recovery of Remaining Storm Balance

Eversource proposes to recover all unrecovered storm costs occurring prior to January 1, 2018 through separate reconciling factors for NSTAR Electric and WMECo. Specifically, for NSTAR Electric, the Companies propose recovery of costs from ten unrecovered storm events to date, at a cost of approximately $105.0 million over a period of five years, plus any new storm fund eligible costs that have occurred prior to January 1, 2018 (Exhs. ES-DPH-1, at 128-129; DPU-30-8). For WMECo, Eversource proposes to continue recovery at the level currently recovered in the SRRCA of the outstanding storm balance through a reconciling factor, anticipated to be fully recovered by December 31, 2019, pending no new storms (Exh. ES-DPH-1, at 130-131). The Attorney General argues that Eversource provided no supporting evidence that it incurred $124,766,641 in incremental O&M costs for ten storms events, which are pending review in D.P.U. 16-74 and D.P.U. 17-51 (Attorney General Brief at 182-183).

The intent of the storm fund analysis in the instant proceeding is to determine the mechanics of storm cost recovery on a going-forward basis. It is not intended for the Department to determine the prudency of cost incurrence related to the ten storms under review in D.P.U. 16-74 and D.P.U. 17-51. Therefore, the Department will not consider in this proceeding the Attorney General's assertion that cost recovery related to these ten storms is inappropriate. Such cost recovery will be more appropriately determined in D.P.U. 16-74 and D.P.U. 17-51.

That said, the Department finds Eversource's proposal to recover the outstanding storm balances for both NSTAR Electric and WMECo through separate reconciling mechanisms over five years is reasonable and appropriate, subject to required prudence reviews and reconciliation.[292] Doing so will allow NSTAR Electric to begin recovering its significant outstanding storm balance, but subject to required prudence reviews and reconciliation, and will allow WMECo to continue recovering storm-related costs through its annual reconciliation factor. The Department will address the Companies' proposal to merge the storm cost recovery reconciliation mechanisms for NSTAR and WMECo, effective January 1, 2019, in our subsequent Order addressing rate design issues.

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[292] Consistent with our findings above regarding the timing of accrual of carrying charges, NSTAR Electric may accrue carrying charges on its outstanding storm fund balance at the prime rate from the time NSTAR Electric is billed for storm cost recovery. WMECo is allowed to accrue carrying charges on its outstanding storm fund balance at the customer deposit rate from the time WMECo is billed for storm cost recovery (see DPU-2-27). D.P.U. 10-70, at 201.

4. Storm Fund Reporting

In an effort to allow for the Department's expedited and efficient review of Eversource's storm-cost filings while also allowing for an evaluation of the prudency of such costs, the Department establishes the following storm reporting requirements. Consistent with the Department's directives in D.P.U. 15-155, Eversource must submit to the Department, no later than six months after the occurrence of a storm fund qualifying event, a preliminary report providing: (1) a detailed explanation of the storm event; (2) a detailed summary of the costs broken-down by cost category; (3) the amount of carrying costs incurred to date; and (4) a detailed summary of anticipated additional costs to be incurred or finalized, including an estimated timeframe for the receipt of outstanding cost information or final cost accounting. D.P.U. 15-155-A at 16-17.[293] Eversource thereafter will provide a quarterly update on the status of finalizing the accounting of storm costs. The Department's expectation is that Eversource will submit a petition for recovery of storm costs, including complete and final documentation and supporting testimony, as soon as practicable after finalizing the storm costs, and no later than six months after such costs are finalized. To the extent that Eversource is unable to prepare a final accounting of storm costs, along with relevant supporting testimony and complete and full documentation to facilitate a full administrative review, within six months of a storm event, the Eversource is directed to file a petition for storm-cost recovery as soon as such information is complete.

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[293] This filing requirement does not relieve Eversource of its obligation to make necessary storm-related filings consistent with other Department directives (e.g., reports concerning emergency preparedness and restoration of service under 220 CMR 19.03(4)).

E. Conclusion

Based on the above findings, the Department directs Eversource to implement its storm fund with the modifications set forth herein. The modified storm fund shall apply to any qualifying storms that occur on or after January 1, 2018. The outstanding storm fund balance for both NSTAR Electric and WMECo shall be recovered consistent with the findings above.

XIV. VEGETATION MANAGEMENT PROGRAM

A. Introduction

In its filing, the Companies propose to implement a vegetation management resiliency tree work pilot program to take place in two stages, the first beginning in 2017 ("2017 Pilot"), and the second taking place between 2018 and 2022 ("2018-2022 Pilot") (collectively, "Vegetation Management RTW Pilot") (Exhs. ES-VLA-1, at 20-27; ES-DPH-3 (East), WP DPH-15, at 1; ES-DPH-3 (West), WP DPH-15, at 1). Through the Vegetation Management RTW Pilot, the Companies propose to complete resiliency tree work ("RTW") that includes expanded application of enhanced tree trimming ("ETT"), hazard tree and risk tree removals, additional mid-cycle pruning, and the deployment of mobile light imaging, detection and ranging ("LiDAR") to assist the Companies with mid-cycle pruning (Exh. ES-VLA-1, at 20).[294] The Companies also propose to recover an annual amount for vegetation management costs and to capitalize certain vegetation management expenditures

[294] LiDAR, as the Companies intend to utilize it, is an inspection tool that catalogs tree density and the proximity of vegetation to the Companies' distribution facilities (Exh. ES-VLA-1, at 20; Tr. 5, at 925).

for the initial cycle implementing ETT (Exh. ES-VLA-1, at 12, 16-17). The Department reviews these proposals below.

B. Enhanced Vegetation Management Pilot

1. Introduction

As of 2015, NSTAR Electric and WMECo combined their vegetation management programs into a single, unified plan called the "Eversource Maintenance Program 5.60 Vegetation Management - Distribution Maintenance Program" ("Eversource VM Program") (Exh. ES-VLA-1, at 8-9). Eversource performs vegetation management activities on the NSTAR Electric and WMECo distribution systems on a consolidated basis, and designates the service areas as Eversource East (NSTAR Electric's service territory) and Eversource West (WMECo's service territory), respectively (Exh. ES-VLA-1, at 8). Eversource states that the Eversource VM Program incorporates provisions of NSTAR Electric and WMECo's former programs in compliance with Department directives (Exh. ES-VLA-1, at 9, citing NSTAR Electric Company, D.P.U. 11-85-B/11-119-B (2012), D.T.E. 06-55). Eversource notes, however, that the work it performs in Eversource East and Eversource West differs because, historically, NSTAR Electric and WMECo executed different vegetation management plans (Exh. ES-VLA-1, at 9).[295] Eversource asserts that its

[295] For example, prior to 2015, Eversource West performed full-scale, blue-sky enhanced ETT on selected segments with an annual budget of $2.5 million for both ETT and enhanced tree removal ("ETR"), resulting in approximately 25 miles of annual ETT work (Exh. ES-VLA-1, at 13). Eversource East performed ETT on all primary sections of the circuit; however, it did so at a 10 x 10 x 15 clearance because ground to sky clearance was unlikely to be approved (Exh. ES-VLA-1, at 14). Prior to 2015, Eversource East had an annual budget of $14.5 million for both ETT and ETR, allowing for approximately 1,850 miles of annual work (Exh. ES-VLA-1, at 13-14).

proposed vegetation management pilot, discussed below, will allow it to achieve a comparable level of vegetation management in both Eversource East and Eversource West (Exh. ES-VLA-1, at 9).

2. Current Vegetation Management Program

NSTAR Electric began performing enhanced vegetation management work in certain areas in 2012 (Exh. ES-VLA-1, at 11). Following Department directives in D.P.U. 11-85-D/11-119-B, NSTAR Electric increased the number of miles for program pruning to meet a four-year cycle for all distribution circuits (Exh. ES-VLA-1, at 11). NSTAR Electric also increased the clearance zone around the distribution primary to an ETT specification, set at 10' x 10' x 15', to the side, under, and above the lines, respectively (Exh. ES-VLA-1, at 11-12).[296] In addition, NSTAR Electric developed an enhanced tree removal component ("ETR") to target the removal of risk and hazard trees, which it conducted in parallel scheduled miles based on a four-year cycle (Exh. ES-VLA-1, at 12). Additionally, NSTAR Electric targeted "blue sky" clearance for poor performing areas with approval by municipal tree-wardens (Exh. ES-VLA-1, at 12). Finally, NSTAR Electric began maintaining a forestry database to track the number of hazard trees removed and associated costs, by circuit (Exh. ES-VLA-1, at 12).

As of 2015, in addition to the work above, the Companies have implemented the consolidated Eversource VM Program, which consists of two aspects (Exh. ES-VLA-1,

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[296] The primary distribution system consists of the feeders emanating from the substation and supplying power to one or more secondary distribution systems.

at 9-10). First, Eversource established trim cycle to ensure that all circuits are trimmed at least once every four years, subject to circuit specific considerations and regardless of current performance (Exh. ES-VLA-1, at 10). Eversource uses a minimum standard clearance specification for the maintenance trims, called the scheduled maintenance trim ("SMT"), at 8' x 8' x 12', to the side, below, and above the lines, respectively (Exh. ES-VLA-1, at 11). Eversource performs this work annually, and books it as an O&M expenditure (Exh. ES-VLA-1, at 11). Eversource also uses reliability-based prioritization methods, identifying the need for mid-cycle trimming or other actions to address poor performing distribution circuits (Exh. ES-VLA-1, at 10).

Second, Eversource executes a hazard tree removal program to identify and target hazard trees for removal, which it coordinates with the cycle-pruning schedule (Exh. ES-VLA-1, at 10).[297] In addition, Eversource identifies and targets risk trees for removal (Exh. ES-VLA-1, at 10).[298] Eversource states that it evaluates risk and performs hazard tree removals on off-cycle circuits in order to mitigate poor performing circuits (Exh. ES-VLA-1, at 10).

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[297] A hazard tree, as defined by the International Society of Arboriculture, is one that is sufficiently large enough to cause damage if it fell, has a target should it fall, and has a condition that makes it likely it will fall (Exh. AG-20-43, at 1).

[298] Risk trees, in addition to obviously dead or dying trees, are trees that exhibit signs of decay, insect damage, or structural deformities(Exh. ES-VLA-3, at 4). They also include incompatible species, such as small-diameter trees and especially fast growing weed trees, which are located underneath the distribution lines (Exh. ES-VLA-3, at 4).

Eversource uses arborists to conduct field reviews and, during routine audits of vegetation management work performed on its system, requires contractors to complete any necessary re-work for no additional cost (Exh. ES-VLA-1, at 14-15). During the test year, the Companies trimmed 2,090 overhead circuit miles in Eversource East (out of 7,946 overhead primary miles) and 847 overheard circuit miles in Eversource West (out of 3,270 overheard primary miles) (Exh. ES-VLA-1, at 15). In 2016, Eversource spent approximately $23.5 million on vegetation management (Exh. AG-20-31 (b)).

3. Companies Proposal

a. Vegetation Management Resiliency Tree Work Pilot Program

Eversource proposes to implement a vegetation management resiliency tree work pilot program in two stages: a 2017 RTW Pilot and a 2018-2022 Pilot (Exhs. ES-VLA-1, at 20-27; ES-DPH-3 (East), WP DPH-15, at 1; ES-DPH-3 (West), WP DPH-15, at 1). Through the Vegetation Management RTW Pilot, the Companies will complete RTW that includes expanded application of ETT, hazard tree and risk tree removals, and additional mid-cycle pruning (Exhs. ES-VLA-1, at 20-27; ES-DPH-3 (East), WP DPH-15, at 1; ES-DPH-3 (West), WP DPH-15, at 1). The Vegetation Management RTW Pilot includes a RTW trimming specification that the Companies will use on circuits considered "at risk" for reliability (Exh. AG-11-14). The RTW specification is different from ETT and SMT, and is 15 feet to the side of the wire and 25 feet above the wire, expanding the clearance zone (Exh. AG-11-14). The Companies propose that the 2017 RTW Pilot will serve as a proof of concept, with the 2018-2022 RTW Pilot serving as an expansion of the initiatives based on the Companies' experience (Exh. ES-VLA-1, at 20). The Companies will implement the

Vegetation Management RTW Pilot as a single, consolidated program operated in both Eversource East and Eversource West service territories, because Eversource has fully integrated NSTAR Electric and WMECo from a management and operational perspective (Exh. ES-VLA-1, at 26-27). The Companies state these initiatives will complement existing tree work and focus on improving reliability and storm resiliency (Exh. ES-VLA-1, at 20).

For the 2017 RTW Pilot, Eversource proposes to deploy a LiDAR unit for its mid-cycle prune (Exh. ES-VLA-1, at 20). Currently, the mid-cycle pruning is a reliability-based strategy that Eversource uses to address emerging poor performing circuits and "hot spots" (Exh. ES-VLA-1, at 20). Eversource states it will deploy the mobile LiDAR unit to patrol and inspect distribution primary on poor performing circuits to identify where mid-cycle pruning is warranted (Exhs. ES-VLA-1, at 20; AG-20-27). Eversource intends to use LiDAR to prioritize geographic areas for removals, which will then take place after an independent condition assessment indicates the removal is warranted (Exh. ES-VLA-Rebuttal at 4).[299] Eversource states that the information will aid arborists in the final decision of priority (Exh. ES-VLA-1, at 21).[300] Eversource intends to focus on backbones and selected laterals with high customer counts or critical facilities and locations where towns have placed restrictions on vegetation clearance (Exh. ES-VLA-1, at 21). Eversource estimates that the total cost for the 2017 RTW Pilot is $3,521,000, which includes LiDAR inspection and

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[299] The LiDAR unit will use software to analyze the distance between trees and primary facilities and categorize this analysis by priority (Exh. ES-VLA-1, at 21).

[300] Eversource proposes that arborists will view photographs of the conditions captured by LiDAR to aid in determining priority (Exh. ES-VLA-1, at 21).

analysis, mid-cycle pruning identified by such analysis, and software and hosting fees (Exh. ES-VLA-1, at 22, Table ES-VLA-5). The cost breakdown of the 2017 RTW Pilot is as follows: $476,000 for LiDAR inspection; $100,000 for LiDAR analysis; $2,875,000 for mid-cycle prune; and $70,000 for software and hosting (Exhs. ES-VLA-1 at 22, Table ES-VLA-5; ES-DPH-3 (East), WP DPH-15, at 1; ES-DPH-3 (West), WP DPH-15, at 1).

For the 2018-2022 RTW Pilot, Eversource proposes to increase mid-cycle pruning, RTW tree trimming activities, and RTW tree removals at an estimated total annual cost of $25,950,000 (Exh. ES-VLA-1, at 23, Table ES-VLA 6). The Companies plan to extend ETT RTW tree trimming clearing to select laterals serving 100 customers or more or to laterals that serve critical infrastructure needs, increasing the annual target of circuits to be trimmed from 25 miles to 100 miles (Exh. ES-VLA-1, at 23). Additionally, Eversource also plans to undertake aerial LiDAR inspection of the entire service territory in order to catalog tree density and proximity to distribution facilities, as well as commission a study by an independent third party to survey service areas and perform a condition assessment of the trees in proximity to the distribution system (Exh. ES-VLA-1, at 24-25). Eversource estimates the costs of the LiDAR inspection and related study to be $5.9 million (Exh. ES-VLA-1, at 25). The cost breakdown of the 2018-2022 RTW Pilot is as follows: $4.72 million annually for enhanced mid-cycle pruning, $5.0 million annually for RTW tree trimming, $15.05 million annually for expanded hazard tree assessment and removal, and an annualized $1.18 million cost based upon the $5.9 million total for LiDAR inspection and the related study expenses (Exhs. ES-VLA-1, at 22, Table ES-VLA-6; ES-DPH-3 (East),

WP DPH-15, at 1; ES-DPH-3 (West), WP DPH-15, at 1). The Company states the budget for the Vegetation Management RTW Pilot is based on an assessment of forestry challenges on the system, using U.S. forestry statistics and the average costs of removal experienced by Eversource (Exh. ES-VLA-Rebuttal at 2-3).

b. Vegetation Management RTW Pilot Cost Recovery

Eversource proposes to recover both the 2017 RTW Pilot costs and the 2018-2022 RTW Pilot costs over five years through base rates (Exhs. ES-DPH-1, at 78; ES-DPH-3 (East), WP DPH-15, at 1; ES-DPH-3 (West), WP DPH-15, at 1).[301] Eversource proposes a cost split between NSTAR Electric and WMECo of 85 percent and 15 percent, respectively, subject to reconciliation and a refund of any cost over recovery at the time of Eversource's next base rate proceeding (Exhs. ES-DPH-1, at 78; ES-DPH-3 (East), WP DPH-15, at 2; ES-DPH-3 (West), WP DPH-15, at 2).[302] Although the Eversource proposes to fund the Vegetation Management RTW Pilot separately through base rates of both NSTAR Electric and WMECo, Eversource states that the program will be implemented, operated, and managed on a consolidated basis (Exh. ES-DPH-1, at 80).

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301 Eversource states that its Vegetation Management RTW Pilot is a combination of one-time, non-recurring activities, and annually recurring expenses (Exh. ES-DPH-1, at 79). As such, Eversource proposes to normalize the costs in base rates to spread the "one-time" costs over time. Eversource further proposes recovery of the Vegetation Management RTW Pilot fixed costs through base rates via a reserve fund (Exh. ES-DPH-1, at 79).

302 Costs are split between NSTAR Electric and WMECo, 85 percent and 15 percent, respectively, based on the customer allocator (Exh. ES-DPH-1, at 77).

4. Positions of the Parties

a. Attorney General

The Attorney General argues Eversource undertook the 2017 RTW Pilot absent Department approval, and that the 2017 RTW Pilot and 2018-2022 RTW Pilot lack any meaningful measuring stick or a cost-benefit analysis (Attorney General Brief at 168-170, citing Exh. AG-20-27; Tr. 5, at 934). The Attorney General argues that doubling Eversource's vegetation management budget to almost $50 million annually does not guarantee improved reliability (Attorney General Reply Brief at 43, citing Exh. AG-11-14).[303] Further, the Attorney General contends that the cost increase associated with the 2018-2022 RTW Pilot alone is $2 million more than the entire 2016 distribution vegetation management program (Attorney General Brief at 169). The Attorney General asserts that while the Department has recognized that more aggressive storm resiliency programs may be a worthwhile step in strengthening a distribution system, the Companies misconstrue the Department's policy position as one that is in favor of aggressive storm

[303] According to the Attorney General, in Rhode Island National Grid is spending less money on vegetation management per circuit mile pruned than both NSTAR Electric and WMECo, yet National Grid has ranked in the first-quartile since 2012 (Attorney General Brief at 165-166, citing Exh. AG-GLB-1, at 26). Thus, the Attorney General asserts that rather than proposing to double its annual vegetation management spending, Eversource should be looking for ways to economize and perform its vegetation management program activities more efficiently, similar to National Grid's efforts in Rhode Island (Attorney General Brief at 166).

resiliency programs (Attorney General Reply Brief at 44, citing Companies Brief at 569, D.P.U. 15-155, at 328).[304]

The Attorney General also argues that Eversource does not have a service reliability problem, and that the Vegetation Management RTW Pilot is an expensive solution to a non-existing vegetation management problem (Attorney General Brief at 171). In this regard, the Attorney General asserts that Eversource maintained first-quartile SAIDI and SAIFI rankings before even beginning the 2017 RTW Pilot (Attorney General Brief at 168). Additionally, the Attorney General argues that the Companies are unable to substantiate whether the wider clearing zones employed in the Vegetation Management RTW Pilot will result in enhanced reliability (Attorney General Reply Brief at 44, citing Attorney General Brief at 168, Exh. AG-11-14). Accordingly, the Attorney General recommends that the Department deny Eversource's request for the recovery of the proposed Vegetation Management RTW Pilot costs (Attorney General Brief at 169, 171).

Further, the Attorney General asserts that Eversource does not need LiDAR or a commissioned study to understand the vulnerabilities of its distribution system (Attorney General Brief at 170). The Attorney General argues that LiDAR is an expensive, superfluous technology, which does little to add to the work of Eversource's engineers and arborists in identifying risk and hazard trees (Attorney General Brief at 173). Moreover, the

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304 The Attorney General points to differences in National Grid's vegetation management programs that were in place at the time the Department directed National Grid to propose a storm resiliency program (Attorney General Reply Brief at 44). Specifically, she argues that National Grid was on a five-year trimming cycle and the minimum clearing distances for 6 x 10 x 10, while Eversource currently is on a four-year cycle pruning to ETT clearance (Attorney General Reply Brief at 44-45).

Attorney General asserts that Eversource is uncertain whether LiDAR will save on operation and maintenance cost or whether LiDAR's static images have any intrinsic value to the Eversource's other departments or divisions (Attorney General Brief at 173, citing Tr. 5, at 969; Attorney General Reply Brief at 47). The Attorney General recommends that the Department deny the Eversource's request to recover the costs associated with any of the proposed LiDAR technology (Attorney General Brief at 173).

b. Cape Light Compact

Cape Light Compact argues that Eversource should issue RFPs from trees service companies on a frequent basis to drive vegetation management costs down (Cape Light Compact Brief at 80, citing Exh. AG-GLB-1, at 28). Cape Light Compact further maintains that Eversource should improve communications with municipal officials in advance of major roadway vegetation clearing work, having recognized the importance of those communications (Cape Light Compact Brief at 81, citing Exh. ES-VLA-3, at 9).[305]

c. UMass

UMass reiterates its support for Eversource expanding its current vegetation management program (UMass Brief at 16, citing Tr. 5, at 943-944). UMASS, however, maintains it is concerned that the proposed Vegetation Management RTW Pilot will exacerbate what it sees as inequities between the Companies' Eastern and Western service territories, specifically Eversource not giving due attention to the Western service territory

[305] Cape Light Compact also argues Eversource should reject the use of the herbicide glyphosate in its rights of way (Cape Light Compact Brief at 81, citing D.P.U. 17-05, Letter of Steven Auerbach (April 27, 2017)). The issue of herbicide use is outside the Department's jurisdiction and, therefore, we do not address this argument raised by Cape Light Compact. See 333 CMR 11.

(UMass Brief at 16-17). UMass contends that more attention for the Eversource Western service territory's vegetation management is required, and it argues that there is no dispute that the numerous outages and other adverse events on the Western service territory have been caused by trees (UMass Brief at 17).[306]

d. Companies

Eversource asserts there are two fundamental reasons why the Department should approve implementation of the Companies' proposed Vegetation Management RTW Pilot (Companies Brief at 131). First, Eversource contends it has long taken proactive steps to enhance and protect its distribution system (Companies Brief at 131). Second, Eversource argues that resilient grid infrastructure is necessary as a foundation for an increasingly modernized grid (Companies Brief at 131, citing Exhs. ES-VLA-1, at 17-18; AG-11-14).

Eversource contends that its system infrastructure is unavoidably exposed to weather events, and vulnerable in the types of harsh conditions that occur with ice storms, heavy wet snow, tropical storms, hurricanes, and other wind events that cause substantial damage and prolonged power outages (Companies Brief at 131, citing Exhs. ES-VLA-1, at 17-18; AG-11-14). Further, Eversource asserts that without a resilient grid, real-time sensing and

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306 UMASS also argues that the Department should recognize the large magnitude of a problem that loss on transmission line due to inadequate vegetation management has on customers and that Eversource should holistically consider the entire electric system in developing and implementing an enhanced vegetation management plan (UMASS Brief at 17-18). The Department does not have jurisdiction over transmission investments in this proceeding. See Harbor Electric Energy Company, D.P.U. 15-157 at 15, 17-18 (2016) (noting that local distribution facilities are subject to the Department's jurisdiction, while transmission facilities are subject to the Federal Energy Regulatory Commission's jurisdiction). Therefore, we will not address this issue any further.

monitoring investments made as part of a grid-modernization program are rendered moot, because the grid would be lacking sufficient foundation to optimize the use of the modern equipment (Companies Brief at 131, citing Exhs. ES-VLA-1, at 17-18; AG-11-14).

Eversource does not dispute that it is a top tier utility in reliability performance or that changes to vegetation management practices in its Western service territory have resulted in improved reliability (Companies Brief at 565, citing Attorney General Initial Brief at 165; Exh. ES-VLA-1 at 13-14). Eversource argues, however, that revised service quality guidelines require constant improvement (Companies Brief at 565, citing Exh. ES-VLA-1, at 7). Eversource contends that meeting these increased performance levels will require innovation and investment given the Companies' already high level of reliability on the distribution system (Companies Brief at 565, citing Exh. ES-VLA-1, at 7; Companies Reply Brief at 168-169). Eversource also asserts that the Attorney General's recommendations that the Companies cut costs is not in line with service quality standards and ignores that increased spending is necessary to maintain high reliability and in turn maintain its performance levels (Companies Brief at 565-566; Companies Reply Brief at 169).[307]

In response to the Attorney General's recommendation that the Department deny 2017 RTW Pilot Costs because the Department did not approve them prior to implementation, Eversource argues its Vegetation Management RTW Pilot is consistent with Department

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307 The Companies dispute the Attorney General's comparison to National Grid's efforts in Rhode Island as proof for vegetation cost management savings (Companies Brief at 566). Specifically, the Companies argue there are key differences between service territories (particularly with tree canopies) resulting in significant differences in costs (Companies Brief at 566).

vegetation management directives and policies (Companies Brief at 567-568, citing D.P.U. 15-155, at 328-329; D.P.U. 13-90, at 19-20,).[308] Further, Eversource contends that the costs of the Vegetation Management RTW Pilot are appropriate as the budget is based on an assessment of forestry challenges on its system (Companies Brief at 569, citing Exh. ES-VLA-Rebuttal at 2). Eversource maintains that it used 2016 historical data and determined that to remove one percent of trees in the "fall zone" it would need to spend $38.9 million (Companies Brief at 569, citing Exh. ES-VLA-Rebuttal at 3). Further, Eversource argues that in recognition of the cost impacts its spending budget could have on customers, it determined that an amount of $25 million was an appropriate level of spending to achieve an impact (Companies Brief at 569, citing Exh. ES-VLA-Rebuttal at 3). In addition, Eversource claims that the Attorney General's recommendation that the Department should deny the Vegetation Management RTW Pilot because Eversource failed to provide a cost-benefit analysis is "nonsensical" (Companies Brief at 572). Eversource maintains that the purpose of the Vegetation Management RTW Pilot is to determine the benefits of the proposed enhanced vegetation management techniques and that, further, it has provided an overview of expected benefits (Companies Brief at 572, citing Exh. AG-20-27).

In response to the Attorney General's arguments against the deployment of LiDAR, Eversource states that LiDAR is not intended to replace arborists but to be used to

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308 The Companies state that the Attorney General did not explicitly recommend the costs for the 2018-2022 RTW Pilot be denied (Companies Brief at 567, n.64). The Companies, however, state it provides a clear argument in support of these costs and responds to arguments the Attorney General made against the 2018-2022 RTW Pilot (Companies Brief at 567, n.64).

supplement the work of arborists (Companies Brief at 570, citing Exh. ES-VLA-1, at 26). Eversource argues that LiDAR will be able to measure and analyze vegetation clearances more objectively for consistency in application of pruning specifications (Companies Brief at 570, citing ES-VLA-1, at 26). Further, Eversource asserts it should not be a surprise that it is the first distribution company to deploy LiDAR given its leading role in vegetation management (Companies Brief at 570).[309] According to Eversource, the use of LiDAR will ensure the Company maintains its first quartile reliability status (Companies Brief at 571, citing Tr. 5, at 919-920).

In response to arguments made by Cape Light Compact that the Companies should issue RFPs from tree service companies on a frequent basis, Eversource explains that it does utilize competitive RFPs and outside vendors for aspects of its vegetation management program (Companies Brief at 574, citing Tr. 5, at 901). Eversource maintains that multi-year contracts are a way for Eversource to maintain costs and its procurement department is constantly testing and monitoring the market (Companies Brief at 574, citing Tr. 5, at 901). Further , Eversource states that, because of this, there is no reason for the Department to substitute its own judgement in place of Eversource regarding the issuance of RFPs (Companies Brief at 574-575).

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309 Eversource argues that the Attorney General also ignores that Unitil is considering whether to deploy LiDAR and further states that the fact that National Grid's vegetation management pilot does not include LiDAR should not be a surprise since National Grid's proposal has them adopting measures that Eversource already has in place (Companies Brief at 570-571, citing Tr. 5, at 920).

Finally, Eversource, in response to UMASS, states that there should be no concern that the Vegetation Management RTW Pilot will be deployed inequitably (Companies Brief at 576). The Companies state that ETT will continue in Western Massachusetts and that Eversource will be focused on maintaining the clearance level in Eastern Massachusetts that has already been obtained (Companies Brief at 576). Further, the Company states that the RTW Pilot will also occur in Western Massachusetts and the programs will complement each other and improve reliability (Companies Brief at 575, citing Tr. 5, at 962).

5. Analysis and Findings

a. Vegetation Management RTW Pilot

The Department has directed companies to implement vegetation management pilots in order to achieve specific directives. See, e.g., D.P.U. 15-155, at 326-329; D.P.U. 13-90, at 15-23. In D.P.U. 15-155, at 328-329, the Department stated that it would consider implementation of a vegetation management pilot program with the expectation that the pilot program would take place over an established period of time, be designed to target trees outside the scope of the company's current vegetation management program, include in its scope of work extensive hazard tree inspections and removals and clearing of all overhead and under hanging branches, and prioritize critical infrastructure.[310] The Department has recognized that a more aggressive storm resiliency program is a worthwhile step in

[310] The Department specifically stated that "the scope of work would include extensive hazard tree inspections and removals and the clearing of all overheard and under hanging branches (i.e., ground-to-sky clearing) associated with the worst performing three-phase circuits, based upon consideration of: (1) tree-related field conditions; (2) customer count; (3) miles of each circuit; and (4) presence of scenic roads or other vegetation management restrictions." D.P.U. 15-155, at 329.

strengthening a company's distribution system, mitigating some of the physical damage and financial impacts of future storm events to the benefit of ratepayers. D.P.U. 15-155, at 328.

The Attorney General asserts that Eversource undertook the 2017 RTW Pilot absent of Department approval (Attorney General Brief at 169, citing Tr. 5, at 934). While the Companies took a risk in going forward by implementing the 2017 RTW Pilot, the Department is not precluded from reviewing the program and its costs.

The Department recognizes that NSTAR Electric and WMECo are currently counted among the top-tier utilities for reliability performance (Exh. AG-20-29). Vegetation management, however, is an important factor contributing to an electric distribution company's system reliability. D.P.U. 15-155, at 328, citing D.P.U. 13-90, at 19. The Department has previously directed utilities to develop vegetation management pilot programs, including in instances where the company has seen improvements in reliability with existing vegetation management programs. See D.P.U. 15-155, at 327-328.[311] Moreover, the Department acknowledges that the recently revised service quality guidelines will require electric distribution companies to continuously improve reliability. See Order Adopting Revised Service Quality Standards, D.P.U. 12-120-D at 9 (2015). Therefore, the Department finds that the Companies' good performance with regard to reliability indices should not be a disincentive for improving vegetation management over time.

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311 In D.P.U. 15-155, at 328, the Department directed National Grid to file a vegetation management program notwithstanding seeing improvements in reliability with its current vegetation management program.

Upon review of the record, the Department determines that most aspects of the Vegetation Management RTW Pilot will benefit ratepayers by improving the reliability and resiliency of Eversource's distribution system (Exhs. ES-VLA-1, at 20-27; AG-11-14; AG-39-6; RR-DPU-12). The Vegetation Management RTW Pilot will take place over a specific period, which in this instance is six years (Exhs. ES-VLA-1, at 20-27; ES-DPH-3 (East), WP DPH-15, at 1; ES-DPH-3 (West), WP DPH-15, at 1). The initial focus in the 2017 RTW Pilot will be on backbones and selected laterals with high customer counts, critical facilities, and locations where towns have placed restrictions on vegetation clearance (Exh. ES-VLA-1, at 21). As such, it prioritizes critical infrastructure and portions of the distribution system that serve large numbers of customers. See D.P.U. 15-155, at 329. Following the 2017 RTW Pilot, the 2018-2022 RTW Pilot will further increase mid-cycle pruning, RTW tree trimming activities, and RTW tree removals (Exh. ES-VLA-1, at 22). The Companies also provided information that demonstrates that trees and vegetation management are the leading cause of customer outages (Exh. AG-39-6; RR-DPU-12). The Department concludes that these activities are likely to improve the reliability of the Companies' distribution system, mitigate damage in future storm events, and put the Companies in a better position to meet the recently revised service quality guidelines that will result in increasingly stringent reliability standards (Exh. ES-VLA-1, at 17-23). See D.P.U. 12-120-D at 9. Specifically, the Department approves the Companies' Vegetation Management RTW Pilot's expanded application of ETT, hazard tree and risk tree removals, and additional mid-cycle pruning (Exh. ES-VLA-1, at 19). Further, the Department finds

that Eversource's Vegetation Management RTW Pilot is consistent with the criteria the Department set out in D.P.U. 15-155. See D.P.U. 15-155, at 328-329.

At this time, however, the Department finds that the Companies have not demonstrated that LiDAR will further the objectives the Department requires for a vegetation management pilot program. Specifically, LiDAR does not provide any new information in addition to what the Eversource already obtains using current practices or that Eversource would require Eversource to use its arborist further confirm and assess how to use the information in prioritizing circuits (Exh. AG-20-42; Tr. 5, at 923-929). Therefore, the Department disallows the LiDAR costs ($0.65 million) for the 2017 RTW Pilot (Exhs. ES-VLA-1, at 22; ES-DPH-3 (East), WP DPH-15, at 1; ES-DPH-3 (West), WP DPH-15, at 1; Tr. 5, at 935-936). Additionally, the Department excludes from the 2018-2022 RTW Pilot the costs associated with third-party studies related to LiDAR inspection and analysis and annual mobile LiDAR survey (Exhs. ES-DPH-3 (East), WP DPH-15, at 1; ES-DPH-3 (West), WP DPH-15, at 1). Nevertheless, the Department encourages the Companies to continue to explore additional options and new methods to include in its vegetation management strategy or to improve the support for the direct benefit LiDAR provides to the Company's vegetation management strategy.

With the exception of the exclusions noted above, the Department finds Eversource's Vegetation Management RTW Pilot is reasonable and in the ratepayers interest. Further, the Department directs Eversource to track and maintain necessary information related to its

enhanced vegetation management initiative, including but not limited to costs, benefits, and contribution to reliability improvements.

b. Vegetation Management RTW Pilot Cost Recovery

With the above exclusions related to LiDAR, the Department approves the Vegetation Management RTW Pilot Eversource proposes that Vegetation Management RTW Pilot cost recovery occur separately in base rates for both NSTAR Electric and WMECo, amortized over a period of five years (Exhs. ES-DPH-1, at 77; ES-DPH-3 (East), WP DPH-15, at 1; ES-DPH-3 (West), WP DPH-15, at 1). While the Attorney General recommended that the Department reject the Vegetation Management RTW Pilot, she did not offer an alternate means of cost recovery should the Vegetation Management RTW Pilot be approved (Attorney General Brief at 169, 171). No other party commented on this issue.

It is a well-established Department precedent that costs recovered through base rates are determined using cost from a historic test year, adjusted for known and measurable changes. D.P.U. 14-150, at 44; D.P.U. 14-120, at 9; D.P.U. 1580, at 13-17, 19; D.P.U. 136, at 3; D.P.U. 19992, at 2; D.P.U. 18204, at 4; D.P.U. 18210, at 2-3; D.P.U. 18264, at 2-4; See also Massachusetts Electric Company v. Department of Public Utilities, 383 Mass. 675, 680 (1981).[312] In establishing rates pursuant to G.L. c. 164, § 94, the Department examines a test year on the basis that the revenue, expense, and rate base

[312] A "known" change means that the adjustment must have actually taken place, or that the change will occur based on the record evidence. A "measurable" change means that the amount of the required adjustment must be quantifiable on the record evidence. D.T.E. 98-51, at 62.

figures during that period, adjusted for known and measurable changes, provide the most reasonable representation of a distribution company's present financial situation, and fairly represent its cost to provide service. D.P.U. 14-120, at 9; see Ashfield Water Company, D.P.U. 1438/1595, at 3 (1984).

The Department recognizes that company-initiated pilot programs play an important role in developing innovative and cost effective programs to help those companies better serve their customers.[313] By their very nature, however, future cost and programmatic effectiveness of pilot programs are largely unknown at the outset as they have no historical data from which to build upon. For this reason, the Vegetation Management RTW Pilot is presented as a proof of concept program in an effort to better establish those cost and its programmatic effectiveness. Further, Eversource's costs for its proposed Vegetation Management RTW Pilot are neither known nor measurable (see Exhs. ES-VLA-1, at 22-23; AG-20-33; AG-20-37). Finally, the level of cost effectiveness has similarly not been established for the Vegetation Management RTW Pilot.

Accordingly, costs for the Vegetation Management RTW Pilot are not appropriate for cost recovery in base rates as proposed by Eversource. Rather, the Department here approves Eversource's Vegetation Management RTW Pilot and allows the associated costs to be recovered through an annual reconcilable factor (outside of base rates). This RTW

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313 The Department recognizes the financial burden borne by ratepayers due to high storm restoration costs. The Department also recognizes that a company's poor pre-storm preparation may have adverse effects on that company's customers. D.P.U. 13-90, at 19, citing D.P.U. 11-01/D.P.U. 11-02, at 70-71; D.P.U. 09-39, at 210-211.

reconciling factor shall recover the actual costs incremental to those recovered in base rates that are directly associated with the Vegetation Management RTW Pilot as approved in the instant proceeding.[314] The Companies shall submit a tariff within 90 days from the date of this Order that states all the terms and conditions for the RTW reconciling factor, consistent with the directives in this Order.

C. Annualization and Capitalization of Vegetation Management Costs

1. Companies' Proposal

a. Annualization of Vegetation Management Expenses

Eversource states that, during the test year, it incurred expenses associated with its annual cycle trim program of $5,283,642 for NSTAR Electric (Exhs. ES-DPH-1, at 75; ES-DPH-2 (East), Sch. DPH-15, at 1). Eversource states that because it capitalized (as opposed to expensed) cycle trimming activities for the first six months of the test year, the $5,283,642 it expensed in the test year reflects only six months of activity. Consequently, its representative level of cycle trim expenses going forward will be higher than the amount expensed in the test year as a result of the full amount of annual cycle trim activity being expensed, with no amounts being capitalized in the future (Exh. ES-DPH-1, at 74-75). To estimate a representative amount of test year vegetation management expenses, Eversource compared the cycle trim program costs in 2015 of $9.1 million to the total cycle trim program costs in the test year of $12.1 million, a portion of which NSTAR Electric capitalized (Exh. ES-VLA-1, at 16-17). Eversource estimated that it would spend slightly

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[314] Similar to the carrying charge treatment for deferred storm costs in the instant proceeding, interest on the monthly balance of Vegetation Management RTW Pilot costs will accrue through this reconciling factor at the prime rate.

less than the $12.1 million test year amount in the future (Exhs. ES-DPH-1, at 76; ES-VLA-1, at 16-17). As a result, Eversource proposes an annualization adjustment of $5,226,646 to represent the full cost of NSTAR Electric's annual trim cycle program in rates and to incorporate a total rate year level of annual expense of $10,510,288 (Exh. ES-DPH-1, at 74-75, citing Exhs. ES-DPH 2 (East), Sch. DPH-15, at 2; ES-VLA-1, at 16).

b. Capitalization

In D.P.U. 11-85 B/11-119-B at 134-135, the Department directed NSTAR Electric to track hazardous tree removal separately from its vegetation management program. Specifically, the Department directed NSTAR Electric to submit an updated vegetation management program for its distribution system that would include: (1) a four- to five-year tree trimming cycle (at a minimum); and (2) a mechanism for tracking the number of hazard trees removed with associated costs D.P.U. 11-85-B/11-119-B, at 134-135.[315]

Eversource states that it capitalized the expenditures for the initial cycle implementing the ETT program because ETT increased the clearance "corridor" beyond the clearance achieved with the SMT cycle (Exh. ES-VLA-1, at 12). From 2012 through 2015, Eversource capitalized a total of $37,378,200 in ETT costs and $14,808,500 in ETR costs for a total of $52,186,700 (see RR-AG-13). At the end of the test year, Eversource had

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315 As discussed above, beginning in 2012, NSTAR Electric instituted a four-year trimming cycle so that the trees along all of its circuits within its distribution system are pruned once every four years (Exh. ES-VLA-1, at 11). NSTAR Electric also began to increase the clearance zone around the distribution primary by trimming to an ETT specification on all primary sections of circuits and developed an ETR element to its program to target the removal of risk and hazard trees in an effort to improve reliability (Exh. ES-VLA-1, at 11-12).

capitalized a total depreciable balance of $48,671,800 ($34.8 million for ETT, and $13.8 million for ETR) (see RR-AG-13). Eversource asserts that it is appropriate to expense the expenditures for ETT work in the second trim cycle and beyond because of the difference between completing a capital improvement to the system (first trim cycle), and performing maintenance of an already widened corridor (second trim cycle and beyond) (Exh. ES-VLA-1, at 12-13, 16).

2. Positions of the Parties

a. Attorney General

The Attorney General agrees that Eversource should be allowed an annualization adjustment to its test year tree trimming costs (Attorney General Brief at 165). The Attorney General, however, asserts that the Department should reject Eversource's capitalization of ETT and ETR costs because capitalizing these costs conflicts with the Department's and FERC's accounting rules (Attorney General Brief at 165, 174-178). The Attorney General maintains that, from 2012 through 2015, Eversource accounted for ETT and ETR costs as capital and booked them to FERC Account 365 (Overhead Conductors and Devices) (Attorney General Brief at 175; Attorney General Reply Brief at 48). The Attorney General argues that this treatment is inconsistent with FERC and Department accounting guidelines and that, instead, Eversource should have booked these tree trimming costs to FERC Account 593 (Maintenance of Overhead Lines) because they represent routine maintenance (Attorney General Brief at 175; Attorney General Reply Brief at 49).

