STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service
Commission held in the City of
New York on November 16, 2023

COMMISSIONERS PRESENT:

Rory M. Christian, Chair
Diane X. Burman, concurring
James S. Alesi
John B. Howard
David J. Valesky
John B. Maggiore

CASE 22-E-0236 - Proceeding to Establish Alternatives to Traditional Demand-Based Rate Structures for Commercial Electric Vehicle Charging.

ORDER IMPLEMENTING IMMEDIATE SOLUTIONS PROGRAMS

(Issued and Effective November 20, 2023)

BY THE COMMISSION:

INTRODUCTION

On January 19, 2022, the Public Service Commission (Commission) issued its Order Establishing Framework for Alternatives to Traditional Demand-Based Rate Structures in this proceeding (Demand Charge Alternatives Order). In the Demand Charge Alternatives Order, the Commission directed Central Hudson Gas & Electric Corporation (Central Hudson), Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation (NYSEG), Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), Orange and Rockland Utilities, Inc. (O&R), and Rochester Gas & Electric Corporation (RG&E) (collectively, the Utilities or the Joint Utilities) to file plans to implement a series of “Immediate Solutions” to provide utility demand charge relief for electric vehicle (EV) charging station operators. The Demand Charge Alternatives Order directed each of the Utilities to implement a Demand Charge Rebate (DCR) Program, terminate the Direct Current Fast Charging (DCFC) Per-Plug Incentive Program (PPI Program), and directed that Con Edison and O&R also implement a Commercial Managed Charging Program (CMCP). On March 20, 2023, Central Hudson, Con Edison and O&R, National Grid, and NYSEG and RG&E submitted filings responsive to the Demand Charge Alternatives Order.

This Order approves the Demand Charge Rebate, and cost recovery mechanism, submitted by National Grid, NYSEG and RG&E. Similarly, this Order approves the Demand Charge Rebate and Commercial Managed Charging Program, and cost recovery mechanisms for Con Edison and O&R. This Order approves Central Hudson’s Demand Charge Rebate with modifications to align Central Hudson’s proposed cost recovery mechanism with that directed by the Commission in the Demand Charge Alternative Order. This Order also requires the utilities to update their filed Implementation Plans to include additional information, particularly with respect to communication with customers regarding the termination of the PPI Program, and to file tariff amendments consistent with the draft tariff leaves submitted by each utility necessary to open these programs for customer participation within sixty days.

With this Order, commercial EV charging customers will begin being eligible for the operating cost relief required under Public Service Law §66-s; however, this Order is not the full measure of the relief directed under the Demand Charge Alternatives Order. Yet to be addressed are utility proposals and stakeholder feedback regarding a load management technology incentive program to replace the PPI Program; Commercial Managed Charging Program proposals for Central Hudson, National Grid, NYSEG, and RG&E; and EV Phase-In Rate options for commercial EV Charging customers. The Commission anticipates considering each of these topics, including stakeholder feedback on such, in upcoming decisions.

BACKGROUND

The Demand Charge Alternatives Order was developed in response to directives in Public Service Law (PSL) §66-s. PSL §66-s required the Commission to commence a proceeding to establish alternatives to traditional demand-based rate structures. Accordingly, the Department of Public Service Staff (Staff) developed the Demand Charge Alternative Cover Letter and Whitepaper (Whitepaper).[1] Following extensive outreach and a public notice and comment period, the Commission issued the Demand Charge Alternatives Order.[2]

The Demand Charge Alternatives Order approved two sets of operating cost relief programs against the costs of traditional demand-based electricity bills for commercial EV charging customers: a portfolio of Immediate Solutions, and the EV Phase-In Rate.[3] The Commission approved two sets of Immediate Solutions, one for the Upstate Utilities and another for the Downstate Utilities, in recognition that these two sets of utilities have differing grid conditions and ability to implement certain solutions swiftly, effectively, and

[1] Case 22-E-0236, Demand Charge Alternative Cover Letter and Whitepaper (filed September 26, 2022).

[2] Case 22-E-0236, Order Establishing Framework for Alternatives to Traditional Demand-Based Rate Structures (Demand Charge Alternatives Order) (issued January 19, 2023).

[3] Utility proposals and stakeholder input regarding implementation of the EV Phase-In Rate will be considered in a future Commission decision.

successfully.[4] The Commission directed that the Immediate Solutions shall be offered until customers are able to participate in the EV Phase-In Rate, at which point the Immediate Solutions programs would end.

The Demand Charge Alternatives Order directed the Upstate Utilities to implement a Demand Charge Rebate for all EV Charging use-cases, whereby EV charging customers would receive an off-bill rebate equivalent to 50 percent of applicable EV charging demand.[5] To avoid the need for separate interval metering of EV charging load, the Commission established computation of a Charging Ratio for use in determining customer eligibility for the Demand Charge Rebate and to determine the amount of demand which would be provided a rebate against.[6] The Commission established that the Charging Ratio would be based on the ratio of EV charging capability to maximum possible customer demand. The Commission required that customers participating in the Demand Charge Rebate Program would be required to have a Charging Ratio of 50 percent or greater, however, customers that separately meter their EV charging load would be assigned a Charging Ratio of 100 percent.

The Demand Charge Alternatives Order required the Downstate Utilities to develop Commercial Managed Charging Programs to provide two core incentives as well as use case

[4] The Upstate Utilities are defined as Central Hudson, National Grid, NYSEG, and RG&E. The Downstate Utilities are defined as Con Edison and O&R.

[5] Demand Charge Alternatives Order, p. 8.

The Demand Charge Alternatives Order also required the Upstate Utilities to develop and make proposals to implement Commercial Charging Programs. Such proposals and stakeholder input on the Upstate Utilities CMCPs will be considered in a future Commission decision.

[6] Demand Charge Alternatives Order, p. 14.

specific adder incentives as needed for EV charging use cases other than public DCFC.[7] The core incentives identified by the Commission are a peak avoidance incentive, based on the difference between a charger's charging capability in kW and the maximum charging demand served by that charger during a defined peak period, and an off-peak charging incentive based on energy used during off-peak periods. The Commission established that the Commercial Managed Charging Programs would continue operating and offering the two core incentives even after the EV Phase-In Rate becomes available, however the use case specific adders would be discontinued.

The Demand Charge Alternatives Order established cost recovery requirements for the Demand Charge Rebate Program and Commercial Managed Charging Program.[8] The Commission found that a reasonable cost recovery mechanism for both programs would recover program costs from all delivery customers on a one-year lag basis through an existing surcharge mechanism, with costs allocated among service classifications using the transmission and distribution revenues allocator, and recovered on a per-kW basis for demand-billed customers and on a per-kWh basis for non-demand-billed customers.

The Demand Charge Alternatives Order directed the utilities to sunset the PPI Program, and to redeploy the PPI Program funding which had already been collected from customers to fund a new program to incentivize EV charging demand

[7] Demand Charge Alternatives Order, p. 18.

