Attachment B

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 15-E-0751 - In the Matter of the Value of Distributed Energy Resources.

ORDER ESTABLISHING UPDATED STANDBY SERVICE RATES AND IMPLEMENTING OPTIONAL MASS MARKET DEMAND RATES

Issued and Effective: October 13, 2023

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on October 12, 2023

COMMISSIONERS PRESENT:

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

CASE 15-E-0751 - In the Matter of the Value of Distributed Energy Resources.

ORDER ESTABLISHING UPDATED STANDBY SERVICE RATES AND IMPLEMENTING OPTIONAL MASS MARKET DEMAND RATES

(Issued and Effective October 13, 2023)

BY THE COMMISSION:

INTRODUCTION

On July 14, 2022, Central Hudson Gas & Electric Corporation (Central Hudson), Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation (NYSEG), Rochester Gas & Electric Corporation (RG&E), Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), and Orange and Rockland Utilities, Inc. (O&R) (collectively, the Utilities) each submitted draft tariff leaves to implement updated standby and buyback service rates, mass market optional demand rates, and a 15-year exemption from buyback service rates for certain stand-alone energy storage systems. These tariff amendments were filed in compliance with the Public Service Commission's (Commission) Order Establishing an Allocated Cost of Service Methodology for Standby and Buyback

Service Rate and Energy Storage Contract Demand Charge Exemptions[1] and Order Directing Standby and Buyback Service Tariff Filings.[2]

In this Order, the Commission takes various actions, including: 1) accepting the Utilities' Allocated Cost of Service (ACOS) Study results; 2) approving the resulting Standby Service, Buyback Service, and mass market optional demand rates, as filed, with updates as needed to address changes in new rate year revenue requirements, and with the exception that O&R is directed to redesign its As-Used Daily Demand Charge periods; 3) requiring the Utilities to file updated tariff leaves to become effective on a temporary basis to implement the updated rates; and 4) directing Department of Public Service Staff (Staff) to develop and propose solutions to issues regarding the ACOS Decision Tree Methodology's Question 4, and regarding purchases of capacity from high load factor non-dispatchable resources through Value Stack Alternative 1 or 2 Capacity Values. This Order directs these updated Standby and Buyback rates to be effective and available for customers as soon as is feasible for new and existing customers that are required to take Standby and/or Buyback Service, with a more measured approach allowing for automation of billing processes before they become available to customers that would participate in these more advanced demand rate options on a voluntary basis, such as the optional mass market demand-based rate.

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[1] Case 15-E-0751, Order Establishing an Allocated Cost of Service Methodology for Standby and Buyback Service Rates and Energy Storage Contract Demand Charge Exemptions (issued March 16, 2022) (ACOS Methodology Order).

[2] Case 15-E-0751, Order Directing Standby and Buyback Service Tariff Filings (issued March 16, 2022) (Rate Design Order).

BACKGROUND

On March 16, 2022, the Commission issued the ACOS Methodology Order and the Rate Design Order (collectively the March 2022 Orders), which were both related to the development and design of Standby and Buyback Service rates, and their use as voluntary demand-based rate options for customers that otherwise would not be required to take Standby or Buyback service. The ACOS Methodology Order considered the recommendations provided in a Department of Public Service Staff Whitepaper to develop a new methodology to determine what amount of revenues should be collected through Standby and Buyback Service delivery rates and their component Customer Charge, Contract Demand Charge, and As-Used Daily Demand Charges, as well as a recommendation to exempt certain standalone energy storage systems from paying Buyback Service Contract Demand Charges. The Rate Design Order considered the proposals filed by each utility to: (1) implement updated As-Used Daily Demand Charges to include a super-peak period for Central Hudson, National Grid, NYSEG, and RG&E; (2) implement new optional demand-based rates for mass market customers based on Standby Service rates for each utility;[3] and (3) implement a requirement to purchase up to five megawatts (MW) of Unforced Capacity (UCAP) through Buyback Service for each utility. The Commission's deliberations, determinations, and directives in the ACOS Methodology Order and Rate Design Order are summarized below.