Specifically, the Attorney General argues that, while Eversource contends that its initial ETT and ETR cycle should be capitalized because it extends the life of an asset, any

type of pruning or tree removal along the distribution system, by its very nature, extends the life of the conductors and improves reliability (Attorney General Brief at 176). Further, the Attorney General contends that both the Department and FERC specifically identify that the costs associated with tree trimming and clearing of brush on overhead conductors and devices are to be included in Account 593 (Attorney General Brief at 175-176, citing FERC Uniform System of Accounts, Distribution Expenses, Maintenance Account: 593 Maintenance of Overhead Lines contained in FERC 18 CFR Part 101, Account 593, Item 2.k (revised as of April 1, 2016); 220 CMR 51.01). The Attorney General maintains that only tree trimming costs associated with newly installed overhead conductors and devices can be capitalized under Account 365 (Attorney General Brief at 177; Attorney General Reply Brief at 48, citing FERC 18 CFR part 101, Account 365, Item 9; 220 CMR 51.01; Tr. 13, at 2760). The Attorney General argues that FERC's instructions require the tree trimming costs incurred after the installation of the distribution line to be expensed to Account 593 (Attorney General Reply Brief at 49). In addition, the Attorney General maintains that other than costs incurred by Eversource to perform initial tree trimming when a distribution line is first installed, that the Uniform System of Accounts for Electric Companies do not contain a provision that allows electric companies to capitalize the costs of subsequent tree trimming to that distribution line (Attorney General Brief at 177; Attorney General Reply Brief at 48).

Further, the Attorney General argues that Eversource should not get a second opportunity to capitalize trimming costs simply because it previously elected narrower clearance zone compared to Eversource's currently elected wider clearance zone (Attorney

General Brief at 178). The Attorney General argues that if Eversource were allowed to capitalize the 2012 through 2015 ETT and ETR costs, it will have effectively charged the customers twice for tree trimming costs: once as an O&M expense through rates that were in effect during the four-year deferral period, and again through the plant-in-service addition included in the rates in the instant case (Attorney General Reply Brief at 49). Accordingly, the Attorney General asserts that the Department should remove from rate base $34.8 million (the depreciable balance of ETT costs at the end of the test year), and $13.8 million (the depreciable balance of ETR costs at the end of the test year) (Attorney General Brief at 178, citing RR-AG-13). Finally, the Attorney General asserts that Eversource be precluded from capitalizing all ETR-related costs on its existing circuits going forward (Attorney General Brief at 178, citing RR-AG-13).

b. Cape Light Compact

Cape Light Compact concurs with the Attorney General's position that Eversource's initial ETT cycle costs should not be capitalized (Cape Light Compact Initial Brief at 80). Cape Light Compact asserts that customary utility practice allows capitalizing these costs only as part of a new powerline construction project with a new right-of-way clearing (Cape Light Compact Initial Brief at 80, citing Exh. AG-GLB-1, at 29).

c. Companies

Eversource argues that its normal vegetation management expenses are based on actual expenses incurred during the split test year ending June 30, 2016 for vegetation work such as ETT (Companies Brief at 136, citing Exh. ES-VLA-1, at 16). Eversource contends that NSTAR Electric's test year actual expenses for the vegetation management program

totaled $10.5 million (Companies Brief at 136). Eversource asserts that it is entitled to recover these prudently incurred actual expenses (Companies Brief at 136).

Further, Eversource argues that it properly accounted for ETT and ETR vegetation management costs in 2012-2016, and that the Department should allow capitalization of these expenditures (Companies Brief at 572; Companies Reply Brief at 170). Eversource asserts that its internal guidelines for capitalization are consistent with the accounting practices of FERC, the Department accounting practices, and generally accepted accounting principles (Companies Brief at 573; Companies Reply Brief at 170, citing Tr. 15, at 3167-3168). Specifically, Eversource argues that Account 365 allows for tree trimming costs to be depreciated over the life of the conductor that is benefitting from the specific tree trimming (Companies Brief at 573, citing AG-37-6; Companies Reply Brief at 170). Further, Eversource asserts that the initial cycle of corridor-expanding work is treated as a capital improvement because it serves to extend the life of Eversource's distribution lines and other equipment on the distribution poles (Companies Brief at 573; Companies Reply Brief at 170-171, citing AG-37-6). In addition, Eversource argues that the level of work involved in the initial ETT differentiates it from routine maintenance (Companies Brief at 573). According to Eversource, it capitalized the initial ETT because it extends the life of its system assets (e.g., poles) rather than merely reducing customer outages (Companies Brief at 573).[316]

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316 Specifically, Eversource argues that standard vegetation maintenance is designed to prevent outages (i.e., trimming a limb that may otherwise make contact with the system causing a fuse to blow or a recloser to trip), whereas ETT is designed to keep

3. Analysis and Findings

a. Annualization

During the test year, NSTAR Electric expensed $5,283,642 in vegetation management costs (Exh. ES-DPH-1, at 75). Because Eversource capitalized vegetation management trimming activities for the first six months of the test year (July 1, 2015 through December 31, 2015), its test year expenses for NSTAR Electric do not include a representative level of vegetation management expenses for the test year (Exh. ES-DPH-1, at 74). Accordingly, Eversource seeks to annualize NSTAR Electric's split test year vegetation management expenses in order to include a representative total annual level of such expense in base rates on a going forward basis (Exhs. ES-DPH-1, at 75; ES-VLA-1, at 16-17; ES-VLA-4; ES-VLA-5). In order to annualize its vegetation management expenses, Eversource proposes to increase NSTAR Electric's test year vegetation management expense by $5,226,646 (Exh. ES-DPH-1, at 75). Accordingly, NSTAR Electric's test year pro forma expenses for its vegetation management program totals $10,510,288 (inclusive of the $5,226,646 trim cycle expense adjustment) (Exhs. ES-DPH-1, at 75; ES-DPH-2 (East), Sch. DPH-15, at 2; ES-VLA-1, at 17).

In order to allow the test year amount of an expense to be annualized a company must demonstrate that the expense is annually recurring and the amount annualized at is representative of future costs. See, e.g., D.P.U. 15-80/15-81, at 130-131. Here, NSTAR Electric had expenses for only half the test year for a cycle tree trimming program that has

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equipment from becoming broken (i.e., a tree falling on a pole, which causes it to break) (Companies Brief at 573, citing Tr. 5, at 3163; Companies Reply Brief at 171).

recurring costs for a full year (Exh. ES-DPH-1, at 74). The Department finds the proposed annualized amount of $10,510,288 to be representative of future costs (Exhs. ES-DPH-1, at 74; AG-11-10). Accordingly, the Department finds the proposed expenses for NSTAR Electric's vegetation management program to be annually recurring and to be reasonable (Exhs. ES-DPH-1, at 75; ES-VLA-1, at 16-17; ES-VLA-4; ES-VLA-5). D.P.U. 10-55, at 216. The Department therefore approves the annualization adjustment of $5,226,646 to NSTAR Electric's proposed cost of service, resulting in a total of $10,510,288 annually in base distribution rates for vegetation management expense.

b. Capitalization

The propriety of NSTAR Electric's capitalization policy has not been previously addressed by the Department. NSTAR Electric represents that its own capitalization policies are consistent with its interpretation of FERC's accounting systems and generally accepted accounting principles (Exhs. AG-11-12; AG-37-6; Tr. 13, at 2755-2756; Tr. 15, at 3167-3168). There is some evidence that other companies, including WMECo, have capitalized the initial costs associated with their own enhanced vegetation management programs (Exh. AG-37 6; Tr. 15, at 3167-3168). Further, there is evidence on the record in this proceeding that in 2012, as a result of the merger between the two entities, NSTAR Electric adopted capitalization of ETT, consistent with the policies employed by WMECO since 2000 (Exhs. AG-37-6; AG-51-6; RR-AG-14).[317] NSTAR Electric completed the initial

[317] Further, the Department notes that the issue of WMECo capitalizing these ETT costs was raised during the course of examination in the D.P.U. 10-70 rate case proceeding

cycle of its ETT and ETR programs, and thus will be expensing its vegetation management costs hereafter (Exh. ES-DPH-1, at 74-75). In view of the historic treatment of enhanced vegetation management program costs, the absence of clear Department guidance on the matter, and the fact that future ETT and ETR costs will be expensed, the Department will not disturb Eversource's accounting treatment of its ETT and ETR costs.

Nonetheless, the Department is aware that the subject of capitalized vegetation management costs is an item of contention by the parties in this proceeding, primarily Eversource and the Attorney General.[318] Since the close of the record in this proceeding, the Department has also become aware of a FERC audit report of American Transmission Systems Incorporated ("ASTI") (Audit of Formula Rates of American Transmission Systems, Inc., Docket No. FA11-8-000, at 15-18 (2013). In that audit, FERC audit staff disagreed with ASTI's position that the expansion of its transmission corridors met FERC's requirements for capitalizing associated transmission-related tree trimming costs. Docket No. FA11-8-000, at 16 (2013). Specifically, FERC audit staff stated that "while the expansion of corridors may improve reliability by decreasing vegetation caused outages, it does not directly make the transmission assets or system more useful, more efficient, or a greater

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(See, e.g., D.P.U. 10-70, Tr. 7 at 1222; Tr. 10 at 1621; Tr. 11 at 1802-1806, 1958-1965).

318 The Department's Uniform System of Accounts for Electric Companies specifies that in order to maintain uniformity of accounting, utilities shall submit questions of doubtful interpretation to the Commission for consideration and decision. 220 CMR 51.01(1), 51.02(1)(a); 18 C.F.R. Pt. 101, General Instruction 5.

durability, or of a greater capacity." Docket No. FA11-8-000, at 17 (2013). FA11-8-000, at 17 (2013).

Based on the conclusions presented by the FERC staff audit, and our review of the Uniform System of Accounts for Electric Companies, the Department questions whether a shift exists as to the capitalizable nature of these types of activities, and hereby instructs any electric distribution company seeking to capitalize distribution system vegetation management costs, except where those costs are associated with the initial installation of a distribution line, to do so only with specific authorization by Department, pursuant to 220 CMR 51.01(1), 51.02(1)(a), 18 CFR Pt. 101, General Instruction 5. Further, the Department places the Companies on notice that the issue of the appropriate accounting treatment of vegetation management.

XV. VERIZON-RELATED VEGETATION MANAGEMENT COSTS

A. Introduction

Both NSTAR Electric and WMECo jointly own utility poles in their respective service territories with Verizon New England, Inc. ("Verizon") and each company has entered into one or more joint ownership agreements ("JOA") with Verizon. See, generally, D.P.U. 13-135-A; D.P.U. 13-52. Further, each JOA incorporates intercompany operating procedures ("IOP") that establish procedures and cost-sharing agreements associated with performing a number of tasks on jointly-owned poles, including preventive tree trimming and storm-related vegetation management.

NSTAR Electric issued invoices in May and August 2014 to Verizon totaling approximately $7.1 million, which represents 50 percent of the total storm-related vegetation

management costs for storm events occurring from 2011 to 2013 (Exhs. ES-VLA-1, at 31-32; DPU-50-1, Att. (a); AG-25-22, Att. (a)).[319] In addition, WMECo issued invoices to Verizon totaling approximately $1 million, which represents 50 percent of the storm-related vegetation management costs for 2008 to 2013 in locations where Verizon received a "demonstrable benefit" (Exhs. ES-DPH-1, at 132; ES-VLA-1, at 32; AG-25-22, Att. (b); Tr. 5, at 975).[320] Verizon did not pay these invoices (Exhs. ES-VLA-1, at 32-33; ES-DPH-1, at 132).

The Companies engaged in settlement discussions with Verizon in relation to the outstanding balances (Exhs. ES-VLA-1, at 31-32, AG-25-11, Att. (confidential); Tr. 5, at 979). On April 4, 2017, the Companies entered into a settlement agreement ("Agreement") with Verizon related to the outstanding storm-related vegetation management costs (Exhs. DPU-50-1, Att. (b); AG-25-26, Att. (Supp.)). Pursuant to the terms of the Agreement, Verizon paid $1,514,242 to the Companies (Exhs. DPU-50-1, Att. (b); AG-25-26, Att. (Supp.)).

The Companies also executed a new IOP with Verizon to address future vegetation management cost-sharing in major storm events (Exhs. DPU-50-1, Att. (b); AG-25-26 & Att. (Supp.)). This IOP includes a provision requiring Verizon to pay seven percent of future

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319 These invoices were issued following the Department's decision in D.P.U. 13-52, at 48-49, requiring NSAR Electric to take prudent steps to seek recovery from Verizon for vegetation management costs.

320 Unlike the NSTAR Electric JOA, the WMECo JOA allows for a work practice using timesheets that generate location-specific information on vegetation clearing and identify the Verizon facilities receiving a benefit (Exh. ES-VLA-1, at 29).

vegetation management costs associated with major storm events (Exhs DPU-50-1, Att. (b); AG-25-26, Att. at 6 (Supp.); Tr. 1, at 106-107).[321]

The Companies propose to recover $6,695,352 in vegetation management costs from ratepayers in the instant proceeding (Exh. DPU-50-1, Att. (a); Tr. 5, at 982). This amount is the difference between the approximately $8.1 million billed to Verizon for storm-related vegetation management costs and the amount paid by Verizon pursuant to the Agreement (Tr. 5, at 982). The Companies propose to recover these costs over five years, beginning January 1, 2018, through the storm cost recovery adjustments for both NSTAR Electric and WMECo (Exhs. DPU-50-1 & Att. (a)).

B. Positions of the Parties

1. Attorney General

The Attorney General contends that the Department should deny Eversource's proposal to recover the difference between the amounts it billed Verizon and the amount that Eversource accepted from Verizon in lieu of full payment (Attorney General Brief at 183). The Attorney General maintains that the Companies and Verizon are signatories to JOAs which explicitly provide that heavy storm-related vegetation management work will be handled "immediately without prior review," and that the Companies and Verizon will each pay 50 percent of the costs for such work (Attorney General Brief at 183, citing Exhs. ES-VLA-1, at 27-28; AG-25-15, Att. (a) at 1). The Attorney General argues that,

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[321] Pursuant to the new IOP, Verizon will pay seven percent of the total vegetation management costs experienced by the Companies in any emergency event classified under the Companies' Emergency Response Plan as a Type 1, 2 or 3 event (Exhs. DPU-50-1, Att. (b); AG-25-26, Att. (Supp.)).

despite Department direction to seek "legal process" regarding Verizon's responsibility for these costs, Eversource never filed suit against Verizon to enforce the terms of the JOAs (Attorney General Brief at 184, citing Exhs. AG-1-82; AG-25-25; AG-25-26 (Supp.)). Rather, the Attorney General maintains that the Agreement NSTAR Electric and WMECo entered into with Verizon was outside of any legal process and, therefore, not in compliance with the Department's directives (Attorney General Brief at 184, citing Exh. AG-25-26 (Supp.)).

Further, pursuant to the terms of the Agreement, the Attorney General states that Verizon is responsible only for seven percent of the total cost of storm-related vegetation management in the overlapping service areas going forward (Attorney General Brief at 184, citing AG-25-26, Att. at 5 (Supp.)). The Attorney General asserts that the terms of the Agreement ask ratepayers to pay 93 percent of these costs going forward, an outcome which the Attorney General contends is neither just nor reasonable (Attorney General Brief at 185).

Based on these considerations, the Attorney General argues that the Department should not allow Eversource shareholders to benefit from the Companies' imprudence, to the detriment of ratepayers, by ignoring their failure to comply with the Department's directive to obtain a determination from the courts as to the extent of Verizon's responsibility for storm-related vegetation management costs under the JOAs (Attorney General Brief at 186). Accordingly, the Attorney General asserts that the Department should deny Eversource's request to recover the difference between what the Companies billed Verizon and the amount

Verizon paid to Eversource pursuant to the Agreement (Attorney General Brief at 186, citing Exh. AG-25-26 (Supp.)).

2. Companies

The Companies assert that the Department should approve their request to recover the difference in vegetation management costs that were invoiced to Verizon pursuant to the JOAs and the amount paid by Verizon pursuant to the Agreement (Companies Brief at 122, 488). Contrary to the Attorney General's interpretation, Eversource argues that the Department did not mandate that it file suit against Verizon as a prerequisite for recovery of any unpaid Verizon-related costs from ratepayers (Companies Brief at 488). Instead, Eversource contends that the Department directed the Companies to take prudent steps to establish the level of costs properly attributable to Verizon, including, if necessary, instituting "legal process" against Verizon for unpaid storm-related vegetation management costs (Companies Brief at 488, citing D.P.U. 13-135-A at 45, D.P.U. 13-52, at 48; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 11-56, at 30-31 (2013)). The Companies argue that such "legal process" may include pursuing Verizon in court, or arriving at a resolution through arbitration or mediation (Companies Brief at 488, citing D.P.U. 13-52, at 48, n.30). In this regard, Eversource asserts that the settlement negotiations it entered into with Verizon that resulted in the Agreement fully satisfied the Department's directives regarding legal process (Companies Brief at 488). Further, the Companies maintain that the Agreement is a legally enforceable contract (Companies Brief at 488; Companies Reply Brief, App. C at 16).

Eversource also argues that the amount it recovered from Verizon pursuant to the Agreement was appropriate (Companies Brief at 122). Eversource contends that, pursuant to the JOAs, Verizon must pay a share of vegetation management costs only where there was a mutual benefit and, for the applicable period, this amount was less than the $8.1 million the Companies billed Verizon (Companies Reply Brief at 122, App. C at 16). Eversource argues that because the Companies were not owed the full $8.1 million they billed to Verizon, ratepayers were not harmed by the Companies settlement of $1.5 million (Companies Brief at 122, citing Exh. AG-11-16, Tr. 1, at 103; Companies Reply Brief, App. C at 16). Accordingly, the Companies assert that they should be permitted to recover the balance of $6,695,352 from ratepayers, as proposed (Companies Brief at 122, 488; Tr. 5, at 982).

C. Analysis and Findings

The Department has consistently found that when seeking to recover storm-related costs from ratepayers, a company has the burden to demonstrate that those costs are reasonable and prudently incurred, and that a company is not seeking to recover any costs from its customers that a third-party is contractually obligated to pay under the terms of a JOA. Western Massachusetts Electric Company, D.P.U. 11-102/11-102-A at 101 (2012); D.P.U. 11-01/D.P.U. 11-02, at 50, 56; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 11-56, Interlocutory Order at 5; (2012); D.P.U. 10-70, at 68; D.P.U. 09-39, at 212-213. More specifically, the Department has directed electric distribution companies to take prudent steps to seek recovery from Verizon for vegetation management costs including, if necessary, pursuing legal action to recover those costs in

court before seeking recovery of those costs from ratepayers. D.P.U. 13-52, at 48. Legal process may include pursuing Verizon in court, or arriving at a resolution through arbitration or mediation. D.P.U. 13-52, at 48, n.30. Where a company fails to collect vegetation management costs from Verizon through the legal process, the company may then file for recovery of those costs with the Department. D.P.U. 13-52, at 48.

The Attorney General argues that the Companies did not pursue the prerequisite legal process to determine the appropriate extent of Verizon's responsibility for storm-related vegetation management costs under the JOAs and, therefore, should not be allowed to recover any uncollected costs from ratepayers here (Attorney General Brief at 186). Eversource disagrees and maintains that, through its negotiations with Verizon, it has taken reasonable action to establish the level of costs properly attributable to Verizon (Companies Brief at 122).

While the Companies did not reach the Agreement with Verizon through a court action, mediation, or arbitration as contemplated in D.P.U. 13-52, we find that Eversource has demonstrated that its decision to resolve this issue without recourse to formal legal process was reasonable under the circumstances. The Agreement represents a voluntary resolution of the longstanding issue of responsibility for costs associated with storm-related vegetation management work. As joint owners of an essential distribution asset, there is significant benefit from a cooperative resolution of this issue between Verizon and Eversource. In addition to resolving the issue of outstanding costs, the Agreement will reduce future uncertainty by putting in place a clear process to address costs related to storm

events (Exhs. DPU-50-1, Att. (b); AG-25-26 (Supp.)). Accordingly, we find that Eversource is eligible to request recovery of the unrecovered storm-related vegetation management costs at issue.

Eversource must demonstrate that the amount it seeks to recover from ratepayers in this case is reasonable. As noted above, Eversource proposes to recover $6,695,352 in vegetation management costs from ratepayers representing the difference between the approximately $8.1 million billed to Verizon for storm-related vegetation management costs and the $1,514,242 paid by Verizon pursuant to the Agreement (Exhs. DPU-50-1, Atts. (a), (b); AG-25-26, Att. (Supp.); AG-25-22, Atts. (a), (b); Tr. 5, at 982). Our review of the record shows that Verizon had an arguable case under the JOAs that is was not liable to the Companies for the full amounts billed (Exhs. ES-VLA-1, at 31-32; AG-25-11, Att. (confidential); AG-25-26 (Supp.); Tr. 5, at 975-979). Accordingly, we find that the amount of the settlement paid by Verizon pursuant to the agreement is reasonable under the circumstances as it avoids the uncertainties of litigation.

Based on the findings above, the Department will allow the Companies to recover through Eversource's storm cost recovery adjustments the difference between the outstanding balance of storm-related vegetation management costs invoiced to Verizon and the amounts paid by Verizon pursuant to the Agreement (Exhs. DPU-50-1, Atts. (a), (b); AG-25-26, Att. (Supp.); AG-25-22, Atts. (a), (b); Tr. 5, at 982). As noted above, the Companies proposed to amortize recovery of the balance over a period of five years (Exhs. ES-DPH-1, at 133; ES-VLA-1, at 33). Amortization periods are determined based on a case-by-case review of

the evidence. D.P.U. 08-27, at 99; D.P.U. 93-223-B at 14; D.P.U. 84-145-A at 54. In this case, we consider the size of the balance to be recovered, the underlying facts giving rise to the accumulation of the balance, and the impact of recovery on ratepayers. Based on these considerations and the record in this case, the Department finds that five years is an appropriate amortization period.

The Department will allocate the amounts to be recovered to NSTAR Electric and WMECo based on the proportional share of the $8.1 million amount billed to Verizon (i.e., 87.7 percent to NSTAR Electric and 12.3 percent to WMECo) (Exhs. ES-DPH-1, at 132; ES-VLA-1, at 32; Tr. 5, at 975). Amortizing 87.7 percent of $6,695,352 over five years produces an annual expense of $1,173,753 for NSTAR Electric. Amortizing 12.3 percent of $6,695,352 over five years produces an annual expense of $165,317 for WMECo.

Going forward, Verizon has agreed to pay seven percent of the total applicable storm-related vegetation management costs as specified in the Agreement (Exh. AG-25-26 (Supp.)).[322] In the event that Verizon fails to pay these amounts, the Companies' shall not be eligible to recover such costs from ratepayers. In this regard, the Companies will be

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322 The Attorney General contends that the revised cost sharing percentage is not reasonable (Attorney General Brief at 185). The Department does not address the reasonableness of the revised cost-sharing arrangement between Verizon and Eversource in this proceeding (Exh. DPU-50-1, Att. (b) at 6). Instead, Eversource shall provide data and analysis to support the reasonableness of the cost sharing arrangement as part of its next storm fund cost recovery proceeding. In particular, the Company shall monitor future fieldwork and collect data to show that the cost sharing arrangement outlined in the Agreement is reasonably representative of the actual benefits to both the Companies and Verizon.

properly incented to take all necessary steps to recover those costs from Verizon and ratepayers will not be at risk for any non-payment.

As a final matter, the Department notes that Unitil addressed a similar issue and has come to a resolution with Verizon that involved the transfer of ownership of jointly owned poles from Verizon to the distribution company. See Fitchburg Gas and Electric Light Company, D.P.U. 17-ARR-04, Exhibit DPU-1-1 (2017). Further, the Companies indicated that they are aware of a similar agreement with National Grid and anticipate that Verizon will seek similar treatment from Eversource (Tr. 5, at 983).[323] The Department directs the Companies to explore the benefits to ratepayers and feasibility of a transfer of jointly owned poles from Verizon to Eversource and report on such efforts in its next base rate case proceeding.

XVI. CAPITAL STRUCTURE AND RATE OF RETURN

A. Introduction

Eversource proposes a 7.42 percent weighted average cost of capital ("WACC") for NSTAR Electric and a 7.50 percent WACC for WMECo, representing the rate of return to be applied on rate base to determine the Companies' total return on their respective investments (Exhs. ES-DPH-2 (East), Sch. DPH-31, at 1 (Rev. 3); ES-DPH-2 (West),

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323 National Grid and Verizon entered into a new utility pole ownership agreement, effective May 31, 2017, under which poles will continue to be jointly owned by both companies, but the responsibilities for pole set, replacement, or relocation will be based on the type of work needed. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 17-ARR-01, Exhibit DPU-8 (2017). Further, a percentage of National Grid's actual costs will be recovered from Verizon for vegetation management costs pursuant to a new IOP for emergency restoration activity. D.P.U. 17-ARR-01, Exh. DPU-8.

Sch. DPH-31, at 1 (Rev. 3)). NSTAR Electric's proposed WACC is based on: (1) a proposed capital structure that consists of 45.69 percent long-term debt, 0.94 percent preferred stock, and 53.37 percent common equity; (2) a proposed cost of long-term debt of 3.88 percent; and (3) a proposed rate of return on common equity (i.e., return on equity or ROE) of 10.50 percent (Exhs. ES-RBH-1, at 3, 7, 70-73; ES-DPH-1, at 176-177; ES-DPH-2 (East), Sch. DPH-31, at 1 (Rev. 3)). WMECo's proposed rate is based on: (1) a proposed capital structure containing 46.66 percent long-term debt and 53.34 percent common equity; (2) a proposed cost of long-term debt of 4.07 percent; and (3) a proposed ROE of 10.50 percent (Exhs. ES-RBH-1, at 3, 7, 70-73; ES-DPH-1, at 176-177; ES-DPH-2 (West), Sch. DPH-31, at 1 (Rev. 3)).

In determining their proposed ROEs, the Companies used the market and financial data developed for a comparison group of 20 electric utility companies and applied: the discounted cash flow ("DCF") model, including the constant growth and multi-stage forms; the risk premium model ("RPM"); and the capital asset pricing model ("CAPM") (Exhs. ES-RBH-1, at 3, 16-20; ES-RBH-3; ES-RBH-4; ES-RBH-6; ES-RBH-9).

The Attorney General calculates a WACC of 6.60 percent, developed using an ROE of 8.875 percent for both NSTAR Electric and WMECo (Exh. AG-JRW-1, at 4; JRW-1). The Attorney General's WACC also is based on proposed capital structures consisting of: (1) 48.99 percent long-term debt, 1.01 percent preferred stock, and 50.00 percent common equity for NSTAR Electric; and (2) 50.00 percent for both WMECo's long-term debt and common equity (Exhs. AG-JRW-1, at 3, 5, 39; JRW-1).

FEA and Sunrun and EFCA also calculate alternate WACCs and ROEs based on their own capital structure determinations for both NSTAR Electric and WMECo (Exhs. FEA-MPG-1, at 4, 48-49 (Corrected); FEA-MPG-3; SREF-DJG-1, at 9-10; SREF-DJG-1, App. F; SREF-DJG-3; SREF-DJG-4). FEA proposes a WACC of 6.83 percent, developed using an ROE of 9.35 percent for both NSTAR Electric and WMECo (Exhs. FEA-MPG-1, at 4, 48-49 (Corrected); FEA-MPG-3). FEA's WACC for NSTAR Electric is based on a capital structure consisting of: (1) 49.06 percent debt, 0.94 percent preferred stock, and 50.00 percent common equity (Exhs. FEA-MPG-1, at 4, 48-49 (Corrected); FEA-MPG-3). FEA's WAAC for WMECo is based on a capital structure consisting of 50.00 percent debt and 50.00 percent common equity (Exhs. FEA-MPG-1, at 4, 48-49 (Corrected); FEA-MPG-3).

Sunrun and EFCA propose a WACC of 6.45 percent for NSTAR Electric and 6.49 percent for WMECo, developed using an ROE of 8.75 percent for both companies (Exhs. SREF-DJG-1, at 9-10; SREF-DJG-1, App. F; SREF-DJG-3; SREF-DJG-4). Sunrun and EFCA's WACCs are based on proposed capital structures consisting of: (1) 51.0 percent long-term debt, 0.94 percent preferred equity, and 49.06 percent common equity for NSTAR Electric; and (2) 51.0 percent long-term debt and 49.00 percent common equity for WMECo (Exhs. SREF-DJG-1, at 9-10; SREF-DJG-1, App. F; SREF-DJG-3; SREF-DJG-4).

Cape Light Compact and UMass also make recommendations. Cape Light Compact recommends an 8.75-percent ROE and use of a capital structure with a 51-percent long-term

debt ratio, while UMass recommends a 9.5-percent ROE (Cape Light Compact Brief at 72-78; UMass Brief at 18-20).

Below, we examine: (1) the Companies' capital structures; (2) their cost of debt and preferred stock; (3) the respective proxy group selections used by the parties in supporting their proposed ROEs; (4) the Attorney General's arguments for authorizing an ROE consistent with regional and national trends; and (5) the appropriate ROE.

B. Capital Structure

1. Companies Proposal

Eversource calculates separate capital structures for NSTAR Electric and WMECo in support of proposing separate revenue requirements (Exhs. ES-DPH-1, at 3, 177; ES-RBH-1, at 370).[324] Eversource proposed to apply the June 30, 2016, test year-end capital structure for NSTAR Electric and WMECo (Exhs. ES-DPH-1, at 176-177; ES-DPH-2 (East), Sch. DPH-31, at 1 (Rev. 3); (Exh. ES-DPH-2 (West), Sch. DPH-31, at 1 (Rev. 3)). For NSTAR Electric that capital structure consisted of $2,100,000,000 in long-term debt, $43,000,000 in preferred stock, and $2,452,820,959 in common equity (Exh. ES-DPH-2 (East), Sch. DPH-31, at 1 (Rev. 3)). These balances produce a capital structure consisting of 45.69 percent long-term debt, 0.94 percent preferred stock, and 53.37 percent common equity (Exhs. ES-DPH-1, at 176; ES-DPH-2 (East), Sch. DPH-31, at 1 (Rev. 3); ES-RBH-1, at 3).

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[324] As stated above in Section V above, Eversource plans to complete a corporate consolidation of NSTAR Electric and WMECo effective January 1, 2018. For this proceeding, the Companies maintain separate revenue requirement calculations (Exh. ES-DPH-1, at 3).

As of the test year-end, WMECo's capital structure consisted of $565,000,000 in long-term debt and $643,905,916 in common equity (Exhs. ES-RBH-1, at 3; ES-DPH-2 (West), Sch. DPH-31, at 1 (Rev. 3)). These balances correspond to a test year-end capital structure consisting of 46.66 percent long-term debt and 53.34 percent common equity (Exhs. ES-RBH-1, at 3; ES-DPH-1, at 176-177; ES-DPH-2 (West), Sch. DPH-31, at 1 (Rev. 3)). WMECo excluded the portion of capitalization attributable to its solar investments, calculated in accordance with Article 8.2 of the settlement between WMECo and the Attorney General in Western Massachusetts Electric Company, D.P.U. 09-05 (2009) (Exhs. ES-DPH-1, at 177; ES-DPH-2 (West), Sch. DPH-31, at 1 (Rev. 3)). In order to effect this settlement provision, WMECo reduced its test year-end long-term debt balance by $17,024,396 and reduced its test year-end common equity balance by $17,495,502[325] (Exhs. ES-DPH-1, at 177; ES-DPH-2 (West), Sch. DPH-31, at 1 (Rev. 3)). WMECo's capitalization adjustments produce a capital structure consisting of $547,975,604 in long-term debt and $626,410,414 in common equity (Exh. ES-DPH-2 (West), Sch. DPH-31, at 1 (Rev. 3)).

2. Attorney General Proposal

The Attorney General proposes capital structures for both NSTAR Electric and WMECo that scale the Companies' common equity ratios so that they are equal in proportion to their long-term debt ratios, as a way to reduce the cost of equity, take advantage of

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[325] The settlement in D.P.U. 09-05 provides that the revenue requirement associated with WMECo's solar investments will be determined using a capital structure equal to its average debt and equity ratios over the previous five quarters. D.P.U. 09-5, at 11; M.D.P.U. No. 1044E, at 2-3.

lower-cost debt, and reduce the revenue requirement to the benefit of ratepayers (Exh. AG-JRW-1, at 37). In support of her proposal, the Attorney General notes that the average common equity ratio of both her proxy group and the Companies' proxy group are lower than the Companies' proposed capital structures (Exh. AG-JRW-1, at 35-36). The Attorney General's proxy group has an average common equity ratio of 45.33 percent and the Companies' proxy group has an average common equity ratio of 46.90 percent, compared to the Companies' proposed 53.37 percent for NSTAR Electric and 53.34 percent for WMECo (Exhs. AG-JRW-1, at 34-36; AG-JRW-4, at 1).[326] Reasoning that the Companies' common equity proposals produce higher costs and lower financial risk relative to both sets of proxy groups, the Attorney General recommends an imputed common equity ratio of 50.00 percent for both NSTAR Electric and WMECO (Exhs. AG-JRW-1, at 38-39; AG-JRW-5). To achieve this ratio, the Attorney General proportionally increases NSTAR Electric's long-term debt ratio from 45.69 percent to 48.99 percent, and correspondingly increases NSTAR Electric's preferred stock from 0.94 percent to 1.01 percent (Exhs. AG-JRW-1, at 39; AG-JRW-5). She adjusts WMECo's long term debt to 50.00 percent (Exhs. AG-JRW-1, at 39; AG-JRW-5).

Based on this analysis, the Attorney General recommends an imputed capital structure for NSTAR Electric consisting of 48.99 percent long-term debt, 1.01 percent preferred stock, and 50.00 percent common equity, and an imputed capital structure for WMECo of

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326 The Attorney General presents financial results using both mean and medians, however, she has used the median as a measure of central tendency intending to cancel out the influence of outliers among means (Attorney General Brief at 69 n.23, citing Exh. AG-JRW-1, at 33 n.24).

50.00 percent long-term debt and 50.00 percent common equity (Exhs. AG-JRW-1, at 39; AG-JRW-5).

3. FEA Proposal

FEA states that Standard & Poor's Financial Services, LLC's ("S&P")[327] credit rating assessments of utilities consider both on-balance sheet and off-balance sheet debt obligations in measuring a utility's financial risk (Exh. FEA-MPG-1, at 43-44 (Corrected)).[328] FEA determines that NSTAR Electric and WMECO's adjusted debt ratios are 47 percent and 48 percent, respectively, which FEA considers to be significantly lower than that of industry medians for utilities with comparable bond ratings (Exh. FEA-MPG-1, at 44-45 (Corrected)). Based on this information, FEA concludes that both NSTAR Electric and WMECO have capital structures that are too heavily weighted with common equity, which unjustifiably increases their cost of capital, cost of service, and retail rates (Exh. FEA-MPG-1, at 45 (Corrected)).

In order to remedy what it considers to be unbalanced capital structures, FEA reduces the common equity ratio for both NSTAR Electric and WMECo to 50.00 percent by transferring common equity to long-term debt (Exhs. FEA-MPG-1, at 43-44, 84 (Corrected);

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327 Standard & Poor's Financial Services LLC is a financial services company that provides credit ratings, financial research and analysis on stocks, and is known for its stock market indices.

328 According to S&P, off-balance sheet debt obligations include "the debt-like characteristics of purchased power obligations, operating leases, and other financial obligations that are not capitalized on a utility's balance sheet" (Exhs. FEA-MPG-1, at 43; FEA-MPG-3, n.3; FEA-MPG-22 (note), citing S&P Capital IQ, CreditStats Direct, last updated March 29, 2017).

FEA-MPG-6; FEA-MPG-22). To accomplish the adjustment, FEA reduces NSTAR Electric's common equity balance by $154,910,480, thus bringing that company's common equity ratio to 50.00 percent, with a corresponding increase to NSTAR Electric's long-term debt balance (Exhs. FEA-MPG-1, at 48-49 (Corrected); FEA-MPG-6; FEA-MPG-22, at 2). This adjustment produces a capital structure consisting of $2,254,910,480 in long-term debt, $43,000,000 in preferred stock, and $2,297,910,480 in common equity (Exhs. FEA-MPG-1, at 48-49 (Corrected); FEA-MPG-22, at 2). For WMECo, FEA reduces its common equity balance by $39,217,405, thus bringing that company's common equity ratio to 50.0 percent, with a corresponding increase to WMECo's long-term debt (Exhs. FEA-MPG-1, at 48-49 (Corrected); FEA-MPG-22, at 2). This adjustment produces a capital structure consisting of $587,193,009 in long-term debt and $587,193,009 in common equity (Exhs. FEA-MPG-1, at 48-49 (Corrected); FEA-MPG-22, at 2).

4. Sunrun and EFCA Proposal

Sunrun and EFCA propose imputing a debt ratio of 51.00 percent for both NSTAR Electric and WMECo, while proposing common equity ratios of 48.06 percent for NSTAR Electric and 49.00 percent for WMECo, and a preferred stock ratio of 0.94 percent for NSTAR Electric (Exh. SREF-DJG-1, at 7-10; SREF-DJG-1, App. F).[329] Sunrun and EFCA note that, although NSTAR Electric and WMECo can support debt ratios above 60.00 percent, they selected debt and capital ratios closer to the Companies' proxy group

[329] On brief, Cape Light Compact also supports use of a 51.00-percent debt ratio for both NSTAR Electric and WMECo (Cape Light Compact Brief at 74).

average to avoid making too abrupt a change to the Companies' proposals (Exh. SREF-DJG-1, App. F at 8-15).

5. Positions of the Parties

a. Attorney General

The Attorney General challenges the Companies' proposed capital structures (Attorney General Brief at 64-66; Attorney General Reply Brief at 63-64). Specifically, she contests Eversource's proposed capitalization ratios and the omission from NSTAR Electric's proposed capital structure of $350 million in long-term debt issued in May 2017 (Attorney General Brief at 64-66; Attorney General Reply Brief at 63-64).[330]

On the first point, the Attorney General argues that NSTAR Electric's and WMECo's proposed capital structures have more common equity and, consequently, indicate less financial risk than the capital structures of other electric utilities (Attorney General Brief at 64; Attorney General Reply Brief at 63). She notes that her proxy group companies show lower average capitalization ratios than Eversource's proposed capital structures, with common equity averaging 45.33 percent, long-term debt averaging 48.76 percent, short-term debt averaging 5.78 percent, and preferred debt averaging 0.12 percent (Attorney General Brief at 64; Attorney General Reply Brief at 64). She also contests the Companies' claims

330 As discussed in Section V.D above and further below, the Department previously approved NSTAR Electric's application to issue long-term debt securities from time-to-time until December 31, 2018, in an amount not to exceed $700 million. NSTAR Electric Company, D.P.U. 16-189, at 16-19, 24-25 (March 30, 2017). Pursuant to this authorization, NSTAR Electric issued long-term debt as follows: $350 million on May 10, 2017 and $350 million on October 5, 2017. At the time that the parties submitted briefs on the capital structure issue, Eversource had issued only $350 million in long-term debt pursuant to D.P.U. 16-189.

that NSTAR Electric's and WMECo's proposed capital structures are "very similar" to those approved by the Department in D.P.U. 15-80/D.P.U. 15-81 and D.P.U. 15-155, stating that their common equity ratios are actually higher than what she considers to be the already high equity ratios approved in those proceedings (Attorney General Reply Brief at 64, citing D.P.U. 15-155, at 346; D.P.U. 15-80/D.P.U. 15-81, at 253). The Attorney General maintains that when a regulated utility's capital structure contains a high equity ratio, options include: (1) imputing a more reasonable capital structure to be reflected in revenue requirements; and (2) recognizing the high equity ratio's influence on reducing financial risk as a rationale for authorizing a lower ROE (Attorney General Brief at 64; Attorney General Reply Brief at 63). For these reasons, the Attorney General recommends the Department use an imputed common equity ratio of 50.00 percent for both NSTAR Electric and WMECo (Attorney General Brief at 65; Attorney General Reply Brief at 63).

On the second point, the Attorney General claims that the Companies failed to include NSTAR Electric's May 6, 2017 long-term debt issuance of $350 million in its determination of the capital structure and revenue deficiency in the current proceeding (Attorney General Brief at 65, citing Exhs. ES-DPH-2, Sch. DPH-31, at 1-2 (East); ES-DPH-2, Sch. DPH-31, at 1-2 (West)). The Attorney General maintains that the debt issuance is consequential because it increases the outstanding balance of long-term debt and the ratio of long-term debt used in the WACC (Attorney General Brief at 65). The Attorney General argues that the Department requires a company to adjust its capital structure for long-term debt issued after the end of the test year, and thus she recommends that the Department include NSTAR

Electric's $350 million debt issue in the calculation of the capital structure and the cost of debt when determining the Company's overall WACC (Attorney General Brief at 65-66, citing the following regarding inclusion of post-test year debt issuances: D.P.U. 15-155, at 343-344; D.P.U. 11-43, at 204-205; D.P.U. 07-71, at 122-123; D.T.E. 05-27, at 272; D.P.U. 84-94, at 52-53).

b. FEA

FEA argues that the Companies' proposed capital structures contain excessive amounts of common equity relative to total capital, which unnecessarily inflates the revenue requirement and places too heavy a rate burden on ratepayers (FEA Brief at 17). FEA assessed NSTAR Electric's and WMECo's off-balance sheet obligations and determined that both Companies had adjusted debt ratios that were much lower than the industry median adjusted debt ratios for regulated utilities with the same bond ratings (FEA Brief at 18). According to FEA, the Companies' actual capital structures contain more common equity than necessary to support their bond ratings (FEA Reply Brief at 1). Additionally, FEA asserts that the Companies' proposed common equity ratios of over 53.00 percent are significantly higher than the Companies' proxy group average common equity ratio of 48.50 percent, and, therefore, are unreasonable (FEA Brief at 19). FEA contends that an imputed 50.00-percent common equity ratio will preserve the Companies' investment grade bond ratings at a lower cost to customers, and is consistent with sound utility financing principles (FEA Reply Brief at 2). In addition, FEA argues that adjusting the capital

structures of both Companies to a 50.00-percent common equity ratio strikes a better balance between the interests of investors and ratepayers in setting rates (FEA Brief at 20).

c. Sunrun and EFCA, and Cape Light Compact

Sunrun and EFCA, as well as Cape Light Compact, comment briefly on the Companies' proposed capital structures, and maintain that the Companies' debt ratios should be increased to replace higher-cost equity and to lower rates charged to customers (Sunrun and EFCA Brief at 20; Cape Light Compact Brief at 74). Cape Light Compact supports the use of an imputed debt ratio of 51.00 percent to represent what is considers to be a more prudent capital structure for both NSTAR Electric and WMECo (Cape Light Compact Brief at 74).

d. Companies

The Companies argue that their use of the actual test year capital structure is consistent with Department precedent (Companies Brief at 279, citing D.P.U. 13-75, at 274-276; D.P.U. 12-25, at 386-388; D.P.U. 09-30, at 303-304; Companies Reply Brief at 148, citing D.P.U. 15-80/D.P.U. 15-81, at 253). Eversource additionally contends that the proposed capital structures are within range of the equity ratios of the Companies' proxy group (Companies Brief at 280, citing Exh. ES-RBH-1, at 71). According to Eversource, the 53.37- and 53.34-percent common equity ratios proposed for NSTAR Electric and WMECo, respectively, are consistent with the equity capitalization ratios of other comparable electric distribution companies (Companies Brief at 516, citing Exhs. ES-RBH-Rebuttal-1, at 67; ES-RBH-Rebuttal-8; Companies Reply Brief at 148). Further, Eversource asserts that the Department consistently accepts a utility's test year-end capital structure and that the

Department will depart from using the actual capital structure only when it "deviates from sound utility practices" (Companies Brief at 280, citing D.P.U. 15-155, at 343, 346; D.P.U. 15-80/15-81, at 250, 253; D.P.U. 14-150, at 315). For these reasons, the Companies assert that the Department should reject the Attorney General's, Sunrun and EFCA's, and FEA's proposed imputed capital structures for NSTAR Electric and WMECo (Companies Brief at 515, 532-533, 536; Companies Reply Brief at 149).