[8] Demand Charge Alternatives Order, p. 22.

management technologies.[9] The Commission required the utilities to provide existing PPI Program participants a one-time choice to either continue participating in the PPI Program for the remaining term of such program, or to begin participating in the applicable Immediate Solutions programs available in their service territory, and that such participants would be provided at least 60 days to make such determination.

IMMEDIATE SOLUTIONS FILINGS

Joint Utilities

On March 21, 2023, the Joint Utilities filed a joint implementation plan describing their collective approach to establish a Demand Charge Rebate program throughout the State, establish a Commercial Managed Charging Program in the Con Edison and O&R service territories, formalize a transition plan to terminate the PPI Program and reallocate remaining funding of that program, terminate the EV Quick Charging Station Program component of Con Edison's Business Incentive Rate (BIR) program, and establish future reporting requirements related to the Immediate Solutions programs.[10] The Joint Utilities note that

[9] Demand Charge Alternatives Order, p. 11.

Utility proposals and stakeholder input regarding implementation of the new EV charging demand management technology program will be considered in a future Commission decision.

[10] Case 22-E-0236, JU Immediate Solution Program Design (joint implementation plan) (filed March 21, 2023).

specific implementation plans for each of these programs and associated draft tariff leaves are provided in separate utility-specific filings.

As outlined in the joint implementation plan, the Joint Utilities propose to offer the Demand Charge Rebate Program and the use-case specific adder incentive components of the Downstate Utilities' Commercial Managed Charging Programs to eligible commercial charging stations until the EV Phase-In Rate is implemented. Consistent with the Demand Charge Alternative Order, the Joint Utilities propose that the Demand Charge Rebate would be available to all commercial charging customers in the Upstate Utilities' service territories and only to publicly accessible DCFC charging stations in the Downstate Utilities' service territories. The JU propose that participants in the PPI Program would not be eligible to also participate in the Demand Charge Rebate program.

Demand Charge Rebate

Regarding the Demand Charge Rebate Program, the Joint Utilities propose that it would be available to both EV charging customers that separately meter their EV charging demands, and those that co-mingle EV charging and non-EV load. The Joint Utilities propose to use a Charging Ratio to determine both eligibility to participate in the Demand Charge Rebate program as well as to determine incentive payments for Demand Charge

The details of each utility's Demand Charge Rebate program and termination of the PPI Program contained in their individual utility filings are largely duplicative of the information contained in the Joint Utilities' filing, and are described together as part of the description of the Joint Utilities' filing in this Order. Topics that are unique to each utility, such as the Con Edison and O&R Commercial Managed Charging Program, termination of Con Edison's EV Quick Charging Program component of the BIR, and details regarding recovery of Immediate Solutions programs costs are described in utility-specific sections, below.

Rebate Program participants. The Joint Utilities propose that a customer that co-mingles EV charging and non-EV load must have a Charging Ratio of 50 percent or higher be eligible to participate in the Demand Charge Rebate program. The Joint Utilities propose that customers that separately meter their EV charging loads would be assigned a Charging Ratio of 100 percent.

As directed in the Demand Charge Alternatives Order, the Joint Utilities propose to compute a Charging Ratio for such customers equal to the ratio of a customer's maximum potential simultaneous EV charging load to the customers maximum potential connected load.[11] Specifically, the Joint Utilities propose to compute the Charging Ratio as the ratio of: (1) the lesser of (a) the sum of the nameplate of all EV chargers on the customer account, or (b) the maximum load of any load limiting hardware, such as fused switches or rectifier cabinets; to (2) the customer's maximum potential load as identified by the customer's load letter generated as part of a new or additional electrical service request. The Joint Utilities propose that a customer may be required to submit an updated load letter to establish eligibility to participate in the Demand Charge Rebate if the previous load letter is out of date, and propose to update the Charging Ratio in the event that a customer makes any changes to their loads.

The Joint Utilities propose to calculate Demand Charge Rebate Program payments based on the customer's Charging Ratio and applicable delivery service demand rate. Specifically, the Joint Utilities propose that payments under the Demand Charge

[11] A customer's maximum potential load includes all EV charging and non-EV load, including lighting; heating, ventilation, and air conditioning; elevators; and any other on-site customer loads.

Rebate would be calculated for each participant as the product of: (1) the actual kW of metered demand for the billing period; (2) the participant's Charging Ratio; (3) the 50 percent rebate level; and (4) the applicable dollar-per-kilowatt ($/kW) delivery service demand rate. The Joint Utilities explain that while each utility would provide the Demand Charge Rebate program payment in a different manner, all of the utilities would provide the payment in a manner that allows customers to clearly see that they are receiving a rebate and would easily be able to identify the amount of rebate they are receiving in each rebate period.

In their individual Implementation Plan and draft tariff leaves filings, Con Edison, National Grid, NYSEG, O&R, and RG&E each propose to also exclude customers participating in economic development programs such as the Business Incentive Rate, Excelsior Jobs Program, Recharge New York Program, and Empire Zone Rider from simultaneously participating in the Demand Charge Rebate.[12] Con Edison and O&R explain in their Implementation Plan filing that customers participating in these economic development programs should not be eligible to participate in the Demand Charge Rebate Program because the Demand Charge Alternatives Order specifically addresses providing alternatives to traditional demand rates - i.e., not against special rate schedules established for economic development – and because these economic development programs already provide a form discount against traditional demand rates.

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[12] Central Hudson's Implementation Plan and draft tariffs make no mention of excluding economic development rate recipients from participating in the Demand Charge Rebate Program.

Termination of PPI Program

As directed in the Demand Charge Alternatives Order, the Joint Utilities propose to terminate the PPI Program by closing the PPI Program to new participants. The Joint Utilities propose to establish a deadline for new participation in the PPI Program of March 20, 2023. The Joint Utilities propose to offer existing PPI Program participants a one-time option of continuing to participate in the PPI Program or switch to the Demand Charge Rebate and/or Commercial Managed Charging Program, as applicable. The Joint Utilities propose that customers that choose to continue participating in the PPI Program would receive the declining annual PPI Program incentives until the end of the PPI Program on February 28, 2026. The Joint Utilities propose to give current PPI Program participants 60 days to make their selection, with the 60-day period beginning on this Order's effective date.