The Companies further recommend that the Department reject the Attorney General's proposal to incorporate NSTAR Electric's May 2017 issuance of $350 million in long-term debt because it ignores other post-test year changes in NSTAR Electric's capital structure (Companies Brief at 517-518). The Companies argue that the $350 million debt issuance is only one of multiple post-test year changes to NSTAR Electric's capital structure, including to both debt and common equity levels (Companies Brief at 518, citing Tr. 13, at 2800-2801; Tr. 15, at 3123-3124). According to the Companies, during the first six months after the end of the test year, increases in NSTAR Electric's retained earnings resulted in an increase in the common equity ratio from 53.34 percent to 55.49 percent (Companies Brief at 518, citing Tr. 13, at 2800; Tr. 15, at 3123). Prior to the issuance of the $350 million in debt in May 2017, NSTAR Electric's common equity ratio had risen to 55.7 percent (Companies Brief at 518, citing Tr. 15, at 3123). By the end of 2017, the Companies project that NSTAR Electric's common equity ratio will be 53.34 percent after Eversource issues an additional $350 million in new long-term debt (Companies Brief at 518, citing Tr. 15,

at 3124).[331] Eversource maintains that because NSTAR Electric's levels of common equity and long-term debt fluctuate over time, it would not be appropriate to accept only the issuance of $350 million long-term debt as a post–test year adjustment to the capital structure without accepting other post-test year adjustments related to common equity (Companies Brief at 518, citing Tr. 13, at 2801).

6. Analysis and Findings

a. Introduction

A company's capital structure typically consists of long-term debt, preferred stock, and common equity. D.P.U. 07-71, at 122; D.T.E. 03-40, at 319; D.T.E. 01-56, at 97; Pinehills Water Company, D.T.E. 01-42, at 17-18 (2001). The ratio of each capital structure component to the total capital structure is used to weight the cost (or return) of each capital structure component to derive a WACC. The WACC is used to calculate the rate of return, which is applied to the company's rate base as part of the revenue requirement established by the Department, and is made up of two components: (1) the cost of the company's long-term debt and preferred stock and (2) the ROE set by the Department. D.P.U. 07-71, at 122; D.T.E. 03-40, at 319; D.T.E. 01-42, at 17-18; South Egremont Water Company, D.P.U. 86-149, at 5 (1986).

The Department normally will accept a company's test year-end capital structure, allowing for known and measurable changes. D.T.E. 03-40, at 323-324; D.P.U. 88-67 (Phase I) at 174; D.P.U. 84-94, at 50. Within a broad range, the Department will defer to

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331 The additional $350 million in new debt issuances would complete the redemption of $400 million total in maturing debt the Companies identified, and the Department authorized, in D.P.U. 16-189, at 2, 16-19, 24-25 (Exh. DPU-31-6).

the management of a utility in decisions regarding the appropriate capital structure, unless the capital structure deviates substantially from sound utility practice. Mystic Valley Gas Company v. Department of Public Utilities, 359 Mass. 420, 428-429 (1971); D.P.U. 1360, at 26-27; Blackstone Gas Company, D.P.U. 1135, at 4 (1982); see also Cambridge Electric Light Company, D.P.U. 20104, at 42 (1979).

b. Test-Year Capital Structure

As stated above, at test-year end, June 30, 2016, NSTAR Electric reported a long-term debt balance of $2,100,000,000; WMECo reported a long-term debt balance of $565,000,000. The Companies made no adjustment to NSTAR Electric's long-term debt balance. As stated above, the Companies reduced WMECo's test-year end long-term debt balance by $17,024,396 to effect the settlement agreement approved in D.P.U. 09-05, which produces an adjusted test-year end long-term debt balance of $547,975,604.

At test-year end, June 30, 2016, NSTAR Electric reported a preferred stock balance of $43,000,000. The Companies made no adjustment to NSTAR Electric's preferred stock balance.

At test-year end, June 30, 2016, NSTAR Electric reported a common equity balance of $2,452,820,059, consisting of: (1) $100 in common stock; (2) $2,180,445,418 in additional paid-in capital; (3) $269,648,377 in retained earnings; (4) $2,202,893 in undistributed earnings from subsidiaries; and (5) $524,171 in accumulated other comprehensive income ("AOCI") (Exhs. ES-DPH-4 (East), Sch. DPH-1, at 5; ES-DPH-2

(East), Sch. DPH-31, at 1 (Rev. 3)).[332] The Companies made no adjustment to NSTAR Electric's common equity balance. As of the end of the test year, WMECo reported a common equity balance of $643,905,916, consisting of: (1) $10,866,325 in common stock; (2) $3,905,151 in premiums on capital stock; (3) $422,492,440 in additional paid-in capital; (4) $209,934,694 in retained earnings; (5) a negative $702,479 in undistributed earnings from subsidiaries; and (6) a negative $2,590,215 in AOCI (Exhs. ES-DPH-4 (West), Sch. DPH-1, at 5; ES-DPH-2 (West), Sch. DPH-31, at 1 (Rev. 3)). As described above, WMECo reduced its common equity balance by $17,495,502 attributable to its solar investments, producing a revised common equity balance of $626,410,414 (Exh. ES-DPH-2 (West), Sch. DPH-31, at 1 (Rev. 3). The Companies made no other adjustments to WMECo's common equity balance. None of the parties briefed on the issue of the components of the Companies' proposed common equity balances.

Regarding undistributed investment in subsidiaries, equity investment in affiliates (i.e., original investment plus accumulated earnings) is excluded from utility capital structures. Including these amounts would improperly weight a company's capital structure by including investment not used in the utility's operations. D.P.U. 94-50, at 440; D.P.U. 84-94, at 51; D.P.U. 18515, at 56-58. Therefore, the Department excludes these amounts from the Companies' proposed common equity balances. Regarding AOCI, while it is reported on the balance sheet for financial reporting purposes, the Department does not

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332 AOCI refers to balance sheet entries associated with certain types of financial activity, including gains and losses on investments and pension obligations. D.P.U. 09-39, at 337 n.86; Nantucket Electric Company and Massachusetts Electric Company, D.T.E. 04-74, at 21-22 (2004)).

include these types of balance sheet entries in capitalization. D.P.U. 15-155, at 344; D.P.U. 09-39, at 337 n.86; Nantucket Electric Company and Massachusetts Electric Company, D.T.E. 04-74, at 21-22 (2004). Therefore, the Department excludes these ACOI amounts from the Companies' proposed common equity balances.

c. Post Test-Year Changes

NSTAR Electric issued $350 million in long-term debt in May 2017 and an additional $350 million on October 5, 2017, pursuant to the Department's authorization in NSTAR Electric Company, D.P.U. 16-189 (March 30, 2017) (Exhs. DPU 31-6; AG-26). See D.P.U. 16-189, Compliance Filing (October 13, 2017). NSTAR Electric's October 5, 2017 long-term debt issuance would be applied to redeeming $400 million in long-term debt maturing November 15, 2017 (Exhs. DPU-31-6; AG-1-2). D.P.U. 16-189, at 2, 11. WMECo has no post test-year long-term debt issuances.

On November 30, 2016, after the end of the test year, NSTAR Electric received $25,000,000 in capital contributions from its parent company, Eversource Energy (Exh. AG-15-7, Att. (b)). NSTAR Electric received an additional $25,000,000 from Eversource Energy on December 30, 2016 (Exh. AG-15-7, Att. (b)). On September 30, 2016, WMECo received $18,000,000 in capital contributions from Eversource Energy (Exh. AG-15-7, Att. (b)). The Companies report that there have been no additional capital contributions made during 2017 (Exhs. DPU-31-8; AG-15-7, Att. (b)).

As of December 31, 2016, NSTAR Electric reported a retained earnings balance of $438,467,346 (Exh. AG-1-2, Att. (a) at 32 (Supp.3)). As of December 31, 2016, WMECo

reported a retained earnings balance of $218,917,697 (Exh. AG-1-2, Att. (b) at 37 (Supp. 3)). During the course of the evidentiary proceedings, the Companies' witness testified that, during 2017, retained earnings continued to grow, resulting in an increased equity ratio, which was offset by the issuance of the indebtedness by the Companies in 2017 (Tr. 13, at 2800-2802; Tr. 15, at 3123-3124). The Companies contend that the debt issuances were necessary to keep the equity ratio in line with the test year amounts (Tr. 13, at 2800-2802; Tr. 15, at 3123-3124). A retained earnings balance as of the date of the issuances, however, is not available in the record.

Because retained earnings balances fluctuate from one quarter to another to a greater degree than other components of capitalization, the Department has not generally considered post-test year adjustments to retained earnings balances to be more representative than test year-end balances. D.P.U. 09-39, at 338; Milford Water Company, D.P.U. 92-101, at 36-37 (1992); D.P.U. 1350, at 156; Massachusetts Electric Company, D.P.U. 1133, at 21-22 (1982); D.P.U. 18515, at 54. Notwithstanding this general practice, however, the Department has recognized post-test year adjustments to retained earnings balances, upon a showing that the updated retained earnings balance was more representative of that company's future retained earnings. D.P.U. 14-120, at 121-122.

The Department has examined the Companies' retained earnings activities, based on NSTAR Electric's Annual Returns to the Department for the years 2007 through 2016 and WMECo's Annual Returns to the Department for the years 2009 through 2016. NSTAR Electric's retained earnings increased from $831,528,187 as of December 31, 2007 (i.e., the

first full year after the merger of the predecessor companies to NSTAR Electric) to $1,234,807,729 as of December 31, 2011 (Exhs. AG-1-2, Att. (7)(b through j); AG-1-2, Att. (a) at 40 (Supp. 3)). In 2012, NSTAR Electric transferred $1,181,068,901 in retained earnings to paid-in capital in connection with the merger of Northeast Utilities with NSTAR in D.P.U. 10-170, after which NSTAR Electric's retained earnings increased year over year to $438,467,346 as of December 31, 2016 (Exh. AG1-2, Att. (7)(g) at 38, 40). Aside from this transaction, and occasional transfers from unappropriated undistributed subsidiary earnings, there appears to be no particularly unusual activity in NSTAR Electric's retained earnings account (Exhs. AG-1-2, Att. (7)(b through j); AG-1-2, Att. (a) at 40 (Supp. 3)). Similarly, WMECo's retained earnings have increased from $91,143,206 as of December 31, 2009 to $218,917,697 as of December 31, 2016 (Exhs. AG-1-2, Att. (7)(k through p); AG-1-2, Att. (b) at 37 (Supp. 3)). Aside from a decrease in retained earnings in 2014 because dividends exceeded net earnings by about $2 million in that year, and some small transfers from unappropriated undistributed subsidiary earnings made at various times during this period, there appears to be no particularly unusual activity in WMECo's retained earnings account (Exhs. AG-1-2, Att. (7)(k through p); AG-1-2, Att. (b) at 37 (Supp. 3)). Based on our examination of this information, the Department finds it relevant to no longer treat a company's test year-end retained earnings balance necessarily as the most representative basis for determining its capital structure for ratemaking purposes.

Regarding capital structure, the Department will make adjustments only for known and measurable amounts and properly matched changes to test year-end balances. The

purpose of these adjustments would be to accurately reflect a utility's present financial situation and fairly predict its future financial position. See, e.g., Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 24 (1978).[333] In so doing, we also must decline known or anticipated changes that would distort the correlation among the capital structure components. In this case, we recognize changes to various components to NSTAR Electric and WMECo's capital structures during various times after the test year. Changes to NSTAR Electric's test year long-term debt balance occurred with long-term debt issuances in May 2017 and October 2017, and with a long-term debt redemption in connection with the October 2017 issuance. As noted above, changes to NSTAR Electric's test year common equity balance occurred with Eversource Energy capital contributions in November 2016 and December 2016. In addition, the record provides the retained earnings balances at December 31, 2016, for NSTAR Electric and WMECo. Because of the timing mismatch among these post test-year changes, making these changes would not produce a suitable correspondence among the components to fairly represent NSTAR Electric's capital structure, nor would those adjustments be based on fully known and measurable record evidence in this proceeding. In particular, the lack of record evidence for post test-year retained earnings balances near NSTAR Electric's post test-year long-term debt issuances does not allow for a

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333 The Court has similarly held that to the extent that known or anticipated changes in revenues, expenses, or rate base will distort the correlation among these elements, adjustments are made in the test-year data to reflect those changes. The approach depends on keeping the three elements in phase, however, and if an out-of-period adjustment is made to one, corresponding adjustments to the others may be necessary to preserve a fair relationship. Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, at 24 (1978); Bay State Gas Company v. Dep't of Public Utilities, 459 Mass. 807, at 814-815 (2011).

pertinent correlation. Therefore, the Department finds it appropriate to apply NSTAR Electric's test year-end capital structure, which is supported on the record in this proceeding and for which all elements correlate to the test year end of June 30, 2016, adjusted for: (1) undistributed investment in subsidiaries of $2,202,893 and (2) ACOI of $524,171.

Changes to WMECo's test year common equity balance occurred with an Eversource Energy capital contribution in September 2016. We find that WMECo's retained earnings balance at December 31, 2016 is sufficiently proximate to the capital contribution that we will make these post test-year changes to WMECo's capital structure. Therefore, the Department finds it appropriate to adjust WMECo's test year-end common equity balance for: (1) undistributed investment in subsidiaries of negative $702,479; (2) ACOI of negative $2,590,215; (3) solar investment adjustment to common equity of $17,495,502; and (4) retained earnings at December 31, 2016. Also, WMECo's test year-end long-term debt balance is adjusted for solar investment $17,024,396.

Based on WMECo's test year-end common equity balance, adjusted for the $18,000,000 in capital contributions and its retained earnings balance as of December 31, 2016, WMECo's common equity balance is $674,181,613, consisting of: (1) $10,866,325 in common stock; (2) $3,905,151 in premiums on capital stock;(3) $440,492,440 in additional paid-in capital; and (4) $218,917,697 in retained earnings (Exh. AG-1-2(b) at 30 (Supp. 3)). After reducing WMECo's common equity by $17,495,502 associated with solar investments recovered through a separate mechanism, based on WMECo's test year-end common equity balance, adjusted for the $18,000,000 in capital contributions and its retained earnings

balance as of December 31, 2016, WMECo's adjusted common equity balance is $656,686,129 (Exh. AG-1-2, Att. (b) (Supp. 3)). Therefore, the Department uses these adjusted balances to calculate WMECo's common equity component of its capital structure.

d. Conclusion

The aforementioned adjustments produce a capital structure for NSTAR Electric consisting of $2,100,000,000 in long-term debt 45.72 percent), $43,000,000 in preferred stock (0.94 percent), and $2,450,093,895 in common equity (53.34 percent). The Department does not consider this ratio to be so weighted towards equity as to deviate substantially from sound utility practice or impose an unfair burden on consumers. Mystic Valley Gas Company v. Department of Public Utilities, 359 Mass. 420, 428-430 (1971); Boston Gas Co. v. Department of Public Utilities, 359 Mass. 292, 301-302 (1971). Accordingly, we decline to adopt the imputed capital structures recommended by the Attorney General, FEA, and Sunrun and EFCA. Instead, the Department will use the capital structure determined above for purposes of calculating NSTAR Electric's overall cost of capital.

For WMECo, our adjustments produce a capital structure consisting of $547,975,604 in long-term debt (45.49 percent) and $656,686,129 in common equity (54.51 percent). While this common equity ratio is somewhat higher than those approved by the Department in recent years for electric distribution companies,[334] we do not conclude that such a ratio is

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[334] The Department approved common equity ratios of 47.78 percent for the electric division of Fitchburg Gas and Electric Light Company ("Fitchburg") in D.P.U. 13-90, at 203; 52.92 percent for Fitchburg's electric division in

so weighted towards equity as to deviate substantially from sound utility practice or impose an unfair burden on consumers. Mystic Valley Gas Co. v. Department of Public Utilities, 359 Mass. 420, 428-430 (1971); Boston Gas Co. v. Department of Public Utilities, 359 Mass. 292, 301-302 (1971). To the extent that the Companies' common equity ratios vary from those of the proxy groups used in this case, that factor will be considered in determining the appropriate ROE for Eversource. Accordingly, we decline to adopt the imputed capital structures recommended by the Attorney General, FEA, Sunrun and EFCA, and the Cape Light Compact. Instead, the Department will use the capital structure determined above for purposes of calculating WMECo's overall cost of capital.

The effects of NSTAR Electric's and WMECo's capital structures on their respective WACCs and revenue requirements are provided in each operating company's Schedule 5 of this Order.

C. Cost of Debt and Preferred Stock

1. Companies Proposal

The Companies have proposed long-term debt costs of 3.88 percent for NSTAR Electric and 4.07 percent for WMECo (Exhs. ES-DPH-2 (East), Sch. DPH-31, at 2 (Rev. 3); ES-DPH-2 (West), Sch. DPH-31, at 2 (Rev. 3)). The Companies derived these embedded cost rates by dividing the adjusted annual interest and amortization expense by the adjusted (pro forma) net carrying value of the long-term debt as described below (Exhs. ES-DPH-2 (East), Sch. DPH-31, at 2 (Rev. 3); ES-DPH-2 (West), Sch. DPH-31, at 2 (Rev. 3)).

D.P.U. 15-80/D.P.U. 15-81, at 253; and 50.70 percent for Massachusetts Electric Company and Nantucket Electric Company in D.P.U. 15-155, at 346.

In the initial filing, Eversource calculated a cost of long-term debt of 4.31 percent for NSTAR Electric, produced by dividing $89,533,000, representing the sum of (1) $88,075,000 in annual interest expense, and (2) $1,458,000 in amortization of premiums, by the net carrying value of its long-term debt of $2,078,810,000, consisting of $2,100,000,000 in face value of its long-term bonds outstanding, less the sum of (1) $8,113,000 in debt discounts and (2) $13,077,000 in issuance costs (Exh. ES-DPH-2 (East), Sch. DPH-31, at 2). The Companies adjusted NSTAR Electric's cost of long-term debt from 4.31 percent to 4.32 percent to correct an error (Exh. AG-15-11). Further, during the course of the proceeding, Eversource adjusted NSTAR Electric's initially proposed cost of debt to recognize the replacement of $400 million in long-term debt maturing on November 15, 2017, with $350 million in long-term debt issued at a lower interest rate, based on the rate associated with NSTAR Electric's issuance of $350 million in May 2017 (Exhs. ES-DPH-2 (East), Sch. DPH-31, at 2; ES-DPH-2 (East), Sch. DPH-31, at 2 (Rev. 3); DPU-31-6; Tr. 15, at 3124-3125; RR-DPU-42).[335] The debt swap reduced the embedded cost of long-term debt from 4.32 percent to 3.88 percent (Exhs. ES-DPH-2 (East), Sch. DPH-2 (Rev. 2); ES-DPH-2 (East), Schs. DPH-31, at 2 (Rev. 2), DPH-33, at 4 (Rev. 3); RR-DPU-42). Eversource proposed a cost rate of 4.56 percent for NSTAR Electric's preferred stock (Exh. ES-DPH-2 (East), Sch. DPH-31, at 1 (Rev. 3)).

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335 In this calculation, Eversource replaced $400,000,000 of NSTAR Electric's 5.625 percent series debentures maturing on November 15, 2017 with $350,000,000 in long-term debt issued at a rate of 3.20 percent associated with the Department's approval in D.P.U. 16-189 of the issuance of up to $700,000,000 from time to time through December 31, 2018 (Exhs. ES-DPH-2 (East), Sch. DPH-31, at 2 (Rev. 2); DPU-31-6; RR-DPU-42). See also D.P.U. 16-189, at 24-26.

In the initial filing, Eversource calculated a cost of long-term debt of 4.32 percent for WMECo, produced by dividing $23,530,000, representing the sum of (1) $23,704,000 in annual interest expense and (2) $613,000 in amortization of premiums, less (3) $787,000 in interest expense associated with solar investments, by the net carrying value of its long-term debt of $544,781,000, consisting of $565,000,000 in face value of its long term bonds outstanding, less the sum of (1) $16,362,000 in debt costs associated with solar investment costs being recovered through the Solar Cost Adjustment Factor, (2) $831,000 in debt discounts, and (3) $3,025,000 in issuance costs (Exh. ES-DPH-2, Sch. DPH-31, at 2 (East)). During the course of the proceeding, WMECo revised its proposed cost of long-term debt to 4.07 percent based on a number of corrections (Exhs. ES-DPH-2 (West), Sch. DPH-31, at 2 (Rev. 1); AG-15-11). The 4.07 percent cost of debt is derived from dividing $22,426,000 in annual interest and amortization expense by $550,538,000 in the net carrying value of its outstanding long-term debt (Exh. ES-DPH-2 (West), Sch. DPH-31, at 2 (Rev. 3)). WMECo's annual interest and amortization expense includes $23,704,000 in annual interest costs, less (1) $491,000 in amortization expense, and (2) $787,000 representing debt costs associated with solar investment being recovered through the Solar Cost Adjustment Factor (Exh. ES-DPH-2 (West), Sch. DPH-31, at 2 (Rev. 3)). WMECo's revised net carrying charge of 4.07 percent is based on the $565,000,000 face value of its long-term bonds outstanding and $4,715,000 in debt premiums, less (1) $16,362,000 in solar adjustments and (2) $2,815,000 in issuance costs (Exh. ES-DPH-2 (West), Sch. DPH-31, at 2 (Rev. 3)).

2. Intervenor/Limited Intervenor Proposals

FEA, as well as Sunrun and EFCA, propose to use the cost rates for long-term debt that Eversource initially proposed for each operating company (Exhs. AG-JRW-1, at 39; JRW-1; JRW-5; FEA-MPG-1, at 50; FEA-MPG-3; FEA-MPG-22, at 2; SREF-DJG-1, at 9-10; SREF-DJG-3; SREF-DJG-4). FEA and Sunrun and EFCA did not revise their proposals to incorporate Eversource's revised cost rates. The Attorney General initially accepted Eversource's proposed cost of long-term debt (Exhs. AG-JRW-1, at 39; JRW-1; JRW-5). As noted below, however, on brief the Attorney General contests the Companies' calculation of the proposed cost of long-term debt.

3. Positions of the Parties

a. Intervenors/Limited Intervenors

The Attorney General argues that the Companies inappropriately applied carrying charges on unamortized issuance costs when issuing long-term debt (Attorney General Brief at 66). She asserts that the appropriate treatment of issuance costs is to allow their recovery as a straight line amortization over the term of the debt issuance without carrying charges (Attorney General Brief at 67, citing D.P.U. 15-155, at 343-344; D.T.E. 05-27, at 269-272; D.T.E. 03-40, at 319-324; D.P.U. 84-94, at 51-52). The Attorney General recommends that the Department correct the Company's calculation of the embedded cost of long-term debt for both NSTAR Electric and WMECo by using the total amount of debt outstanding as the denominator and the sum of the annual interest expense and the amortization of the issuance expense as the numerator when determining the embedded cost ratio, leaving

carrying charges out of the equation (Attorney General Brief at 67). The Attorney General does not provide the results of such a recalculation.

Neither FEA nor Sunrun and EFCA addressed on brief Eversource's proposed cost rates for long-term debt. Further, no other intervenor or limited intervenor addressed the issue.

b. Companies

The Companies did not respond to the Attorney General's request for recalculation of long-term debt issuance costs. Eversource noted that the 4.56-percent cost rate for NSTAR Electric's preferred stock is based on the operating company's average annual dividend rate (Companies Brief at 281, citing Exh. ES-DPH-2, Sch. DPH-31 (East)). The Companies recommend that the Department approve the proposed cost rates for both the long-term debt and preferred stock because each represents the actual costs, consistent with Department precedent (Companies Brief at 281, citing D.T.E. 01-56, at 97, 100; D.P.U. 90-121, at 157).

4. Analysis and Findings

The Department recognizes that costs associated with the issuance of long-term debt, such as issuance costs, debt discounts, and other amortizations, are necessary operating expenses and are expected to occur from time to time as long-term debt is issued by a company. D.P.U. 10-114, at 294; D.T.E. 01-56, at 99; D.P.U. 90-121, at 160. The appropriate ratemaking treatment of issuance costs is to include them in the effective cost of debt by amortizing the issuance costs over the life of the issue without providing a return on the unrecovered portion of the issuance costs. See D.P.U. 92-78, at 91-92; D.P.U. 90-121, at 160-161.

While Eversource's proposed debt expenses for NSTAR Electric and WMECo appropriately consider issuance costs, the Companies also have factored in carrying charges associated with these issuance costs by subtracting premiums and discounts and unamortized balances from their outstanding debt (Exhs. ES-DPH-2 (East), Sch. DPH-31, at 2 (Rev. 3); ES-DPH-2 (West), Sch. DPH-31, at 2 (Rev. 3)). The Department's policy with respect to the calculation of debt costs is to base the effective cost of debt on the face value of the outstanding debt, as opposed to the face value less various unamortized balances. D.P.U. 10-70, at 243-244; D.P.U. 95-40, at 80-81; D.P.U. 90-121, at 160-161; Boston Edison Company, D.P.U. 86-71, at 12 (1986). By reducing the outstanding debt balance by these amounts, Eversource's calculation artificially inflates the Companies' effective cost of debt. D.P.U. 14-150, at 324; D.P.U. 10-114, at 294; D.P.U. 90-121, at 160-161. The Companies have not presented any evidence or argument to support a departure from established Department precedent. Therefore, the Department declines to accept the Companies' proposed cost of long-term debt.

Based on Eversource's most recent updates, NSTAR Electric proposes an annual interest and amortization expense associated with long-term debt of $89,533,000 (Exhs. ES-DPH-2 (East), Sch. DPH-31, at 2 (Rev. 3); AG-15-11, Att. (a)). This annual expense includes $11,434,000 in costs associated with the $350 million in long-term debt issued on May 10, 2017 (Exh. ES-DPH-2 (East), Sch. DPH-31, at 2 (Rev. 3)). As discussed above, the Department has accepted the use of NSTAR Electric's test year-end capital structure. Consequently, the Department has excluded both the post-test year issuances of

$700,000,000 in long-term debt pursuant to D.P.U. 16-189 and the redemption of $400,000,000 in long-term debt that occurred on November 15, 2017. Consistent with this treatment, the Department will exclude the cost of the additional $700 million in long-term debt, and retain the cost of the $400,000,000 in redeemed debt in NSTAR Electric's cost of debt.

NSTAR Electric calculates a total interest and amortization expense of $89,652,000 associated with its test year-end long-term debt balance (Exh. ES-DPH-2 (East), Sch. DPH-31, at 2 (Revised 1). The Department has reviewed the Companies' calculations, and finds that Eversource has appropriately calculated NSTAR Electric's cost of long-term debt. Therefore, the Department will use a total annual interest and amortization expense of $89,653,000 for NSTAR Electric.

WMECo proposes an annual interest and amortization expense associated with long-term debt, net of solar-related adjustment, of $22,426,000 (Exhs. ES-DPH-2 (West), Sch. DPH-31, at 2 (Rev. 3); AG-15-11, Att. (b)). The Department has reviewed the Companies' calculations, and finds that Eversource has appropriately calculated WMECo's cost of long-term debt.

Dividing NSTAR Electric's annual interest and amortization expense of $89,653,000 by the face value of its test year-end long-term debt of $2,100,000,000 produces a cost of long-term debt of 4.27 percent, instead of the 3.88 percent cost rate proposed by Eversource (see Exh. ES-DPH-2 (East), Sch. DPH-31, at 2 (Rev. 3)). Dividing WMECo's annual interest and amortization expense of $22,426,000 by the face value of its outstanding

long-term debt of $565,000,000 produces a cost of long-term debt of 3.97 percent, instead of the 4.07 percent cost rate proposed by Eversource (see Exhs. ES-DPH-2 (West), Sch. DPH-31, at 2 (Rev. 3)). Therefore, the Department will apply a cost of long-term debt of 4.27 percent for NSTAR Electric and 3.97 percent for WMECo.

Turning to NSTAR Electric's preferred stock, these securities represent two series consisting of $18,000,000 with a dividend rate of 4.25 percent, and $15,000,000 with a dividend rate of 4.78 percent (Exh. ES-DPH-2 (East), Sch. DPH-31, at 1 (Rev. 3)). Eversource has proposed a weighted average dividend rate of 4.56 percent, based on the annual dividend for these securities (Exhs. ES-DPH-2 (East), Sch. DPH-31, at 1 (Rev. 3); AG-15-11, Att. (a)). No intervenor or limited intervenor addressed Eversource's proposed divided rate. The Department finds that Eversource calculated the cost of NSTAR Electric's preferred stock in a manner consistent with Department precedent. D.T.E. 01-56, at 97-100. Therefore, the Department will apply a cost of preferred stock of 4.56 percent for NSTAR Electric.

D. Proxy Groups

1. Companies Proxy Group

NSTAR Electric and WMECo are wholly owned subsidiaries of Eversource Energy, and are not publicly traded (Exh. ES-RBH-1, at 16). Therefore, the Companies have no public market for their stock. Consequently, Eversource presents its ROE analysis using the capitalization and financial statistics of a proxy group of 20 electric companies (Exhs. ES-RBH-1, at 18-20; ES-RBH-9). The Companies selected their proxy group from a group of 41 companies classified as "electric utilities" by Value Line Investment Survey

("Value Line") (Exh. ES-RBH-1, at 18). From that group, Eversource chose companies that: (1) have consistently paid quarterly dividends; (2) have been covered by at least two utility industry equity analysts; (3) have investment grade senior unsecured bond and/or corporate credit ratings from S&P; (4) have received at least 60 percent of their total income from regulated utility operations over the past three fiscal years; (5) have received at least 60 percent of total regulated operating income from regulated electric utility operations over the three most recent fiscal years; and (6) are not currently known to be a party to a merger or other significant transaction (Exh. ES-RBH-1, at 18-19).

2. Attorney General's Proxy Group

In order to develop her rate of return recommendation, the Attorney General evaluated the return requirements of investors on the common stock of a proxy group of 30 publicly held electric utility companies (Exhs. AG-JRW-1, at 32-34; AG-JRW-4, at 1-2). In selecting those 30 companies, the Attorney General chose companies that: (1) have at least 50 percent of revenues from regulated electric operations as reported in their Form 10-K filed with the SEC; (2) are listed as an electric utility by Value Line; (3) have an investment grade issuer credit rating by Moody's Investors Service, Inc. ("Moody's")[336] and S&P; (4) have paid a cash dividend in the past six months, with no reductions or omissions; (5) have not been involved in an acquisition of another utility, nor have been the target of an acquisition in the past six months; and (6) have analysts' long-term earnings per share

[336] Moody's Investors Service is a bond credit ratings firm that also provides international financial research on bonds issued by commercial and government entities.

("EPS") growth rate forecasts available from Yahoo! Inc. ("Yahoo"), Thomson Reuters First Call ("First Call"), and/or Zacks Investment Research, Inc. ("Zacks") (Exh. AG-JRW-1, at 33). On an overall basis, the Attorney General's resulting proxy group: (1) receives 82 percent of their revenues from regulated electric operations; (2) have an BBB+ bond rating from S&P,[337] and Baa1 Moody's bond rating;[338] (3) have a current median common equity ratio of 46.9 percent; and (4) have an earned ROE of 9.3 percent (Exhs. AG-JRW-1, at 33-34; AG-JRW-4, at 1).

The Attorney General developed financial and market data for her proxy group and the Companies' proxy group and applied the DCF model to arrive at her common equity and ROE recommendation for Eversource of 8.875 percent for both NSTAR Electric and WMECo (Exh. AG-JRW-1, at 72; AG-JRW-10).

3. FEA, Sunrun and EFCA Proxy Groups

FEA, as well as Sunrun and EFCA, used Eversource's proxy group to determine their respective common equity and ROE recommendations (Exhs. FEA-MPG-1, at 52; FEA-MPG-7; SREF-DJG-1, at 7; SREF-DJG-5).

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337 Bonds rated "BBB+" by S&P exhibit adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. The ratings from "AA" to "CCC" may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. D.P.U. 15-155, at 349-350 n.259.

338 Bonds rated "Baa1" by Moody's are judged to be medium-grade and are subject to moderate credit risk, and thus may possess certain speculative characteristics. The modifier "1" indicates that the obligation ranks in the higher end of its generic rating category. D.P.U. 15-155, at 350 n.260.

4. Positions of the Parties

a. Intervenors/Limited Intervenors

The Attorney General: (1) maintains that her analysis shows that the Companies' investment risk is below that of the proxy group companies: (2) challenges the Companies' assertion concerning the use of short-term debt in her capital structure; and (3) claims that holding companies should not be used to estimate an equity cost rate for operating companies like NSTAR Electric and WMECo (Attorney General Brief at 64-65; Attorney General Reply Brief at 63-64). These arguments are set forth in further detail below.

With respect to investment risk, the Attorney General evaluated the return requirements of investors on the common stock of both her proxy group and the Companies' proxy group of publicly held electric utility distribution companies (Attorney General Brief at 68, citing Exhs. AG-JRW-1, at 32-35; AG-JRW 4).[339] According to the Attorney General, the issuer credit ratings for NSTAR Electric and WMECo are A according to S&P, and A2 according to Moody's, while the average issuer credit ratings for both her proxy group and the Companies' proxy group are BBB+ and Baa1, according to S&P and Moody's, respectively (Attorney General Brief at 68, citing Exhs. AG-JRW-1, at 73; AG-JRW-4, at 1). The Attorney General contends that Eversource's credit ratings are thus two notches above the S&P and Moody's issuer credit rating averages of BBB+ and Baa1 assigned to the proxy groups (Attorney General Brief at 69). Therefore, the Attorney General

[339] On brief, the Attorney General states that her proxy group includes 26 companies when, in fact, it includes 30 companies (Attorney General Brief at 68; Exhs. AG-JRW-1, at 33; AG-JRW-4).

concludes that the Companies' investment risk is below that of the proxy groups (Attorney General Brief at 69, citing Exh. AG-JRW-1, at 73).

Next, the Attorney General disputes the Companies' assertion that she improperly compared common equity ratios proposed by Eversource with those of holding companies in the proxy groups (Attorney General Reply Brief at 64). The Attorney General maintains that she included holding companies to estimate an equity cost rate because these holding companies have publicly traded common stock and NSTAR Electric and WMECo do not (Attorney General Reply Brief at 64, citing Exh. AG-JRW-1, at 36).

Finally, the Attorney General states that, contrary to Eversource's claim, she did not include short-term debt in her recommended capital structure for NSTAR Electric and WMECo (Attorney General Reply Brief at 64, citing Exh. AG-JRW-1, at 36). The Attorney General maintains that, while short-term debt should not be included in the capital structure, she appropriately included it in her comparison of proxy group capital structures for financial risk purposes because short-term debt, like long-term debt, is a fixed obligation that must be repaid (Attorney General Reply Brief at 64, citing Exh. AG-JRW-1, at 39).

Neither FEA nor Sunrun and EFCA addressed on brief the issue of proxy groups. Further, no other intervenor or limited intervenor addressed the issue.

b. Companies

Eversource argues that, in determining its ROE, it has used an appropriate proxy group that includes companies that: (1) are based on valid selection criteria; (2) have sufficient financial and operating data to discern the investment risk of NSTAR Electric and

WMECo versus the comparison group; and (3) derive at least 60 percent of operating income from regulated electric utility operations (Companies Brief at 285, citing Exhs. NG-RBH-1, at 18-20; AG-14-6; D.P.U. 08-35, at 176). In addition, the Companies maintain that "many" of their 20 proxy companies have a form of decoupling in place at their electric utility subsidiaries as well as alternative regulation and incentive plans, including formula-based rate plans, and adjustment mechanisms that automatically adjust rates when an earned return is above or below an authorized range for these subsidiaries (Companies Brief at 285, citing Exhs. NG-RBH-1, at 47-48; ES-RBH-10, at 1-2; RR-DPU-9, Att.). Further, Eversource notes that the Companies' proxy group selected from Value Line consists of companies that have been found comparable by the Department to other Massachusetts electric distribution companies in recent years (Company Brief at 285, citing D.P.U. 15-55, at 348-349, 353-354; D.P.U. 15-80/D.P.U. 15-81, at 260; D.P.U. 10-70, at 246-247, 249.

The Companies argue that the Attorney General's contentions concerning the role of holding companies versus operating companies in evaluating comparability of capitalization are irrelevant (Companies Reply Brief at 147-148). Eversource contends that the Department has rejected the Attorney General's previous attempts to adopt imputed capital structures with 50.00 percent common equity based on capital structures of holding companies (Companies Reply Brief at 147-148, citing D.P.U. 13-75, at 272-273, 275-276). Further, the Companies argue that the Attorney General errs in her approach to calculating the capitalization ratio of her proxy group at the holding company level rather than the operating company levels, because utility operating companies have comparable operations and assets while holding

companies do not (Companies Brief at 517, citing Exh. ES-RBH-Rebuttal-1, at 67; Companies Reply Brief at 147).

The Companies also maintain that the Attorney General errs in including short-term debt when calculating the capitalization ratio of her proxy group, because permanent capital, rather than short-term capital, is used to finance long-lived assets (Companies Brief at 517, citing Exh. ES-RBH-Rebuttal-1, at 67; Companies Reply Brief at 147). The Companies aver that the Department does not include short-term debt in the capital structure because short-term debt is not used to finance costs included in rate base and short-term debt does not reflect permanent capital used to finance permanent assets (Companies Brief at 517, citing Exh. ES-RBH-Rebuttal-1, at 67, D.P.U. 09-39, at 341-342; Companies Reply Brief at 147 citing Exh. ES-RBH-Rebuttal-1, at 65-66). The Companies state that if short-term debt cannot be included in a company's capital structure, it logically cannot be included in the capitalization ratio of a proxy group for comparison purposes (Companies Reply Brief at 147, citing D.P.U. 09-39, at 341-342).

5. Analysis and Findings

a. Introduction

Apart from the disagreement over the use of holding companies in the Attorney General's proxy group and the inclusion of short-term debt in capital structure calculations discussed above, the Attorney General, FEA, and Sunrun and EFCA do not object to the Companies' proxy group. The use of a proxy group of companies is standard practice in setting an ROE that is comparable to returns on investments of similar risk. D.P.U. 08-35, at 176-177; D.T.E. 99-118, at 80-82; D.P.U. 92-78, at 109-110; D.P.U. 1300, at 97. The

use of a proxy group is especially relevant for evaluation of a cost of equity analysis when a distribution company does not have common stock that is publicly traded. D.P.U. 08-35, at 176-177; D.T.E 99-118, at 80-82; D.P.U. 92-78, at 109-110. The Department has stated that companies in the proxy group must have common stock that is publicly traded, and must be generally comparable in investment risk. D.P.U. 1300, at 97.

b. Proxy Groups

In our evaluation of the proxy groups used by the Companies and the Attorney General, we recognize that it is neither necessary nor possible to find a group in which the companies match NSTAR Electric and WMECo in every detail. D.P.U. 09-39, at 386; D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; D.P.U. 1100, at 135-136. Rather, we may rely on an analysis that employs valid criteria to determine which companies will be in the proxy group, and that provides sufficient financial and operating data to discern the investment risk of the Companies versus the proxy group. D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; D.P.U. 1100, at 135-136.

The Department expects diligence by parties in assembling proxy groups that will produce statistically reliable analyses required to determine a fair rate of return for the company. D.P.U. 10-55, at 480-482. Overly exclusive selection criteria may affect the statistical reliability of a proxy group, especially if such screening criteria result in a limited number of companies in the proxy group. D.P.U. 10-55, at 480-482. The Department expects parties to limit criteria to the extent necessary to develop a broader as opposed to a narrower proxy group. D.P.U. 10-114, at 299; D.P.U. 10-55, at 481-482. To the extent

that a particular company's characteristics differ from those of the others in a proxy group, those differences should be identified in sufficient detail to enable a reviewer to discern any effects on investment risk. D.P.U. 10-114, at 299; D.P.U. 10-55, at 480-482.

c. Use of Holding Companies

The Companies and Attorney General dispute the use of holding companies in proxy groups. Eversource contends that utility operating companies are more fitting because they have comparable operations and assets while holding companies do not (Companies Reply Brief at 147). The Attorney General asserts that the inclusion of holding companies is appropriate here where the holding companies have publicly traded common stock and NSTAR Electric and WMECo do not (Attorney General Reply Brief at 64).

Companies considered for a proxy group must have common stock that is publicly traded and must be of generally similar investment risk. D.P.U. 1300, at 97. As noted above, the Department recognizes that it is neither necessary nor possible to find a group that matches a company in every detail. D.P.U. 09-39, at 386; D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; D.P.U. 1100, at 135-136. Moreover, the current structure of the utility industry, with fewer publicly traded companies resulting from merger and acquisition activities, makes the inclusion of holding companies in proxy groups unavoidable. D.P.U. 10-55, at 482; D.P.U. 09-39, at 350; D.P.U. 09-30, at 308; D.P.U. 08-35, at 175; D.P.U. 07-71, at 135; D.T.E. 99-118, at 81. Eliminating holding companies from a proxy group may unduly limit the ability to determine a company's comparability to the proxy group.

The disagreements at issue occur in the context of recommending appropriate capital structure ratios based on comparisons of common equity between proxy groups and the Eversource proposals (Exhs. ES-RBH-1, at 70-72; ES-RBH-9, at 1; ES-RBH-Rebuttal-1, at 66-67, 92-93; ES-Rebuttal-8, at 1; AG-JRW-1, at 36; JRW-4, at 1; JRW-5). Because the Department has allowed the use of holding companies in the selection of proxy group companies while acknowledging their differences from operating companies, we accept the Attorney General's use of her proxy group in capital structure comparisons (Exhs. AG-JRW-1, at 36; JRW-4, at 1; JRW-5). D.P.U. 10-55, at 482; D.P.U. 09-39, at 350; D.P.U. 09-30, at 308; D.P.U. 08-35, at 175. We also recognize in the choice of operating companies Eversource's efforts to develop as close a comparison group as possible, and, therefore, we accept the Companies' comparison results (Exhs. ES-RBH-1, at 70-72; ES-RBH-9, at 1; ES-RBH-Rebuttal-1, at 66-67, 92-93; ES-Rebuttal-8, at 1).

d. Use of Short-term Debt

The Attorney General and the Companies disagree on the role of short-term debt in comparing proxy group capital structures (Exhs. ES-RBH-Rebuttal-1, at 64-67; AG-JRW-1, at 2, 35-36). While the Attorney General includes short-term debt as part of her proxy group's capital structure ratios, the Companies assert that short-term debt should not be considered when determining the capitalization of companies in a proxy group (Exhs. ES-RBH-Rebuttal-1, at 64-67; ES-RBH-Rebuttal-8, at 1; AG-JRW-1, at 35-36; JRW-4, at 1; JRW-5). The Department generally excludes short-term debt from a utility's capitalization for ratemaking purposes. D.P.U. 09-39, at 340-341; D.T.E. 05-27,

at 271-272; D.T.E. 02-24/25, at 209. Nevertheless, the extent to which a company's balance sheets carry short-term debt is indisputably a factor in evaluating the relative risk of that company in relation to a proxy group. In this case, the Attorney General chose to include short-term debt in her analysis of capital structures (Exh. AG-JRW-1, at 39). There is no single approach as to how a party offering a proxy group analysis should present the supporting financial and operating data associated with companies in that proxy group. So long as information about a proxy group's capital structure is presented in sufficient detail to allow a fact finder to evaluate the relative risk characteristics of a company in relation to that proxy group, the inclusion of short-term debt in a proxy group's capital structure would not compromise the reliability of the proxy group.[340] Therefore, the Department does not reject the Attorney General's use of short-term debt as a factor.

e. Conclusion

The Department finds that Eversource and the Attorney General each employed a set of valid criteria to select their respective proxy groups, and that they each provided sufficient information about the proxy groups to allow the Department to draw conclusions about the relative risk characteristics of the Companies versus the members of the proxy groups. D.P.U. 12-25, at 402; D.P.U. 09-30, at 307. Therefore, the Department will accept the Companies' proxy group and the Attorney General's proxy group to assist the Department in determining both NSTAR Electric's and WMECo's fair and reasonable costs of equity.

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[340] The inclusion of short-term debt in a proxy group's capital structure will, of course, tend to reduce the common equity ratio of the proxy group as a whole (Exhs. ES-RBH-Rebuttal-8, at 1; JRW-4, at 1; JRW 5; ES-AG-1-2).

Our acceptance of the proxy groups notwithstanding, we identify several factors that the Department will take into consideration in determining the appropriate ROE for the Companies. First, as discussed below, NSTAR Electric, WMECo, and the proxy group members have a number of reconciling mechanisms. The extent to which these particular reconciling mechanisms affect a company's cash flow and financial performance will affect the evaluation of the Companies' comparability to the proxy groups. Second, some of the holding companies in the Attorney General's comparison group are also involved in non-regulated businesses beyond gas distribution activities, potentially making these companies more risky, all else being equal, and in turn, more profitable than the Companies. D.P.U. 09-39, at 350; D.P.U. 09-30, at 308; D.P.U. 08-35, at 175. The Companies' high credit ratings will also affect our evaluation of investment risk, as well as WMECo's favorable common equity ratio (Exhs. ES-RBH-1, at 17-18; RBH-R-18; AG-1-11, Att. (a)). Therefore, while we accept Eversource's and the Attorney General's proxy groups as a basis for evaluating their ROE proposals, we also will consider the particular characteristics of the Companies as compared to members of the proxy groups when determining the appropriate ROE.

E. Return on Equity

1. Companies Proposal

In determining their proposed ROE,[341] the Companies rely on the discounted cash flow ("DCF") model (including the constant growth and multi stage models), capital asset

[341] The terms ROE and cost of equity are used interchangeably herein.

pricing model ("CAPM"), and the bond yield plus risk premium approach ("risk premium model") (Exhs. ES-RBH 1, at 6-7; ES-RBH-3; ES-RBH-4; ES-RBH-5; ES-RBH-7; ES-RBH-8). These models were applied to market and financial data developed from the Companies' proxy group (Exh. ES-RBH-1, at 16-21). Based on the results of these models and the Companies' evaluation of their business risks relative to the proxy group,[342] Eversource determines that its consolidated ROE for both NSTAR Electric and WMECo is in the range of ten percent to 10.75 percent (Exhs. ES-RBH-1, at 3, 6-7, 69, 73; ES-RBH-Rebuttal-1, at 3, 161). As part of this analysis, the Companies state that they considered flotation costs and the effect of the Companies' ROE on their financial integrity (Exh. ES-RBH-1, at 3, 44, 49-51).[343]

The Companies state that their proposed ROE of 10.5 percent takes into account the implementation of revenue decoupling, DER, long-term renewable energy contract obligations, and a PBR mechanism, the Companies' particular business risks, and additional qualitative considerations to which the Department has previously given weight in establishing authorized returns (Exhs. ES-RBH-1, at 3, 16, 44-48, 73; ES-RBH-10; ES-RBH-Rebuttal-1, at 107-114, 161-162; RR-DPU-9). In this regard, the Companies state that their proposed ROE of 10.50 percent is based, in part, on a proxy group of electric

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342 On the low end, the Companies' constant growth analysis produced an ROE of 8.08 percent (Exhs. ES-RBH-R-2, at 1; ES-RBH-Rebuttal-1, at 163). On the high end, the Company's CAPM analysis produced an ROE of 11.46 percent (Exhs. ES-RBH-R-6; ES-RBH-Rebuttal-1, at 163).

343 Flotation costs are the costs, such as underwriting fees, legal fees, and registration fees, incurred by a publicly traded company when it issues new securities. D.P.U. 88-135/151, at 115; D.P.U. 85-266-A/271-A at 169.

distribution companies that, in general, already have implemented revenue stabilization mechanisms (Exh. ES-RBH-1, at 16, 45-48). Thus, according to Eversource, any reduction in the ROE because the Companies have implemented revenue decoupling, DER, long-term renewable energy contract obligations, PBR mechanism, or capital-cost recovery mechanisms is a matter of speculation and conjecture and would ignore established legal standards requiring a return commensurate with the return for enterprises with corresponding risks (Exh. ES-RBH-1, at 7-9, 18-20, 46-48, citing Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944) ("Hope"); Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia, 262 U.S. 679, 692-93 (1923) ("Bluefield")).

2. Attorney General Proposal

The Attorney General relies on the DCF model, including the constant growth model, and the CAPM, and applied these models to both her proxy group and the Companies' proxy group (Exhs. AG-JRW-1, at 3-4, 47-75; AG-JRW-10; AG-JRW-11). The Attorney General calculates an ROE for Eversource of 8.875 percent based on an evaluation of her DCF results of 8.80 percent and 8.95 percent and her CAPM results of 7.90 percent for both proxy groups (Exhs. AG-JRW-1, at 4, 72; AG-JRW-10; AG-JRW-11).

3. FEA Proposal

FEA recommends an ROE of 9.35 percent for Eversource, calculated by the DCF model, including the constant growth and multi-stage growth models, the risk premium model, and the CAPM to the Companies' proxy group (Exhs. FEA-MPG-1, at 51-81 (Corrected); FEA-MPG-9; FEA-MPG-10; FEA-MPG-11; FEA-MPG-12; FEA-MPG-14; FEA-MPG-16; FEA-MPG-17; FEA-MPG-18; FEA-MPG-21). FEA's 9.35 percent ROE is

the midpoint of DCF, CAPM, and risk premium modeling results for the Companies' proxy group ranging from a low of 9.00 percent to a high of 9.70 percent (Exhs. FEA-MPG-1, at 4, 81 (Corrected); DPU-FEA 1-1).[344]

4. Sunrun and EFCA Proposal

Sunrun and EFCA propose an 8.75 percent ROE for the Companies based on the results of two equity cost models: the DCF model and the CAPM (Exhs. SREF-DJG-1, at 7, 9-10, 25 & Apps. C-E, H; SREF-DJG-8; SREF-DJG-14; SREF-DJG-15). On the basis of their DCF and CAPM analyses, Sunrun and EFCA calculate two identical ROEs of 7.5 percent, and then select their recommended 8.75 percent ROE from the upper end of a so-called "range of reasonableness" between 7.5 percent and 9.0 percent (Exhs. SREF-DJG-1, at 7-10, 25 & Apps. C, E; SREF-DJG-3; SREF-DJG-4). Sunrun and EFCA also used the Companies' proxy group to conduct their modeling (Exh. SREF-DJG-1, at 7).

5. UMass Proposal

UMass proposes for Eversource to be required to defend its recommended 10.50 percent ROE proposal by showing that utilities in other New England states have authorized rates of return too low to attract capital and preserve their financial integrity (Exh. UMass-RS-1, at 56). UMass states that Eversource's choice of the mid-point in its recommended 10.00 percent to 10.75 percent ROE range is too high because it is at odds with the regulatory paradigm that expects utility services franchises substituting for

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344 FEA used the Companies' proxy group to conduct its modeling (Exhs. FEA-MPG-1, at 52 (Corrected); FEA-MPG-7).

competitive markets to generate comparable results; i.e., the entity with the lowest cost of capital should be the most competitive (Exh. UMass-RS-1, at 53-55). According to UMass, in a hypothetical competitive solicitation process for franchise rights, Eversource would lose to the lower bids of the utilities in other New England states because of the Companies' overstated estimate of its required return (Exh. UMass-RS-1, at 56). Although UMass did not propose a specific ROE in its direct case, on brief, UMass recommends an ROE of 9.5 percent (UMass Brief at 20).

6. Market Conditions and Cost of Equity Trends

a. Introduction

Market conditions and their related data play an important role in defining the parties' respective positions on cost of equity (Exhs. ES-RBH-1, at 55; AG-JRW-1, at 21). The Companies and intervenors offer conflicting interpretations of market conditions and the corresponding risk profiles for NSTAR Electric and WMECo (Exhs. ES-RBH-1, at 55-70; ES-RBH-Rebuttal-1, at 2-6, 14, 25-26, 68-70; AG-JRW-1, at 18-32; AG-JRW-Surrebuttal-1, at 2-5; FEA-MPG-1, at 32-41 (Corrected); SREF-DJG-1, at 13 & Apps. C at 6-10, D at 8-9, 11-12). By way of illustration, the Companies and intervenors vigorously dispute the implications of recently observed trends in authorized utility ROEs regionally and nationally (Exhs. ES-RBH-1, at 9-16; ES-RBH-Rebuttal-1, at 8-12; AG-JRW-1, at 8-17; AG-JRW-Surrebuttal-1, at 26-29; FEA-MPG-1, at 24-32 (Corrected); SREF-DJG-1, App. A at 4-8; UMass-RS-1, at 55-56). The Companies and intervenors draw on data selected from the market place to implement their models in an effort to accurately assess current market conditions and to forecast the market's likely future course with respect to and in support of

the most appropriate cost of equity for Eversource (Exhs. ES-RBH-1; ES-RBH-Rebuttal-1; AG-JRW-1; AG-JRW-Surrebuttal-1; FEA-MPG-1 (Corrected); SREF-DJG-1 and Appendices; UMass-RS-1).

In support of her position, the Attorney General notes that recent rate case records show that authorized electric and gas utility ROEs across the U.S. have trended downward (Exh. AG-JRW-1, at 8).[345] The Attorney General attributes this trend to (1) low utility industry risk for equity investment; (2) historically low capital costs for utilities as evidenced by long-term bond yields and interest rates; (3) continued tepid annual gross domestic product ("GDP") growth of the U.S. economy at 2.00 percent to 2.50 percent; (4) low forecast growth for the world's economies compared to historical averages; and (5) greatly reduced investment risk in utilities attributable to revenue decoupling and cost reconciling rate adjustment mechanisms (Exhs. AG-JRW-1, at 8-9; see also ES-RBH-1, at 9-10). The Attorney General goes on to enumerate the market conditions related to the trend, including low utility industry betas,[346] increasing upgrades in utility credit ratings, long-term bond yields near and below 4.0 percent, and noting further a Moody's report concluding that lower

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345 The Attorney General also observes that ROEs granted to utilities in Massachusetts have increased during the same period (Exhs. AG-JRW-1, at 16-18; see also Exh. ES-RBH-1, at 12).

346 Beta is a measure of volatility, or systematic risk, of a security or portfolio in comparison to the market as a whole.

ROEs between 9.0 percent and 10.0 percent are not impairing utilities' credit profiles (Exh. AG-JRW-1, at 9-13).[347]

Conversely, the Companies observe "no discernable trend" in authorized ROEs for electric and gas utilities, noting that authorized ROEs have maintained at about 10.00 percent (Exh. ES-RBH-1, at 10). The Companies also observe that interest rates are expected to increase as the Federal Reserve System ("Federal Reserve") moves away from its post-financial crisis monetary policy of lowering interest rates and toward policy normalization, including two increases to the Federal Funds rate (Exh. ES-RBH-1, at 15).[348] The Companies state that credit ratings agencies also consider the risk of the regulatory environments in which the utilities operate, adding that the predictability and consistency of regulatory actions have a significant impact on cash flow (Exh. ES-RBH-1, at 15). Further, Eversource notes that revenue stabilization mechanisms may mitigate risk, but only affect the cost of equity if the mechanisms reduce risk below the Companies' peers in the proxy group and if investors knowingly reduce their return requirements in the Companies as a direct consequence of the mechanisms (Exh. ES-RBH-1, at 16).

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347 Moody's Investors Service is a bond credit ratings firm that also provides international financial research on bonds issued by commercial and government entities.

348 The Federal Funds Rate is the rate at which banks lend reserve balances to other banks on an overnight basis. Reserves are excess balances held at a Federal Reserve Bank to maintain reserve requirements. The Federal Open Market Committee of the Federal Reserve sets the Federal Funds Rate. The Federal Funds Rate is one of the most important interest rates in the U.S. economy since it affects monetary and financial conditions, which in turn have a bearing on critical aspects of the broad economy including employment, growth, and inflation.

b. Positions of the Parties

i. Attorney General

The Attorney General challenges the financial modeling practices and observations that the Companies use to support their view that current market conditions and utility cost of equity trends warrant the higher ROE that they propose for NSTAR Electric and WMECo (Attorney General Brief at 84-101). In support of her position, the Attorney General argues that: (1) the electric utility industry is one of the lowest risk industries in the United States and, as such, its cost of equity capital is among the lowest in the United States; (2) NSTAR Electric and WMECo's risk profile conforms to this low-risk industry category as measured by their own S&P, as well as Moody's issuer credit ratings, of A and A2, respectively, which are higher than both the Companies' and Attorney General's proxy groups S&P and Moody's issuer credit ratings of BBB+ and Baa1, respectively; (3) NSTAR Electric and WMECo have higher common equity ratios and, therefore, lower financial risk than the capital structures of the two proxy groups; (4) historically low interest rates and long-term bond yields have depressed capital costs; and (4) authorized ROEs for electric utilities companies have declined in recent years (Attorney General Brief at 98-99, citing Exhs. AG-JRW-1, at 72-74; JRW-2; JRW-3; JRW-8; Attorney General Reply Brief at 75-77, citing Exhs. AG-JRW-1, at 63-64; AG-JRW-Surrebuttal, at 1; Tr. 11, at 2161). Further, the Attorney General argues that the Companies' proposed cost of capital is based on "fatally flawed" analyses used to develop that cost (Attorney General Brief at 98, citing Exh. AG-JRW-1, at 72-74).

While acknowledging that her recommended ROE of 8.875 percent is low by historic standards, the Attorney General asserts that her recommended ROE nonetheless satisfies the requirements of Hope and Bluefield (Attorney General Brief at 62, 100; Attorney General Reply Brief at 75, 77). In support of her position, the Attorney General argues that the fundamental factors driving interest rates, capital costs, and GDP growth remain at low levels and are likely to remain so for some time (Attorney General Brief at 85, citing Exh. AG-JRW-1, at 21-32; Attorney General Reply Brief at 77). She further argues that the Companies' forecasts of higher interest rates and capital costs with the end of the Federal Reserve's quantitative easing program are erroneous because:[349] (1) actual interest rates have gone down; (2) recent studies show that economists' forecasts of higher interest rates consistently have been wrong; and (3) slow economic growth and low inflation continue to keep interest rates and capital costs low (Attorney General at 85-86, citing Exhs. ES-RBH-1 at 24-26, 56-57; AG-JRW-1, at 21-32).

The Attorney General also takes issue with the Companies' claim that their proposed ratemaking mechanisms should have no effect on the Companies' risk relative to its peers and, therefore, no influence on their ROE recommendation (Attorney General at 86-87, citing Exhs. ES-RBH-1 at 44-49; ES-RBH-10; AG-JRW-1, at 95-97; Attorney General Reply Brief at 76, citing Exh. AG-JRW-Surrebuttal-1, at 12-13). The Attorney General notes that

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[349] Quantitative easing is a monetary tool used by central banks to stimulate the economy by making it easier for banks to borrow money. In an effort to promote more accommodative financial conditions following the financial crisis of 2008 and the ensuing recession, the Federal Reserve conducted large-scale purchases of assets including long-term Treasury securities and mortgage-backed securities.

97 percent of NSTAR Electric's distribution revenues and 95 percent of WMECo's distribution revenues will be affected by the Companies' proposed revenue decoupling mechanism (Exh. AG-JRW-1, at 96). By contrast, she contends that not all the proxy companies' revenues are covered by rate mechanisms, since many do not receive 100 percent of their revenues from regulated operations (Attorney General at 87, citing Exhs. AG-JRW-1, at 96; JRW-4). The Attorney General further contends that not all regulated operating subsidiary utilities in the Companies' proxy group have rate mechanisms, and that the rate mechanisms at the proxy companies vary widely (Attorney General at 87, citing Exh. ES-RBH-1, at 47). Finally, the Attorney General notes that the Companies will have an revenue decoupling mechanism and PBR mechanism in place affecting at least 95 percent of each operating company's revenues, versus an unknown percent of the revenues of the Companies' proxy group are affected by similar rate mechanisms (Attorney General Brief at 88, citing Exh. AG-14-9).

Accordingly, for the reasons stated above, the Attorney General concludes that the Department should take into consideration that NSTAR Electric and WMECo are less risky than either of the proxy groups and find a lower allowed return for the Companies as compared to the proxy groups (Attorney General Brief at 88, citing Exh. AG-JRW-1, at 97). Adding that the Companies' requested allowed ROE of 10.50 percent will result in unjust and unreasonable rates, the Attorney General recommends the Department use her ROE of 8.875 percent to set base rates (Attorney General Reply Brief at 77).

ii. FEA

FEA similarly challenges the Companies' financial modeling practices and observations of current market conditions behind their proposed allowed ROE, including unsustainable growth expectations (FEA Brief at 2-5). Noting that the other intervenors' recommended ROEs fall within a range of 8.75 percent to 9.35 percent, FEA asserts that the Companies' proposed ROE of 10.50 percent is a material outlier that does not represent current market conditions (FEA Brief at 1-5). According to FEA, current market conditions have allowed electric distribution companies such as NSTAR Electric and WMECo to: (1) support investment grade bond ratings, (2) access capital on favorable terms, and (3) support strong valuation of utility stock (FEA Brief at 2). FEA considers that all of these factors support a finding that the Companies' current earned returns provide them with fair compensation, and that the Companies' requested ROE will significantly exceed this level of fair compensation (FEA Brief at 2).

FEA also contends that electric utilities across the country have experienced a steady decline in authorized returns by approximately 90 basis points since 2009 (FEA Brief at 2, citing Exh. FEA-MPG-1, at 25-26 (Corrected)). FEA maintains that even with this clear trend towards lower authorized returns, the market continues to recognize the electric utility industry as a low-risk investment, with continuing improvements in credit ratings (FEA Brief at 2, citing Exh. FEA-MPG-1, at 25-26, 28-29 (Corrected)). FEA asserts that, despite credit ratings agencies' assessments that lower authorized ROEs will not harm utilities' ability to earn fair returns, attract capital and maintain stable investment grade bond ratings, the

Companies have ignored the existence of such favorable market conditions in their analysis, and instead rely on excessive and unsustainable growth rates to artificially inflate their ROE estimate (FEA Brief at 3-5, citing Exhs. FEA-MPG-1, at 18, 29, 40-41, 86, 91-92 (Corrected); ES-RBH-1, at 9-12, 18).

iii. Sunrun and EFCA

Sunrun and EFCA recommend that the Department reject the Companies' proposed ROE, and argue that it significantly overstates the revenue requirements and shifts large amounts of capital from customers to shareholders without showing measurable customer, system, or societal benefits (Sunrun and EFCA Brief at 2, 17). Sunrun and EFCA maintain that the Companies' cost of equity modeling employs assumptions that violate fundamental and widely accepted financial and valuation tenets, and, thus, artificially inflates their proposed ROE (Sunrun and EFCA Brief at 19, citing Exh. SREF-DJG-1, at 12).

Sunrun and EFCA identify what they consider to be four specific problems in the Companies' analysis. First, Sunrun and EFCA argue that the Companies base their recommended ROE on the mistaken standard that an investor's subjective expectation determines the level of ROE sufficient to attract capital (Sunrun and EFCA Brief at 21, citing Exh. ES-RBH-Rebuttal-1, at 125; Sunrun and EFCA Reply Brief at 8).[350] Rather, Sunrun and EFCA maintain that the correct standard is a fair and reasonable return on the utility's cost of equity as determined through objective tests articulated by federal and state courts

[350] Sunrun and EFCA cite to the Companies' rebuttal testimony linking DCF model growth estimates to investors' growth rate expectations (Sunrun and EFCA Brief at 21, citing Exh. ES-RBH-Rebuttal-1, at 125).

(Sunrun and EFCA Brief at 21, citing Exhs. SREF-DJG-1, at 8; SREF-DJG-Rebuttal at 1; Sunrun and EFCA Brief at 8, citing Hope at 605; Lowell Gas Company v. Department of Public Utilities, 324 Mass. 80, 96 (1948)).

Additionally, Sunrun and EFCA assert that the Companies' proposed ROE will disincentivize investments in DER because it increases the level of the proposed minimum monthly reliability charge ("MMRC"), which the Companies base on the purported costs of serving DER customers (Sunrun and EFCA Brief at 21). According to Sunrun and EFCA, if the authorized ROE is greater than the Companies' market-based cost of equity, this inflated return will artificially inflate the revenue requirement, which, in turn, will increase any MMRC imposed on DER customers (Sunrun and EFCA Brief at 21).

Next, Sunrun and EFCA contend that an overstated ROE will incentivize the Companies to construct or upgrade traditional infrastructure over investing in lower cost, local DER or non-wires alternatives (Sunrun and EFCA Reply Brief at 9). Sunrun and EFCA contend that, although Eversource has claimed that the disruptive financial effects of DER warrant a higher ROE, the Companies have failed to quantify the effects of DER on its financial performance (Sunrun and EFCA Brief at 21, citing Exh. ES-RBH-Rebuttal-1, at 119). Sunrun and EFCA argue that Eversource cannot support its claim that Massachusetts' embrace of DER threatens to make the Companies a less attractive investment (Sunrun and EFCA Brief at 23; Sunrun and EFCA Reply Brief at 9).

Finally, Sunrun and EFCA maintain that Eversource should harmonize its proposed ROE and PBR mechanism in ways that produce benefits for the Companies, the customers,

and shareholders (Sunrun and EFCA Brief at 13). Specifically, Sunrun and EFCA propose that the Department set a lower base ROE and consider using performance incentives as a means by which the Companies may obtain additional earnings on top of the base ROE as a reward for improved service (Sunrun and EFCA Brief at 14-15, citing Tr. 12, at 2443; D.P.U. 94-158, at 56-57).

Accordingly, for the foregoing reasons, Sunrun and EFCA recommend that the Department reject the Companies' proposed ROE of 10.50 percent. Instead, they recommend that the Department set the Companies' allowed ROE at 8.75 percent (Sunrun and EFCA Brief at 2, 17; Sunrun and EFCA Reply Brief at 10).

iv. Cape Light Compact

Cape Light Compact supports the recommendation of Sunrun and EFCA for an ROE of 8.75 percent, and argues that a high ROE contravenes the shift from capital-driven to performance-driven revenues commenced with the Department's grid modernization Orders (Cape Light Compact Brief at 72, 74, 75-76, citing D.P.U. 12-76-B at 16, 19, and App. 1, at 12). Further, Cape Light Compact contends that the Companies' proposed 10.50 percent ROE overstates the return needed to attract capital and to maintain financial integrity, and further notes that Eversource, which is earning a return above peer utilities in other New England states, has not demonstrated that authorized ROEs well below 10.50 percent for these peer companies have put those companies' financial integrity in jeopardy or prevented them from attracting capital (Cape Light Compact Brief at 72-73).

Contending that climate and grid modernization policies have created a new context for moving from cost of service ratemaking toward PBR, Cape Light Compact argues that electric distribution companies' authorized returns should be set at low base levels, but should provide opportunities for increased returns through performance (Cape Light Compact Brief at 75). Thus, Cape Light Compact recommends that the Department take incremental steps to align the utility business model with grid modernization objectives (Cape Light Compact Brief at 76, citing Exh. AC-AA-1, at 13). According to Cape Light Compact, the Department could gradually decrease the pre-authorized rate of return on traditional utility investment and allow extra compensation for achieving desired performance goals (Cape Light Compact Reply Brief at 13, citing Companies Brief at 541; Exh. AC-AA-7, at 54).

Cape Light Compact contends that the instant case should mark the beginning of a gradual shift in the Companies' profit model, away from profits derived from spending towards profits derived from performance (Cape Light Compact Reply Brief at 14). Further, Cape Light Compact contends that, contrary to Eversource's claims, new opportunities to earn higher returns through performance on challenging environmental and grid modernization goals should provide the Companies with an advantage in attracting capital and maintaining financial integrity (Cape Light Compact Reply Brief at 14, citing Companies Brief at 541). For all of these reasons, Cape Light Compact supports the recommendation of Sunrun and EFCA for an ROE of 8.75 percent (Cape Light Compact Brief at 74).

v. UMass

UMass recommends that the Department reject the Companies' proposal and adopt a lower ROE of 9.5 percent to balance the interest of customers and shareholders (UMass Brief at 20). UMass argues that Eversource's requested 10.50 percent is excessive in light of generally lower levels of risk for regulated utilities, and contends that the Companies are further protected from risk through reconciliation and other cost recovery mechanisms such as the PBR mechanism proposed in the current proceeding (UMass Brief at 18). Additionally, UMass contends that the Companies' choice of an ROE equivalent to the midpoint of the proxy group selected is inappropriate, because it is inconsistent with market-based principles, which provide that, in a competitive environment, the entity with the lowest costs is likely to be the more successful (UMass Brief at 19). UMass maintains that because the Companies' proxy group companies are all financially stable with investment grade bond and credit ratings and have returns that preserve their financial integrity, setting Eversource's ROE at the low end of the proxy group range would be consistent with Department precedent (UMass Brief at 19-20, citing ES-RBH-1, at 9 n.7). For these reasons, UMass recommends an ROE of 9.5 percent (UMass Brief at 20).

vi. Companies

Eversource argues that its proposed ROE of 10.50 percent reflects current capital market conditions and is the result of a number of widely accepted common equity cost models (Companies Brief at 283, 290, 531-532, 535, citing Exh. ES-RBH-1, at 3, 56, 64-68). Eversource contends that the Department is obligated to provide a return for NSTAR Electric and WMECo commensurate with the returns for similar enterprises having

corresponding risks (Companies Brief at 281, 290-291, 530, citing Attorney General v. Department of Public Utilities, 392 Mass. 262, 266 (1984), quoting Hope at 603).

In this regard, the Companies note that their proposed ROE of 10.50 percent is based, in part, on a proxy group of electric distribution companies that have comparable risk given that these utility companies, in general, already have implemented revenue stabilization mechanisms and incentive plan mechanisms (Companies Brief at 282, 290-291, citing Exh. ES-RBH-1, at 44-48). The Companies argue that decoupling and PBR mechanism-like forms of alternative regulation and incentive plans only affect ROE if (1) the mechanism's effect is to reduce risk below the levels faced by proxy group peer companies, and (2) investors knowingly reduced their return requirements as a direct result of the mechanism (Companies Brief at 289, citing Exh. ES-RBH-1, at 48). The Companies additionally note that a number of proxy companies have incentive plans, including formula-based rate plans, and automatic adjustment mechanisms, and that, because such mechanisms are common among the proxy group, there is no reason to assume that the Companies would be materially less risky (Companies Brief at 290, citing Exhs. ES-RBH-1, at 47-48; ES-RBH-10; AG-14-9; Tr. 4, at 670-671, 735-736; RR-DPU-9). Thus, according to Eversource, any reduction in the ROE because the Companies have a revenue decoupling or incentive plan mechanism would be inappropriate (Companies Brief at 282, 525).

Further, Eversource argues that the ROE authorized in this case must allow the Companies to maintain their credit and ability to attract capital (Companies Brief at 282, citing Boston Edison v. Department of Public Utilities, 375 Mass. 305, 315 (1978), citing

Hope at 603; New England Telephone and Telegraph Company v. Department of Public Utilities, 327 Mass. 81, 88 (1951); Massachusetts Electric Company v. Department of Public Utilities, 376 Mass. 294, 299 (1978); Attorney General v. Department of Public Utilities, 392 Mass. 262, 265 (1984)). According to the Companies, in setting the ROE, the Department must recognize the Companies' need to attract capital on a going forward basis (Companies Brief at 283).

Eversource argues that, without a fair return, the Companies will not be able to attract investors to maintain safe and reliable service (Companies Brief at 283). In this regard, the Companies assert that the Attorney General's recommended ROE of 8.875 percent will deny the Companies a fair rate of return and impair their ability to attract capital (Companies Brief at 530, 532; Companies Reply Brief at 147). The Companies also note that the Attorney General's recommended ROE represents a significant departure from the returns granted by the Department over the past two decades and by other public utility commissions in recent years (Companies Brief at 531-532; Companies Reply Brief at 156). Additionally, Eversource disputes Sunrun and EFCA's suggestion that the Companies based their proposed ROE's ability to attract capital on a speculative, undisclosed, subjective expectation of investors, stating rather that their ROE recommendation is based on observable market data (Companies Reply Brief at 156; citing Exh. ES-RBH-1, at 22).

The Companies also contest the arguments of Sunrun and EFCA, FEA, UMass, and Cape Light Compact for reducing the allowed ROE in order to: (1) prevent associated DER disincentives; (2) link ROE with performance standards, (3) favor the low end of the proxy

group range, and/or (4) align with regional and national trends (Companies Brief at 532-541; Companies Reply Brief at 156-160). On the first point, Eversource counters that it is unreasonable for Sunrun and EFCA to argue that the Companies' proposed ROE will erode their incentive to invest in DER, because an ROE cannot be legally set to maximize DER if using the ROE to that purpose risks damaging the Companies' financial integrity (Companies Brief at 535; Companies Reply Brief at 157, citing Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 16-17 (1978)). The Companies point out that the Massachusetts Supreme Judicial Court has recognized the role of ROE as a fair and reasonable vehicle for covering expenses, debt service, and dividends while compensating investors' risk as it attracts capital and assures confidence in the enterprise's financial integrity (Companies Brief at 535, citing Massachusetts Electric Company v. Department of Public Utilities, 376 Mass 294, 299 (1978); Fitchburg Electric Light Company v. Department of Public Utilities, 371 Mass. 881, 884 (1977)). The Companies note that Massachusetts has been identified as among the first states where DER is most likely to disrupt the electric industry (Companies Brief at 535, citing Exhs. ES-RBH-1, at 51-55; ES-RBH-Rebuttal-1, at 117-119, DPU 31-5; Companies Reply Brief at 157, citing Exh. ES-RBH-1, at 55 n.59). Eversource maintains that DER presents a long-term risk impact on capital market conditions and, because credit rating agencies have noted the negative influence of DER on utility risk profiles, the Companies have taken this risk into consideration in formulating their proposed ROE (Companies Brief at 535, citing Exhs. ES-RBH-1, at 3, 51-55; ES-RBH-Rebuttal-1, at

117-119; DPU 31-5). The Companies recommend that the Department reject Sunrun and EFCA's analysis and, instead, set an ROE that is consistent with law and record evidence.

Second, in response to Cape Light Compact's recommendation for a performance-based ROE tied to grid modernization, the Companies maintain that setting a minimum ROE would be contrary to legal precedent (Companies Brief at 540, citing Fitchburg Electric Light Company v. Department of Public Utilities, 371 Mass. 881, 884 (1977); Massachusetts Electric Company v. Department of Public Utilities, 376 Mass. 294, 299 (1978); Attorney General v. Department of Public Utilities, 392 Mass. 262, 266, quoting Hope at 603; Companies Reply Brief at 159). The Companies contend that a minimum ROE would place them at a disadvantage in attracting capital relative to other utilities, and would not properly compensate investors for their risk, nor would that maintain the firms' financial integrity, all of which contravenes well-settled Massachusetts law (Companies Brief at 541; Companies Reply Brief at 159, citing Incentive Regulation, D.P.U. 94-158, at 46; 392 Mass. 262, 266, quoting Hope at 591, 603). Moreover, the Companies argue that the concept of a minimum ROE relative to grid modernization efforts has not been fully litigated and that there is a lack of substantial evidence for the Department to rely on in determining whether a minimum ROE should be adopted, and, if so, the appropriate level of that minimum ROE (Companies Brief at 541, citing New England Telephone and Telegraph Company v. Department of Public Utilities, 371 Mass. 67, 80, 84 (1976); Companies Reply Brief at 160). Consequently, the Companies contend that the Department should reject Cape Light Compact's recommendation.

Third, the Companies reject UMass' recommended 9.50 percent ROE based on the low end of the range of companies in the Companies' proxy group (Companies Brief at 539, citing UMass Brief at 20). The Companies assert that UMass' argument is inconsistent with Department precedent, which is to set ROEs that are at the higher end or lower end of the reasonable range based on above average or subpar management performance or customer service (Companies Brief at 539, citing D.P.U. 15-155, at 381-382 n.270). Moreover, the Companies contend that there is no evidence of subpar management performance or customer service on the part of the Companies that would warrant use of an ROE at the low end of the range (Companies Brief at 539).

Fourth, Eversource challenges the claims of FEA and UMass that authorized ROEs are trending downward in other New England states and nationwide, and that Eversource should reduce its own ROE recommendation to align with those trends (Companies Brief at 539; Companies Reply Brief at 158). The Companies maintain that their data charts show no discernable national trends associated with authorized ROEs from 2010 to 2016, and contend that ROEs authorized in Massachusetts are comparable to ROEs authorized in other New England states (Companies Brief at 539; Companies Reply Brief at 158).

Accordingly, for all the reasons above, the Companies assert that the Department should allow their proposed ROE of 10.50 percent because it is based on analysis of market-based data detailed in record evidence and consistent with legal precedent.

c. Analysis and Findings

The Companies and intervenors present observations in the instant case that paint two distinctly different pictures of capital market conditions and the relative risks posed to Eversource in support of their respective ROE recommendations (Exhs. ES-RBH-1, at 55-70; ES-RBH-Rebuttal-1, at 2-6, 14, 25-26, 68-70; AG-JRW-1, at 18-32; AG-JRW-Surrebuttal-1, at 2-5; FEA-MPG-1, at 32-41 (Corrected); SREF-DJG-1, at 13 & Apps. C at 6-10, D at 8-9, 11-12; UMass-RS-1, at 56). First addressing the market conditions debated among the Companies and intervenors, there is an abundance of record evidence indicating the slow pace of economic recovery since the 2008 economic crisis. GDP growth, inflation, and interest rates all remain historically low (Exhs. ES-RBH-Rebuttal-1, at 40-42; ES-RBH-1, at 63-65; AG-JRW-1, at 11-12, 81; AG-JRW-14). Projecting future market trends, whether interest rates, dividends and earnings growth, or GDP growth is difficult through surveys and modeling alike, and both the Companies and intervenors urge caution on the conclusions (Exhs. ES-RBH-1, at 21-22; AG-JRW-1, at 50, 56-57; AG-JRW-Rebuttal-1, at 3-5; FEA-MPG-1, at 116 (Corrected)).

The parties draw from a host of data sources and methodologies to draw their competing interpretations and conclusions (Exhs. ES-RBH-1, at 26-28, 64-69; ES-RBH-Rebuttal-1, at 32-35, 38-45, 73-77; AG-JRW-1, at 55-61, 79-84). The Companies offer a view of an economy on the verge of accelerated growth (Exh. ES-RBH-1, at 64-67). The intervenors weigh existing conditions more heavily to color their more cautious, tempered view (Exhs. AG-JRW-1, at 11-12, 18-19, 21-31; AG-JRW-Surrebuttal-1, at 2-3,

19-21; FEA-MPG-1, at 37-39, 57, 61-65 (Corrected); SREF-DJG-1, at 13 & Apps, C at 7-10, D at 8-9, 11-12). The Companies offer more optimistic future trends for the U.S. economy, and emphasize signs of increasing interest rates and long-term Treasury yields, higher GDP growth rates, and higher dividend yields (Exh. ES-RBH-1, at 64-67). The intervenors offer a less enthusiastic outlook based on their interpretation of present and recent past events, and their skepticism for future capital market projections (Exhs. AG-JRW-1, at 11-12, 18-19, 21-31; AG-JRW-Surrebuttal-1, at 2-5, 19-21; FEA-MPG-1, at 37-39, 57, 61-65 (Corrected); SREF-DJG-1, at 13 & Apps., C at 7-10, D at 8-9, 11-12). We will consider capital market projections in evaluating the analysis models used by the parties in proposing an ROE for Eversource.

Turning to Eversource's risk profile as it compares to proxy group peers, we review the credit issuer ratings and evidence relating to revenue stabilization and reconciling mechanisms. The number of annual credit upgrades in the electric and gas utilities industry is at or over 70 percent between 2012 and 2016, indicating that credit rating agencies see declining risk in the industry overall (Exh. AG-JRW-1, at 9-10). Low betas, indeed the lowest among most industries measured, also indicate low risk for the utility sector (Exhs. AG-JRW-1, at 9-10; JRW-8). Such indicators of risk are the baseline, and the Companies do not disagree (Exhs. ES-RBH-1, at 11-12; ES-RBH-Rebuttal-1, at 68). Nevertheless, credit ratings are not a direct proxy for an individual firm's risk level (Exhs. ES-RBH-1, at 11-12; ES-RBH-Rebuttal-1, at 62-64, 72-73; ES-RBH-Rebuttal-18). Rather, allowed ROEs and the regulatory process behind have a significant bearing on credit

rating agencies' setting ratings for regulated utilities (Exhs. ES-RBH-1, at 14-15; ES-RBH-Rebuttal-1, at 95-97). Other factors such as cash from operations and volatility in credit spreads and valuations also influence risk (Exhs. ES-RBH-1, at 56, 60-62, 67-69; ES-RBH-Rebuttal-1, at 16).

Regarding trends in authorized ROE nationally and regionally, those arguments are superfluous and inoperative here. As stated below, under the principles of Hope and Bluefield, regulated utilities are entitled to earn a return on capital investments consistent with the returns for businesses of similar risk levels. The return for regulated utilities must be adequate to provide access to capital and to support credit quality, and must result in just and reasonable rates for consumers. ROE trends are not a factor in setting a specific company's ROE under the Hope and Bluefield principles. Therefore, the Department will not factor ROE trends in setting the allowed ROE for the Companies.

7. Discounted Cash Flow Model

a. Companies DCF Analysis

The DCF model is based on the premise that a stock's current price is equal to the present value of the expected future cash flows that investors expect to receive (Exh. ES-RBH-1, at 17). The Companies used both constant growth and a multi-stage DCF models (Exhs. ES-RBH-1, at 3, 6, 24-37; ES-RBH-3; ES-RBH-4).

The constant growth DCF model comprises a forward looking dividend yield component and an expected dividend growth rate into perpetuity. The Companies calculated the dividend yield component based on the current annualized dividends of their proxy group (Exh. ES-RBH-1, at 24). The Companies use the Professional Services ("Bloomberg")

dividend estimates, adjusting them by one-half of the growth rate (Exh. ES-RBH-1, at 25; ES-RBH-3).[351] For the expected growth rate, the Companies used a consensus of Zacks, Firstcall, and Value Line surveys to estimate a long-term earnings growth rate (Exhs. ES-RBH-1, at 26-28; ES-RBH-Rebuttal-2).[352] The Companies' initial analysis produced a cost of equity range using the constant growth DCF model of 8.89 percent to 8.94 percent (Exhs. ES-RBH-1, at 6, 29, 74; ES-RBH-3). During the proceedings, the Companies updated their data to produce a cost of equity range using the constant growth DCF model of 8.77 percent to 8.95 percent (Exh. ES-RBH-Rebuttal-1, at 163).

To address what they contend are certain simplifying assumptions underlying the constant growth model, the Companies also used a multi-stage DCF model (Exh. ES-RBH-1, at 30). This model employs multiple earnings growth rate and payout rate assumptions (Exh. ES-RBH-1, at 33-37). Earnings growth and payout ratio assumptions change throughout the three stages of this model (Exh. ES-RBH-1, at 33-37).[353] The Companies' model sets the stock price equal to the present value of future cash flows received over three stages, with cash flows defined as project dividends in the first two stages (Exh. ES-RBH-1, at 32). In the third stage, cash flows equal both dividends and the expected price at which

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351 Bloomberg provides financial data, news, and analytics.