Con Edison and O&R's implementation plan includes additional details regarding communications with present PPI Program participants, whereas the implementation plans of Central Hudson, National Grid, and NYSEG and RG&E do not.[13] Con Edison and O&R specify that they would reach out to existing PPI Program participants twice by email, at least one week apart, to inform participants that they would need to make an election between continuing in the PPI Program or transitioning to one or more of the Demand Charge Rebate and/or Commercial Managed Charging Program, as applicable, following an Order in this

[13] Central Hudson, National Grid, and NYSEG and RG&E's implementation plans include a description of the 60-day one-time decision to either continue participating in the PPI Program or transition to the Demand Charge Rebate, but do not include details regarding how those utilities intend to communicate this requirement to existing PPI Program participants.

proceeding.[14] For PPI Program applicants that have already applied by March 20, 2023, but have not yet begun participation in the PPI Program, Con Edison and O&R propose to reach out twice by email and once by phone, each attempt not less than one week apart, to inform would-be participants of the need to make a choice to either participate in the PPI Program or the Demand Charge Rebate and/or Commercial Managed Charging Program, as applicable.[15] Following this Order, Con Edison and O&R propose to reach out to PPI Program participants twice by email and once by phone, each attempt no less than one week apart, to solicit a selection between either continuing to participate in the PPI Program or to transition to the Demand Charge Rebate and/or Commercial Managed Charging Program, as applicable. Con Edison and O&R propose that failure of PPI Program participants to respond to these three final communication attempts will result in a retaining PPI Program participation.

Following the conclusion of the 60-day selection period, the Joint Utilities state that they would estimate the budget required for participants that decide to continue participating in the PPI Program through 2026, and allocate the remainder toward their respective Load Management Technology Incentive Programs.[16] The Joint Utilities propose to redirect any funds that are not paid out from the retained PPI Program

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[14] Con Edison and O&R state that failure to respond to this round of communication will not result in any changes to participation in the PPI Program.

[15] Con Edison and O&R will reach out by phone only if no response is provided by email. Failure to respond to these three communication attempts will result in a withdrawn PPI Program application.

[16] The Joint Utilities filed plans for implementing Load Management Technology Incentive Programs on May 19, 2023, in this proceeding.

budget to the Load Management Technology Incentive Program after February 28, 2026.

Reporting Requirements

The Joint Utilities propose a series of reporting requirements, some of which would be reported semi-annually, and others would be reported annually. The Joint Utilities propose to begin both annual and semi-annual reporting three months after the first full year of operation of the Demand Charge Rebate and/or Commercial Managed Charging Program, and would thereafter begin semi-annual and annual reporting cadences.[17]

The Joint Utilities propose to collect and report the following data on a semi-annual basis, on a per-participant basis if feasible: (1) the number of accounts participating; (2) participants' average peak demand kilowatts (kW); (3) participants' average monthly energy kilowatt-hours (kWh) consumption; (4) participants' average annual load factor on a year-to-date basis; and (5) the number and type of each charger participating. The Joint Utilities propose to report participants' peak demand kW, monthly energy kWh, and year-to-date annual load factor at the account level for the Demand Charge Rebate, and at a site level for the Commercial Managed Charging Rebate.

The Joint Utilities propose to collect and report the following data annually if feasible: (1) the year-over-year growth rate in number of accounts participating in the Immediate Solutions; (2) an assessment of whether incremental EV charging load has resulted in local grid impacts; (3) an assessment of the extent to which incremental EV charging load has resulted in upward or downward rate pressure on non-participating customer rates; (4) an assessment on the impacts of the Immediate

[17] The first annual and semi-annual report would be submitted during the first quarter of 2025.

Solutions on low- and moderate-income customers and disadvantaged community residents.

Central Hudson

Central Hudson's implementation plan includes a description of the Demand Charge Rebate Program consistent with the Joint Utilities' filing.[18] Central Hudson proposes to provide Demand Charge Rebate payments as a bill credit under the "Payments and Adjustments" section of a customer's monthly statement, allowing customers to easily identify the rebate amount and period. Central Hudson states that it plans to begin accepting applications for the Demand Charge Rebate shortly after this Order, and would continue offering such program until the EV Phase-In Rate is made available to customers. Central Hudson estimates that the Demand Charge Rebate would cost approximately $0.637 million over an assumed 16-month availability period.

Central Hudson proposes to market the Demand Charge Rebate to two core audiences: Make-Ready Program participants, and EV project developers and stakeholders. Central Hudson states that it plans to include send direct mail, initiate personal outreach, and provide bill inserts or fliers to Make-Ready Program participants to market the Demand Charge Rebate. For EV project developers and stakeholders, Central Hudson plans to leverage existing Make-Ready Program outreach efforts with trade allies and developers, as well as publish frequently-asked-questions guides and hold webinars about the Demand Charge Rebate application process.

Central Hudson proposes to issue Demand Charge Rebate credits, defer the associated costs, and amortize such costs over a 5-year period with carrying charges accruing at its

[18] Case 22-E-0236, CHGE Immediate Solution Implementation Plan (filed March 20, 2023).

overall weighted average cost of capital (WACC). Central Hudson proposes to recover costs from all customers, allocated among service classifications using the transmission and distribution revenues allocator. Central Hudson proposes begin recovery of allocated Demand Charge Rebate costs following a one-year lag through the existing EV Make-Ready surcharge mechanism on a per-kW basis for demand-billed customers and on a per-kWh basis from non-demand-billed customers. Central Hudson also proposes to recover incremental labor costs associated with the Demand Charge Rebate through the EV Make-Ready surcharge.

Central Hudson states that it would work with an independent third-party evaluation vendor to review Demand Charge Rebate program performance. Central Hudson proposes that the evaluation will, at minimum: (1) assess the impact of the Demand Charge Rebate on deployment of EV charging; (2) assess the costs and benefits of the program on low- and moderate-income customers and disadvantaged community residents; and (3) identify lessons learned from program implementation. Central Hudson states that it will seek to balance evaluation costs with a reasonable level of evaluation rigor.

Central Hudson includes draft tariff leaves designed to (1) implement the Demand Charge Rebate; (2) address customer eligibility for the Demand Charge Rebate; and (3) implement exemptions from Standby Service for customers with energy storage systems with inverter capability greater than one megawatt (MW) and less than or equal to the sum of nameplate EV charging capability.

Con Edison and O&R

Con Edison and O&R’s implementation plan includes a description of the Demand Charge Rebate Program for the publicly accessible DCFC use case consistent with the Joint Utilities’ filing.[19] Con Edison and O&R further specify eligibility restrictions on participation in the Demand Charge Rebate, proposing that O&R customers receiving a discount under Rider H – Economic Development Rider, Con Edison and O&R customers participating in the Excelsior Jobs Program, and Con Edison and O&R customers participating in Recharge-NY would not be eligible to participate in the Demand Charge Rebate. Further, Con Edison and O&R specify that there would be no rebate against surcharges or supply charges that are billed on a per-kW basis under the Demand Charge Rebate Program. Con Edison and O&R propose to provide Demand Charge Rebate payments as rebate payments, paid via issuance of a check or an electronic payment method on a quarterly basis.[20]

Con Edison and O&R's Commercial Managed Charging Program is described in both the Joint Utilities' filing and in Con Edison and O&R's implementation plan. Con Edison and O&R propose two "core incentives" that would be available to all participants in the Commercial Managed Charging Program: a Pro-Rated Peak Avoidance kW Incentive (Peak Avoidance Incentive), and an Overnight Off-Peak Charging kWh Incentive (Off-Peak Charging Incentive). Con Edison and O&R also propose use-case specific Adder Incentives for Public Level 2 charging and transit fleet charging customers, which would only be available to participants until the EV Phase-In Rate becomes available. Con Edison and O&R's proposed Peak Avoidance Incentive and Off-

[19] Case 22-E-0236, CECONY and ORU Immediate Solution IP (filed March 21, 2023).

[20] Con Edison specifies that payments will be made on a quarterly basis at minimum, but may be made more frequently, and may be provided as a direct offset to customer delivery charges on the monthly bill. O&R states that it will only make quarterly off-bill payments.

Peak Charging Incentive, and Adder Incentive payment rates are provided in the Appendix.

Con Edison and O&R explain that their proposed Commercial Managed Charging Program incentives are designed to simultaneously be large enough to provide effective price signals to spur beneficial charging behavior, provide meaningful operating cost relief to participants, and not cause market distortionary effects from customers participating in multiple operating cost relief solutions or incentive programs. Con Edison and O&R state that their proposed incentive levels were developed based on comparison to two metrics: (1) the discount provided by a 50 percent Demand Charge Rebate for public DCFC stations, and (2) achieving a relatively level cost on a dollar-per-kWh basis at least as low as a site operating at a maximum load ratio of 25 percent.[21] Con Edison and O&R define maximum load ratio as the ratio of (1) the kWh energy used by an EV charging customer during a specified period to (2) the product of (a) that customer's peak EV charging kW demand during the time period and (b) the duration of the time period, in hours.[22] Con Edison and O&R propose to periodically review and adjust incentive levels as the value of avoidable costs change, to incorporate insights from larger EV charging and load profile data sets, manage the Commercial Managed Charging Program budget and maintain cost-effectiveness, and avoid market-distortionary

[21] Based on comments received in an earlier phase of this proceeding, EV charging station developers typically seek to build additional charging capacity once the maximum load ratio of a station reaches 20 to 25 percent to avoid negative impacts on the driver experience, such as queueing.

[22] Maximum load ratio is commonly referred to as "load factor" in the EV industry, however, "load factor" is a commonly used term in the utility industry with a somewhat different meaning. To avoid confusion, the Commission will adopt the term "maximum load ratio" in the context of these programs.

effects of other operating cost relief programs as they come online.

Con Edison and O&R's proposed Peak Avoidance Incentive would provide an incentive on a dollar per avoided summer kW and dollar per avoided winter kW, computed during peak periods. For the Peak Avoidance Incentive, the avoided kW would be calculated by subtracting the highest charging station site load, in kW, occurring during the peak period throughout the billing period, from the maximum potential simultaneous EV charging output of the site, in kW.[23] Con Edison and O&R propose to establish peak periods for the Peak Avoidance Incentive based on local network peak periods correlating to the four four-hour Commercial System Relief Program peak windows for Con Edison, and based on four-hour local substation peak windows for O&R.

Con Edison and O&R propose to set different dollar-per-kW incentive levels for the Peak Avoidance Incentive by utility, and by use case within the same utility. Specifically, Con Edison and O&R propose a utility-specific "standard offering" Peak Avoidance Incentive levels applicable to most EV charging use cases, and more targeted Peak Avoidance Incentive levels for three use cases: (1) Public Level 2 charging; (2) Public DCFC charging that is simultaneously participating in the Demand Charge Rebate Program (DCR Public DCFC); and (3) Public DCFC charging that does not participate in the Demand Charge Rebate Program (non-DCR Public DCFC). Con Edison and O&R propose to offer enhanced Peak Avoidance Incentive payment rates

[23] For example, if a customer experiences 50 kW maximum demand during a peak period every day but one during the billing period, and experiences a 100 kW demand during peak hours on the remaining day, the peak period kW for that billing period would be set at 100 kW. If that customer's maximum simultaneous EV charging output is 150 kW, then they will earn incentives on 50 kW of avoided peak demand.

relative to the standard offering for Public Level 2 and non-DCR Public DCFC participants, whereas DCR Public DCFC participants would receive a lower Peak Avoidance Incentive payment rate relative to the standard offering. Further, Con Edison and O&R propose to set different Peak Avoidance Incentive payment rates for non-DCR Public DCFC participants based on whether that participant's maximum load ratio is greater than or equal to 15 percent, or below 15 percent.[24]

Con Edison and O&R's proposed Off-Peak Charging Incentive would provide an incentive on a dollar-per-kWh for each kWh of EV charging consumed between midnight and 8 a.m. in both utilities' service territories. Con Edison and O&R state that the value of Off-Peak Charging Incentive would vary by utility.

Con Edison and O&R propose to also offer additional use-case-specific adder incentives for transit fleets (Transit Adder) and for publicly accessible Level 2 charging (Public Level 2 Adder). For both the Transit Adder and the Public Level 2 Adder, Con Edison and O&R propose to offer a fixed incentives on a dollar per kW of maximum potential simultaneous charging output. Con Edison and O&R's proposed adders differ, however, with Con Edison proposing to offer differing incentive levels based on the maximum load ratio for eligible customers, with higher incentives available at lower maximum load ratios and no incentive available above 15 percent maximum load ratio. O&R proposes to offer a flat Transit Adder and Public Level 2 Adder incentives regardless of customer maximum load ratio. Con Edison and O&R state that the incentive levels are designed to

[24] Participants with maximum load ratios greater than or equal to 15 percent would earn a higher Peak Avoidance Incentive payment rate compared to participants with maximum load ratios less than 20 percent.

right-size incentives to smooth out and reduce the effective delivery cost per kWh of charging use. The specific incentive levels for the Transit Adder and Public Level 2 Adder proposed by Con Edison and O&R are shown in the Appendix.

Con Edison and O&R specify eligibility for customers simultaneously participating in the Commercial Managed Charging Program and other similar programs. Con Edison and O&R propose that customers participating in the electric demand response Dynamic Load Management programs would be able to simultaneously participate in the Commercial Managed Charging Program.