352 Zachs Investment Research, Inc., Firstcall Research, and Value Line, Inc. provide a wide range of investment research and industry analysis services.

353 Generally, the three stages are described as: (1) a high-growth rate for a period of time (usually three to seven years); (2) followed by a transition period during which the growth will decline in linear increments; and (3) followed by a stable growth rate forever.

the stock will be sold at the end of the period, also called the "terminal price" (Exh. ES-RBH-1, at 32). The Companies calculated the terminal price based on the Gordon model, which defines the price as the expected dividend divided by the difference between the cost of equity (the discount rate) and the long-term expected growth rate (Exh. ES-RBH-1, at 32). The Companies also used the terminal price-earnings ("P/E") ratio multi-stage DCF model to assess the reasonableness of the inputs and results by dividing the terminal stock price by the expected earnings per share in the terminal year to calculate the expected P/E ratio (Exh. ES-RBH-1, at 34).[354]

In particular, the Companies employed a long-term GDP growth rate of 5.36 percent (Exhs. ES-RBH-1, at 35; ES-RBH-Rebuttal-1, at 38, 40). In its initial filing, Eversource's multi-stage Gordon growth method DCF model produced a cost of equity range of 9.09 percent to 9.14 percent,[355] and its multi-stage terminal P/E method DCF model produced a cost of equity range of 10.11 percent to 10.24 percent (Exhs. ES-RBH-1, at 6, 37, 74; ES-RBH-4). During the proceedings, the Companies updated their data to produce a multi-stage DCF Gordon growth method model mean range of 8.81 percent to 9.00 percent, and a multi-stage DCF terminal P/E method model mean range of 10.40 percent to

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354 The Companies state that the terminal P/E ratio can be divided by the terminal growth rate to develop a price-to-earnings growth ratio, which, if inconsistent with historical experience, may indicate incorrect or inconsistent modeling assumptions (Exh. ES-RBH-1, at 34).

355 The Gordon growth method is a methodology used in a DCF analysis that assumes the company will grow and generate free cash flows forever at a consistent rate.

10.88 percent (Exhs. ES-RBH-Rebuttal-1, at 2-3, 40 n.68, 62-63; ES-RBH-Rebuttal-2; ES-RBH-Rebuttal-3).

b. Attorney General DCF Analysis

The Attorney General relies on a constant growth DCF model, reasoning that the public utility business is in the steady state (or constant growth) stage of a three-stage DCF model (Exh. AG-JRW-1, at 49-50). To determine the cost of equity using her constant growth DCF model, the Attorney General summed the estimated dividend yield and growth rates of her proxy group (Exh. AG-JRW-1, at 61). The Attorney General calculated the DCF dividend yield for the proxy group using the current annual dividend and the 30-day, 90-day, and 180-day average stock prices based on data supplied by Yahoo Finance (Exhs. AG-JRW-1, at 51; AG-JRW-10, at 2).[356] Using this method, the median dividend yields for the Attorney General's proxy group range from 3.3 percent to 3.5 percent (Exhs. AG-JRW-1, at 51; AG-JRW-10, at 2). Within this range, the Attorney General chose the average of the medians of 3.45 percent as the dividend yield for her proxy group (Exhs. AG-JRW-1, at 51, 61; AG-JRW-10, at 2). The Attorney General then calculated the corresponding dividend yield for the Companies' proxy group of 3.35 percent, which represented the average of the median dividend yields ranging from 3.2 percent to 3.5 percent (Exhs. AG-JRW-1, at 51, 61; AG-JRW-10, at 2).

The dividend yield is obtained by dividing the annualized expected dividend in the coming quarter by the current stock price (Exh. AG-JRW-1, at 51-52). To annualize the

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356 Yahoo Finance provides financial data, business news, and related information.

expected dividend, the Attorney General multiplied the expected dividend for the coming quarter by four, and multiplied the result by one half of the expected growth rate (Exh. AG-JRW-1, at 51-52).

In developing the expected growth rate, the Attorney General relies on the historic and projected growth rates of earnings per share ("EPS"), dividends per share, and book value per share provided by Value Line, as well as the EPS growth forecasts of Wall Street analysts provided by Yahoo Finance, Firstcall, and Zacks (Exhs. AG-JRW-1, at 53; AG-JRW-10, at 3-6). Although the Attorney General assumes that EPS and dividends per share will exhibit similar growth rates over the very long term, she relies on historic and projected dividends per share and book value per share as well as internal growth to balance what she states are the shortcomings of relying solely on EPS as a proxy for the DCF growth rate (i.e., an upward bias among Wall Street analysts) (Exhs. AG-JRW-1, at 56-57; AG-JRW-10, at 3-6). The DCF projected growth rate for the Attorney General proxy group and the Companies' proxy group is 5.25 percent and 5.5 percent, respectively (Exhs. AG-JRW-1, at 60-61; AG-JRW-10, at 1, 3-6).

The Attorney General adds the adjusted dividend yields and the estimated growth rates to determine a cost of equity for both her proxy group and the Companies' proxy group (Exhs. AG-JRW-1, at 61; AG-JRW-10, at 1). The DCF analysis performed by the Attorney General yields a cost of equity of 8.80 percent for her proxy group and 8.95 percent for the Companies' proxy group, respectively (Exhs. AG-JRW-1, at 61; AG-JRW-10, at 1).

c. FEA DCF Analysis

FEA calculates two constant growth DCF models and one multi-stage DCF model to produce average equity costs ranging from 7.89 percent to 9.10 percent (Exhs. FEA-MPG-1, at 54-67 (Corrected); FEA-MPG-9; FEA-MPG-12; FEA-MPG-14). For its securities inputs, FEA relies on the average weekly high and low stock prices of the utilities in the Companies' proxy group over a 13-week period ending March 31, 2017 (Exhs. FEA-MPG-1, at 52, 54 (Corrected); FEA-MPG-9; FEA-MPG-11; FEA-MPG-12; FEA-MPG-14). FEA also collected the most recent quarterly dividends paid by each company in the Companies' proxy group as reported by Value Line between January 27, 2017 and March 17, 2017 (Exh. FEA-MPG-1 at 55 n.31 (Corrected)). FEA then used consensus professional security analysts' earnings growth estimates from Zacks, SNL Financial LC ("SNL"), and Thompson Reuters Corporation ("Reuters") to produce an average growth rate of 5.67 percent for the proxy group (Exhs. FEA-MPG-1, at 55-56 (Corrected); FEA-MPG-8).[357] The average and median constant growth DCF returns for the Companies' proxy group for the 13-week analysis are 9.10 percent and 9.22 percent, respectively (Exhs. FEA-MPG-1, at 56 (Corrected); FEA-MPG-9).

In its second constant growth DCF calculation, FEA uses a sustainable long-term growth rate of 4.51 percent derived from dividend payout ratios and earnings retention ratios as well as from market to book ratios and Value Line projections of earnings, dividends,

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357 SNL provides industry-specific financial market data feed of public and private companies worldwide. Among other things, Reuters provides financial news, information, and analytics services.

earned returns on book equity, and stock issuances (Exhs. FEA-MPG-1, at 58 (Corrected); FEA-MPG-11). This second, "sustainable" constant growth DCF analysis over a 13-week period produces Companies' proxy group average and median DCF results of 7.89 percent and 7.55 percent, respectively (Exhs. FEA-MPG-1, at 59 (Corrected); FEA-MPG-12).

FEA's multi-stage growth DCF analysis employs: (1) the 5.67 percent consensus analysts' growth projections for the first stage, short-term growth period; (2) a growth rate range of 4.45 percent to 5.43 percent for the second stage transition period;[358] and (3) 4.2 percent consensus analysts' projections of long-term GDP growth for the third stage (Exhs. FEA-MPG-1, at 66 (Corrected); FEA-MPG-14).[359] This multi-stage model produces average and median DCF returns on equity of 7.90 percent and 7.96 percent, respectively (Exhs. FEA-MPG-1, at 66 (Corrected); FEA-MPG-14). Noting its concerns that DCF model results below eight percent were not consistent with market evidence, FEA relies on its 9.10-percent constant growth DCF model result for a high-end DCF return estimate (Exhs. FEA-MPG-1, at 67 (Corrected); FEA-MPG-9).

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358 FEA states that growth rates for the second stage, transition period were reduced or increased by an equal factor reflecting the difference between the analysts' growth rates and the long-term sustainable growth rates, resulting in growth rates of 5.43, 5.18, 4.94, 4.69, and 4.45 percent in years six through 10, respectively (Exhs. FEA-MPG-1, at 60 (Corrected); FEA-MPG-14).

359 For the third stage analysis, FEA relied on the consensus economists' projected five- and ten-year average GDP growth rates as published by Blue Chip Economic Indicators (Exhs. FEA-MPG-1, at 63 (Corrected); FEA-MPG-14).

d. Sunrun and EFCA DCF Analysis

Sunrun and EFCA employed a constant growth DCF model that assumes dividends are paid on a quarterly basis and held constant for four consecutive quarters (Exh. SREF-DJG-1, App. C at 3). The model also uses 30-day averages of adjusted closing stock prices reported by Yahoo Finance for each company in the Companies' proxy group, (Exhs. SREF-DJG-1, App. C at 4-5; SREF-DJG-6).[360] Sunrun and EFCA used the quarterly dividend paid in the first quarter of 2017 obtained from NASDAQ for each company in the Companies' proxy group (Exhs. SREF-DJG-1, at 7 & App. C at 6; SREF-DJG-7). Additionally, Sunrun and EFCA assume that the Companies increase dividend payments each quarter by an annual growth rate (SREF-DJG-1, App. C at 6). For the growth rate, Sunrun and EFCA chose 4.1 percent, representing the long-term forecast for nominal GDP provided by the Congressional Budget Office, which includes an inflation rate of two percent (Exh. SREF-DJG-1, App. C at 7-9). Sunrun and EFCA state that their 4.1-percent growth rate assumes that, over the long-term, the annual growth in Eversource's earnings will match the growth of the entire U.S. economy (Exh. SREF-DJG-1, App. C at 9). Sunrun and EFCA placed Eversource's terminal growth rate between two percent and four percent, and maintain that the terminal growth rate for utilities will fall between the rate of inflation and the expected rate of nominal GDP growth (Exhs. SREF-DJG-1, App. C at 8; SREF-DJG-8). With the average of reported dividends and stock prices from the Companies' proxy group,

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360 Sunrun and EFCA maintain that adjusted closing prices, rather than actual closing prices, are ideal for analyzing historical stock prices, because adjusted prices provide accurate representation of a firm's equity value beyond the market price by accounting for stock splits and dividends (Exh. SREF-DJG-1, App. C at 5 n.3).

and using what they state is a "reasonable" terminal growth rate estimate, Sunrun and EFCA calculated a 7.5-percent DCF cost of equity estimate for Eversource (Exh. SREF-DJG-1, App. C at 10; SREF-DJG-9).

e. Positions of the Parties

i. Attorney General

The Attorney General argues that the Department should reject Eversource's DCF analysis for three reasons (Attorney General Brief at 72). First, the Attorney General contends that the Companies' have given little weight to their constant growth DCF results, and she claims that utility P/E ratios have persisted, based on expectations of continued reduced risk in the utility industry and corresponding lower risk utility stocks (Attorney General Brief at 72; Attorney General Reply Brief at 66-68, citing Exh. AG-JRW-Surrebuttal-1, at 12-14). She notes that, despite calculating 29 constant-growth stage DCF equity cost rates averaging 8.9 percent, the Companies used only six of the ROE estimates to derive their 10.50-percent ROE recommendation (Attorney General Brief at 72, citing Exh. AG-JRW-1, at 78; Attorney General Reply Brief at 67-68).

Second, the Attorney General argues that the Companies' DCF analyses rely solely on what she considers to be inflated long-term EPS growth rate projections of Wall Street analysts and Value Line (Attorney General Brief at 72, citing Exh. AG-JRW-1, at 56-57, 78-81; Attorney General Reply Brief at 67-69). Third, the Attorney General contends that the Companies are inconsistent in their use of historic versus projected data (Attorney General Brief at 76, citing Exh. AG-JRW-1, at 84). In particular, the Attorney General contends that in developing their constant growth DCF analysis, the Companies ignored data

on historical EPS, dividends per share, and book value per share (Attorney General Brief at 76, citing Exh. AG-JRW-1, at 84; Attorney General Reply Brief at 70). In addition, the Attorney General claims that, in developing a terminal DCF growth rate for its multi-stage growth DCF analysis, the Companies ignored well known, long-term real GDP growth rate forecasts and, instead, relied solely on historical GDP data going back to 1929 (Attorney General Brief at 76, citing Exh. AG-JRW-1, at 84; Attorney General Reply Brief at 70).

Finally, the Attorney General contends that the Companies' GDP growth rate of 5.36 percent used in their multi-stage DCF model is excessive, unsupported by theoretical or empirical evidence, not reflective of economic growth in the United States, and about 100 basis points above projections of long-term GDP growth (Attorney General Brief at 72-74, citing Exh. AG-JRW-1, at 60-61, 81-83; Attorney General Reply Brief at 69-70). The Attorney General claims that despite some fluctuations, nominal GDP growth rates have declined over the years and have been in the 3.5 to four percent range over the past five years (Attorney General Brief at 74, citing Exh. AG-JRW-1, at 74). Further, she argues that the compounded GDP growth rate of 6.45 percent over the 50 years since the mid-1960s belies a "monotonic and significant" decline in nominal GDP growth rates in recent decades (Attorney General Brief at 74, citing Exh. AG-JRW-1, at 82). Therefore, the Attorney General concludes that a more appropriate nominal GDP growth rate figure for today's economy is in the range of four to five percent (Attorney General Brief at 74).

ii. FEA

FEA contends that the Companies' DCF analysis ignores Eversource's favorable risk under current market conditions and has excessive and unsustainable growth rate assumptions that inflate their ROE results (FEA Brief at 5). Specifically, FEA asserts that the Companies' arguments for a higher cost of capital defy market evidence, which reflects high stock prices, low dividend yields, and the resulting low costs of capital (FEA Brief at 8; FEA Reply Brief at 2-3). According to FEA, the Companies incorrectly discount the market's current high valuation of utility stocks and their resulting high P/E ratios (FEA Brief at 8; FEA Reply Brief at 2-3, citing Companies Brief at 537). FEA contends that this assessment ignores market sentiments that are favorable toward utility companies and lumps utility investments in with general corporate investments having higher expected ROEs (FEA Brief at 8).

Further, FEA notes that the Companies' multi-stage DCF model assumes an inflated growth rate that is significantly higher than consensus economists' projections of future GDP growth (FEA Brief at 5). According to FEA, the Companies' nominal GDP growth projections for their multi-stage DCF model is flawed because their growth forecast was based on a combination of historical real GDP growth and projected inflation outlooks (FEA Reply Brief at 3-4). FEA maintains that the Companies' reliance on historical growth rate numbers overstates real GDP growth, and, therefore, overstates a sustainable long-term growth rate for use in their DCF methodology (FEA Reply Brief at 4). FEA argues that a DCF result implying an ROE below 8.0 percent reasonably reflects investor-required returns,

and concludes that an ROE of 9.0 percent is appropriate for NSTAR Electric and WMECo (FEA Brief at 10).

iii. Sunrun and EFCA

Sunrun and EFCA challenge Eversource's DCF model for its use of a long-term growth rate that exceeds the growth rate of the entire U.S. economy (Sunrun and EFCA Brief at 19). Sunrun and EFCA argue that the Companies' long term growth rate conflicts with a fundamental tenet of finance that, in the long run, a company cannot grow at a faster rate than the aggregate economy in which it operates (Sunrun and EFCA Brief at 19 n.71, citing Exhs. SREF-DJG-1, at 13; SREF-DJG-Rebuttal at 7). Sunrun and EFCA note that Eversource uses long-term growth rates in its DCF analysis that are as high as 9.0 percent, which produces cost of equity results up to 10.61 percent (Sunrun and EFCA Brief at 19 n.72, citing Exh. SREF-DJG-1, at 14). However Sunrun and EFCA's assert that 4.1 percent is the highest realistic growth rate, which produces a cost of equity of 7.5 percent (Sunrun and EFCA Brief at 19 n.72, citing Exh. SREF-DJG-1, at 14).

iv. Companies

(A) Constant Growth DCF Model

Eversource argues that the Attorney General's constant growth DCF calculation is subjective and incapable of replication (Companies Brief at 519, citing Exh. ES-RBH-Rebuttal-1, at 14, 18-19, 32-33; Companies Reply Brief at 149). The Companies also assert that the Attorney General's constant growth DCF approach inappropriately relies on historical growth rates as a measure of investors' expected growth rates, when the model's growth rate is a forward-looking measure (Companies Brief at 519,

citing Exh. ES-RBH-Rebuttal-1, at 31). In addition, the Companies contend that the Attorney General's DCF recommendation incorrectly relies on dividend per share and book value per share growth rates, which they contend are merely derivative of earnings growth (Companies Brief at 519, citing Exh. ES-RBH-Rebuttal-1, at 27-32).

Eversource also challenges Sunrun and EFCA's contention that the Companies' long-term growth rate improperly exceeds that of the national economy, asserting that the Companies' constant growth DCF growth rates are correctly a function of investor growth expectations, based on analysts' growth expectations (Companies Brief at 534, citing Exh. ES-RBH-Rebuttal-1, at 125-126). Additionally, Eversource disputes Sunrun and EFCA's suggestion that the Companies based their recommended ROE on a speculative, undisclosed, subjective expectation of investors, stating rather that their growth rate and subsequent ROE recommendation is based on observable market data (Companies Reply Brief at 156, citing Exh. ES-RBH-1, at 22). The Companies also challenge FEA's argument that the Companies' DCF analysis assumes an inflated growth rate relative to future GDP growth, maintaining that the consensus growth rates the Companies used in their model are actually below the average consensus growth rates relied on by FEA for its own constant growth DCF model (Companies Brief at 537, citing Exh. ES-RBH-Rebuttal-1, at 99).

The Companies dispute the Attorney General's claim that they gave insufficient weight to the results of their constant-growth DCF analysis (Companies Brief at 520; Companies Reply Brief at 150). Instead, the Companies contend that the Attorney General apparently refuses to consider a multi-stage DCF model in setting a ROE, despite the limiting

assumptions underlying the constant-growth DCF model, such as her assumption of using a constant P/E ratio in perpetuity (Companies Brief at 520, citing Exh. ES-RBH-1, at 24; Companies Reply Brief at 150).

In this regard, the Companies maintain that the Attorney General's and FEA's use of unusually high P/E ratios in perpetuity is an unrealistic assumption for the constant growth DCF model, leading to cost of equity anomalies (Companies Brief at 519, 536-537, citing Exh. ES-RBH-Rebuttal-1, at 17-18, 79; Companies Reply Brief at 149, 158, citing D.P.U. 13-90, at 219 (2014)). Referring to FEA's 9.00 percent DCF calculation as "problematic," the Companies fault FEA for not placing less weighing on its constant growth DCF model results despite acknowledging an "abnormal expansion" of P/E ratios (Companies Brief at 536-537, citing Exh. ES-RBH-Rebuttal-1, at 79). The Companies add that with P/E ratios for utilities currently at unusually high levels, it is necessary to consider the results of the multi-stage DCF model when determining an appropriate level of ROE (Companies Brief at 520, citing Exh. ES-RBH-1, at 29-30; Companies Reply Brief at 150, citing Exh. ES-RBH-1, at 29-30).

Turning to DCF growth rates, Eversource dismisses the Attorney General's contention that their EPS growth rate estimates were upwardly biased (Companies Brief at 520; Companies Reply Brief at 150). First, the Companies assert that litigation and new financial regulations in 2003 have helped to neutralize analysts' bias in the median forecast errors (Companies Brief at 520, citing Exh. ES-RBH-Rebuttal-1, at 26-27; Companies Reply Brief at 150). Second, the Companies maintain that the Department has noted, and the Attorney

General's witness has admitted, a lack of pronounced bias in the EPS forecasts for utilities (Companies Brief at 520-521, citing D.P.U. 15-155, at 362-363; D.P.U. 13-75, at 302; Companies Reply Brief at 150). Third, the Companies maintain that regardless of analysts' forecasts, investor expectations are more important when applying the DCF model, and the DCF-estimated ROE must recognize that the EPS growth rate expectations of investors drive stock prices, even if those expectations are influenced by analysts' forecasts (Companies Brief at 521, citing D.P.U. 15-155, at 362-363; Companies Reply Brief at 150). Further, the Companies note that the Attorney General conceded that any bias that may exist for utilities is at most in the range of 20 basis points (Companies Brief at 520-521, citing D.P.U. 15-155, at 362-363).[361]

(B) Multi-Stage DCF Model

The Companies dispute the Attorney General's assertion that the Companies' proposed multi-stage DCF growth rate of 5.36 percent, based on GDP growth rate, fails to take into consideration the more recent lower trends in GDP growth or the current forecasts by economists and some federal agencies (Company Brief at 521, citing Attorney General Brief at 73-75). In support of its GDP-derived growth rate, Eversource notes that the annual nominal GDP growth rate has remained relatively stable since 1990 and was greater than five percent in twelve of the last 27 years (Companies Brief at 521-522, citing Exh. ES-RBH-Rebuttal-1, at 38-39). Additionally, in opposition to FEA's preference for

[361] The Companies also note that the Attorney General claims to have given "primary weight" in her DCF model to the same projected growth rates of Wall Street analysts that she criticizes the Companies for using (Companies Reply Brief at 150-151, citing Exh. AG-JRW-Surrebuttal-1, at 17).

five- or ten-year consensus GDP projections, the Companies argue that their multi-stage DCF analysis reflects growth expectations beginning ten years in the future when there are no consensus forecasts and when it is reasonable to assume that real growth will revert to the long-term average over time (Companies Brief at 537, citing Exh. ES-RBHRebuttal-1, at 100).

Further, the Companies argue that their proposed long-term growth rate is consistent with the long-term growth rates of other respected economic forecasts (Companies Brief at 522). In support of its position, Eversource asserts that a 2010 report issued by McKinsey & Company ("McKinsey Report"), relied upon by the Attorney General in developing her testimony, states that the long-term earnings growth for the market as a whole is unlikely to differ significantly from growth in GDP (Companies Brief at 522, citing Exh. ES-RBH-Rebuttal-1, at 47-48; Companies Reply Brief at 151). The Companies also note that the McKinsey Report states that: "[r]eal GDP has averaged 3 to 4 percent over [the] past seven or eight decades, which would indeed be consistent with nominal growth of 5 to 7 percent given current inflation of 2 to 3 percent" (Companies Brief at 522, citing Exh. ES-RBH-Rebuttal-1, at 41-42).[362] Therefore, the Companies maintain that their proposed growth rate of 5.36 percent is supported by the McKinsey Report because the selected growth rate represents a combination of historical real GDP growth rate and a

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[362] The Companies note that the Attorney General points to a more recent McKinsey study to support her claim of lower expected GDP growth associated with slowing employment growth, but neglects to include McKinsey's observations that best practices and technological innovations could also potentially elevate GDP (Companies Reply Brief at 151, citing McKinsey & Company, "Can Long-Term Growth be Saved?", McKinsey Global Institute, January 2015, at 53).

corresponding level of expected inflation, and falls within the lower end of the five to seven percent range noted by the McKinsey Report (Companies Brief at 522, citing Exh. ES-RBH-Rebuttal-1, at 41-42). Moreover, the Companies argue that the Attorney General has not explained why she considers economists' near-term interest rate projections to be improper while at the same time accepting their long-term real GDP growth rate projections (Companies Reply Brief at 151).

In addressing the Attorney General's and FEA's contention that the Companies' multi-stage DCF approach incorrectly relies on historical GDP data rather than economists' projections, the Companies state that they did not use economists' GDP forecasts because they did not encompass the entire period covered by the multi-stage DCF model and because the forecasts are not consensus-based (Companies Reply Brief at 151, 158, citing Exh. ES-RBH-Rebuttal-1, at 42).

Finally, in response to the Attorney General's contention that economists' forecasts of higher interest rates should be given no weight because they have been proven wrong, the Companies maintain that they have augmented economists' forecasts with observable market data (Companies Reply Brief at 151, citing Exh. ES-RBH-1, at 64). The Companies argue that with the 30-year Treasury yield increasing by over 50 basis points since July 2016 and with Federal Reserve monetary policies ending, it is all but certain that interest rates will rise (Companies Reply Brief at 151-152, citing Exhs. ES-RBH-1, at 60, 64; ES-RBH-Rebuttal-1, at 75-76; Tr. 4, at 684, 686, 735). Accordingly, the Companies recommend that the Department reject the intervenors' DCF analyses, calculations, and criticisms of the

Companies' DCF calculations and set an ROE consistent with law and record evidence (Companies Brief at 532, 535-537).

v. Analysis and Findings

In developing their proposed ROEs, the Companies and intervenors use a form of the DCF model that assumes an infinite investment horizon and a constant growth rate (Exhs. ES-RBH-1, at 24-26; AG-JRW-1, at 49; SREF-DJG-1, at 7 & App. C at 2; FEA-MPG-1, at 51-53 (Corrected)). This model has a number of very strict assumptions (e.g., the infinite investment horizon and dividend growth at a constant rate in perpetuity) (Exh. ES-RBH-1, at 24). These assumptions affect the estimates of the cost of equity. D.P.U. 10-114, at 312; D.P.U. 09-39, at 387.

Because regulatory commissions establish a level of authorized earnings for a utility that, in turn, implicitly influences dividends per share, the estimation of the growth rate from such data is an inherently circular process. D.P.U. 10-114, at 312; D.P.U. 10-55, at 512; D.P.U. 09-30, at 357-358. Specifically, the DCF model includes an element of circularity when applied in a rate case because investors' expectations depend upon regulatory decisions. D.P.U. 10-70, at 253; D.P.U. 09-30, at 357-358. Consequently, this circularity affects the results of both the Companies' and the intervenors' DCF models. The Attorney General's, Sunrun and EFCA's, and FEA's DCF models place less emphasis on analyst forecasts of EPS growth rates which, to some extent, compensates for this circularity (Exhs. AG-JRW-1, at 56-57; SREF-DJG-Rebuttal at 10-12; FEA-MPG-1, at 63-65 (Corrected)).

The Companies and intervenors use different data sources to estimate the dividend yield and growth rates (Exhs. ES-RBH-1, at 24-25; ES-RBH-3; AG-JRW-1, at 47-56; AG-JRW-10; SREF-DJG-1, App. C at 6-10; FEA-MPG-1, at 55-66 (Corrected)). Although the various parties applied their quarterly and average dividend yields differently in their respective DCF equations, the common objective of projecting annual growth balanced out to achieve comparable results (Exhs. ES-RBH-1, at 23-25; AG-JRW-1, at 47-49; FEA-MPG-1, at 53-54 (Corrected); SREF-DJG-1, App. C at 6).

In addition, the Companies and the Attorney General use different growth rates in their respective DCF analyses (Exhs. ES-RBH-1, at 35-36; ES-RBH-4; ES-RBH-R-3; AG-JRW-1, at 60-61; AG-JRW-10, at 1). Determining the appropriate long-term growth expectations of investors in a DCF analysis can be difficult and controversial. Fitchburg Gas and Electric Light Company, D.T.E. 99-18, at 83 (2001); D.T.E. 98-51, at 120; D.P.U. 88-135/151, at 125. As stated above, FEA and Sunrun and EFCA also use different growth rates than the Companies' growth rate (Exhs. FEA-MPG-1, at 55-64 (Corrected); FEA-MPG-8 through FEA-MPG-12; FEA-MPG-14; SREF-DJG-1, App. C, at 6-10; SREF-DJG-8; SREF-DJG-9).

The Department finds that both the Companies' and intervenors' approaches are logical and reasonable. Further, there is no evidence to establish that investors rely overwhelmingly on one approach over the other. Therefore, we find that all approaches provide a credible basis for evaluating a determination of the Companies' allowed ROE. The Department has found that investors' heavy reliance on EPS forecasts gives credence to the

Attorney General's argument that investors are aware of upward biases. D.P.U. 13-75, at 302. Accordingly, the Department will take these biases into consideration in evaluating the DCF analyses.

8. Capital Asset Pricing Model

a. Companies Proposal

The Companies use the CAPM to estimate the cost of equity for its proxy group (Exhs. ES-RBH-1, at 37; ES-RBH-5; ES-RBH-6; ES-RBH-7). The application of the Companies' CAPM results in eight individual costs of equity estimates, ranging from 9.16 percent to 11.46 percent (Exhs. ES-RBH-1, at 40, 74; ES-RBH Rebuttal-1, at 163; ES-RBH-Rebuttal-6). Eversource asserts that it considered these results when determining its proposed ROE (Exhs. ES-RBH-1, at 6, 37; ES-RBH-Rebuttal-6).

The CAPM is a market-based investment model based on capital markets theory and modern portfolio theory. In the CAPM, the required rate of return on common equity is equal to the expected risk free rate of return plus a premium for the implicit systematic risk of the security (Exh. ES-RBH-1, at 37-38). There are three necessary components to calculate the cost of equity in the CAPM: (1) an expected risk free rate of return; (2) the market risk premium; and (3) the beta, a measure of systematic risk (Exhs. ES-RBH-1, at 37-38; ES-RBH-5; ES-RBH-6; ES-RBH-7).[363]

The Companies calculated a market risk premium range of 9.16 percent to 11.46 percent based on DCF analyses (Exhs. ES-RBH-Rebuttal-1, at 163;

[363] The beta of a stock measures the stock's volatility relative to that of the rest of the market. Betas for utility stocks are usually less than 1.0, which indicates a lower variability and hence lower risk relative to the market.

Sch. ES-RBH-Rebuttal-6). The Companies first used the current and forecasted 30-year Treasury bond yields to arrive at current, near-term, and long-term risk free rates (Exhs. ES-RBH-1, at 39; ES-RBH-5; ES-RBH-6; ES-RBH-7). The CAPM market risk premium is derived from the total return on the overall market minus the risk free rate of return. The Companies developed a range of risk-free rates from 2.97 percent to 3.43 percent, relying on the current 30-year Treasury bond rates as published in Bloomberg, as well as the near- and long-term projected 30-year Treasury bond rates based on interest rate forecasts published in Blue Chip Financial Forecasts (Exhs. ES-RBH-Rebuttal-1, at 163; ES-RBH-Rebuttal-6).[364] The Companies then developed ex-ante market risk premiums based on data from both Bloomberg and Value Line by calculating their respective estimated market required returns less the Treasury bond yield (Exhs. ES-RBH 1, at 39-40; ES-RBH-5; ES-RBH-7).

More specifically, the Companies obtained beta coefficients for their proxy group from Bloomberg (0.603) and Value Line (0.73) (Exhs. ES-RBH-1, at 40; ES-RBH-6). Using these beta coefficients in combination with separate Bloomberg and Value Line data and current, near term, and long-term risk free rates, Eversource then calculated four Bloomberg market DCF-derived CAPM results and four Value Line market DCF-derived CAPM results (Exhs. ES-RBH-1, at 40; ES-RBH-7).

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[364] Blue Chip Financial Forecasts is a publication product of Wolters Kluwer Legal & Regulatory U.S., which provides top analysts' forecasts of U.S. and foreign interest rates and currency values, and the factors that influence those forecasts.

b. Attorney General Proposal

The Attorney General uses a traditional CAPM approach in which the cost of equity is equal to the sum of the interest rate on risk-free bonds and an equity risk premium ("ERP") (i.e., the excess return that an investor expects to receive above the risk-free rate for investing in stocks) (Exhs. AG-JRW-1, at 62; AG-JRW-11, at 1). The Attorney General's CAPM analysis results in a cost of equity of 7.90 percent (Exhs. AG-JRW-1, at 68-71; AG-JRW-11, at 1).

In her analysis, the Attorney General first used the upper bound of the six-month average yield on 30-year Treasury bonds (i.e., four percent) as the risk-free rate (Exhs. AG-JRW-1, at 63; AG-JRW-11). The Attorney General then calculated an estimated market risk premium of 5.5 percent, in the upper end of a range of market risk premiums between four percent and six percent (Exhs. AG-JRW-1, at 69; AG-JRW-11, at 1, 5-6). The Attorney General based her market risk premium on analysis of numerous surveys of financial professionals, including financial forecasters, chief financial officers, and academics (Exhs. AG-JRW-1, at 69-71; AG-JRW-11, at 1). To calculate the beta coefficient, the Attorney General performed a regression analysis of the returns of the companies in her proxy group against the return of the Standard & Poor's 500 Index ("S&P 500"),[365] representing the market, which resulted in a median beta coefficient of 0.70 percent (Exhs. AG-JRW-1, at 71; AG-JRW-11, at 1, 3). The Attorney General then multiplied the

[365] The S&P 500 is an American stock market index based on the market capitalizations of 500 large companies having common stock listed on the New York Stock Exchange or the NASDAQ Stock Market.

estimated market risk premium of 5.5 percent by the beta coefficients of 0.70 percent to produce an expected ERP of 4.00 percent (Exhs. AG-JRW-1, at 71; AG-JRW-11, at 1). The risk-free rate of four percent added to beta of the expected risk premiums of 5.50 percent results in a cost of equity of 7.90 percent (Exhs. AG-JRW-1, at 71; AG-JRW-11, at 1).

c. FEA Proposal

FEA's CAPM analysis produces a range of returns from 8.17 percent to 9.40 percent, and FEA recommends using the high-end return of 9.40 percent (FEA-MPG-1, at 80 (Corrected); FEA-MPG-21). FEA uses a projected 30-year Treasury bond yield of 3.80 percent for its risk-free rate, a beta of 0.73 percent derived from the Companies' proxy group average, and a market risk premium range of 6.0 percent to 7.7 percent, incorporating both forward-looking and historic estimates (FEA-MPG-1, at 76-78, 80 (Corrected); FEA-MPG-19; FEA-MPG-20). The 7.70 percent market risk premium is a forward-looking estimate of the expected return on the market as represented by the S&P 500, and the 6.0-percent market risk premium is an estimate of the historical arithmetic average of the achieved total return on the S&P 500 covering the period 1926 through 2016 (Exh. FEA-MPG-1, at 77-78 (Corrected)).

d. Sunrun and EFCA Proposal

Sunrun and EFCA calculate a cost of equity of 7.5 percent through their CAPM analysis (Exhs. SREF-DJG-1, at 14-16; SREF-DJG-14). Sunrun and EFCA develop their CAPM by using a 3.04 percent risk-free rate based on the current 30-day average yield on 30-year Treasury bonds, a 0.73 beta, and an equity risk premium of 6.2 percent taken from selected ERP results supplied by expert surveys and prominent economists

(Exhs. SREF-DJG-1, at 14-16 & App. D at 8-12; SREF-DJG-10 through SREF-DJG-14).[366] Sunrun and EFCA calculate their own ERP of 5.26 percent, but after comparing risk premiums offered in surveys and by financial forecasters, settle on the comparison group's highest ERP estimate of 6.2 percent (Exh. SREF-DJG-1, App. D at 11-12).[367]

e. Positions of the Parties

i. Attorney General

The Attorney General argues that the Companies' CAPM analysis produces long-term EPS growth rate projections that are highly overstated (Attorney General Brief at 81, citing Exh. AG-JRW-1, at 90-91). According to the Attorney General, the Companies' primary errors are with their use of inflated market risk premiums of 10.19 percent and 11.21 percent (Attorney General Brief at 79, citing Exh. AG-JRW-1, at 86-88). Further, the Attorney General contends that the Companies' long-term EPS growth rates of 11.04 percent and 12.00 percent are based on overly optimistic and upwardly biased Wall Street analysts' forecasts that are inconsistent with both historic and projected economic growth and earnings growth in the U.S. (Attorney General Brief at 80-81, citing Exh. AG-JRW-1, at 88-91; Attorney General Reply Brief at 69 n.29, citing Exh. AG-JRW-Surrebuttal-1, at 16).

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366 Sunrun and EFCA develop their ERP in part by reviewing statistics contained in a survey of economists and institutions collected by the IESE Business School, the graduate business school of the University of Navarra (Exh. SREF-DJG-1, App. D at 8-9 n.15).

367 Sunrun and EFCA compare their ERP estimate with estimates from the following: IESE Business School Survey (5.3 percent); Graham & Harvey Survey (4.0 percent); Duff & Phelps Report (5.5 percent); and Dr. Aswath Damodaran (6.2 percent) (Exh. SREF-DJG-1, App. D at 12).

In this regard, the Attorney General maintains that long-term economic, earnings, and dividend growth rates in the United States indicate that historical long-term growth rates are in the five percent to seven percent range (Attorney General Brief at 80). Moreover, the Attorney General asserts that more recent trends suggest lower future economic growth than the long-term historic GDP growth, in the range of four percent to five percent for today's economy, and notes that the projected long-term GDP growth rate forecasts by economists and government agencies are currently in the four percent to five-percent range as well (Attorney General Brief at 81, citing Exh. AG-JRW-1, at 89-90).

Finally, the Attorney General argues that, given current low inflation and limited economic growth, the Companies' projected earnings growth rates, implied expected stock market returns, and equity risk premiums are not indicative of the realities of the economy (Attorney General Brief at 81-82, citing Exh. AG-JRW-1, at 91). According to the Attorney General, the interest rate forecasts used by the Companies for their CAPM ROE recommendations are higher than actual interest rates, and, therefore, should be given no weight (Attorney General Reply Brief at 72). Based on the above, the Attorney General concludes that the Department should reject the Companies' proposed CAPM findings and resulting ROE recommendations (Attorney General Brief at 82).

ii. FEA

FEA contends that the Companies have overstated a reasonable market return estimate in deriving the market risk premium for their CAPM by focusing on exaggerated DCF returns on the market (FEA Brief at 14-15, citing Exh. ES-RBH-Rebuttal-1, at 81-82). FEA

notes that the Companies critiqued FEA's 11.50 percent expected market return estimate as too low in relation to historical returns (FEA Brief at 14-15, citing Exh. ES-RBH-Rebuttal-1, at 81-82; FEA Reply Brief at 4). However, FEA maintains that the Companies' projection of a return significantly in excess of 12 percent between 1976 and 2015 exceeds the 40-year average and does not reflect the expectation that market returns can be strong in some years and weak in others (FEA Brief at 14-15, citing Exh. ES-RBH-Rebuttal-1, at 81-82). FEA asserts that its forward-looking expected return on the market more accurately reflects expected market returns than historical returns, and, therefore, produces a more reasonable CAPM result than those recommended by the Companies (FEA Reply Brief at 4).

iii. Sunrun and EFCA

Sunrun and EFCA argue that the Companies' CAPM analysis is flawed because it uses an ERP more than twice as high as the estimate reported by "thousands of experts" (SREF and EFCA Brief at 20, citing Exh. SREF-DJG-1, at 13). Sunrun and EFCA also fault the Companies for deriving their ERP by comparing Treasury note returns and authorized utility ROEs (SREF and EFCA Brief at 20, citing Exh. ES-RBH-Rebuttal at 138-139). Sunrun and EFCA assert that their 6.2 percent ERP estimate, which they claim is based on ERP data compiled in surveys and by economists rather than utility commission ROE awards, is more credible than the 11.21 percent ERP the Companies use as an input for their CAPM analysis (SREF and EFCA Brief at 20, citing Exh. SREF-DJG-1, at 14). Accordingly, SREF and EFCA recommend that the Department find that the Companies have

failed to meet their burden of proving the propriety of their proposed ROE (SREF and EFCA Brief at 19).

iv. Companies

The Companies argue that the Attorney General's CAPM calculation must be rejected because the equity risk premium she relied on assumes market returns that do not make theoretical or practical sense (Companies Brief at 522, citing Exh. ES-RBH-Rebuttal-1, at 47-48). Further, the Companies contend that the Attorney General's CAPM analyses do not reflect fundamental risk-return relationships (Companies Brief at 522). The Companies also disagree with Sunrun and EFCA's critique of using authorized returns as an input and FEA's low expected market return relative to long-term historical market experience (Companies Brief at 534-535, 537).

The Companies dismiss the Attorney General's claim that reliance on analysts' forecasts invalidates the Companies' CAPM approach (Companies Brief at 522). Using the same analysis as discussed above regarding the DCF model, the Companies maintain that recent evidence does not support any upward bias in analysts' forecasts in particular for electric utilities (Companies Brief at 522-523). Finally, the Companies contend that the Attorney General's 8.78 percent implied market return produced by her CAPM is illogical because it is lower than the 8.875 percent recommended ROE resulting from her DCF approach, despite the fact that a return for the overall market should be higher than the return for utilities, which are seen as less risky than the overall market (Companies Brief at 523, citing Exh. ES-RBH-Rebuttal-1, at 47-48).

In addition, the Companies argue that FEA's CAPM calculation of 9.70 percent is not reasonable and that FEA's expected market return is well below the long-term historical market experience (Companies Brief at 537, citing Exh. ES-RBH-Rebuttal-1, at 81-82). In particular, the Companies note that it is not reasonable that FEA's expected total market return estimates are in the bottom twelfth percentile of the 90 annual returns reported by Morningstar, Inc.[368] (Companies Brief at 537, citing Exh. ES-RBH-Rebuttal-1, at 81-82).

For all these reasons, the Companies recommend that the Department reject the arguments of the intervenors associated with their CAPM analyses. Finally, the Companies assert that the Department should consider Eversource's CAPM results in addition to the Companies' DCF model analysis to augment any unreasonable results of the constant growth DCF model due to anomalous capital market conditions (Companies Brief at 523, citing Exh. ES-RBH-Rebuttal-1, at 79-81). Eversource concedes that the Department has placed "limited weight" on CAPM results in the past, but the Companies recommend giving their CAPM results some weight in setting NSTAR Electric's and WMECo's ROE (Companies Brief at 523, citing D.T.E. 01-56, at 113).

f. Analysis and Findings

The Department has previously found that the traditional CAPM as a basis for determining a utility's cost of equity has limited value because of a number of questionable assumptions that underlie the model. D.P.U. 10-114, at 318; D.P.U. 10-70, at 270;

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368 Morningstar, Inc. provides a variety of investment services to financial advisors, asset management firms, retirement plans and retirement sponsors, individual investors, and private and institutional investors. These services include financial news, financial data, research, analysis, and modeling tools.

D.P.U. 08-35, at 207; D.T.E. 03-40, at 359-360; D.P.U. 956, at 54. For example, the Department has not been persuaded that long-term government bonds are the appropriate proxy for the risk-free rate, and has found that the coefficient of determination for beta is generally so low that the statistical reliability of the results is questionable. D.T.E. 01-56, at 113; D.P.U. 93-60, at 256-257; D.P.U. 92-78, at 113; D.P.U. 88-67 (Phase I) at 182-184.