Con Edison and O&R propose somewhat more restrictive rules regarding simultaneous participation in the Commercial Managed Charging Program and the SmartCharge New York Program (SmartCharge Program), Con Edison and O&R's residential customer-focused vehicle-based managed charging program. Con Edison and O&R propose that there would be no restriction against residential and light-duty fleet operators that are SmartCharge Program participants charging at sites participating in the Commercial Managed Charging Program, however, medium- and heavy-duty fleets would only be eligible for the Commercial Managed Charging Program. Con Edison and O&R explain that the SmartCharge Program and the Commercial Managed Charging Program work together at different levels since the SmartCharge Program provides price signals to mitigate the need to build infrastructure for overall system peak needs, whereas the Commercial Managed Charging Program's focus on achieving reductions during local peak windows mitigates the need to build distribution system infrastructure.[25] For medium- and heavy-duty

[25] The overall system peak period applicable to the SmartCharge Program is the four-hour period between 2 p.m. and 6 p.m. The four-hour local peak periods applicable to the Commercial Managed Charging Program can begin as early 11 a.m. and end as late as 11 p.m.

fleet participants, Con Edison and O&R assert that such customers' energy costs will typically include price signals that encourage charging away from the system peak period, and therefore participation in the SmartCharge Program is not necessary to provide such price signals.[26]

Con Edison estimates that the Immediate Solutions programs will cost between $272 million to $432 million over three years, with between $97 million and $194 million resulting from the Commercial Managed Charging Program, between $130 million and $193 million for the Demand Charge Rebate, and $45 million for program implementation and administration. O&R estimates that the Immediate Solutions programs will cost approximately $18.1 million over three years, with $13.5 million from the Commercial Managed Charging Program, $0.3 million from the Demand Charge Rebate, and $4.3 million in program implementation and administration.

Con Edison and O&R propose that Commercial Managed Charging Program and Demand Charge Rebate Program costs would be recovered on a one-year lag basis with carrying costs accruing at each utility's weighted average cost of capital, allocated among service classifications using the transmission and distribution revenues allocator, recovered through the existing Electric Vehicle Make Ready Surcharge mechanism for each utility, and assessed on a per-kW basis for demand-billed customers and on a per-kWh basis for non-demand billed customers. Con Edison and O&R note that all costs would be evaluated for cost categorization using the Generally Accepted

[26] Large commercial customers operating medium- and heavy-duty fleets are likely to be required to take Mandatory Hourly Pricing, which would include Location-Based Marginal Price energy Supply charges during system-coincident peak hours, as well as be subject to individual Installed Capacity tags and associated Supply Capacity charges.

Accounting Principles, and costs determined to be capital expenses would instead be amortized as appropriate to the asset's depreciation schedule and recovered either through base rates or using the methodology for recovering capital expenses established in the Commission's July 14, 2022 Order Approving Managed Charging Programs with Modifications in Case 18-E-0138 (Managed Charging Order).[27]

Con Edison and O&R's Implementation Plan also includes a proposal to sunset the EV Quick Charging Station Program component of Con Edison's Business Incentive Rate Program.[28] Con Edison states that the Demand Charge Rebate and Commercial Managed Charging Program would offer sufficient operating cost relief for existing Business Incentive Rate Program participants, therefore further incentives through the Business Incentive Rate Program would lead to market distorting effects.[29] Similar to its plans to communicate with existing PPI Program

[27] In the Managed Charging Order, the Commission clarified that for capital expenditures related to utility-side make-ready work, utilities would be allowed to recover the depreciation expense and return on the average unrecovered capital investment, net of deferred income taxes, over a subsequent one-year period through the Make-Ready Surcharge until included in base rates. Thereafter, utility-owned make-ready capital work would be treated as capitalized plant in service with cost allocation and recovery via traditional ratemaking methodologies.

[28] Con Edison's Business Incentive Rate Program is an economic development program that provides a delivery bill reduction of between 34 percent and 39 percent for qualifying customers. The EV Quick Charging Station Program component is scheduled to end after April 2025, even if no action is taken as part of this proceeding. The EV Quick Charging Program component of the Business Incentive Rate Program is unique to Con Edison.

[29] Con Edison states that if a customer were allowed to layer the Demand Charge Rebate incentives, Commercial Managed Charging Program incentives, and Business Incentive Rate discounts, it would be possible to achieve effectively free charging on a dollar-per-kWh basis.

participants, Con Edison plans to reach out to existing Business Incentive Rate Program participants twice by email, and once by phone if no response to the emails is received, to inform such participants of the termination of the EV Quick Charging Station Program component of the Business Incentive Rate Program, and inform them of the other Immediate Solutions offerings.

Con Edison and O&R include draft tariff leaves designed to detail the Demand Charge Rebate and associated cost recovery mechanism, cost recovery for the Commercial Managed Charging Program, exemptions from Standby Service for customers with energy storage systems with inverter capability greater than one MW and less than or equal to the sum of nameplate EV charging capability, and termination of the EV Quick Charging Station Program.

National Grid

National Grid's implementation plan includes a description of the Demand Charge Rebate Program consistent with the Joint Utilities' filing.[30] National Grid proposes to provide Demand Charge Rebate payments as semi-annual off-bill rebate payments, paid via issuance of a check using the existing process in place to issue payments through the PPI Program.[31] National Grid states that the Demand Charge Rebate payments to participants would be made on a six-month period based on enrollment date, following evaluation of the Charging Ratio of the previous six-month period. National Grid proposes to prorate Demand Charge Rebate payments made for any partial six-month period at the time the Demand Charge Rebate Program ends once the EV Phase-In Rate becomes available. National Grid

[30] Case 22-E-0236, Immediate Solutions – NMPC Implementation Plan (filed March 20,2023).

[31] PPI Program payments are also made by check on a semi-annual basis.

states that for present PPI Program participants that choose to participate in the Demand Charge Rebate, the final PPI Program payment would only be calculated through the end of the last month in which they were actively enrolled in the PPI Program.

National Grid states that it would post the Demand Charge Rebate Program enrollment application on its website, and would begin accepting applications for the Demand Charge Rebate shortly after this Order. National Grid states that customer accounts enrolling in the Demand Charge Rebate program would be provided rebates from the time they enroll until the program is discontinued "[o]nce the EV Phase-In Rate is approved."[32] National Grid estimates that the Demand Charge Rebate would cost between $0.7 million and $3.4 million in rebates in total, and between $0.1 million and $0.2 million annually for administrative and implementation costs.[33]

To market the Demand Charge Rebate Program, National Grid states that it would inform existing known EV Charging customers of the program, and provide instructions on how to enroll. National Grid states that it would coordinate marketing efforts with the Joint Utilities to ensure outreach to key stakeholders and messaging across the State is implemented.

National Grid proposes to recover the costs of Demand Charge Rebate credits and incremental administrative costs from all customers on a one-year lag. National Grid proposes to allocate Demand Charge Rebate Program costs among service classifications using the transmission and distribution revenues allocator. National Grid proposes to recover allocated Demand Charge Rebate costs through the existing EV Make-Ready surcharge

[32] Id. at 5.

[33] These estimates vary significantly based on how quickly customers are enrolled in the Demand Charge Rebate Program, and how long it takes to implement the EV Phase-In Rate.

mechanism on a per-kW basis for demand-billed customers, on a per-kWh basis from non-demand-billed customers, and on a per-kW of Contract Demand basis for Standby Service customers.

National Grid includes draft tariff leaves designed to detail: (1) customer eligibility for the Demand Charge Rebate; (2) calculation of the Charging Ratio; (3) calculation of Demand Charge Rebate credits; (4) opt-in eligibility for customers presently participating in the PPI Program; (5) sunsetting the Demand Charge Rebate Program once the EV Phase-In Rate is made available to customers; and (6) exemptions from Standby Service for customers with energy storage systems with inverter capability greater than one MW and less than or equal to the sum of nameplate EV charging capability.

NYSEG and RG&E

NYSEG and RG&E's implementation plan includes a description of the Demand Charge Rebate Program consistent with the Joint Utilities' filing.[34] NYSEG and RG&E propose to provide Demand Charge Rebate payments as quarterly off-bill rebate payments, to be paid within 30 days of the end of each calendar quarter. NYSEG and RG&E state that they would implement the Demand Charge Rebate Program immediately upon the effective date of this Order, and would begin calculating the Demand Charge Rebate for each eligible EV charging customer in the preceding first full calendar month after the effective date of this Order. NYSEG and RG&E estimate that the Demand Charge Rebate credits, administrative, marketing, and evaluation costs would be between $0.8 million and $2.4 million for NYSEG and between $0.3 million and $1.2 million for RG&E, based on numerous factors including participation rates, participants' Charging

[34] Case 22-E-0236, NYSEG-RGE Demand Charge Rebate Implementation Plan (filed March 20, 2023).

Ratios, participants' demand charges, and duration of the Demand Charge Rebate Program until the EV Phase-In Rate is implemented.

NYSEG and RG&E state that they intend to calculate the Charging Ratio of each of their Make-Ready Program participants with existing load letters on file to determine Demand Charge Rebate Program eligibility. NYSEG and RG&E state that they would begin communicating with eligible customers to inform them of the program and solicit their participation. NYSEG and RG&E states that they will modify their "all in one" EV Make-Ready Program application and application portal to replace requests for participation in the PPI Program with requests to participate in the Demand Charge Rebate Program. NYSEG and RG&E state that they intend to communicate with EV charging customers that do not participate in the Make-Ready Program through proactive communications with EV supply equipment developers and trade allies. NYSEG and RG&E state that they would prominently display the Demand Charge Rebate on their websites, include links to those websites on promotional materials, and provide informational aides to its customer service staff including information about the Demand Charge Rebate Program and contact information for its EV Program team.

NYSEG and RG&E propose proposes to defer the costs of Demand Charge Rebate credits, including carrying charges calculated at their respective authorized pre-tax cost of capital applied to net-of-tax balances, until the end of each calendar year. Thereafter, NYSEG and RG&E propose to recover the deferred balance during the subsequent program year through the EV Make-Ready surcharge. NYSEG and RG&E's implementation plan did not specify how applicable costs would be allocated among service classifications, or whether those costs recovered through the EV Make-Ready surcharge mechanism would be on a per-kW or per-kWh basis.

NYSEG and RG&E provide draft tariff leaves designed to (1) implement the Demand Charge Rebate; (2) address customer eligibility for the Demand Charge Rebate; and (3) implement exemptions from Standby Service for customers with energy storage systems with inverter capability greater than one megawatt (MW) and less than or equal to the sum of nameplate EV charging capability.

NOTICE OF PROPOSED RULE MAKING

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), Notices of Proposed Rulemaking were published in the State Register on May 10, 2023 [SAPA Nos. 22-E-0236SP2, 22-E-0236SP3, 22-E-0236SP4, 22-E-0236SP5, 22-E-0236SP6]. The time for submission of comments pursuant to the Notice expired on July 10, 2023. One comment was received from the City of New York; this comment is addressed below.

COMMENTS

The City of New York (City) submitted comments in support of the JU, Con Edison, and O&R filings on October 10, 2023. The City asserts that both the JU, the Con Edison and O&R filings are consistent with the Demand Charge Alternatives Order, and represent efficient and effective ways to implement the CMCP. The City requests that the Commission approve the JU's proposed Immediate Solutions program designs, and Con Edison's proposed plan for implementing those programs.

The City states that proposed CMCP can simultaneously provide targeted and necessary relief from the impact of demand charges for EV charging stations and provide price signals to encourage charging at optimal times. The City asserts that the CMCP's focus on incentivizing charging station sites, as opposed to incentivizing charging behavior on a vehicle-by-vehicle basis simplifies program administration and gives charging station operators control over station demands instead of relying on the charging decisions made by individual drivers. The City further states that the CMCP's focus on incentivizing charging stations makes it possible to send network- or area-specific price signals, and thus maximize the value of the CMCP to the distribution grid.

The City states that it is supportive of Con Edison's proposed CMCP incentive structure, noting that encouraging grid-beneficial behavior is critical as electrification increases across the State. The City asserts that the two CMCP incentive adders proposed by Con Edison – the Transit Use Case adder and Publicly Accessible DCFC and Level 2 Use Cases adders – will also encourage buildout of EV charging stations in areas that will benefit residents of disadvantaged communities. The City further asserts that the incentive structure of the CMCP will help encourage customers to charge during off-peak hours, thereby reducing charging station peak load.

LEGAL AUTHORITY

In carrying out its responsibilities, the Commission has broad discretion and judgment in choosing the means of achieving statutory mandates and has the authority to adopt different methodologies or combinations of methodologies in balancing ratepayer and investor interests. PSL §5 grants the Commission authority to direct utilities to "formulate and carry out long-range programs, individually or cooperatively, with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources."

The Commission has further authority under PSL §66(2)to "examine or investigate the methods employed by ...

persons, corporations and municipalities in manufacturing, distributing and supplying ... electricity ... and have power to order such reasonable improvements as will best promote the public interest, preserve the public health and protect those using such ... electricity."

Moreover, the Commission has authority pursuant to PSL §66(14) "to require each ... electric corporation to establish classifications of service based upon the quantity used, the time when used, the purpose for which used, the duration of use and upon any other reasonable consideration, and to establish in connection therewith just and reasonable graduated rates and charges; and ... to require such changes in such classifications, rates and charges as [is] ... just and reasonable ... ."

Pursuant to PSL §66-s, the Commission was required to commence this proceeding to "establish a commercial tariff utilizing alternatives to traditional demand-based rate structures, other operating cost relief mechanisms, or a combination thereof (collectively, "solutions") to facilitate faster charging for eligible light duty, heavy duty, and fleet electric vehicles." The actions taken herein with respect to the Immediate Solutions to the traditional demand-based rates fall within this legal authority and are designed to support long-range program goals economically and efficiently, support public health and safety, preserve environmental values, and conserve natural resources.