Current federal monetary policy that is intended to stimulate the economy has pushed treasury yields to near historic lows (Exh. AG-JRW-1, at 30-31). Consequently, the Department has found that a CAPM analysis based on current treasury yields may tend to underestimate the risk-free rate over the long term and, thereby, understate the required ROE. D.P.U. 14-150, at 350; D.P.U. 12-25, at 427; D.P.U. 11-01/D.P.U. 11-02, at 416. The CAPM is based on investor expectations and, therefore, it is appropriate to use a prospective measure for the risk-free rate component. The Department has found that Blue Chip Financial Forecasts is widely relied on by investors and provides a useful proxy for investor expectations for the risk-free rate. D.P.U. 13-75, at 314.

Because the CAPM is considered an ex-ante, forward looking model that recognizes that investors are generally risk averse and will demand higher returns in exchange for assuming higher levels of investment risk, the Department finds that the Companies' approach based on DCF analyses is less reliable than the survey results of financial professionals, such as relied on by the Attorney General. D.P.U. 13-90, at 225-226; D.P.U. 13-75, at 314. The Department notes that a 2015 survey of over 8,000 academics,

financial analysts, and companies estimates a market risk premium of 5.5 percent, which is far lower than the 9.16 percent to 11.46 percent range used in the Companies' analysis (Exhs. ES-RBH-Rebuttal-1, at 163; ES-RBH-Rebuttal-6; AG-JRW-1, at 68; AG-JRW-11, at 6). To the extent that FEA's and Sunrun and EFCA's market risk premium analyses rely on forward-looking projections or survey results, the Department places more weight on the results of these analyses than on historic results offered by FEA. Accordingly, the Department places more weight on the Attorney General's and Sunrun and EFCA's approaches to developing a market risk premium, with somewhat less weight on the FEA's approach.

Based on the above considerations, the Department will place limited weight on the results of the respective CAPM estimates in determining the appropriate ROE. However, to the limited extent that we rely on CAPM estimates, the Department gives more weight to the Attorney General's and Sunrun and EFCA's proposed CAPM.

9. Risk Premium Model

a. Company Proposal

The Companies state that the risk premium model is based on the concept that investing in common stock is riskier than investing in debt and, therefore, investors require a higher rate of return for equity (Exh. ES-RBH-1, at 40-41).[369] In the bond yield plus risk

[369] The equity risk premium is defined as the incremental return that an equity investment provides over the risk-free rate (Exhs. ES-RBH-1, at 40-41; ES-RBH-8). The risk premium method of determining the cost of equity recognizes that common equity capital is more risky than debt from an investor's standpoint, and that investors require higher returns on stocks than on bonds to compensate for the additional risk. The general approach is relatively straightforward: (1) determine the historical spread

premium model used by the Companies, the cost of equity is derived by calculating a risk premium over the returns available to bondholders (Exh. ES-RBH-1, at 40-41). Based on data from 1,488 electric utility proceedings between January 1, 1980 and November 29, 2016, the Company derived a risk premium analysis producing a cost of equity range of 10.01 percent to 10.34 percent applicable to its proxy group (Exh. ES-RBH-8).

Eversource calculated the risk premium as the difference between: (1) actual authorized returns using data from 1,488 electric utility rate proceedings between January 1, 1980, and November 29, 2016; and (2) the then prevailing long-term Treasury yield (i.e., 30-year bonds) (Exhs. ES-RBH-1, at 41; ES-RBH-8). To account for the forward-looking return and interest rates, Eversource calculated the average return period between the filing of each case and the approval of rates, as well as the level of interest rates during the pendency of the proceedings (Exh. ES-RBH-1, at 41). To assess the relationship between the 30-year Treasury yield and the equity risk premium, Eversource relied on a statistical analysis that concluded there was a statistically significant inverse relationship between the 30-year Treasury yield and the equity risk premium (Exhs. ES-RBH-1, at 42-43; ES-RBH-8).

b. FEA Proposal

FEA's risk premium model is based on two estimates of an equity risk premium: the first estimating the difference between the required return on utility common equity investments and U.S. Treasury bonds; the second estimating the difference between common

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between the return on debt and the ROE; and (2) add this spread to the current debt yield to derive an estimate of current equity return requirements. D.P.U. 13-75, at 316 n.201.

equity returns and contemporary A-rated utility bond yields by Moody's (Exh. FEA-MPG-1, at 68 (Corrected)). For both estimates, FEA used regulatory commission-authorized returns as the proxy for the required return on utility common equity (Exh. FEA-MPG-1, at 68 (Corrected)).

In estimating the risk premium on Treasury bonds, FEA measured the difference between utility common equity returns and Treasury bond yields on an annual basis for each year over the period 1986 through 2016, noting that utility stocks consistently traded at a premium to book value (Exhs. FEA-MPG-1, at 68-69 (Corrected); FEA-MPG-15). This analysis produced a range of equity risk premiums over U.S. Treasury bond yields of 4.25 percent to 6.72 percent for five-year averages, and 4.38 percent to 6.40 percent for ten-year averages (Exhs. FEA-MPG-1, at 69 (Corrected); FEA-MPG-16). FEA incorporated five- and ten-year rolling average risk premiums over the study period to gauge risk premium variability over time and to mitigate the impact of anomalous market conditions and skewed risk premiums over an entire business cycle (Exhs. FEA-MPG-1, at 69 (Corrected); FEA-MPG-16; FEA-MPG-17).

The risk premiums over contemporary Moody's A-rated utility bond yields ranged from 2.88 percent to 5.57 percent for the five-year rolling average and 3.20 percent to 5.04 percent for the ten-year rolling average (Exhs. FEA-MPG-1, at 69 (Corrected); FEA-MPG-17). FEA weighted the resulting high-end risk premiums more heavily than the low-end risk premiums and determined a range of Treasury bond and utility bond risk

premiums between 4.9 percent and 6.1 percent that resulted in ROEs of 9.5 percent to 9.9 percent (Exh. FEA-MPG-1, at 73-74 (Corrected)).

c. Sunrun and EFCA Proposal

Sunrun and EFCA calculate the ERP using an implied risk premium model similar to the constant growth DCF model that determines the discount rate for the entire market, and uses as inputs the current value of the S&P 500, dividends paid by the entire market, and potential dividends including stock buybacks (Exh. SREF-DJG-1, App. D at 9-10). After collecting data for the S&P 500 , operating earnings, dividends, and buybacks for the S&P 500 covering the previous six years, Sunrun and EFCA calculated the dividend yield, buyback yield, gross cash yield for each year, and the compound annual growth rate from operating earnings (Exh. SREF-DJG-1, App. D at 11). Combining these inputs with the risk-free rate and current value of the index, Sunrun and EFCA calculated a current expected return on the entire market of 8.3 percent and then subtracted the risk-free rate to produce an implied equity risk premium of 5.26 percent (Exh. SREF-DJG-1, App. D at 11). As discussed above, Sunrun and EFCA compared their implied equity risk premium with selected ERPs from expert surveys and economists and found the average to be close to their own (Exh. SREF-DJG-1, App. D at 11-12; SREF-DJG-13).

d. Positions of the Parties

i. Attorney General

The Attorney General asserts that the Companies' application of the bond yield plus risk premium model is flawed for four reasons (Attorney General Brief at 83). First, the Attorney General argues that the Companies' method produces an inflated measure of the risk

premium because it is based on historic authorized ROEs less Treasury yields, and then is applied to projected Treasury yields that always are forecasted to increase (Attorney General Brief at 83). Second, the Attorney General contends that the Companies' overall approach improperly uses authorized ROEs as an input to the model, and that such an approach is more of a gauge of public utility commission behavior than a consideration of investor behavior (Attorney General Brief at 83-84, citing Exh. AG-JRW-1, at 94). In this regard, the Attorney General claims that in setting ROEs, regulatory commissions evaluate capital market data such as dividend yields, expected growth rates, interest rates, as well as rate case specific regulatory information (Attorney General Brief at 83-84, citing Exh. AG-JRW-1, at 94). Further, the Attorney General argues that the Companies' risk premium analysis and resulting ROE recommendations rely on forecasted interest rates that are higher than actual interest rates (Attorney General Reply Brief at 72).

Third, the Attorney General argues that a comparison of the Companies' risk premium results to actual authorized ROEs for electric utility companies confirms the errors in the Companies' approach (Attorney General Brief at 84). The Attorney General notes that authorized ROEs for electric distribution companies have decreased in recent years, from 10.01 percent in 2012, to 9.8 percent in 2013, to 9.76 percent in 2014, 9.58 percent in 2015, and to 9.60 percent in 2016 (Attorney General Brief at 84, citing Exh. AG-JRW-1, at 14). Fourth, the Attorney General asserts that Eversource's long-term projected Treasury bond yield of 4.35 percent is 100 basis points above current yields and, therefore, is not reasonable (Attorney General Brief at 83, citing Exh. AG-JRW-1, at 93).

ii. FEA

FEA contends that the Companies overstate the significance of the inverse relationship between equity risk premiums and interest rates, and fault the Companies for using the inverse relationship as the sole driver of their risk premium study (FEA Brief at 12). FEA avers that, while academic studies have shown an inverse relationship among these variables in the past, researchers have found that the relationship changes over time and is influenced by changes in perception of risk between bond investments and equity investments (FEA Brief at 12; FEA Reply Brief at 5). Arguing that the inverse relationship is not based simply on changes to interest rates, FEA asserts that the Companies' exclusive reliance on interest rates as the explanatory variable for the equity risk premium takes the notion of a simplistic inverse relationship too far (FEA Brief at 12). FEA contends that all relevant factors affecting how investors perceive the relative risk of equity and bond investments should be considered, not just interest rates (FEA Brief at 12, citing Exh. FEA-MPG-1, at 101 (Corrected)). For these reasons, FEA argues that the Companies' claims related to a fair return on equity based on a risk premium methodology are without merit and should be rejected (FEA Reply Brief at 5).

iii. Sunrun and EFCA

Sunrun and EFCA argue that the Companies' ERP based on the comparison of returns on Treasury notes to returns on equity awarded by regulatory commissions is less credible than Sunrun and EFCA's ERP based on market data (Sunrun and EFCA Brief at 20, citing Exh. ES-RBH-Rebuttal, at 138-139). Sunrun and EFCA further note that the Companies'

ERP of 11.21 percent is more than twice as high as the estimate reported by thousands of experts across the country (Sunrun and EFCA Brief at 20, citing Exh. SREF-DJG-1, at 14).

iv. Companies

The Companies dispute the Attorney General's and Sunrun and EFCA's argument that the Companies' bond yield plus risk premium approach gauges regulatory commission behavior rather than investor behavior (Companies Brief at 523, 534). The Companies argue that regulatory decisions reflect market based analyses (Companies Brief at 523, 534, citing Exh. ES-RBH-Rebuttal-1, at 48-49). Further, the Companies contend that because authorized returns are publicly available, such data are to some degree reflected in investors' return expectations and requirements (Companies Brief at 523, 534, citing Exh. ES-RBH-Rebuttal-1, at 48-49). The Companies maintain that Sunrun and EFCA's reliance on IESE Business School survey responses that excluded authorized return data for estimating an ERP, incorrectly includes market risk premium data in developing Sunrun and EFCA's ERP (Companies Brief at 534, citing Exh. ES-RBH-Rebuttal-1, at 139-140).[370] For these reasons, the Companies assert that authorized returns are a reasonable measure of investor required returns (Companies Brief at 523, citing Exh. ES-RBH-Rebuttal-1, at 48-49).

The Companies also maintain that FEA's risk premium calculation is flawed, and they contend that FEA's method ignores the important inverse relationship between the risk

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370 The Companies state that the IESE Business School survey sources Sunrun and EFCA cited were references used to justify use of market risk premiums, and therefore Sunrun and EFCA's survey included market risk premium data that is inappropriate for the Bond Yield Plus Risk Premium approach (Exh. ES-RBH-Rebuttal-1, at 139).

premium and level of interest rates, whether measured by Treasury or utility bond yields (Companies Brief at 537-538, citing Exh. ES-RBH-Rebuttal-1, at 86). According to the Companies, FEA's method understates the required risk premium in the current market (Companies Brief at 537-538, citing Exh. ES-RBH-Rebuttal-1, at 86). The Companies also contend that the low end of FEA's risk premium results is far lower than any ROE authorized since at least 1986 and, as such, has no relevance in estimating the ROE in the instant case (Companies Brief at 538, citing Exh. ES-RBH-Rebuttal-1, at 86).

Finally, the Companies note that in the past, the Department has viewed the risk premium approach as a "supplemental approach" in determining the level of ROE (Companies Brief at 523-524, citing D.P.U. 07-71, at 137). Based on the above, Eversource argues that the Department should at least supplement its calculation of the Companies' ROE with the risk premium approach (Company Brief at 524).

e. Analysis and Findings

The Department has repeatedly found that an equity risk premium analysis can overstate the amount of company-specific risk and, therefore, the cost of equity. D.P.U. 10-114, at 322; D.P.U. 88-67 (Phase I) at 182-184. More specifically, the Department has found that the return on long-term corporate or public utility bonds may have risks that could be diversified with the addition of common stock in investors' portfolios and, therefore, the risk premium model overstates the risk accounted for in the resulting cost of equity. D.P.U. 10-114, at 322; D.P.U. 90-121, at 171; D.P.U. 88-67 (Phase I) at 182-183. Nonetheless, the Department has acknowledged the value of the risk premium model as a

supplemental approach to other ROE models. D.P.U. 10-114, at 322; D.P.U. 07-71, at 137; D.T.E. 99-118, at 85-86.

In the instant case, the Companies' and FEA's risk premium analyses are flawed. First, the Department has recognized the circularity inherent in the use of authorized utility returns to derive the risk premium. D.P.U. 13-75, at 319; D.P.U. 90-121, at 171; D.P.U. 88-67 (Phase I) at 182-183. In addition, the Department has criticized the use of corporate bond yields in determining the base component of the risk premium analysis, and we are not convinced that the Companies' or FEA's substitution of projected Treasury debt yields provide a better approach. D.P.U. 09-39, at 388-389; D.P.U. 08-35, at 202; D.P.U. 90-121, at 171. The Companies and FEA use projected cost of Treasury debt in this model, suggesting that the risk premium approach is forward-looking and, therefore, and maintain that using the forward-looking approach is appropriate (Exhs. ES-RBH-8; FEA-MPG-1, at 68-74 (Corrected)). The Department disagrees. The risk premium model is not a forward looking approach, and is, instead, based on current market conditions. See D.P.U. 13-75, at 319; D.P.U.12-25, at 433. Sunrun and EFCA's calculation of the S&P 500's current value in their implied equity risk premium more closely approaches current market conditions, but Sunrun and EFCA's application of the risk premium among other models produces an ROE that is too low (Exhs. SREF-DJG-1, App. D at 11-12; SREF-DJG-1, App. D at 1-3). Accordingly, the Department finds that current treasury yields are more appropriate than projected yields for use in a risk premium analysis. For

these reasons, the Department finds that Eversource's risk premium model overstates the required ROE for the Companies.

10. Flotation Costs

a. Companies' Proposal

The Companies factor flotation costs into their proposed ROE and assert that such costs must be considered part of capital costs that are properly reflected on the balance sheet under "paid in capital" rather than current expenses (Exh. ES-RBH-1, at 39-51). According to the Companies, flotation costs represent a permanent reduction to common equity, and, therefore, they should be recovered similar to the recovery of debt issuance costs (Exh. ES-RBH-Rebuttal at 141-143).

To determine flotation costs, the Companies use the equity issuing costs incurred in the two most recent stock issuances for Eversource Energy and its proxy group, and they modified the DCF calculation to derive the dividend yield that would reimburse investors for direct issuance costs to develop a flotation cost estimate of 0.12 percent (Exhs. ES-RBH-1, at 51; ES-RBH-11).[371] Eversource states, however, that it did not simply increase its proposed ROE by twelve basis points to reflect the effect of the flotation costs. Instead, the Companies state that they considered the effect of these flotation costs in addition to other business risks when determining the appropriate ROE within the range of results produced by the various cost of equity models (Exh. ES-RBH-1, at 50).

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[371] The Companies used the two most recent open market common stock issuances for Eversource Energy (2009 and 2005) and for the companies in their proxy group (Exh. ES-RBH-11, at 1).

b. FEA Proposal

FEA states that flotation cost adders are inappropriate because such costs are approximated by the Companies and therefore are not known and measurable (Exh. FEA-MPG-1, at 111 (Corrected)). Additionally, FEA notes that NSTAR Electric and WMECo are not publicly traded companies, but rather are subsidiaries of a publicly traded company and the Companies do not incur costs related to selling common stock (Exh. FEA-MPG-1, at 111 (Corrected)).

c. Sunrun and EFCA Proposal

Sunrun and EFCA consider the recovery of flotation costs to be inappropriate in the instant case (Exh. SREF-DJG-1, at 22). Sunrun and EFCA state that the Companies' claim that flotation costs are "out of pocket" expenses is misleading because such costs are embedded in an underwriting spread (i.e., the difference between the price at which the underwriter purchases the firm's shares and the price at which the underwriter sells the shares to investors) (Exh. SREF-DJG-1, at 22-23). Sunrun and EFCA also state that the market already accounts for flotation costs since investors are aware of underwriter's fees and know that flotation costs are priced into shares (Exh. SREF-DJG-1, at 23). Finally, Sunrun and EFCA oppose any effort to increase a proposed cost of equity proposal that they consider already to be far above Eversource's true required return (Exh. SREF-DJG-1, at 24).

d. Positions of the Parties

i. Attorney General

The Attorney General argues that the Companies' flotation cost adjustment results in overstating their required ROE (Attorney General Brief at 63). No other intervenors addressed flotation costs on brief.

ii. Companies

The Companies argue that flotation costs for stock issuances must be considered part of capital costs rather than current expenses on the income statement (Companies Brief at 289, citing Exh. ES-RBH-1, at 49). According to the Companies, flotation costs are incurred over time and, although a great majority of these costs are incurred prior to the test year, they remain part of the cost structure during the test year and beyond (Companies Brief at 289, citing Exh. ES-RBH-1, at 49).

e. Analysis and Findings

The Department has previously rejected issuance cost adjustments for the purpose of determining ROE. D.P.U. 90-121, at 180; D.P.U. 88-67 (Phase I) at 193; Western Massachusetts Electric Company, D.P.U. 86-280-A at 112 (1987); D.P.U. 85-137, at 100. The Companies have not persuaded us to depart from our precedent here. The Companies' proposal to weigh flotation costs when establishing its ROE relies on issuance costs that investors are well aware of when they enter the market for publicly traded stocks. Therefore, the Companies' proposal suffers from the same defects that the Department has previously identified, namely the double-counting of flotation costs. D.P.U. 10-70, at 259; D.P.U. 88-67 (Phase I) at 193; D.P.U. 85-137, at 100.

The Department allows companies to recover issuance costs associated with common stock by amortizing those costs over a period of time. 220 CMR 51.02, 18 CFR Ch. 1, Subchapter C, Part 101, Other Income and Deductions, Account 425; 220 CMR 50, Income Accounts, Account 425. NSTAR Electric and WMECo, however, are wholly-owned subsidiaries of Eversource Energy, and, therefore, have no publicly-traded stock on which to incur flotation costs (Exh. AG-1-2, Att. (a) at 8 (Supp. 1)). Moreover, neither NSTAR Electric nor WMECo have issued any significant amount of common stock for a number of years, and thus do not have any flotation costs. See Massachusetts Electric Company, D.P.U. 800, at 51 (1982) (common stock issued to parent; flotation allowances inappropriate for subsidiary company); Western Massachusetts Electric Company, D.P.U. 20279, at 37 (1980) (subsidiary of holding company does not experience issuance costs; to the extent issuance costs affect marketing of holding company's securities, it has no bearing on securities of subsidiary); Massachusetts Electric Company, D.P.U. 19376, at 7-13 (1979) (stock issuance selling costs of parent company not to be considered in setting cost of common equity in subsidiary's rate case). Department records indicate that, aside from several minimal common stock issues made in connection with merger and acquisition petitions, NSTAR Electric's most recent common stock issuance was approved in Boston Edison Company, D.P.U. 94-160 (1994). WMECo's most recent common stock issuance was approved in Western Massachusetts Electric Company, D.P.U. 13403 (1960). For these reasons, the Department will not take flotation costs into consideration when determining the Companies' required ROE.

11. Conclusion

The standard for determining the allowed ROE is set forth in Bluefield and Hope. The allowed ROE should preserve a company's financial integrity, allow it to attract capital on reasonable terms, and be comparable to returns on investments of similar risk. Bluefield at 692-693; Hope at 603, 605. The allowed ROE should be determined "having regard to all relevant facts." Bluefield at 692.

The Companies recommend that the Department approve an ROE of 10.50 percent, based on an ROE performance range of 10.0 percent to 10.75 percent. The Attorney General recommends an ROE of 8.875 percent. Other parties made the following recommendations: FEA, 9.35 percent; Sunrun and EFCA, 8.75 percent; Cape Light Compact, 8.75 percent; and UMass, 9.5 percent. The Department has found that both quantitative and qualitative factors must be taken into account in determining an allowed ROE. D.P.U. 11-01/D.P.U. 11-02, at 424; D.P.U. 08-27, at 134-138; D.T.E. 02-24/25, at 229-231; D.P.U. 92-78, at 115; D.P.U. 89-114/90-331/91-80 (Phase I) at 224-225.; see also Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 11 (1978); Boston Gas Co. v. Department of Public Utilities, 359 Mass. 292, 305-306 (1971). Thus, in determining an appropriate ROE for the Companies, the Department first evaluates the quantitative factors presented in this case.

The use of empirical analyses in this context is not an exact science. A number of judgments are required in conducting a model based rate of return analysis. Even in studies that purport to be mathematically sound and highly objective, crucial subjective judgments

are made along the way and necessarily influence the end result. Western Massachusetts Electric Company, D.P.U 18731, at 59 (1977). Each level of judgment to be made in these models contains the possibility of inherent bias and other limitations. D.T.E. 01-56, at 117; D.P.U. 18731, at 59.

As discussed above, the evidence demonstrates that each equity cost model used by the Companies, the Attorney General, FEA, and Sunrun and EFCA suffers from a number of simplifying and restrictive assumptions. Applying them to the financial data of a proxy group of companies could provide results that may not be reliable for the purpose of setting the Companies' ROE. For example, we note the limitations of the DCF models, including the simplifying assumptions that underlie the constant growth form of the model, and its element of circularity, as well as the inherent limitations in comparing the Companies to publicly traded companies. In particular, we find that the Companies' DCF analysis overestimates the cost of equity by minimizing the low-outlier estimates. We also find that the Attorney General's DCF model retains some elements of circularity because investor expectations depend upon regulatory decisions. Similarly, the Department finds the Attorney General's and FEA's use of high P/E ratios will affect the results of their analyses, as does Sunrun and EFCA's assumption that a company's long-term growth rate cannot exceed that of the national economy.

The Department further finds that the CAPM analyses also are flawed because of the simplifying assumptions underlying CAPM theory and the subjectivity inevitable in estimating market risk premiums. To the extent we rely on the CAPM estimates, we give more weight

to the Attorney General's and FEA's analyses, with some weight on Sunrun and EFCA's analysis, because the magnitude of the deficiencies within the Companies' proposed CAPM, including the estimate of a market risk premium, is greater. Finally, we find that the Companies' risk premium approach suffers from a number of limitations and tends to overstate NSTAR Electric's and WMECo's required ROE.

While the results of analytical models are useful, the Department must ultimately apply its own judgment to the evidence to determine an appropriate ROE. We must apply to the record evidence and arguments considerable judgment and agency expertise to determine the appropriate use of the empirical results. Our task is not a mechanical or model driven exercise. D.P.U. 08-35, at 219-220; D.P.U. 07-71, at 139; D.T.E. 01-56, at 118; D.P.U. 18731, at 59; see also Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 15 (1978).[372] The Department must account for additional factors specific to a company that may not be reflected in the results of the models.

We note that a portion of the revenues of the companies in both proxy groups is derived from unregulated and competitive lines of business (Exhs. AG-JRW-4, at 1; AG-14-6; AG-1-2, Att. (a) at 8 (Supp. 1)). All else equal, this mix of regulated and

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[372] As the Department stated in New England Telephone and Telegraph Company, D.P.U. 17441, at 9 (1973):

> Advances in data gathering and statistical theory have yet to achieve precise prediction of future events or elimination of the bias of the witnesses in their selection of data. Thus, there is no irrefutable testimony, no witness who has not made significant subjective judgments along the way to his conclusion, and no number that emerges from the welter of evidence as an indisputable "cost" of equity.

unregulated operations would tend to overstate the proxy groups' risk profiles relative to that of the Companies. Therefore, in applying this comparability standard, we will consider such risk differentials when weighing the results of the models used to estimate the Companies' allowed ROE.

Turning to rate mechanisms, as set forth in further detail in the Department's subsequent Order addressing rate design, the Department will consider NSTAR Electric's implementation of a revenue decoupling mechanism. The Department previously approved a revenue decoupling mechanism for WMECo in D.P.U. 10-70, at 40-43, and has directed all gas and electric distribution companies to file for revenue decoupling in a base rate proceeding. D.P.U. 07-50-A at 84. The Department has found that revenue decoupling mechanisms can act to reduce the variability of a company's revenues and, accordingly, reduce its risks. See D.P.U. 09-39, at 398; D.P.U. 09-30, at 371-372; D.P.U. 07-50-A at 72-73. In addition, the Department granted in this Order establishment of a PBR mechanism, which, among other things, allows the Companies to implement an annual rate adjustment to support the net increase in rate base arising from the annual capital additions that the Companies make to upgrade their distribution system (see Section IX above). In addition, as described in Section VIII.J above, the Department has approved the Companies' proposal as to the calculation of property taxes for communities using the NBV method.

In the instant case, the Companies and the intervenors debate the cause-effect connection between rate mechanisms and the cost of equity (Exhs. ES-RBH-1, at 44-48; ES-RBH-Rebuttal-1, at 107-114; AG-JRW-1, at 95-97; AG-JRW-Surrebuttal-1, at 13, 26;

FEA-MPG-1, at 20-23, 107-110). The Companies state that, even though such mechanisms in general reduce risk, separating peer companies by levels of risks enough to affect the cost of equity is infeasible where such mechanisms are common and because investors do not reduce their return requirements in response (Exhs. RBH-1, at 47-48; ES-RBH-10; ES-RBH-Rebuttal-1, at 108-111; DPU-31-16; AG-14-9; AG-14-10; Tr. 4, at 735-736). Although many companies in both proxy groups employ some form of revenue stabilization or revenue decoupling mechanism, the Department finds that the degree of revenue stabilization varies among the companies, and calculating their relative impacts is infeasible (Exhs. ES-RBH-10; AG-JRW-4). We take these uncertainties into consideration when determining an ROE.

Finally, there are other qualitative factors that the Department will consider in determining a company's allowed ROE. It is both the Department's long-standing precedent[373] and accepted regulatory practice[374] to consider qualitative factors such as

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[373] For example, the Department has set a utility's ROE at the low end of a range of reasonableness upon a showing that a utility's management performance was deficient. D.P.U. 12-86, at 257-258 (deficiencies regarding affiliate transactions and selection of rate case consultants warranted ROE at lower end of reasonable range); D.P.U. 11-43, at 218-222 (company's improper handling of a billing error, failure to provide acceptable unaccounted for water report, improper flushing practices, and insufficient communication with customers warranted ROE at lower end of reasonable range); D.P.U. 11-01/D.P.U. 11-02, at 424-426 (company shortcomings in storm response warranted ROE at lower end of reasonable range); D.P.U. 10-114, at 339-340 (company activities related to Department-ordered audit warranted ROE at lower end of reasonable range); D.P.U. 08-35, at 220 (customer service deficiencies warranted ROE at lower end of reasonable range); D.P.U. 08-27, at 136, 137 (failure to conduct competitive bidding for outside consultants and provide detailed rate case expense invoices warranted ROE at lower end of reasonable range); see also

management performance and customer service in setting a fair and reasonable ROE. With respect to a company's performance, the Department has determined that where a company's actions have had the potential to affect ratepayers or have actually done so, the Department may take such actions into consideration in setting the ROE. D.P.U. 11-01/D.P.U. 11-02, at 424; D.T.E. 02-24/25, at 231; D.P.U. 85-266-A/271 A at 6-14. Thus, the Department may set ROEs that are at the higher end or lower end of the reasonable range based on above average or subpar management performance and customer service. See, e.g., D.P.U. 12-86, at 274-276 & n.181 (deficiencies regarding affiliate transactions and selection of rate case consultants warranted ROE at lower end of reasonable range); D.P.U. 11-01/D.P.U. 11-02, at 424, 427 (company shortcomings in storm response warranted ROE at lower end of reasonable range). In this case, the Department has reviewed the Companies' annual service quality reports filed with us, and notes that the Companies

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D.P.U. 85-266-A/271-A at 172 (failure to fulfill public service obligations warranted ROE at lower end of reasonable range).

374 See, e.g., In re Citizens Utilities Company, 171 Vt. 447, 453 (2000) (general principle that rates may be adjusted depending on the adequacy of the utility's service and the efficiency of its management); US West Commc'ns, Inc. v. Washington Utils. and Transp. Comm'n, 134 Wash.2d 74, 121 (1998) (a utility commission may consider the quality of service and the inefficiency of management in setting a fair and reasonable rate of return); North Carolina ex rel. Utils. Comm'n v. Gen. Tel. Company of the Southeast, 285 N.C. 671, 681 (1974) (the quality of the service rendered is, necessarily, a factor to be considered in fixing the just and reasonable rate therefore); Gulf Power Company v. Wilson, 597 So.2d 270, 273 (1992) (regulator was authorized to adjust rate of return within reasonable range to adjust for mismanagement); Wisconsin Pub. Serv. Corp. v. Citizens' Util. Bd., Inc., 156 Wis.2d 611, 616 (1990) (prudence is a factor regulator considers in setting utility rates and can affect the allowed ROE).

have met or exceed all of their performance standards for the years 2013 through 2016. Service Quality Reports for Electric Distribution Companies, D.P.U. 17-SQ-10 through 14, at 3 (2017); Service Quality Reports for Electric Distribution Companies, D.P.U. 16-SQ-10 through 14, at 3 (2016); Service Quality Reports for Electric Distribution Companies, D.P.U. 15-SQ-10 through 14, at 3-5 (2016); Service Quality Reports for Electric Distribution Companies, D.P.U. 14-SQ-10 through 14, at 3-4 (2016). Moreover, the Department finds no evidence of systematic service quality shortcomings in other areas of the Companies' operations that warrant an adjustment to Eversource's allowed ROE.

Based on a review of the evidence presented in this case, the arguments of the parties, and the considerations set forth above, the Department finds that an allowed ROE of 10.0 percent is within a reasonable range of rates that will preserve the Companies' financial integrity, will allow it to attract capital on reasonable terms and for the proper discharge of its public duties, will be comparable to earnings of companies of similar risk and, therefore, is appropriate in this case.[375] In making these findings, the Department has considered both qualitative and quantitative aspects of the parties' various methods for determining the

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375 In setting this ROE, the Department has taken into consideration the amount of the storm fund assessment paid by the Companies pursuant to G.L. c. 25, § 18. See Fitchburg Gas and Electric Light Company at al. v. Department of Public Utilities, 467 Mass. 768 (2014).

Companies' proposed ROE, as well as the arguments of and evidence presented by the parties in this proceeding.[376]

XVII. PROPOSED TARIFF CHANGES AND FEES

A. Introduction

The current tariffs for NSTAR Electric and WMECo can be classified into four primary categories: (1) terms and conditions; (2) distribution rates; (3) reconciling rates; and (4) other provisions (Exh. ES-RDP-9, at 11). There are separate terms and conditions governing the provision of distribution service and the provisions associated with competitive suppliers (Exh. ES-RDP-9, at 11). The distribution rate tariffs are applicable to all customers taking service under retail rates (Exhs. ES-RDP-9, at 11). Reconciling rate tariffs govern all rates that require an annual reconciliation of costs and revenue (Exh. RDP-9, at 11). Finally, there are other provisions, including various riders that specify adjustments and services to the distribution rate tariffs (Exh. ES-RDP-9, at 11, 35).

Eversource proposes changes in various provisions of all four categories of tariffs. Eversource also proposes to consolidate, for effect January 1, 2018, the Companies' terms and conditions, reconciling rate tariffs, and the various other provisions (Exh. ES-RDP-9, at 17). In the sections below and in other sections of this Order, the Department addresses the proposed changes to the Companies' (1) terms and conditions, applicable to both distribution service and competitive suppliers; (2) certain reconciling rate tariffs; and (3) certain other provisions. The Companies' proposed changes to the distribution rate

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[376] In setting this ROE, the Department does not find any subpar management performance or customer service by the Companies that would warrant an adjustment to the ROE within the reasonable range.

tariffs, along with any reconciling rate tariffs and other provisions not specifically addressed in this Order will be discussed in our subsequent Order addressing rate design issues.

B. Proposed Terms and Conditions for Distribution Service

1. Introduction

The Companies explain that their Terms and Conditions for Distribution Service ("Terms and Conditions"), proposed M.D.P.U. No. 500, set forth rules for the provision of distribution service (Exh. ES-RDP-9, at 11). The Other Provisions describe adjustments and services that apply to the standard distribution rate tariffs (Exh. ES-RDP-9, at 11). The Companies explain that there is a significant amount of overlap in their current tariffs, and they propose to consolidate their Terms and Conditions and Other Provisions for effect January 1, 2018 (Exhs. ES-RDP-9, at 11, 17; ES-RDP-12; ES-RDP-14; RR-DPU-51, Att. (a) (proposed M.D.P.U. No. 500)). In consolidating the Terms and Conditions, the Companies compared the individual tariffs of the four legacy operating companies and incorporated the major provisions from each of the individual tariffs into the consolidated tariff (Exh. AG-46-2). The basis of the Companies' proposed consolidated tariff is Commonwealth Electric Company's current Terms and Conditions tariff (i.e., M.D.T.E. No. 300A) (Exh. AG-49-6).

Specifically, the Companies propose: (1) to adopt new definitions for service areas because of their rate consolidation proposal; (2) to adopt WMECo's current language relating to the availability of station service power for distributed generation customers; (3) to replace references to standard offer service with references to basic service; (4) to adopt new

language regarding final bill provisions;[377] (5) to update and consolidate the line extension provisions in Appendix B of the proposed Terms and Conditions; (6) to include a new Appendix C that lists the cities and towns in the Companies' service territory; (7) to include provisions on curtailment or interruption of service and on force majeure; and (8) to add new language on past due interest charges for generation service charges on standard complete billing service (Exhs. ES-RDP-9, at 19-20; AG-46-2).[378]

2. Positions of the Parties

a. Attorney General

i. Introduction

The Attorney General argues that the Department should: (1) eliminate the Companies' force majeure provision; (2) limit the Companies' obligation for meter and communication device installation to 30 days; and (3) eliminate language that limits the Companies' liability for curtailment or interruption of service (Attorney General Brief at 202). These arguments are discussed in further detail below.

ii. Force Majeure

The Attorney General opposes the Companies' proposed force majeure provision that exempts the Companies from liability from conditions over which the Companies have no

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377 The Companies originally proposed final bill language (in Section II.F.3) that already existed in their proposed Terms and Conditions in Section II.B.5 (Exhs. AG-49-2; RR-DPU-51, Att. (a) at 5, 12-13). Therefore, the Companies proposed to restore the original language regarding customer notice of termination (Exh. AG-49-2, at 2; RR-DPU-51, Att. (a) at 12-13). No parties commented on this issue on brief.

378 Eversource also proposes to update the Schedule of Fees and Charges in Appendix A of the Terms and Conditions (Exh. ES-RDP-9, at 20). The Department will address this proposal separately in Section XVII.C below.

control (Attorney General Brief at 202, citing Exh. ES-RDP-14, at 181; Tr. 11, at 2254-2255). According to the Attorney General, the Companies' proposed language could preempt Department authority and is duplicative of the "Limitation of Liability" provision in the Terms and Conditions (Attorney General Brief at 202, citing Exh. ES-RDP-12, at 181). The Attorney General contends that only the Department or "a court of competent jurisdiction" determines whether the Companies "shall be excused from performing under the Schedule of Rates and … not be liable for damages" due to a force majeure (Attorney General Brief at 203, citing Exh. ES-RDP-14, at 181).

Further, the Attorney General maintains that the Companies' "Limitation of Liability" provision exempts the Companies from liability for damages unless the Companies are negligent (Attorney General Brief at 203, citing Exh. ES-RDP-14, at 181). The Attorney General argues that a force majeure event outside the control of the Companies would not be caused by any action or omission that the Department would find as negligent (Attorney General Brief at 203). Therefore, the Attorney General concludes that the "Limitation of Liability" provision precludes the necessity of the Companies' force majeure provision in their proposed Terms and Conditions (Attorney General Brief at 203).

iii. Obligation for Meter and Communication Device Installation

The Attorney General argues that the Companies are providing themselves with more flexibility by changing their obligation for meter and communication device installation upon customer request from "within 30 days" to "if reasonably possible, within 30 days" (Attorney General Brief at 204, citing Exh. ES-RDP-14, at 166-167). According to the

Attorney General, any delay in the Companies' installation of metering or communication devices could delay restoration or initiation of service and could have an adverse impact on a customer's quality and cost of service (Attorney General Brief at 204, citing G.L. c. 164, §§ 122, 124(a)-124(i)). Moreover, the Attorney General asserts that the Companies state that they are not aware of any meter changes that were not completed within 30 days of a customer request (Attorney General Brief at 204, citing Exh. AG-49-6). Therefore, the Attorney General recommends that the Department exclude the Companies' proposed language "if reasonably possible" from Section II.D.1 of the proposed Terms and Conditions (Attorney General Brief at 204).

iv. Limitation of Liability for Curtailment or Interruption of Service

The Attorney General objects to the Companies' proposed tariff language that would automatically exclude the Companies' liability regarding curtailment or interruption of service (Attorney General Brief at 204, citing Exh. ES-RDP-14, at 181; Tr. 11, at 2254-2255). According to the Attorney General, the Companies' proposed language – "the Company may, in its sole judgment, curtail or interrupt electric service or reduce voltage and such action shall not be construed to constitute a default nor shall the Company be liable therefor in any respect" – could preclude a customer from resolving disputes (Attorney General Brief at 205, citing G.L. c. 164, §§ 1a, 1f, 1i, 139, 139a, 140, 142; 220 CMR 8.00, 10.00, 18.00, 19.00. 25.00).

The Attorney General asserts that the Companies' rationale that the language currently exists in the Commonwealth Electric tariff, and therefore, that the provision is not new, does

not justify implementing more stringent language for all of Eversource's customers (Attorney General Brief at 205, citing Exh. AG-49-16). Moreover, the Attorney General argues that only relying on the fact that the provision is preexisting does not explain why the Companies proposed to include it in the consolidated Terms and Conditions tariff (Attorney General Brief at 205). The Attorney General disputes the Companies' claim that the provision is necessary to maintain system integrity and she maintains that it is unnecessary (Attorney General Brief at 205). Therefore, the Attorney General recommends that the Department exclude the Companies' proposed language that limits the Companies' liability during curtailments or interruption of service (Attorney General Brief at 205).

b. Cape Light Compact

Cape Light Compact asserts that Eversource's proposed tariff M.D.P.U. No. 500 includes a provision entitled "Unusual Load Characteristics" (Cape Light Compact Brief at 70-71, citing ES-RDP-12-A at 8). According to Cape Light Compact, Eversource could invoke this provision in a way that subverts its obligations to integrate DER as part of grid modernization efforts (Cape Light Compact Brief at 70). Cape Light Compact argues that the Department's grid modernization Orders contemplate changing customer load patterns through all manners of distributed energy resources, such as microgrids, customer-sited storage, EVs, and distributed generation, for demand optimization (Cape Light Compact Brief at 70). Cape Light Compact notes that Eversource does not define the term "unusual characteristics" for load and reserves too much discretion for itself (Cape Light Compact Brief at 71). Cape Light Compact asserts that Eversource has an obligation to proactively

integrate all forms of DER and should clarify this definition so that grid modernization efforts may not constitute "unusual [load] characteristics" (Cape Light Compact Brief at 71).

c. Companies

i. Introduction

On brief, Eversource did not respond to the Attorney General's arguments regarding the above issues. However, Eversource discussed its proposals at various points in this proceeding, as set forth below.

ii. Force Majeure

Eversource proposes a force majeure provision that would exempt the Companies from liability from damages as a result of a force majeure event, i.e., outside interferences beyond the Companies' control (Exh. ES-RDP-14, at 181). The Companies states that, with the exception of the WMECo tariff, the force majeure provision appears in all of Eversource's legacy tariffs (Tr. 11, at 2256-2257). Eversource argues that it is maintaining consistency among the legacy companies by including the force majeure provision in the proposed tariff (Tr. 11, at 2257).

iii. Obligation for Meter and Communication Device Installation

Eversource states that its proposed language providing for meter and communication device installation upon customer request "if reasonably possible, within 30 days" appears in its existing Commonwealth Electric Company legacy tariff (Exh. AG-49-6). Eversource also

states that it is unaware of any instance in which it was unable to install a meter within the 30-day time frame (Exh. AG-49-6).[379]

iv. Limitation of Liability for Curtailment or Interruption of Service

The Companies state that implementation of a provision for limitation of liability for interruption or curtailment of service is necessary to maintain system integrity and safety (Tr. 11, at 2257). Eversource states that, with the exception of the WMECo tariff, the limitation of liability for interruption or curtailment of service appears in all of the legacy company tariffs (Tr. 11, at 2258).[380]

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379 Eversource states that typical reasons it would not complete a request for installation of a meter or communication device within 30 days are due to storm-related events or safety issues (Exh. DPU-6-2).