DISCUSSION

The Commission finds that the Demand Charge Rebate Program and Commercial Managed Charging Program proposed in the Joint Utilities' filing and further described in the individual Implementation Plan filings of Central Hudson, Con Edison and

O&R, National Grid, and NYSEG and RG&E closely match the directives to implement Demand Charge Rebate Programs and Commercial Managed Charging Programs in the Demand Charge Alternatives Order. Similarly, the proposals to terminate PPI Program, and data reporting requirements and schedule proposed by the utilities reflect the requirements established in the Demand Charge Alternatives Order. Therefore, the Joint Utilities' Demand Charge Rebate Programs, Commercial Managed Charging Programs, termination of the PPI Program, and other related matters as proposed in the Joint Utilities' filing and the individual utilities' Implementation Plans are approved, except as discussed below.

The Commission finds that there are two substantive issues which requires modification as part of Central Hudson's Implementation Plan and draft tariff leaves. First, as discussed, above, in the Demand Charge Alternative Order the Commission directed the utilities to recover the Immediate Solutions program costs on a one-year lag without the need to amortize program costs over a multi-year period. Central Hudson's Implementation Plan, however, proposes to amortize Demand Charge Rebate Program incentives over a five-year period. The Commission finds Central Hudson's longer amortization period proposal to be inconsistent with the directive in the Demand Charge Alternative Order to recover costs on a one-year lag with no multi-year amortization. Central Hudson shall file an update to its Implementation Plan reflecting recovery of program costs on a one-year lag without multi-year amortization of such costs.

Second, the Commission finds Con Edison, National Grid, NYSEG, O&R, and RG&E's proposal to exclude economic development rate participants from simultaneously participating in the Demand Charge Rebate Program to be reasonable. The

Demand Charge Rebate is designed to provide sufficient operating cost relief to EV charging customers, and further rate reductions through simultaneous participation in economic development rate programs could lead to distortionary price effects. Con Edison, National Grid, NYSEG, O&R, and RG&E's draft tariffs already include language to this effect, however, Central Hudson's draft tariff leaves do not. Central Hudson is directed to include tariff language excluding economic development rate participants from also participating in the Demand Charge Rebate.

There are several areas where the utilities' Implementation Plans must be updated to provide additional clarity and specificity as to how those programs will be operated. First, Central Hudson, National Grid, and NYSEG and RG&E shall update their Implementation Plans to include detailed information on how those utilities will inform existing PPI Program participants that the program is ending. This outreach shall include at least two attempts to contact participants via email, and at least one attempt to contact participants via phone, if the emails do not garner a response. If an existing PPI Program participant fails to respond to these attempts by the end of the 60-day window proposed in the filings, the utility shall infer that the participant chooses to continue participation in the PPI Program. Since both the PPI Program and the Immediate Solutions programs are opt-in, it would be unreasonable to switch a customer who has previously agreed to participate in the PPI Program to a different program without first gaining consent to do so.

Second, Central Hudson, National Grid, and NYSEG and RG&E shall update their Implementation Plans to clarify that that there will be no rebate against surcharges or supply charges that are billed on a per-kW basis under the Demand

Charge Rebate Program. This update must also be reflected on Central Hudson, NYSEG, and RG&E's draft tariffs, particularly those tariff leaves which discuss calculation of Demand Charge Rebate Program incentives.[35]

Third, NYSEG and RG&E shall update their Implementation Plan to specify that Demand Charge Rebate Program costs will be allocated among service classifications using the transmission and distribution revenue allocator, as specified in the Demand Charge Alternative Order.

Fourth, NYSEG and RG&E shall update their Implementation Plan to clarify that payment will be prorated for Demand Charge Rebate customers that begin or end participation partially within a calendar year quarter, either at the beginning or end of a customer's participation.

Fifth, National Grid shall clarify its Implementation Plan to specify that the Demand Charge Rebate Program will end when the EV Phase-In Rate becomes available for customers, instead of the present language referring to when the EV Phase-In Rate is approved.[36] The need for this particular clarification is subtle, however, it is worthwhile to level-set expectations going forward for when the Immediate Solutions programs will end and when the EV Phase-In Rate will begin. There is likely to be a substantial amount of time between when the EV Phase-In Rates are *approved* by the Commission and when those rates will actually be available for customers to participate in because each traditional demand rate will be expanded to represent four separate tiers of EV Phase-In Rates.

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[35] Updates should be made to Central Hudson's draft leaves 171, 187, and 252; NYSEG's draft tariff leaf 117.66; and RG&E's draft tariff leaf 160.50. National Grid's draft tariff leaves already include this feature, but it is not described in the body of the Implementation Plan.

[36] Case 22-E-0236, National Grid Implementation Plan, p. 5.

Implementing the EV Phase-In Rates will require a significant expansion of rates needed to be programmed into utility billing systems, which will take time to program and test for accuracy. To ensure that all stakeholders share an understanding of when the Immediate Solutions programs will end, the Commission reaffirms that the Immediate Solutions shall only be terminated once the EV Phase-In Rates are approved, implemented in billing systems, tested for accuracy, and ready for customers to actually begin being billed under those rates.

Updates to the Implementation Plans directed in this Order shall be filed by December 1, 2023, to coincide with opening these programs for customer participation. The Implementation Plans shall be updated on an annual basis, or more frequently as needed, with future updates to be submitted concurrently with annual reporting requirements of the Make-Ready Programs beginning on March 1, 2025.

Finally, to fully implement the Immediate Solutions approved in this Order, Central Hudson, Con Edison, National Grid, NYSEG, O&R, and RG&E shall file tariff leaves consistent with the draft tariff leaves submitted with their Implementation Plans to become effective sixty days after the effective date of this Order, on not less than one day's notice.[37] Since these tariffs are being filed in compliance with this Order and because stakeholders have already had the opportunity to comment on the contents of the draft tariff leaves, the requirements of PSL §66(12)(b) and 16 NYCRR §720-8.1 as to newspaper publishing requirements are waived.

[37] PSL §66-s(6) requires that utilities make demand charge alternative solutions available for customer participation within sixty days of Commission approval.

<u>The Commission orders</u>:

1. Central Hudson Gas and Electric Corporation; Consolidated Edison Company of New York, Inc.; New York State Electric & Gas Corporation; Niagara Mohawk Power Corporation d/b/a National Grid; Orange and Rockland Utilities, Inc.; and Rochester Gas & Electric Corporation's proposed Demand Charge Rebate Programs, Commercial Managed Charging Programs, termination of the PPI program, data reporting requirements are approved as modified per the discussion in the body of this Order.

2. Central Hudson Gas and Electric Corporation, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas & Electric Corporation shall file updated Implementation Plans, including modifications as discussed in the body of this Order, by December 1, 2023.

3. Central Hudson Gas and Electric Corporation; Consolidated Edison Company of New York, Inc.; New York State Electric & Gas Corporation; Niagara Mohawk Power Corporation d/b/a National Grid; Orange and Rockland Utilities, Inc.; and Rochester Gas & Electric Corporation shall file annual updates, or more frequent updates as needed, to their Implementation Plans beginning on March 1, 2025.

4. Central Hudson Gas and Electric Corporation; Consolidated Edison Company of New York, Inc.; New York State Electric & Gas Corporation; Niagara Mohawk Power Corporation d/b/a National Grid; Orange and Rockland Utilities, Inc.; and Rochester Gas & Electric Corporation shall file tariff amendments consistent with the draft tariff leaves submitted in their respective Implementation Plans, as modified consistent with the discussion in the body of this Order, to become

effective sixty days after the effective date of this Order, on not less than one day's notice.

5. Central Hudson Gas and Electric Corporation shall update its Implementation Plan to specify that Demand Charge Rebate Program costs shall be recovered on a one-year lag without multi-year amortization of such costs, as discussed in the body of this Order.

6. Central Hudson Gas and Electric Corporation shall include tariff amendments excluding customers participating in economic development rate programs from also participating in the Demand Charge Management Program, as discussed in the body of this Order, in its tariff filing directed in Ordering Clause No. 4.

7. Central Hudson Gas and Electric Corporation, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas & Electric Corporation shall update their Implementation Plans, as required in Ordering Clause No. 2, to include detailed information requiring outreach to Per-Plug Incentive Program participants.

8. Central Hudson Gas and Electric Corporation, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas & Electric Corporation shall update their Implementation Plans, as required in Ordering Clause No. 2, to clarify that there will be no rebate against surcharges or supply charges that are billed on a per-kilowatt basis under the Demand Charge Rebate Program.

9. Central Hudson Gas and Electric Corporation, New York State Electric & Gas Corporation, and Rochester Gas & Electric Corporation shall clarify that there will be no rebate against surcharges or supply charges that are billed on a per-kilowatt basis under the Demand Charge Rebate Program in the tariff filing required in Ordering Clause No. 4.

10. New York State Electric & Gas Corporation and Rochester Gas & Electric Corporation shall update their Implementation Plans, as required in Ordering Clause No. 2, to clarify that Demand Charge Rebate Program costs will be allocated among service classifications based on the transmission and distribution revenues allocator.

11. Niagara Mohawk Power Corporation d/b/a National Grid shall update its Implementation Plans, as required in Ordering Clause No. 2, to clarify that the Demand Charge Rebate Program will end when the EV Phase-In Rate becomes available for customers.

12. The requirements of PSL §66(12)(b) and 16 NYCRR §720-8.1 regarding newspaper publication associated with the filed tariff amendments required in Ordering Clause No. 4 are waived.

13. In the Secretary's sole discretion, the deadlines set forth in this Order may be extended. Any request for an extension must be in writing, must include a justification for the extension, and must be filed at least three days prior to the affected deadline.

14. This proceeding is continued.

By the Commission,

(SIGNED)

MICHELLE L. PHILLIPS
Secretary

CON EDISON AND O&R IMMEDIATE DEMAND CHARGE REBATE AND COMMERCIAL MANAGED CHARGING PROGRAM ELIGIBILITY

Charging Level	Sector	Option No.	DCFC PPI Program	Demand Charge Rebate	Commercial Managed Charging Program	
					Core Incentives	Adder
DCFC	Public	1	**X**			
DCFC	Public	2		**X**	**X** (Lower Incentive Rate)	
DCFC	Public	3			**X** (Higher Incentive Rate)	
DCFC	Non-Public	ONLY			**X** (Standard Rate)	
DCFC	Transit	ONLY			**X** (Standard Rate)	**X**
Level 2	Public	ONLY			**X** (Lower Incentive Rate)	**X**
Level 2	Non-Public	ONLY			**X** (Standard Rate)	
Level 2	Transit	ONLY			**X** (Standard Rate)	**X**

CON EDISON PROPOSED COMMERCIAL MANAGED CHARGING PROGRAM INCENTIVES

Charging Level	Sector	Max Load Ratio Range	Peak Avoidance Incentive		Off-Peak Charging Incentive	Adder
			Summer	Winter		
DCFC	Public	< 15%	$20/kW	$8/kW	$0.03/kWh	
DCFC	Public	>= 15%	$26/kW	$8/kW	$0.03/kWh	
DCFC	Public, DCR†	ANY	$3/kW	$0.50/kW	$0.03/kWh	
DCFC	Non-Public	ANY	$10/kW*	$2/kW*	$0.03/kWh	
DCFC	Transit	<= 5%	$10/kW*	$2/kW*	$0.03/kWh	$6/kW
DCFC	Transit	6% - 10%	$10/kW*	$2/kW*	$0.03/kWh	$5/kW
DCFC	Transit	6% - 15%	$10/kW*	$2/kW*	$0.03/kWh	$4/kW
DCFC	Transit	> 15%	$10/kW*	$2/kW*	$0.03/kWh	
Level 2	Public	<= 5%	$17/kW	$6/kW	$0.03/kWh	$3/kW
Level 2	Public	6% - 10%	$17/kW	$6/kW	$0.03/kWh	$2/kW
Level 2	Public	6% - 15%	$17/kW	$6/kW	$0.03/kWh	$1/kW
Level 2	Public	> 15%	$17/kW	$6/kW	$0.03/kWh	
Level 2	Non-Public	ANY	$10/kW*	$2/kW*	$0.03/kWh	
Level 2	Transit	<= 5%	$10/kW*	$2/kW*	$0.03/kWh	$6/kW
Level 2	Transit	6% - 10%	$10/kW*	$2/kW*	$0.03/kWh	$5/kW
Level 2	Transit	6% - 15%	$10/kW*	$2/kW*	$0.03/kWh	$4/kW
Level 2	Transit	> 15%	$10/kW*	$2/kW*	$0.03/kWh	

* Incentive payment rates marked with an asterisk are the "Standard Payment"

† Only applicable to Public DCFC charging customers that participate in the Demand Charge Rebate Program

O&R PROPOSED MANAGED CHARGING PROGRAM INCENTIVES

Charging Level	Sector	Max Load Ratio Range	Peak Avoidance Incentive		Off-Peak Charging Incentive	Adder
			Summer	Winter		
DCFC	Public	< 15%	$13/kW	$5/kW	$0.03/kWh	
DCFC	Public	>= 15%	$17/kW	$5/kW	$0.03/kWh	
DCFC	Public, DCR†	ANY	$2/kW	$0.40/kW	$0.03/kWh	
DCFC	Non-Public	ANY	$7/kW*	$1/kW*	$0.03/kWh	
DCFC	Transit	ANY	$7/kW*	$1/kW*	$0.03/kWh	$5/kW
Level 2	Public	ANY	$11/kW	$4/kW	$0.03/kWh	$2/kW
Level 2	Non-Public	ANY	$7/kW*	$1/kW*	$0.03/kWh	
Level 2	Transit	ANY	$10/kW*	$2/kW*	$0.03/kWh	$5/kW

* Incentive payment rates marked with an asterisk are the "Standard Payment"

† Only applicable to Public DCFC charging customers that participate in the Demand Charge Rebate Program