380 The Companies did not address Cape Light Compact's arguments on brief.

3. Analysis and Findings

a. Force Majeure

As set forth above, the Attorney General maintains that Eversource's proposed "Force Majeure" provision is duplicative of the proposed "Limitation of Liability" provision[381] in the Terms and Conditions that releases the Companies from liability for damages in instances where there is no negligence attributable to Eversource (Attorney General Brief at 203). The Attorney General maintains that the force majeure provision could preempt the authority of the Department or a court of competent jurisdiction to determine whether damage is the result of a force majeure (Attorney General Brief at 203). The two proposed provisions at issues are as follows:

> Force Majeure
>
> The Company shall be excused from performing under the Schedule of Rates and shall not be liable in damages or otherwise if and to the extent that it shall be unable to do so or prevented from doing so by statute or regulation or by action of any court or public authority having or purporting to have jurisdiction in the premises; or by loss, diminution or impairment of electrical supply from its generating plants or suppliers or the systems of others with which it is interconnected; or by a break or fault in its transmission or distribution system; failure or improper operation of transformers, switches or other equipment necessary for electric distribution; or by reason of storm, flood, fire, earthquake, explosion, civil disturbance, labor dispute, act of God or public enemy, failure of any supplier to perform, restraint by any court or regulatory agency, or any other intervening cause, whether or not similar thereto; the Company shall use efforts reasonable under the circumstances to overcome such cause and to resume full performance.

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381 This stand-alone provision is different from the limitation of liability language associated with the curtailment of or interruption of service provision, which is discussed below.

> Limitation of Liability
>
> Unless there is negligence on the part of the Company, the Company shall not be liable for damage to the person or property of the Customer or any other persons resulting from the use of electricity or the presence of the Company's appliances and equipment on the Customer's premises. In any event, for non-residential Customers served under general service rates, the Company shall not be liable in contract, in tort (including negligence and M.G.L. c. 93A), strict liability or otherwise for any special, indirect, or consequential damages whatsoever including, but not limited to, loss of profits or revenue, loss of use of equipment, cost of capital, cost of temporary equipment, overtime, business interruption, spoilage of goods, claims of Customers of the Customer or other economic harm.

(RR-DPU-51, Att. (a) at 16-17 (proposed M.D.P.U. No. 500, §§ II.I.2, II.I.3)).

Consistent with the Attorney General's argument, a force majeure provision and a limitation of liability provision are based on principles of mitigating a utility's risk and limiting exposure to liability in the utility's provision of service to customers. However, the record is not sufficient for the Department to find that the Companies' proposed limitation provision affords adequate protection from liability in the event of a force majeure occurrence. Therefore, we are not persuaded by the Attorney General's argument that these provisions are duplicative.

Moreover, the proposed provisions are substantially similar to the provisions already in place in NSTAR Electric's legacy companies' tariffs and contain no substantive changes from those existing tariffs (see M.D.T.E. No. 100A, §§ II.9B, II.9.D (Boston Edison Company); M.D.T.E. No. 200A, §§ II.9B, II.9C (Cambridge Electric Light Company); M.D.T.E. No. 300A, §§ II.9B, II.9C (Commonwealth Electric Company); Exh. AG-49-16). Thus, inclusion of the force majeure and limitation of liability provisions in the consolidated tariffs maintains consistency of application of these provisions with NSTAR Electric's legacy

tariffs. In addition, we note that Fitchburg Gas and Electric Light Company and all of the electric distribution companies subject to the Department's jurisdiction companies have both force majeure and a limitation of liability provisions in their currently effective terms and conditions. See, e.g., M.D.P.U. No. 266, § II.9.C., F (Fitchburg Gas and Electric Light Company); M.D.P.U. No. 1316, § I.9.A., B (Massachusetts Electric Company/Nantucket Electric Company). As such, the request by the Companies is neither new nor novel.

Based on these considerations, the Department approves the force majeure and the limitation of liability provisions contained in the Companies' proposed terms and conditions, M.D.P.U. No. 500; provided, however, that in their next base distribution rate case filing, the Companies must demonstrate the continuing propriety of including both a force majeure provision and a limitation of liability provisions in their terms and conditions. Further, the Department directs all electric and gas companies to make the same showing in their respective next base distribution rate case filings where they propose both a force majeure provision and a limitation of liability provision.

b. Obligation for Meter and Communication Device Installation

As noted above, the Attorney General recommends that the Department remove the phrase "if reasonably possible" from the sentence: "The Company shall complete installation of the meter or communication device, if reasonably possible, within thirty (30) days of receiving a written request from the Customer or Competitive Supplier" in the Companies' proposed Terms and Conditions in Section II.D.1 (Attorney General Brief at 204;

RR-DPU-51, Att. (a) at 7 (proposed M.D.P.U. No. 500, § II.D.1)). The Department agrees with this recommendation.

The record shows that Eversource's current practice is to complete meter or communication device installations within 30 days in the Boston Edison Company and WMECo service territories (Exhs. AG-49-2, Att. (a) at 7 (M.D.T.E. No. 100A, § II.4A); Att. (b) at 8 (M.D.P.U. No. 1023C, § II.4A)). Moreover, the Companies are not aware of any meter changes that were not completed within 30 days, if the request was within the Companies' capabilities (Exh. AG-49-6). Thus, we find that the Companies' need to allow for more than 30 days for installations of a meter or a communication device is speculative and unsupported by record evidence (see Exh. AG-49-6; Tr. 11, at 2249-2250). Accordingly, the Department directs Eversource to strike the phrase, "if reasonably possible," from the sentence: "The Company shall complete installation of the meter or communication device, if reasonably possible, within thirty (30) days of receiving a written request from the Customer or Competitive Supplier" (RR-DPU-51, Att. (a) at 7).

c. Limitation of Liability for Curtailment or Interruption of Service

The Attorney General recommends that the Department reject the Companies' proposed tariff language that would eliminate Eversource's liability in the event of interruption or curtailment of service. The proposed provision is as follows:

> Curtailment or Interruption of Service
>
> Whenever the integrity of the Company's system or the supply of electricity is believed to be threatened by conditions on its system or upon the systems with which it is directly or indirectly interconnected, the Company may, in its sole judgment, curtail or interrupt electric service or reduce voltage and such action shall not be construed to constitute a default nor shall the Company be liable

> therefor in any respect. The Company will use efforts reasonable under the circumstances to overcome the cause of such curtailment, interruption or reduction and to resume full performance.

(RR-DPU-51, Att. (a) at 16 (proposed M.D.P.U. No. 500, § II.I.1)).

Similar to the force majeure and limitation of liability provisions discussed above, the curtailment or interruption of service provision is neither new nor novel. The current tariffs applicable to NSTAR Electric's three legacy companies each have the same or similar liability disclaimer language (i.e., "such action shall not be construed to constitute a default nor shall the Company be liable therefor in any respect") objected to by the Attorney General (see M.D.T.E. No. 100A, § II.9A (Boston Edison Company); M.D.T.E. No. 200A, § II.9A (Cambridge Electric Light Company); M.D.T.E. No. 300A, § II.9A (Commonwealth Electric Company)). Further, this language appears in even earlier versions of these legacy tariffs (see M.D.T.E. No. 100, § II.9A (Boston Edison Company); M.D.T.E. No. 200, § II.9A (Cambridge Electric Light Company); M.D.T.E. No. 300, § II.9.A (Commonwealth Electric Company)).[382]

One difference among the current terms and conditions tariffs for the NSTAR Electric three legacy companies is Boston Edison Company uses a "reasonableness" standard in applying this curtailment/interruption provision; neither Cambridge Electric Light Company nor Commonwealth Electric Company uses a reasonableness standard. That is, the Boston Edison Company provision states: "reasonably believes the integrity..." and "in the exercise

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[382] Western Massachusetts Electric Company's currently effective Terms and Conditions (M.D.P.U. No. 1023C) has no express provision concerning curtailment/interruption.

of reasonable judgment…"[383] In considering Eversource's proposed M.D.P.U. No. 500, § II.I.1 (Curtailment or Interruption of Service) and the currently effective equivalent provisions, we find that application of a reasonableness standard as provided in the Boston Edison Company tariff is appropriate. In this context, we consider reasonable to mean not arbitrary, capricious, or in bad faith. Accordingly, the Department directs Eversource to modify proposed M.D.P.U. No. 500, § II.I.1 to include "reasonably believes the integrity…" and "in the exercise of reasonable judgment…" as provided in Boston Edison Company's currently effective M.D.T.E. No. 100A, § 9A.

Based on this finding regarding the inclusion of the reasonableness standard and the fact that this curtailment/interruption provision pertains to protection of the integrity of Companies' electric distribution system, and similar to our finding above, we are not persuaded that it is necessary or appropriate to modify the long-standing language disclaiming liability in this curtailment/interruption provision. Therefore, the Department does not exclude the language proposed by the Attorney General. However, we note that our decision today should not be construed as dispositive of whether a customer may maintain a viable action against the Companies under this provision.

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383 M.D.T.E. No. 100A, § 9A reads in pertinent part:

> Whenever the Company reasonably believes the integrity of the Company's system or the supply of electricity to be threatened by conditions on its system or upon the systems with which it is directly or indirectly interconnected, the Company may, in the exercise of reasonable judgment, curtail or interrupt electric service or reduce voltage, and such action shall not be construed to constitute a default nor shall the Company be liable therefore in any respect. The Company will use reasonable efforts under the circumstances to overcome the cause of such curtailment, interruption, or reduction and to resume full performance…. (emphasis added).

d. Unusual Load Characteristics

Cape Light Compact argues that the following language in the proposed M.D.P.U. No. 500 is vague and should be clarified:

> Unusual Load Characteristics
>
> The Company may, in the exercise of reasonable judgment, refuse to supply service to loads having unusual characteristics that might adversely affect the quality of service supplied to other Customers, the public safety, or the safety of the Company's personnel. In lieu of such refusal, the Company may require a Customer to install any necessary operating and safety equipment in accordance with requirements and specifications of the Company provided such installation does not conflict with applicable electrical code, and Federal, State or Municipal law.

(RR-DPU-51, Att. (a) at 8 (proposed M.D.P.U. No. 500, § II.D.3)).

The Department finds that this language is consistent with the Model Terms and Conditions established in Investigation into Developing Competitive Supplier Model Terms and Conditions, D.P.U./D.T.E. 97-65, Att. I at 108 (1997). Further, the language is found in the Companies' current tariffs (see M.D.T.E. No. 100A, § II.4C (Boston Edison Company); M.D.T.E. No. 200A, § II.4C (Cambridge Electric Light Company); M.D.T.E. No. 300A, § II.4C (Commonwealth Electric Company); M.D.P.U. No. 1023C § II.4C (WMECo)) and no change to the language is proposed. We are not persuaded by Cape Light Compact's arguments. Consistent with the requirements of this provision, we expect that the Companies will exercise reasonable engineering judgment and discretion, in light of all relevant circumstances, in determining whether unusual load characteristics should preclude service to a particular customer. Accordingly, we do not require any modification to this provision.

e. Conclusion

The Department has reviewed the proposed tariff language changes and finds them to be reasonable, except as they pertain to the above directives. All of the approved changes are designed to bring the Companies' tariffs in compliance with Department precedent and to make them consistent with other proposals that the Companies have put forth in this proceeding.

C. Administrative Fees and Charges

1. Introduction

The Companies propose to update the fees in Appendix A of the Terms and Conditions such that the fees will be the same for NSTAR Electric and WMECo customers (Exh. ES-RDP-9, at 24). The proposed updated charges include a returned check fee, account restoration fees, and a warrant fee (Exh. ES-RDP-9, at 24). Additionally, the Companies propose to implement a new sales tax abatement fee, which is intended to cover the administrative cost that the Companies incur to refund sales taxes at the request of customers who had not provided sales tax exemption certificates in a timely manner (Exh. ES-RDP-9, at 24).[384] The Companies' proposed fees are:

- Returned Check: $11.00
- Sales Tax Abatement: $52.00
- Warrant: $214.00

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384 Pursuant to G.L. c. 64H, § 6, non-residential electric customers are liable for sales and use taxes, subject to a variety of exemptions. In order to qualify for exemption from sales and use taxes, eligible customers must submit a sales tax exemption certificate to the Companies. G.L. c. 64H, § 8.

- Account Restoration (Meter): $71.00
- Account Restoration (Pole): $101.00
- Account Restoration (Manhole): $161.00

(Exhs. DPU-6-4, Atts. (a) - (g); DPU-62-11, Att. (b) at 217; Tr. 11, at 2231-2232, 2260-2266).

2. Positions of the Parties

a. Attorney General

According to the Attorney General, the Companies' proposed $71.00 fee for account restoration (meter) represents approximately a 700 percent increase for Commonwealth Electric Company and Cambridge Electric Light Company, a 450 percent increase for Boston Edison Company, and a 225 percent increase for WMECo (Attorney General Brief at 206, citing Tr. 11, at 2260). Additionally, the Attorney General maintains that the proposed warrant fee increased significantly to $214.00 (Attorney General Brief at 206, citing Tr. 11, at 2266). Because the fee increases are large, the Attorney General maintains that they could disproportionately impact a disadvantaged segment of the Companies' customer base (Attorney General Brief at 202, 207). The Attorney General recommends that the Department allow the Companies to implement their proposed fee increase over time, which she asserts is consistent with the principle of rate continuity (Attorney General Brief at 207). The Attorney General recommends that the fees be set at the level established in 2010 for WMECo and adjusted upwards annually over seven years to reflect the cost increases (Attorney General Brief at 207).

Moreover, the Attorney General argues that low-income customers should be exempt from the Companies' proposed increase to certain fees, such as the account restoration fee (Attorney General Brief at 202, 207). According to the Attorney General, there is precedent for the Department to exempt customers on the low-income rate from certain fees on the basis of income criteria (Attorney General Brief at 207 & n.55, citing American Hoechest Corporation, 379 Mass 408 (1980); Boston Edison Company v. Department of Public Utilities, 375 Mass 443, 489 (1971)). The Attorney General claims that National Grid exempts its low-income customers from its account restoration fee, and she recommends that the Department approve similar language in Eversource's Terms and Conditions (Attorney General Brief at 207, citing Massachusetts Electric Company and Nantucket Electric Company, M.D.P.U. No. 1192, Appendix A).

b. Low Income Network

The Low Income Network requests that the Department reject the Companies' proposed increases to certain restoration and warrant fees (Low Income Network Brief at 1; Low Income Network Reply Brief at 1). According to the Low Income Network, the Companies' proposals to increase restoration and warrant fees by 118 percent to 610 percent violate the Department's principle of rate continuity, and, therefore, should be rejected (Low Income Network Brief at 3, 5; Low Income Network Reply Brief at 1). The Low Income Network purports that the Companies' fee proposal could increase fees by more than seven times and would be imposed on low-income households that already struggle to pay their electric bill (Low Income Network Brief at 5).

The Low Income Network asserts that the proposed $214.00 warrant fee is an unjustly high burden for a low-income family, as it represents more than half of that customer's weekly take-home pay (Low Income Network Reply Brief at 3, citing G.L. c. 161, § 1). Additionally, the Low Income Network maintains that a restoration fee of $71 is equal to 140 percent the cost of a week's groceries for an average low-income household (Low Income Network Reply Brief at 2-3 & n.6, citing to a 2015 Bureau of Labor Statistics survey). For these reasons, the Low Income Network argues that the proposed fees are unjust and unreasonable (Low Income Network Reply Brief at 3).

According to the Low Income Network, it is Department policy to maintain a customer's connection to electricity service when a customer is faced with the choice between food or rent and utility service (Low Income Network Brief at 7, citing D.P.U. 87-260, at 177-178; D.P.U. 88-67 (Phase I) at 240-241; Low Income Network Reply Brief at 3). The Low Income Network explains that protections include the low-income discount rates, no-cost energy efficiency programs, payment plans that may include arrearage forgiveness, and restrictions on termination of service for low-income households in the winter and at all times for vulnerable households (Low Income Network Brief at 7, citing G.L. c. 164, §§ 1F(7), 124A, 124D, 124E, 124F, 124H, 141; 220 CMR 25.00, 27.00, & 29.00). Therefore, in the alternative to the Department rejecting the increases to the restoration and warrant fees, the Low Income Network maintains that the Department should protect low-income customers, and their access to utility service, by directing the Companies to adopt the same approach as National Grid in its Terms and Conditions tariff to exempt

low-income customers from these fees (Low Income Network Brief at 3-4, 6, citing Massachusetts Electric Company and Nantucket Electric Company, M.D.P.U. No. 1192, Appendix A, § I; Low Income Network Reply Brief at 1, 3). In the alternative to waiving the proposed restoration and warrant fees for low-income customers, the Low Income Network recommends that the restoration and warrant fees be raised by no more than the proposed two-year increase to WMECo's R-2 and R-4 rates (i.e., 4.2 percent and 2.5 percent, respectively) (Low Income Network Brief at 9).[385]

In response to the Companies' proposal to phase-in account restoration and warrant fees over five years, the Low Income Network claims that this scheme would provide only partial and temporary relief for customers by deferring the full amount of the fees (Low Income Network Reply Brief at 2). Therefore, the Low Income Network maintains that these fees should be rejected, or in the alternative, that low-income customers on Rate R-2 and Rate R-4 should be exempt for any such fees (Low Income Network Reply Brief at 3).

c. Companies

Eversource asserts that its proposal to charge a $71.00 restoration fee (meter) and a $214.00 warrant fee is cost based and is a long due change in its fee structure (Companies Brief at 560, citing Tr. 11, at 2268).

In response to the Low Income Network's concerns, the Companies are willing to phase-in the cost increases over five years (Companies Brief at 560). The Companies explain

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385 Also, without referencing the record or advancing any substantive argument for a change in the current structure, the Low Income Network suggests that the low-income discount (i.e., 36-percent) should apply to the restoration and warrant fees (Low Income Network Brief at 9).

that, for example, Boston Edison Company's fee would increase $11.20 per year for five years to move from the current restoration fee of $15.00 to the actual cost of $71.00 (Companies Brief at 560). The Companies assert that this proposal mitigates the increase in fees that the Companies would charge and protects low-income customers from the increased fees for a reasonable period (Companies Brief at 560). According to the Companies, their proposal to mitigate the fee increases provides a reasonable balance between cost-causation and tempering impacts to customers (Companies Brief at 560).

The Companies offer the phase-in option as an alternative to the Low Income Network's recommendation to fully exempt low-income customers from both the warrant and restoration fees (Companies Brief at 560; Companies Reply Brief at 178). Eversource maintains that it provides many protections for low-income customers (Companies Brief at 560, citing Tr. 11, at 2269). According to the Companies, they ensure that during most of the year, their low-income customers are not disconnected for non-payment (Companies Brief at 560). Further, the Companies argue that they offer other programs, such as the arrears forgiveness program, that serve to avoid disconnection in the first place (Companies Brief at 560, citing Tr. 11, at 2269). Moreover, the Companies note that either exempting low-income customers from the warrant and restoration fee (meter), or implementing a phase-in of these fees, require a commensurate adjustment to their distribution revenue requirement because Eversource would be recovering a lower amount of its revenue requirement through the fees than the level that is reflected in their cost of service (Companies Reply Brief at 179).

3. Analysis and Findings

a. Introduction

Fees for ancillary services such as processing returned checks are intended to reimburse a company for actual costs incurred in providing these particular services. See, e.g., D.P.U. 95-118, at 84; Whitinsville Water Company, D.P.U. 89-67, at 4-5 (1989); D.P.U. 956, at 62. The Department has found that fees for these various services must be based on the costs associated with these functions that the company actually incurred. D.P.U. 08-35, at 58 (2009); D.P.U. 89-67, at 4; D.P.U. 956, at 62. While the Department has accepted gradual adjustments to fees, excessive increases in a single step may violate the Department's continuity goal. D.T.E. 05-27, at 354-355.

b. Returned Check Fee

The Companies propose to increase their existing returned check fees from $9.00 (Boston Edison), $8.00 (Cambridge Electric Light), $9.00 (Commonwealth Electric Company), and $7.00 (WMECo) to $11.00 for all companies (Exhs. ES-RDP-17, Sch. RDP-1 (Rev.); DPU-6-4, Att. (a); AG-49-2, Atts. (a) at 18, (b) at 17, (c) at 17, (d) at 20). The Department has reviewed the Companies' supporting calculations and assumptions, and finds that a returned check fee of $11.00 is reasonable as it is based on the costs Eversource incurs associated with this function (Exhs. ES-RDP-17, Sch. RDP-1 (Rev.); DPU-6-4, Att. (a)). The Department further finds that the Companies have correctly incorporated the additional revenues associated with the fee increase as a revenue credit in their proposed costs of service (Exhs. ES-DPH-3 (East), WP DPH-5, at 1 (Rev. 1);

ES-DPH-3 (West), WP DPH-5, at 1 (Rev. 1); Tr. 11, at 2267-2268). Accordingly, the Department approves a returned check fee of $11.00.

c. Sales Tax Abatement Fee

No Massachusetts gas or electric distribution company currently collects a sales tax abatement fee. The separate charge for sales tax abatements requires customers requesting abatement to pay the associated costs instead of spreading these costs onto all customers (Exh. DPU-6-20). The Companies' expect this fee to discourage customers from postponing the return of their tax exemption forms until after a charge for sales tax reappears on their bills (Exh. DPU-6-20). If the customer returns the sales tax exemption form before their current sales tax exemption expires, the Companies will avoid labor and administrative costs required to complete the sales tax abatement process (Exhs. DPU-6-4, Att. (g); DPU-6-20). In the test year, Eversource completed 2,473 sales tax abatements, representing a cost of $128,708, and processed by the Companies' billing department (Exh. DPU-6-4). The Department finds the sales tax abatement fee to be reasonable because it assigns direct cost responsibility to customers who have failed to provide the Companies a sales tax exemption form in a timely manner and, as a result, have caused the Companies to incur costs. Further, the Department has reviewed the Companies' supporting calculations and assumptions, and finds that a sales tax abatement fee of $52.00 is reasonable as it is based on the costs Eversource incurs associated with this function (Exhs. ES-RDP-17, Sch. RDP-4 (Rev.); DPU-6-4, Att. (d)). The Department further finds that the Companies have correctly incorporated the additional revenues associated with the fee as a revenue credit in their

proposed costs of service (Exhs. ES-DPH-3 (East), WP DPH-5, at 1 (Rev. 1); ES-DPH-3 (West), WP DPH-5, at 1 (Rev. 1); Tr. 11, at 2267-2268). Accordingly, the Department approves the sales tax abatement fee of $52.00.

d. Warrant and Account Restoration Fees

With respect to the account restoration and warrant fees, the Companies concede that the proposed increases are below cost and do not reflect the costs the Companies actually incurred (Tr. 11, at 2268). While the Department accepts that a gradual adjustment to fees set according to cost can be advisable, the Department finds that increasing fees for account restoration at the meter from $10 (Cambridge Electric Light Company and Commonwealth Electric Company), $15 (Boston Edison Company), or $30 (WMECo) to $71 is too large of an increase in a single step and, therefore, violates our own continuity goal. See D.T.E. 05-27, at 354-355. Similarly, the increases to the warrant fee from $70.00 (Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company) and $98.00 (WMECo) to the proposed fee of $214.00 are too large in a single step and, therefore, violate our own continuity goal. See D.T.E. 05-27, at 354-355.

The Attorney General recommends that the fees be set at the level established in 2010 for WMECo and adjusted upwards annually over seven years to reflect the cost increases (Attorney General Brief at 207). As an alternative, the Companies offer to allow the increases to occur over five years, using the existing fee for each legacy company as a starting point (Companies Brief at 560). The Low Income Network requests that the Department reject the increases to these fees, or, in the alternative, exempt low-income

customers taking service on the low-income discount rates from any such fee increases that the Department may allow (Low Income Network Reply Brief at 3). Additionally, the Attorney General argues that low-income customers should be exempt from the Companies' proposed increase to certain fees, such as the account restoration (meter) fee (Attorney General Brief at 202, 207).

The Department declines to adopt the recommendation to exempt customers taking service on the low-income discount rates from these fees because there is not sufficient evidence to make this change. In order to make this adjustment, the Companies' revenue would need to be adjusted by the proposed fee (i.e., $71.00 for account restoration (meter) and $214.00 for warrant) multiplied by the number of customers taking service on the low-income discount rate charged the fee for account restoration (meter) and warrant in the test year. However, there is no evidence on the record regarding the number of low-income customers charged the account restoration (meter) and warrant fees in the test year to perform this calculation. Therefore, the Department declines to adopt the Low Income Network and the Attorney General's recommendation. Further, the Department declines to adopt the phase-in approach because the Department would not be able to properly adjust revenues beyond the adjustment made in this Order. The Department finds it appropriate to approve the same fee for all customers for effect January 1, 2018. Therefore, the Department finds that a $30.00 fee for account restoration (meter) and that a $98.00 fee for warrants for effect January 1, 2018 provide a reasonable balance of our continuity and efficiency goals. These are the current fees charged to customers in the WMECo service

territory (Exh. AG-49-2, Att. (d)). Therefore, we approve an account restoration fee (meter) of $30.00 and a warrant fee of $98.00.

The Department's decision requires an adjustment to the Companies' proposed revenue. NSTAR Electric originally proposed $1,671,549 in test year pro forma account restoration fee revenue based on a proposed fee of $71.03 (Exh. ES-DPH-3 (East), WP DPH-5, at 1 (Rev. 1)). Revising the proposed fee to $30.00 results in test year pro forma account restoration fee revenue of $705,990 (Exh. ES-DPH-3 (East), WP DPH-5, at 1 (Rev. 1)). Therefore, the Department directs the Companies to reduce NSTAR Electric's revenue by $965,559. WMECo originally proposed $607,307 in test year pro forma account restoration fee revenue based on a proposed fee of $71.03 (Exh. ES-DPH-3 (West), WP DPH-5, at 1 (Rev. 1)). Revising the proposed fee to $30.00 results in test year pro forma account restoration fee revenue of $256,500 (Exh. ES-DPH-3 (West), WP DPH-5, at 1 (Rev. 1)). Therefore, the Department directs the Companies to reduce WMECo's revenue by $350,807.

Further, NSTAR Electric originally proposed $198,804 in test year pro forma warrant fee revenue based on a proposed fee of $214.46 (Exh. ES-DPH-3 (East), WP DPH-5, at 1 (Rev. 1)). Revising the proposed fee to $98.00 results in test year pro forma account restoration fee revenue of $90,846 (Exh. ES-DPH-3 (East), WP DPH-5, at 1 (Rev. 1)). Therefore, the Department directs the Companies to reduce NSTAR Electric's revenue by $107,958. WMECo originally proposed $14,583 in test year pro forma warrant fee revenue based on a proposed fee of $214.46 (Exh. ES-DPH-3 (West), WP DPH-5, at 1 (Rev. 1)).

Revising the proposed fee to $98.00 results in test year pro forma warrant fee revenue of $6,664 (Exh. ES-DPH-3 (West), WP DPH-5, at 1 (Rev. 1)). Therefore, the Department directs the Companies to reduce WMECo's revenue by $7,919.

Regarding the account restoration fees at the pole and manhole, the Department has reviewed the Companies' supporting calculations and assumptions, and finds that an account restoration fee at the pole of $101.00 and an account restoration fee at the manhole of $161.00 are reasonable as they are based on the costs that Eversource incurs associated with these functions (Exhs. ES-RDP-17, Sch. RDP-4 (Rev.); DPU-6-4, Att. (d)). The Department further finds that the Companies have correctly incorporated the additional revenues associated with these fees as a revenue credit in their proposed cost of service (Exhs. ES-DPH-3 (East), WP DPH-5, at 1 (Rev. 1); ES-DPH-3 (West), WP DPH-5, at 1 (Rev. 1); Tr. 11, at 2267-2268).

e. Conclusion

With the exception of the warrant and account restoration at the meter fees, the Department approves the Companies' proposed fees. The Department finds it reasonable, based on its continuity goals, to set the warrant and account restoration (meter) fees at the price that WMECo currently charges to its customers. Accordingly, the Department directs the Companies to decrease its revenue by $1,432,243 (i.e., $1,073,517 for NSTAR Electric and $358,726 for WMECo). Further, the Department finds it reasonable to eliminate the service/fuse call charge (see Tr. 11, at 2263-2264).

D. Terms and Conditions – Competitive Suppliers and Competitive Renewable Energy Attribute Suppliers

1. Introduction

Eversource proposes to consolidate the Companies' four existing Terms and Conditions – Competitive Suppliers and Competitive Renewable Energy Attribute ("REA") Suppliers tariffs ("Competitive Supplier Terms and Conditions") and the Terms and Conditions for WMECO Green Options Suppliers tariff into one tariff (Exhs. ES-RDP-9, at 25-26; ES-RDP-14 (Part 3) at 1-135; RR-DPU-51, Att. (a) at 49-83 (proposed M.D.P.U. No. 501)). The Companies also propose changes that are intended to: (1) allow a customer to inform the Companies if the customer wishes to be protected from unwanted solicitation from competitive suppliers; (2) require customers to provide authorization for the release of historical use information; (3) require the Companies to release customer information to competitive suppliers unless the customer has notified the Companies of his or her wish to be protection from unwanted solicitations; (4) require the Companies to transfer customers to basic service upon default of a competitive supplier; (5) require a signed new service contract with a competitive supplier after reinstatement of defaulted supplier service; (6) include rules required for competitive suppliers and competitive REA suppliers to participate in ISO New England ("ISO-NE"); and (7) address competitive supplier and customer load estimation (Exh. ES-RDP-9, at 25). Finally, the Companies propose changes to the Schedule of Fees and Charges in the Competitive Supplier Terms and Conditions, Appendix A ("Appendix A") (Exhs. ES-RPD-9, at 26; ES-RPD-17, Sch. RDP-5). The

changes to Appendix A include, among other things, eliminating the Extending Metering Fee section and increasing the fees and charges for the Competitive Supplier Referral Program.

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that consumers should have the right to request that Eversource refrain from actively providing their names to competitive suppliers (Attorney General Reply Brief at 102). As a result, the Attorney General argues that the Companies, pursuant to the proposed tariff amendments, should be permitted to create a list of customers who do not wish to be solicited by competitive suppliers (Attorney General Reply Brief at 102).

b. Cape Light Compact

Cape Light Compact argues that the Companies' proposed tariff changes are substantial in nature, vague, inappropriate, unnecessary, and made without consultation or input from competitive suppliers (Cape Light Compact Brief at 65). Cape Light Compact also argues that the proposal to increase fees on competitive suppliers participating in the Competitive Supplier Referral Program is unreasonable, acts as a barrier to participation, and should be rejected (Cape Light Compact Brief at 67-69).

c. Choice Energy

Choice Energy argues that many of the Companies' proposed tariff changes impose substantial or significant changes on retail suppliers without any explanation or support (Choice Energy Brief at 3, 8-9). Choice Energy contends that the proposed tariff changes are "ill-considered," "error-riddled," inconsistent with the terms and conditions of other

Massachusetts utilities, and lack input from interested stakeholders (Choice Energy Brief at 3-4, 8-9; Choice Energy Reply Brief at 2). Choice Energy also argues, among other things, that the Companies should not be permitted to make the changes regarding customer "protections" from competitive supplier solicitation, increase fees, or change the process that applies when a competitive supplier defaults at ISO-NE (Choice Energy Brief at 9-21; Choice Energy Reply Brief at 3-7). Choice Energy recommends that the Department reject all of the proposed tariff changes that go beyond simply consolidating NSTAR Electric's and WMECo's existing tariffs (Choice Energy Brief at 3; Choice Energy Reply Brief at 4).

d. Low Income Network

The Low Income Network supports two of the Companies' proposed tariff changes: (1) allowing a customer to notify Eversource if the customer wishes to be protected from unwanted solicitation from competitive suppliers; and (2) requiring Eversource to release customer information to competitive suppliers unless a customer has requested protection from unwanted solicitations (Low Income Network Brief at 14). The Low Income Network also argues that in order to protect customers from unwanted solicitations, the Department should allow the Companies to create a list of customers who do not want to be solicited by competitive suppliers (Low Income Network Brief at 22).

e. RESA

RESA argues that (1) the Companies' proposed changes deviate substantially from the model competitive supplier terms and conditions as they have been revised with Department approval over time; (2) the Companies failed to meet their burden to establish that the proposed changes are appropriate; (3) the Companies failed to engage the competitive

supplier community in proposing the changes; (4) because the proposed changes are unrelated to base distribution rates or PBR mechanisms, "key stakeholders" could not have anticipated the proposal and, therefore, would not have intervened in the proceeding (RESA Brief at 9-10; RESA Reply Brief at 5). RESA also argues, among other things, that the Companies should not be permitted to change the process where competitive suppliers default with ISO-NE, or to increase fees related to the Competitive Supplier Referral Program (RESA Brief at 11-24). RESA recommends that the Department reject the proposed changes and require Eversource to seek approval of the changes in a separate proceeding where all interested stakeholders can participate (RESA Brief at 11; RESA Reply Brief at 5).

f. TEC and WMIG

TEC and WMIG argue that this proceeding is not the appropriate venue for the Department to address the proposed changes to the Competitive Supplier Terms and Conditions because the changes are not related to Companies' base distribution rates or PBR proposal (TEC and WMIG Reply Brief at 13).

g. The Companies

The Companies argue that the proposed tariff changes, among other things, protect customer information and rights under competitive supplier service, clarify specific issues, including participation rules at ISO-NE, and update certain fees (Companies Brief at 562). Further, the Companies contend that the proposed tariff changes streamline the presentation of information to customers and increase administrative efficiency both in terms of internal communications and regulatory filings (Companies Brief at 563). In addition, Eversource maintains that it provided fair notice of the proposed changes, as well as sufficient support

for them throughout the record, and that the proposed changes are consistent with existing practices and Department precedent (Companies Reply Brief at 173). Moreover, the Companies reject the argument that the proposed tariff changes place new or unreasonable burdens on retail electric suppliers, and maintain that their primary obligation is to their customers and not to competitive suppliers (Companies Brief at 563). As a result, Eversource asserts that it has supported all of the proposed changes, including the increased fees, and the Department should approve the proposed changes to the Competitive Supplier Terms and Conditions (Companies Brief at 562-564; Companies Reply Brief at 178).

3. Analysis and Findings

The Department has reviewed the Companies' proposal to consolidate and change the Competitive Supplier Terms and Conditions, including Appendix A, and the parties' arguments regarding such changes. Based on our review, the Department denies the Companies' proposal to consolidate and change the Competitive Supplier Terms and Conditions. The Department, however, approves the Company's proposed fees and changes to Appendix A.

The Department developed and approved model terms and conditions governing the relationship between the distribution companies, customers, and competitive suppliers ("Model Terms and Conditions") in Investigation into Developing Competitive Supplier Model Terms and Conditions, D.P.U./D.T.E. 97-65 (1997). In that proceeding, the Department stated that the Model Terms and Conditions will serve as a basis for the tariffs submitted for approval by each distribution company, and the goal is uniformity among the

distribution companies. D.P.U./D.T.E. 97-65, at 3. To accommodate company-specific circumstances, the Department noted that a company may propose tariff provisions that vary from the Model Terms and Conditions. D.P.U./D.T.E. 97-65, at 3. The company proposing the changes, however, is required to make a strong showing of the reasonableness of the variances, and a departure from the Model Terms and Conditions may only be warranted by compelling circumstances that a distribution company demonstrates are peculiar to it. D.P.U./D.T.E. 97-65, at 3. Further, the Department has found that customers and the competitive market are best served by attaining as much uniformity as reasonable among the electric distribution companies and the marketplace at large. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 16-193 (May 31, 2017).

Further, when changes to the Model Terms and Conditions are required, the Department has opened a generic proceeding to fully investigate the proposals. In Investigation into Terms and Conditions for Competitive Electric Suppliers, D.P.U. 09-46 (2009), the Department required the electric distribution companies to jointly propose revised Model Terms and Conditions that complied with the Green Communities Act, Section 60.[386] D.P.U. 09-46, at 4. After reviewing the electric distribution companies proposal, convening a technical session to discuss the proposal, and receiving a counter proposal from RESA and other competitive supply companies, the Department approved Model Terms and Conditions, and required each electric distribution company to submit revised Competitive Supply Terms and Conditions consistent with the Department's Order. D.P.U. 09-46-A, at 1-2, 25-26.

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[386] Chapter 169 of the Acts of 2008, an Act Relative to Green Communities

Pursuant to the current Model Terms and Conditions, the Companies' currently effective Competitive Supplier Terms and Conditions are substantially similar to those of National Grid and Unitil. While minor differences exist between the three distribution companies' currently effective Competitive Supplier Terms and Conditions[387] none of the differences are as extensive as the Companies' proposed changes. Because of the significance and materiality of the changes in the rules and responsibilities proposed by the Companies, we find that the Companies' proposal would benefit from advance discussion with competitive suppliers, after which time the Companies may make a filing with the Department for review and approval of any changes to the Competitive Supplier Terms and Conditions. Thus, in this circumstance, the Companies first should reach out to competitive suppliers to review significant revisions to the Competitive Supplier Terms and Conditions. Subsequently, as part of any filing with the Department seeking review and approval to revise the Competitive Supplier Terms and Conditions, the Companies must demonstrate their efforts in conferring with competitive suppliers.

Based on these considerations, at this time, the Department denies the Companies' proposed changes to the Competitive Supplier Terms and Conditions, and the proposal to consolidate the Competitive Supplier Terms and Conditions and the Terms and Conditions for

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387 For example, the NSTAR Electric tariffs (M.D.P.U. No. 101D; M.D.P.U. No. 201D; and M.D.P.U. No. 301D) apply to Renewable Energy Attribute Suppliers in addition to competitive supply companies, while WMECo (M.D.P.U. No. 1024F), National Grid (M.D.P.U. No. 1201), and Unitil's (M.D.P.U. No. 285) tariffs for Competitive Supply Terms and Conditions do not include Renewable Energy Attribute Suppliers.

WMECO Green Options Suppliers. Accordingly, proposed tariff M.D.P.U. No. 501 is disallowed.[388]

Regarding the Companies' proposal to increase fees and make changes to Appendix A, the Department finds that Appendix A is not a part of the Model Terms and Conditions, but is to be approved by the Department on a company-specific basis. See D.P.U. 09-46, Stamp-Approved Compliance Filings (February 8, 2010). As such, the fees found in Appendix A must be based on a company's actual costs incurred or on the actual costs of providing the particular services. D.P.U. 09-46-A at 22; D.P.U. 08-27, at 46 (2009). In addition, the Department has stated that the costs associated with the Supplier Referral Program should be reasonable and transparent, and that the competitive suppliers should understand the extent of the costs prior to participating in the program. D.P.U. 09-46-A at 22.

In this case, the intervenors did not argue that the actual costs provided in Exhibit ES-RDP-17, Schedule RDP-5 were incorrect, provide examples on how the costs were inflated, or demonstrate how the costs could be lower. Instead, the intervenors argued that the proposed fee increases were excessive, unreasonable, and would create a barrier to participation in the Supplier Referral Program (Cape Light Compact Brief at 67-69; Choice

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388 On November 22, 2017, the Department approved specific changes to Eversource's Competitive Supplier Terms and Conditions tariff, which memorializes how customers are treated in the municipal aggregation programs. Investigation into Municipal Aggregation Programs, D.P.U. 16-10, Stamp-Approved Compliance Filing (November 22, 2017). These changes were specifically mandated by the Department in D.P.U. 16-10 after a full investigation and, as a result, shall be incorporated in the Companies' current Competitive Supplier Terms and Conditions.

Energy Brief at 18-19; RESA Brief at 20-21). The Department has reviewed the Companies' calculations and assumptions and finds that proposed fees for the Supplier Referral Program are based on costs that Companies actually incur associated with these functions and, therefore, are reasonable and transparent (Exh. ES-RDP-17, Sch. RDP-5). As a result, the Department approves the fee increases and changes to Appendix A, to the extent that the proposed changes remain consistent with the Companies' current Competitive Supply Terms and Conditions.

E. Residential Assistance Adjustment Clause

1. Introduction

In August 2003, the Department established an automatic enrollment program for the purpose of increasing participation in the low-income discount rate. Low-Income Discount Rate Participation Rate, D.T.E. 01-106-A (2003). The Department directed electric and gas companies to exchange information with the Executive Office of Health and Human Services on a quarterly basis so that every recipient of a means-tested public benefit who is also the electric and/or gas customer of record would be automatically enrolled in the discount rate without the usual paper application. D.T.E. 01-106-A at 10, 13. In 2006, the Department established standards for electric and gas arrearage management programs ("AMPs") to help eligible customers pay overdue utility bills with payment programs, debt forgiveness, or a combination of the two. Standards for Arrearage Programs for Low-Income Customers, D.T.E. 05-86, at 10, 14-15 (2006). The Department determined that the appropriate cost recovery mechanism for both the revenue shortfall caused by the discount rate and

incremental AMP expenses is the RAAF. D.T.E. 01-106-C/05-55/05-56, at 11, 14; D.T.E. 05-86, at 12-13.

NSTAR Electric's recovery of the revenue shortfall caused by the discount rate and incremental AMP expenses is governed by provisions set forth in its legacy companies' Residential Assistance Adjustment Clause ("RAAC") tariffs (M.D.P.U. No. 110D (Boston Edison Company); M.D.P.U. No. 210D (Cambridge Electric Company); M.D.P.U. 310D (Commonwealth Electric Company)). The RAAC tariffs contain a net cost/benefit formula that was approved by the Department as part of a settlement agreement in NSTAR Electric's last base rate case. D.T.E. 05-85, at 9-10, 33. The formula sets forth the method by which NSTAR Electric recovers AMP-related costs. Specifically, pursuant to the formula, reasonable costs associated with the AMP in excess of the benefits are reconciled annually through the RAAF. D.T.E. 05-85, at 10.

WMECo's recovery of the revenue shortfall caused by the discount rate and incremental AMP expenses is governed by provisions set forth in its RAAC tariff (M.D.P.U. No. 1040K). WMECo's current RAAC does not contain a net cost/benefit formula.

2. Companies' Proposal

Eversource proposes to consolidate the Companies' RAAC tariffs into one tariff, to eliminate NSTAR Electric's net/cost benefit formula, and to recover all expenses directly associated with the AMP consistent with WMECo's current cost recovery method (Exh. ES-RDP-9, at 32; RR-DPU-51, Att. (a) at 112-115 (proposed M.D.P.U. No. 523)).

Eversource states that for the test year, elimination of the formula would produce an additional $1,396,726 in recoverable costs (Exhs. ES-RDP-9, at 33; ES-DPH-5 (Rev. 3)). In its initial rate design proposal, Eversource proposes to maintain separate RAAFs for the Eastern and Western Massachusetts service territories because the Companies' base distribution rates have been developed under separate revenue requirements and the low-income discounts are different for NSTAR Electric and WMECO (Exh. DPU-41-11). In its revised rate design proposal, Eversource proposes to maintain separate RAAFs for the Eastern and Western Massachusetts service territories in 2018 (Exh. DPU-56-9, at 2 (Supp.); RR-DPU-51, Att. (a) at 114 (proposed M.D.P.U. No. 523, § 1.05)). In 2019, the Companies propose to combine the revenue requirement calculation in the RAAC for a consolidated RAAF for the Eastern and Western Massachusetts service territories (Exh. DPU-56-9, at 2 (Supp.); RR-DPU-51, Att. (a) at 115 (proposed M.D.P.U. No. 523, § 1.05)).[389] No party commented on the Companies' proposal on brief.

3. Analysis and Findings

The Department finds that Eversource's proposal to consolidate the Companies' RAACs is reasonable and appropriate and, therefore, it is allowed. Regarding the proposed elimination of the AMP net cost/benefit formula in the NSTAR Electric tariffs, this formula was established as part of a settlement approved by the Department in D.T.E. 05-85. D.T.E. 05-85, at 9-10, 33. Pursuant to the formula, reasonable costs associated with the

389 Additionally in their revised rate design proposal, the Companies propose a uniform low-income discount (i.e., 36 percent) for both Eastern and Western Massachusetts service territories (Exh. DPU-56-9, at 2 (Supp.)).

AMP in excess of the benefits are reconciled and recovered annually through NSTAR Electric's legacy companies' RAAFs. D.T.E. 05-85, at 10.

AMPs are legislatively mandated by St. 2005, c. 140, § 17 and there is no statutory requirement that they be cost effective. 2013 Arrearage Management Programs, D.P.U. 13-AMP-01 through D.P.U. 13-AMP-08, at 9 (July 17, 2014). Neither WMECo, nor any other gas or electric distribution company (other than NSTAR Electric), currently uses a net cost/benefit formula as part of its recovery of AMP costs. Further, because the settlement in D.T.E. 05-85 that established the net cost/benefit formula is no longer in effect, there is currently no basis to require that the Companies' maintain the net cost/benefit formula. Moreover, we find that eliminating the net cost/benefit formula for NSTAR Electric is consistent with the Department's treatment of the same issue for NSTAR Gas in its last base rate case. D.P.U. 14-150, at 383. Accordingly, the Department allows Eversource's proposal to eliminate the net cost/benefit formula from the proposed consolidated RAAC. The Department will address the Companies' proposal to implement a uniform low-income discount and to consolidate the RAAFs in our subsequent Order addressing rate design issues.

F. Renewable Energy Charge

1. Introduction

Eversource proposes to consolidate the renewable energy charge into one tariff, proposed M.D.P.U. No. 521 (RR-DPU-51, Att. (a) at 107).[390] Pursuant to G.L. c. 25, § 20, the Companies propose a renewable energy charge of $0.00050 per kWh, applicable to all customers (RR-DPU-51, Att. (a) at 107 (proposed M.D.P.U. No. 521)). The renewable energy charge provides funding to the Massachusetts Renewable Energy Trust Fund (RR-DPU-51, Att. (a) at 107 (proposed M.D.P.U. No. 521)). No party addressed the Companies' proposed tariff.

2. Analysis and Findings

The Department has reviewed the proposed tariff language and finds it to be reasonable. Therefore, the Department approves the Companies proposal to consolidate the renewable energy charge, as well as the renewable energy charge of $0.00050 per kWh, applicable to all customers.

G. Optional Load Data Service Tariff

1. Introduction

Eversource proposes several changes to NSTAR Electric's and WMECo's current provisions governing load data services found in M.D.T.E. Nos. 151, 152 (Boston Edison Company); M.D.T.E. No. 251, 252 (Cambridge Electric Light Company); M.D.T.E. Nos. 351, 352 (Commonwealth Electric Company); and M.D.P.U. No. 1038B

390 In doing so, the Companies propose to cancel the following tariffs: M.D.T.E. No. 108, M.D.T.E. No. 208, M.D.T.E. No. 308, and M.D.P.U. No. 1031C (RR-DPU-51, Att. (a) at 107).

(WMECo) (Exh. ES-RDP-14 (Part 4) at 139-188; RR-DPU-51, Att. (a) at 85-87 (proposed M.D.P.U. No. 514)). Specifically, Eversource proposes to: (1) consolidate the tariffs into one new tariff, M.D.P.U. No. 514; (2) align the fees associated with interval load data access; (3) increase the fees associated with load pulse data access; and (4) update certain language, e.g., allow use of cellular rather than analog telephone line (Exh. ES-RDP-14 (Part 4) at 149-188; RR-DPU-51, Att. (a) at 85-87 (proposed M.D.P.U. No. 514)). In addition, Eversource proposes to terminate WMECo's current Extended Metering Options tariff, M.D.P.U. No. 1037D (Exhs. ES-RDP-9, at 35; ES-RDP-14 (Part 4) at 139-148).

2. Positions of the Parties

a. Cape Light Compact

Cape Light Compact contends that Eversource proposes to remove customers' abilities to connect their own metering equipment to the Companies' devices, which adversely affects the competitive supply market (Cape Light Compact Brief at 69-70). Cape Light Compact states that it currently uses meter clamps as part of its energy efficiency plan and the proposed tariff revisions would preclude such use (Cape Light Compact Brief at 70, citing D.P.U. 15-122, Tr. 3, at 437, 459-461). Thus, Cape Light Compact asserts that, to the extent that the Department allows the Companies' proposal to preclude the attachment of external devices, equipment used by Cape Light Compact and others in similar circumstances should be specifically exempt (Cape Light Compact Brief at 70).

With respect to the proposed fee increases for interval load data access and load pulse data access, Cape Light Compact asserts the increases are "hostile" to grid modernization as they raise an additional barrier for customers, suppliers, and aggregators looking to access

usage data, and make it "nearly impossible" to empower or engage customers in a modernized grid (Cape Light Compact Brief at 66-67, citing D.P.U. 12-76-B at 36).

b. Choice Energy

Choice Energy argues that Eversource's proposal to increase its fees for access to customers' usage data is unsupported and will serve as a barrier to customer empowerment or engagement (Choice Energy Brief at 24-25, citing e.g., Exhs. RESA-FL-1, at 25-27; ES-RPD-12, at 82-83). Choice Energy also asserts that Eversource is proposing to prevent any type of external device being attached to any company meter and that such change is discriminatory and should be rejected (Choice Energy at 24-25). With respect to the Extended Metering Options tariff, M.D.P.U. No. 1037D, Choice Energy argues that it would be inappropriate to eliminate a competitive supplier's ability to request the read on request option because it would limit customer switches to the meter read date (Choice Energy Brief at 19).

c. RESA

RESA argues that the Department should deny Eversource's request to increase the fees for interval load data access and load pulse data access (RESA Brief at 16-17). RESA asserts that the fee increases are excessive and that the Companies have not provided sufficient support for the increases (RESA Brief at 16-17). In addition, RESA argues that a fundamental principle of the Department's grid modernization proceedings is to empower customers and Eversource's fee increases contravene this principle (RESA Brief at 18).

Finally, RESA argues that the Department should reject the Companies' proposal to remove the read-on-request option from WMECo's Extended Meter Options tariff,

M.D.P.U. No. 1037D, because Eversource did not seek input from the competitive suppliers (RESA Brief at 23). In addition, RESA argues that while the optional meter read provision is not currently used, current Department initiatives to engage customers and enhance the retail market may lead to instances where a customer seeks to switch to a competitive supplier before his/her scheduled meter read date (RESA Brief at 23-24).

d. TEC and WMIG

TEC and WMIG argue that the Companies' proposed fee increases should be disallowed because (1) access to interval load data is a requirement for competitive suppliers to offer innovative products, and (2) pulse access is required for customers who want real-time, situational awareness of energy consumption or who desire to utilize third-party management systems (TEC and WMIG Reply Brief at 13-14). As such, TEC and WMIG contend that the increased fees represent a barrier to customer engagement enabled by timely access to data (TEC and WMIG Reply Brief at 14).

e. Companies

Eversource asserts that it is not proposing to remove customers' abilities to connect their own metering equipment, but instead is providing clarification regarding requirements for device attachments and providing consistency between the WMECo and NSTAR Electric territories (Companies Reply Brief at 95, citing Tr. 12, at 2601-2602). The Companies assert that they have an obligation to collect accurate data from customer meters and, therefore, it is in the best interest of customers that Eversource's equipment performs properly and without interference from external equipment (Companies Reply Brief at 95-96).

In addition, Eversource asserts that it has fully supported its fee increase proposal (Companies Brief at 562-563, citing e.g., Exhs. ES-RDP-9, at 25-26; ES-RDP-12).

3. Analysis and Findings

We first consider the appropriateness of the Companies' proposed tariff change as it relates to the ability of customers to connect their own metering equipment to Eversource's devices. In comparing the proposed consolidated tariff M.D.P.U. No. 514, with each tariff currently in effect, we note that the Companies continue to offer interval load data access and load pulse data access (see, e.g., M.D.T.E. No. 152, at 2).[391] The Companies also retained a special request section permitting a customer to request special services subject to mutual agreement (proposed M.D.P.U. No. 514, at 2). The Companies have simplified the special requests sections to exclude certain references, e.g., that the Companies will address availability, the cost of implementation, and technical alternatives (compare proposed M.D.P.U. No. 514, at 2 with M.D.T.E. No. 152, at 2). Nonetheless, the tariff continues to permit special requests and we expect Eversource to continue to work with customers and requestors to ensure that authorized attachments are permitted to the extent that they do not interfere with the customer's meter (proposed M.D.P.U. No. 514, at 2).[392] Based on the

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391 The redline comparison provided by the Companies is difficult to follow as it includes tariffs that are deleted in whole (Exh. ES-RPD-14 (Part 4) at 139-188; see also Tr. 12, at 2599). In the future, we expect companies that wish to consolidate tariffs to provide a redline version that compares each tariff individually for ease of review.

392 The continued use by Cape Light Compact of meter clamps as part of its energy efficiency plan is more appropriately handled through the energy efficiency or grid modernization dockets. See, e.g., Thee Cape Light Compact Three-Year Energy Efficiency Plan, D.P.U. 15-166; D.P.U. 15-122.

foregoing, we find that the Companies' proposed consolidation of its load data services tariffs and the revised language contained in the consolidated tariff M.D.P.U. No. 514 is appropriate and, therefore, allowed.

In considering the appropriateness of the proposed fee alignments and increases, the Department has found that fees for various services, such as meter testing, returned checks, and cross-connection inspection fees, must be based on the costs that the company actually incurred associated with these functions. D.P.U. 08-27, at 46; D.T.E. 01-42, at 28; D.T.E. 95-118, at 84; D.P.U. 89-67, at 4-5. Fees for ancillary services such as processing after-hours call-outs are intended to reimburse a company for actual costs incurred in providing these particular services. See, e.g., D.P.U. 95-118, at 84; D.P.U. 89-67, at 4-5; D.P.U. 956, at 62.

The Department has reviewed the Companies' calculations and assumptions and finds that the four fees in proposed M.D.P.U. No. 514 are based on the costs that the Companies actually incur associated with these functions and, thus, are reasonable (Exhs. RESA-1-1; RESA-1-2; RESA-1-3; Tr. 11, at 2374-2377). The Department's rate setting goal of fairness dictates that customers pay the cost to serve them. Thus, the cost to provide this service should be charged to the customers that cause the cost, rather than be subsidized by other customers.

Finally, Choice Energy and RESA have raised concerns with respect to the Companies' request to terminate WMECo's current Extended Metering Options tariff, M.D.P.U. No. 1037D, which would eliminate the read on request provision. The record

demonstrates that competitive suppliers do not currently use WMECo's read-on-request provision (Exh. ES-RDP-9, at 35). RESA also notes that the read on request provision is not used and further recognizes that the Department has open dockets to determine how to "enhance the value of the retail market to customers" (RESA Brief at 23, citing D.P.U. 14-140, D.P.U. 15-122). To the extent that future Department decisions and retail market enhancements make the read-on-request provision reasonable or necessary, the inclusion of such provision would be an appropriate topic for discussion in those dockets that are specific to the competitive supply community. Further, the read-on-request provision at issue only applies to WMECo and not to NSTAR Electric, and for administrative efficiency the Companies are attempting to align their general procedures and tariffs. Based on these considerations, we grant Eversource's request to terminate the Extended Metering Option tariff, M.D.P.U. No. 1037D.

H. Basic Service Cost Adjustment Provision

1. Introduction

NSTAR Electric's and WMECo's current basic service tariffs include basic service cost adjustment provisions ("BSAP"), which provide for the recovery of non-supply costs associated with providing basic service through the basic service cost adjustment ("BSCA") factor that is added to the basic service rate for billing purposes (see M.D.P.U. Nos. 103AB, 203AB, 303AB, 1026BE). The BSAP for NSTAR Electric and WMECo provides for the recovery of supply-related bad debt costs as well as the recovery of fixed levels of costs for administration of basic service, conducting the competitive bidding processes, and regulatory

compliance.[393] In their proposed basic service tariff, M.D.P.U. No. 516, the Companies propose revisions to the BSAP to provide for the annual recovery of (1) $10,988 in administrative costs; (2) $700,988 in costs associated with the competitive bidding process; and (3) $2,822,467 in costs associated with basic service regulatory compliance, including required communication with basic service customers (RR-DPU-51, Att. (a) at 97 (proposed M.D.P.U. No. 516)). Additionally, the existing BSAP for WMECo includes a working capital allowance. Consistent with WMECo's existing BSAP, the Companies propose to provide for the recovery of a working capital allowance associated with basic service for NSTAR Electric (Exh. ES-DPH-1, at 198-199; RR-DPU-51, Att. (a) at 97 (proposed M.D.P.U. No. 516)). D.P.U. 10-70, at 77-78. The Companies state that they will update their BSCA filings based on the basic service net lag factor approved in this proceeding (Exh. ES-DPH-1, at 199). No party addressed these issues on brief.

2. Analysis and Findings

The Department has previously determined that costs associated with supply-related bad debt; the design and implementation of the competitive bidding process, including the evaluation of supplier bids and contract negotiations, the ongoing administration and execution of contracts with suppliers, including accounting activities necessary to track payments made to suppliers; and complying with the Department's basic service regulatory requirements, including required communications with its basic service customers should be included in the calculation of basic service prices. D.T.E. 02-40-B at 16-17.

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393 The Department previously has directed that the BSAP indicate the fixed level of administrative costs to be recovered through the BSCA factor. D.P.U. 10-70, at 367.

The Department has reviewed the proposed costs of (1) $10,988 in administrative costs; and (2) $700,988 associated with the competitive bidding process (Exh. ES-DPH-4, Sch. DPH-11, at 1 (Rev. 1); RR-DPU-51, Att. (a) at 97 (proposed M.D.P.U. No. 516)). In particular, the $700,988 in costs associated with the competitive bidding process include (a) $617,061 for wholesale procurement and support; (b) $296 in website update support; (c) 49,808 for billing system rate change support; and (d) $33,823 for legal support (Exh. ES-DPH-4, Sch. DPH-11, at 1 (Rev. 1)). The Department finds that these two categories of proposed costs reflect the Companies' costs of providing basic service, are consistent with our directives in D.T.E. 02-40-B, and, as such, are appropriately recovered through the BSAP (see Exh. ES-DPH-4, Sch. DPH-11, at 1 (Rev. 1)). Additionally, Eversource proposes recovery of $2,822,467 in regulatory compliance costs, but all of these costs are attributable to regulatory assessments that the Companies propose to reallocate to basic service (compare Exh. ES-DPH-4, Sch. DPH-11, at 1 (Rev. 1) with Exhs. ES-DPH-2 (East), Sch. DPH-17 (Rev. 1); ES-DPH-2 (West), Sch. DPH-17 (Rev. 1)).[394] As addressed in Section VIII.O.3 above, the Department disallowed the Companies' proposal to reallocate regulatory assessment amounts to basic service. As a result, we disallow the Companies' proposal to collect this amount through the BSAP.

In WMECo's last base rate case, the Department excluded basic service cash working capital from the cash working capital allowance recovered through base rates and directed

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394 The Department makes annual assessments to electric companies under its jurisdiction pursuant to G.L. c. 25, § 18.

WMECo to recover basic service cash working capital through the BSAP. D.P.U. 10-70, at 77-78. The Department finds the same method for cash working capital allowances is appropriate for NSTAR Electric. As addressed in Section VII.D above, the Department calculated separate lead-lag factors for O&M expense and for basic service for the Companies.[395] Further, the Department finds that the Companies have properly excluded basic service cash working capital from the cash working capital allowance allowed to be recovered through base rates (Exh. ES-DPH-1, at 198-199). Accordingly, the Department approves the Companies' proposal to collect a basic service cash working capital allowance through the BSAP. At this time, the Department will not address any other provisions of this proposed tariff. Instead, we will address any further issues in our subsequent addressing rate design issues.

I. Additional Tariff Provisions

Eversource proposes to eliminate their economic development riders and interruptible load credit provisions because these programs no longer exist (Exh. ES-RDP-9, at 35). Eversource also proposes changes to the following tariffs that are not addressed above or elsewhere in this Order: (1) Off-Cycle Meter Read for Switch of Supplier, proposed M.D.P.U. No. 513; (2) Power Purchase Availability, proposed M.D.P.U. No. 515; (3) Standards for Interconnection of Distributed Generation, proposed M.D.P.U. No. 526; (4) Farm Discount Rider, proposed M.D.P.U. No. 529; (5) Miscellaneous Charges, proposed M.D.P.U. No. 533; and (6) Load Response Program, proposed M.D.P.U. No. 535.

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[395] The Department calculated a basic service net lag factor of 1.72 days for purposes of the Companies' BSAP cash working capital allowance.

No party opposed the Companies' proposed elimination of the aforementioned tariffs or the proposed tariff changes. The Department finds it reasonable to terminate the Companies' economic development riders and interruptible load credit provisions, because these programs no longer exist. Further, we find that the Companies' proposed changes with respect to the foregoing tariffs are reasonable and, therefore, we approve the proposed changes. Eversource is directed to file revised tariffs with its compliance filing consistent with the directives below.

J. Other Tariff Issues

1. Compliance Filings

As discussed above in various sections of this Order, the Department has allowed certain provisions with respect to some of the Companies' proposed tariffs, but reserved other issues raised by these tariffs for discussion in our subsequent Order addressing rate design issues. Further, as noted above, the Department will address distribution rate tariffs and most of the reconciling rate tariffs in the next Order. In order to facilitate the compliance filing review in this proceeding, the Department directs the Companies to file only one set of compliance tariffs. This filing shall be made following the Department's subsequent Order in this proceeding.

2. Tariff Numbering System

Presently, Eversource relies on multiple tariff numbering systems. NSTAR Electric's tariffs use three different alphanumeric numbering systems, with tariffs applicable to the legacy Boston Edison Company using a 100-series, to the legacy Cambridge Electric Light Company using a 200-series, and to the legacy Commonwealth Electric Company using a

300 series. WMECo uses an entirely different alphanumeric system, with tariffs numbered in a 1000 series. The Companies propose to maintain these numbering systems for the proposed commercial and industrial distribution rate tariffs and the storm cost recovery adjustment factor tariffs (Exh. ES-RDP-10, Sch. RDP-1). The Companies propose to introduce a 500 alphanumeric series system for the proposed terms and conditions tariffs, residential distribution rate and streetlighting tariffs, other reconciling rate tariffs and other provisions (Exh. ES-RDP-10, Schs. RDP-1, RDP-2).

Under G.L. c. 164, § 94, a utility's proposed rates must be found as consistent with the public interest. One component of this standard, applicable to tariff construction, requires that a proposed tariff have sufficient detail to explain the basis for the rate to be charged for the offered service. Boston Gas Company, D.P.U. 92-259, at 47-48 (1993); Dedham Water Company, D.P.U. 13271, at 10 (1961). The Department's regulations prescribe tariff construction. For example, pursuant to 220 CMR 5.02(3)(a), each tariff or schedule shall show prominently the name of the company, firm, association or individual responsible, together with the name of any independent agency filing the tariff or schedule and its or his address. Moreover, each tariff or schedule must be designated by an individual number progressing from that last filed by the same party or in case of a new series, from Number 1 and sequentially thereafter. 220 CMR 5.04(a).

Eversource's tariff numbering systems fails to comply with the Department's regulations. While the Department has previously accepted the use of a tariff numbering system similar to that currently used by NSTAR Electric in Keyspan Energy Delivery New

England, D.T.E. 04-62, at 16, 47-48 (2004), the Department ultimately directed those companies to revise their tariff numbering in order to conform more closely to the requirements of 220 CMR 5.02(4). D.P.U. 10-55, at 602. Moreover, in the case of a post-merger NSTAR Electric, the existing 100 to 300 tariff series for the legacy companies that make up NSTAR Electric, and a separate tariff numbering system for what will become the legacy WMECo, would make it difficult for the Department to ensure that the Companies' tariffs are recorded and maintained in proper order. Adding yet another 500 tariff series on top of this existing system will only serve to increase the present difficulties.

Therefore, in order to prevent customer confusion and ensure compliance with Department regulations, the Companies are directed to submit, as part of their compliance filing, tariffs that clearly identify the legal business name of the particular company (i.e., NSTAR Electric Company).[396] Additionally, the Companies are directed to renumber their tariffs sequentially as required by 220 CMR 5.04(a), using numbering not already used or proposed in this proceeding.

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[396] If the Companies wish to include the d/b/a "Eversource Energy" in their tariffs, they may do so, provided that it is clear that "Eversource Energy" is only being used as part of a d/b/a arrangement.

XVIII. SCHEDULES: NSTAR ELECTRIC COMPANY

A. NSTAR Electric Schedule 1 – Revenue Requirements and Calculation of Revenue Increase

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
COST OF SERVICE				
Total O&M Expense	322,597,077	222,884	(28,959,408)	293,860,553
Depreciation & Amortization	176,196,744	74,023	(6,609,654)	169,661,113
Taxes Other Than Income Taxes	99,430,889	1,185,985	(27,485)	100,589,389
Income Taxes	106,987,033	130,775	(5,122,353)	101,995,455
Return on Rate Base	208,211,099	(5,049,088)	(2,871,303)	200,290,708
Additional Uncollectibles (Revenue Deficiency)	426,407	(29,016)	(310,652)	86,739
Total Cost of Service	913,849,249	(3,464,437)	(43,900,854)	866,483,958
OPERATING REVENUES				
Distribution Revenues	829,692,282	0	0	829,692,282
Total Other Revenues	23,962,582	631,625	(47,112)	24,547,095
Total Operating Revenues	853,654,864	631,625	(47,112)	854,239,377
Total Revenue Deficiency	**60,194,385**	**(4,096,062)**	**(43,853,742)**	**12,244,581**

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

B. NSTAR Electric Schedule 2 – Operations and Maintenance Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Test Year O&M Expense	274,358,971	(470,430)	0	273,888,541
ADJUSTMENTS TO O&M EXPENSE:				
Postage Expense	(126,159)	0	0	(126,159)
Uncollectible Expense	(3,573,684)	0	0	(3,573,684)
Fee Free Payment Processing	5,093,091	0	(5,093,091)	0
Fee Offset	0	0	52,891	52,891
Dues and Memberships	(93,080)	0	0	(93,080)
Employee Benefits Costs	1,548,219	1,104,330	(323,914)	2,328,635
Insurance Expense And Injuries & Damages	(87,075)	0	0	(87,075)
Payroll Expense	10,035,441	(964,281)	0	9,071,160
Variable Compensation	(3,057,252)	(91,433)	(460,042)	(3,608,727)
Vegetation Expense Annualization	5,226,646	0	0	5,226,646
Vegetation Management Resiliency Tree Work Pilot	22,752,025	0	(22,752,025)	0
Rate Case Expense	471,976	153,383	(29,052)	596,307
Regulatory Assessments	(2,188,739)	455,947	2,409,292	676,500
Lease Expense	400,375	219,956	(154,496)	465,835
Information Systems Expense Adjustment	1,362,605	(114,437)	(1,248,168)	0
GIS Verification Adjustment	1,023,615	167,661	(1,191,276)	0
Storm Cost Adjustment	2,880,000	0	0	2,880,000
Storm Fund Adjustment	3,500,000	0	0	3,500,000
Eversource Service Company Charges	0	0	(3,778)	(3,778)
Insurance Policy Distribution	0	0	(158,407)	(158,407)
Residual O&M Inflation Adjustment	3,070,102	(237,812)	(7,342)	2,824,948
Total Other O&M Expenses	48,238,106	693,314	(28,959,408)	19,972,012
Total O&M Expense	**322,597,077**	**222,884**	**(28,959,408)**	**293,860,553**

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

C. NSTAR Electric Schedule 3 – Depreciation and Amortization Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Depreciation and Amortization Expense	152,153,130	74,023	(6,600,402)	145,626,751
Amortization of Deferred Assets	24,043,614	0	(9,252)	24,034,362
Total Depreciation and Amortization Expense	**176,196,744**	**74,023**	**(6,609,654)**	**169,661,113**

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

D. NSTAR Electric Schedule 4 – Rate Base and Return on Rate Base

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Utility Plant in Service	5,277,871,546	5,236,686	0	5,283,108,232
LESS:				
Reserve for Depreciation	1,629,791,051	1,250,000	2,351,645	1,633,392,696
Reserve for Amortization	21,408,453	0	0	21,408,453
Net Utility Plant in Service	3,626,672,042	3,986,686	(2,351,645)	3,628,307,083
ADDITIONS TO PLANT:				
Cash Working Capital	37,453,650	128,535	(2,644,558)	34,937,628
ASC 740 (net)	60,537,693	0	0	60,537,693
Materials and Supplies	34,922,056	0	0	34,922,056
Total Additions to Plant	132,913,399	128,535	(2,644,558)	130,397,377
DEDUCTIONS FROM PLANT:				
Reserve for Deferred Income Tax	984,178,132	669,989	0	984,848,121
Customer Deposits	6,369,673	0	0	6,369,673
Customer Advances	34,634,865	0	0	34,634,865
Total Deductions from Plant	1,025,182,670	669,989	0	1,025,852,659
RATE BASE	2,734,402,771	3,445,232	(4,996,203)	2,732,851,801
COST OF CAPITAL	7.61%	-0.19%	-0.09%	7.33%
RETURN ON RATE BASE	**208,211,099**	**(5,049,088)**	**(2,871,303)**	**200,290,708**

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

E. NSTAR Electric Schedule 5 – Cost of Capital

	PER COMPANY			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$2,100,000,000	45.69%	4.31%	1.97%
Preferred Stock	$43,000,000	0.94%	4.56%	0.04%
Common Equity	$2,452,820,959	53.37%	10.50%	5.60%
Total Capital	$4,595,820,959	100.00%		7.61%
Weighted Cost of				
Debt				1.97%
Preferred				0.04%
Equity				5.60%
Cost of Capital				7.61%

	COMPANY ADJUSTMENTS			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$2,100,000,000	45.69%	3.88%	1.77%
Preferred Stock	$43,000,000	0.94%	4.56%	0.04%
Common Equity	$2,452,820,959	53.37%	10.50%	5.60%
Total Capital	$4,595,820,959	100.00%		7.42%
Weighted Cost of				
Debt				1.77%
Preferred				0.04%
Equity				5.60%
Cost of Capital				7.42%

	PER ORDER			
	PRINCIPAL	PERCENTAGE	COST	RETURN
Long-Term Debt	$2,100,000,000	45.72%	4.27%	1.95%
Preferred Stock	$43,000,000	0.94%	4.56%	0.04%
Common Equity	$2,450,093,895	53.34%	10.00%	5.33%
Total Capital	$4,593,093,895	100.00%		7.33%
Weighted Cost of				
Debt				1.95%
Preferred				0.04%
Equity				5.33%
Cost of Capital				7.33%

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

F. NSTAR Electric Schedule 6 – Cash Working Capital

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Total O&M Expense	322,597,077	222,884	(28,959,408)	293,860,553
Less Uncollectible Accounts	11,499,968	0	0	11,499,968
Taxes Other Than Income	99,430,890	1,185,985	(27,485)	100,589,390
Amount Subject to CWC	**410,527,999**	**1,408,869**	**(28,986,893)**	**382,949,975**
Cash Working Capital Factor (33.30/365)	9.12%	9.12%	9.12%	9.12%
Total Cash Working Capital Allowance	37,453,650	128,535	(2,644,558)	34,937,628

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

G. NSTAR Electric Schedule 7 – Taxes Other Than Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
FICA	6,686,097	(49,763)	(27,485)	6,608,849
Medicare	1,806,639	(13,446)	0	1,793,193
Federal Unemployment	45,739	0	0	45,739
State Unemployment	259,370	0	0	259,370
State Insurance Premium Excise Tax	230,381	0	0	230,381
Tangible Property Tax	1,275,000	0	0	1,275,000
Universal Health Tax	40,372	0	0	40,372
State Sales and Use Tax	3,918	0	0	3,918
Property Taxes	89,083,373	1,249,194	0	90,332,567
Taxes Other Than Income	**99,430,889**	**1,185,985**	**(27,485)**	**100,589,389**

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

H. NSTAR Electric Schedule 8 – Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Rate Base	2,734,402,771	3,445,232	(4,996,203)	2,732,851,801
Return on Rate Base	208,211,099	(5,049,088)	(2,871,303)	200,290,708
Interest Expense	(53,813,047)	5,243,623	(4,748,515)	(53,317,939)
Amortization of Net Unfunded Deferred Tax Liab.	1,488,887	0	0	1,488,887
Income Tax Impact of Flowthrough Items	1,311,689	0	0	1,311,689
Amortization of Investment Tax Credits	0	0	0	0
Total Deductions	(51,012,471)	5,243,623	(4,748,515)	(50,517,363)
Taxable Income Base	157,198,628	194,535	(7,619,818)	149,773,346
Gross Up Factor	1.6722	1.6722	1.6722	1.6722
Taxable Income	262,873,992	325,309	(12,742,172)	250,457,130
Mass Franchise Tax 8%	21,029,919	26,025	(1,019,374)	20,036,570
Federal Taxable Income	241,844,072	299,285	(11,722,798)	230,420,559
Federal Income Tax at 35%	84,645,425	104,750	(4,102,979)	80,647,196
Amort. ITC	1,311,689	0	0	1,311,689
Total Income Taxes	**106,987,033**	**130,775**	**(5,122,353)**	**101,995,455**

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I. NSTAR Electric Schedule 9 - Revenues

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
DISTRIBUTION REVENUES PER BOOKS	829,692,282	69,143	0	829,761,425
Operating Revenues	29,548,876	0	0	29,548,876
Other Revenues				
Special Contracts	217,639	0	0	217,639
Late Payment Charges	3,437,879	0	0	3,437,879
Rent from Electric Property	8,322,192	689,974	577,328	9,589,494
Other Electric Revenue	11,648,697	208,683	(624,440)	11,232,940
Revenues from Transmission of Electricity of Others	336,175	(336,175)	0	0
Total Other Revenues	23,962,582	562,482	(47,112)	24,477,952
Total Operating Revenues	**853,654,864**	**631,625**	**(47,112)**	**854,239,377**

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XIX. SCHEDULES: WESTERN MASSACHUSETTS ELECTRIC COMPANY

SCHEDULE 1 - WESTERN MASSACHUSETTS ELECTRIC COMPANY
REVENUE REQUIREMENTS AND CALCULATION OF REVENUE INCREASE

A. WMECO Schedule 1 – Revenue Requirements and Calculation of Revenue Increase

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
COST OF SERVICE				
Total O&M Expense	67,567,718	82,708	(4,964,458)	62,685,968
Depreciation & Amortization	32,781,024	(1,164,091)	(3,249,638)	28,367,295
Taxes Other Than Income Taxes	18,259,052	948,871	(35,148)	19,172,775
Income Taxes	19,459,290	(46,295)	(561,925)	18,851,069
Return on Rate Base	33,576,776	(597,919)	(1,315,642)	31,663,215
Additional Uncollectibles (Revenue Deficiency)	443,454	(12,264)	(122,990)	308,200
Total Cost of Service	172,087,313	(788,990)	(10,249,800)	161,048,522
OPERATING REVENUES				
Base Distribution Revenues	132,415,741	0	0	132,415,741
Other Operating Revenues	4,008,528	197,255	(358,726)	3,847,057
Total Operating Revenues	136,424,269	197,255	(358,726)	136,262,798
Total Revenue Deficiency	**35,663,044**	**(986,245)**	**(9,891,074)**	**24,785,725**

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WMECO Schedule 2 – Operations and Maintenance Expenses

SCHEDULE 2 - WESTERN MASSACHUSETTS ELECTRIC COMPANY

OPERATIONS AND MAINTENANCE EXPENSES

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Test Year O&M Expense (6/30/2016)	$59,918,641	($159,997)	$0	$59,758,644
ADJUSTMENTS TO TEST YEAR O&M EXPENSE:				
Postage Expense	(27,580)	0	0	(27,580)
Uncollectible Expense	(2,063,199)	0	0	(2,063,199)
Fee Free Payment Processing	906,909	0	(906,909)	0
Fee Free Payment Processing O&M Savings Offset	0	0	9,378	9,378
Dues and Memberships	(2,693)	0	0	(2,693)
Employee Benefits Costs	206,047	205,993	(24,483)	387,557
Insurance Expense and Injuries & Damage	(110,172)	0	0	(110,172)
Payroll Expense	1,694,639	0	(173,600)	1,521,039
Variable Compensation	(714,682)	0	(85,221)	(799,903)
Vegetation Management Resiliency Tree Work Pilot	3,902,175	0	(3,902,175)	0
Rate Case Expense	311,279	37,027	(5,127)	343,179
Regulatory Assessments	(374,453)	80,051	413,176	118,774
Lease Expense	13,819	0	(27,167)	(13,348)
Information Systems Expense Adjustment	244,633	(6,696)	(237,937)	(0)
Storm Cost Adjustment	720,000	0	0	720,000
Storm Fund Adjustment	2,000,000	0	0	2,000,000
Eversource Service Company Charges	0	0	(662)	(662)
Residual O&M Inflation Adjustment	942,355	(73,669)	(1,056)	867,630
Insurance Policy Distribution	0	0	(22,675)	(22,675)
Sum of O&M Expense Adjustments	7,649,077	242,705	(4,964,458)	2,927,324
Total O&M Expense	67,567,718	82,708	(4,964,458)	62,685,968

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SCHEDULE 3 - WESTERN MASSACHUSETTS ELECTRIC COMPANY
W-MECO Schedule 3-A Depreciation and Amortization Expenses
DEPRECIATION AND AMORTIZATION EXPENSES

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Depreciation and Amortization Expense	30,276,615	(44,091)	(3,248,078)	26,984,446
Amortization of Deferred Assets	2,504,409	(1,120,000)	(1,560)	1,382,849
Total Depreciation and Amortization Expense	32,781,024	(1,164,091)	(3,249,638)	28,367,295

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SCHEDULE 4 - WESTERN MASSACHUSETTS ELECTRIC COMPANY
D. WMECO Schedule 4 – Rate Base and Return on Rate Base
RATE BASE AND RETURN ON RATE BASE

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Utility Plant in Service	834,673,665	(1,586,025)	(3,488,926)	829,598,714
LESS:				
Reserve for Depreciation	232,345,474	(6,919)	0	232,338,555
Reserve for Amortization	19,245,859	0	0	19,245,859
Net Utility Plant in Service	583,082,332	(1,579,106)	(3,488,926)	578,014,300
ADDITIONS TO PLANT:				
Cash Working Capital	7,547,362	94,114	(452,922)	7,188,554
ASC 740 (net)	19,209,890	0	0	19,209,890
Materials and Supplies	2,242,787	0	0	2,242,787
Total Additions to Plant	29,000,039	94,114	(452,922)	28,641,231
DEDUCTIONS FROM PLANT:				
Reserve for Deferred Income Tax	168,804,718	(255,350)	(672,829)	167,876,539
Customer Deposits	2,114,715	0	0	2,114,715
Customer Advances	291,410	0	0	291,410
Total Deductions from Plant	171,210,843	(255,350)	(672,829)	170,282,664
RATE BASE	440,871,528	(1,229,642)	(3,269,019)	436,372,867
COST OF CAPITAL	7.62%	-0.11%	-0.25%	7.26%
RETURN ON RATE BASE	**33,576,776**	**(597,919)**	**(1,315,642)**	**31,663,215**

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SCHEDULE 5 - WESTERN MASSACHUSETTS ELECTRIC COMPANY
E. WMECO Schedule 5 – Cost of Capital
COST OF CAPITAL

	PER COMPANY			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$547,975,604	46.66%	4.32%	2.02%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$626,410,414	53.34%	10.50%	5.60%
Total Capital	$1,174,386,018	100.00%		7.62%
Weighted Cost of				
Debt				2.02%
Preferred				0.00%
Equity				5.60%
Cost of Capital				7.62%

	COMPANY ADJUSTMENTS			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$547,975,604	46.66%	4.07%	1.90%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$626,410,414	53.34%	10.50%	5.60%
Total Capital	$1,174,386,018	100.00%		7.50%
Weighted Cost of				
Debt				1.90%
Preferred				0.00%
Equity				5.60%
Cost of Capital				7.50%

	PER ORDER			
	PRINCIPAL	PERCENTAGE	COST	RETURN
Long-Term Debt	$547,975,604	45.49%	3.97%	1.81%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$656,686,129	54.51%	10.00%	5.45%
Total Capital	$1,204,661,733	100.00%		7.26%
Weighted Cost of				
Debt				1.81%
Preferred				0.00%
Equity				5.45%
Cost of Capital				7.26%

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SCHEDULE 6 - WESTERN MASSACHUSETTS ELECTRIC COMPANY
F. WMECO Schedule 6 – Cash Working Capital
CASH WORKING CAPITAL

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Total O&M Expense	67,567,718	82,708	(4,964,458)	62,685,968
Less Uncollectible Accounts	3,100,435		0	3,100,435
Taxes Other Than Income	18,259,052	948,871	0	19,207,923
Total Costs Applicable to Cash Working Capital	82,726,335	1,031,579	(4,964,458)	78,793,456
Cash Working Capital Factor (33.30/365)	9.123%	9.123%	9.123%	9.123%
Total Cash Working Capital Allowance	**7,547,362**	**94,114**	**(452,922)**	**7,188,554**

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

SCHEDULE 7 - WESTERN MASSACHUSETTS ELECTRIC COMPANY

TAXES OTHER THAN INCOME TAXES

G. WMECO Schedule 7 – Taxes Other Than Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
FICA	1,294,826	0	(17,574)	1,277,252
Medicare	356,766	0	0	356,766
Federal Unemployment	10,015	0	0	10,015
State Unemployment	63,080	0	(17,574)	45,506
State Insurance Premium Excise Tax	30,003	0	0	30,003
Federal Highway Tax	1,610	0	0	1,610
Universal Health Tax	8,203	0	0	8,203
State Sales and Use Tax/Other	942	0	0	942
Property Tax	16,493,608	948,871	0	17,442,479
Taxes Other Than Income	**18,259,052**	**948,871**	**(35,148)**	**19,172,775**

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SCHEDULE 8 - WESTERN MASSACHUSETTS ELECTRIC COMPANY
INCOME TAXES WMECO Schedule 8 – Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Rate Base	440,871,529	(1,229,642)	(3,269,019)	436,372,867
Return on Rate Base	33,576,776	(597,919)	(1,315,642)	31,663,215
Add: Flow-Through and Permanent Items	3,815,783	0	0	3,815,783
Less: Interest Expense	(8,885,325)	529,051	479,743	(7,876,530)
Add: FAS 109 Income Taxes and ITC	176,747	0	0	176,747
Total Deductions	(4,892,795)	529,051	479,743	(3,884,000)
Taxable Income Base	28,683,981	(68,867)	(835,898)	27,779,215
Gross Up Factor	1.672241	1.672241	1.672241	1.672241
Taxable Income	47,966,524	(115,163)	(1,397,823)	46,453,537
Massachusetts Income Tax (8%)	3,837,322	(9,213)	(111,826)	3,716,283
Federal Taxable Income	44,129,202	(105,950)	(1,285,998)	42,737,254
Federal Income Tax Calculated (35%)	15,445,221	(37,082)	(450,099)	14,958,039
Total Income Taxes Calculated	19,282,543	(46,295)	0	19,236,248
Add: FAS 109 Income Taxes and ITC	176,747	0	0	176,747
Total Income Taxes	**19,459,290**	**(46,295)**	**(561,925)**	**18,851,069**

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WMECO Schedule 9 - Revenues

SCHEDULE 9 - WESTERN MASSACHUSETTS ELECTRIC COMPANY
REVENUES

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Distribution Revenues				
Distribution Revenues	132,218,977	0	(464,646)	131,754,331
Revenue Decoupling (Prior Year Refund)	(5,104,988)	0	0	(5,104,988)
Revenue Decoupling	5,301,752	0	464,646	5,766,398
Total Distribution Revenues	132,415,741	0	0	132,415,741
Other Revenues				
Sales for Resale (447)	55,380	0	0	55,380
Late Payment Charges (450)	526,847	(238,893)		287,954
Misc. Revenues (451)	246,414	436,148	(358,726)	323,836
Rent from Electric Property (454)	800,581	0		800,581
Other Electric Revenue (456)	2,379,306	0	0	2,379,306
Total Other Revenues	4,008,528	197,255	(358,726)	3,847,057
Adjusted Total Operating Revenues	136,424,269	197,255	(358,726)	136,262,798

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

XX. ORDER

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

ORDERED: That the proposed tariffs filed in the instant proceeding by NSTAR Electric Company and Western Massachusetts Electric Company, to become effective, after suspension by the Department, on December 1, 2017, are DISALLOWED; and it is

FURTHER ORDERED: That NSTAR Electric Company shall file new schedules of rates and charges designed to increase annual electric revenues by $12,244,581; and it is

FURTHER ORDERED: That Western Massachusetts Electric Company shall file new schedules of rates and charges designed to increase annual electric revenues by $24,785,725; and it is

FURTHER ORDERED: That NSTAR Electric Company and Western Massachusetts Electric Company shall file the aforementioned new schedules of rates and charges following the issuance of and in compliance with the Department's subsequent Order addressing rate design; and it is

FURTHER ORDERED: That the new rates shall apply to electricity consumed on or after January 1, 2018, but unless otherwise ordered by the Department, shall not become effective earlier than seven days after the rates are filed with supporting data demonstrating that such rates comply with this Order; and it is

FURTHER ORDERED: That NSTAR Electric Company and Western Massachusetts Electric Company shall comply with all other orders and 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.