ACOS Methodology Order

The ACOS Methodology Order established a new, standardized method for completing ACOS Studies to determine the amount of revenues to be allocated to three cost categories –

[3] Mass market customers are defined as Residential and Small Commercial customers not billed on a demand-basis.

Customer costs, Local costs, and Shared costs – which in turn inform the level and design of Standby and Buyback Service rates and charges. The ACOS Methodology Order firmly established an expectation that Standby and Buyback Service rates and charges would be set to match cost causation principles as closely as is feasible, with applicable costs collected through charges that best match the either fixed or variable nature of such costs, and match the time periods of when costs are caused with the charges through which revenues are collected from customers. The Commission required that Standby rates be designed to be revenue neutral to the Otherwise Applicable Service Class (OASC) – that is, the rates designed under the updated Standby Service charges are to collect the same amount of revenue from all members of their OASC under Standby Service rates as they do under the default rates for the OASC.[4] Further, the Commission specified that all customers, including mass market customers, would be allowed to use the updated Standby Service rates applicable to their OASC as a opt-in rate option.

Standby Service includes three charges – a Customer Charge, a Contract Demand Charge, and an As-Used Daily Demand Charge - whereas Buyback Service only imposes a Customer Charge and a Contract Demand Charge, if applicable.[5] The ACOS Methodology Order specified that costs allocated to the Customer cost category are intended to be recovered through the Customer Charge; costs allocated to the Local cost category are intended

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[4] The OASC is the service class that a customer would take service under but for requirements that such customer take service under Standby or Buyback Service, for example, installing a Distributed Energy Resource (DER) technology that is not exempt from Standby or Buyback Service.

[5] Since Buyback Service customers do not impose Shared costs on the system due to their nature as generators, Shared costs are not allocated to, or collected from, Buyback Service customers.

to be recovered through the Contract Demand Charge; and costs allocated to the Shared cost category are intended to be recovered through the As-Used Daily Demand Charge. The Commission also directed that the Utilities are to perform the ACOS Study by examining costs on an individual Federal Energy Regulatory Commission (FERC) Account basis. However, Central Hudson, Con Edison, and O&R were allowed to submit their first ACOS Study on a functionalized revenue requirement basis, with subsequent ACOS studies to be submitted on a by FERC Account-basis thereafter.

The ACOS Methodology Order requires that ACOS studies be performed for each combination of service class and interconnection voltage level, using two different Decision Trees depending on whether costs being considered are for the relevant system costs at the same voltage that a customer in the class interconnects to (Interconnection Voltage Decision Tree), or whether the costs being considered are for the system at higher than interconnection voltages (Higher Than Interconnection Voltage Decision Tree). The Decision Trees approved in the ACOS Methodology Order, and later corrected in an Errata Notice dated April 15, 2022, are included in Appendix A.[6]

In determining the answers to Decision Tree questions, the Commission directed the Utilities to consider the characteristics of the typical usage of a piece of equipment, and not rely on unique or unusual uses of such equipment to justify answers to decision tree questions. Further, the Commission directed the Utilities to define and consider Local costs as those designed to serve the non-coincident maximum demand related to a small group of up to 10 residential

[6] Case 15-E-0751, Errata Notice (issued April 15, 2022).

customers, or those designed to serve the non-coincident maximum demand of a single non-residential customer.

The Interconnection Voltage Decision Tree is intended to be very granular and precise, and requires that all costs flow through a series of nine "yes" or "no" questions to determine whether a cost, at the voltage level a customer interconnects to, should be allocated to the Customer, Local, or Shared cost category. The Higher Than Interconnection Voltage Level Decision Tree is somewhat simplified and includes a series of five "yes" or "no" questions to determine whether a cost at a voltage level higher than the customer's interconnection should be allocated to the Customer, Local, or Shared cost category. The five questions that make up the Higher Than Interconnection Voltage Level Decision Tree are a subset of the questions asked in the Interconnection Voltage Decision Tree.[7]

Question 1 asks, "is the cost linked to a type of asset?" Question 1 is designed to determine whether the cost in question is an asset cost or is otherwise a Customer or General cost. Answering "yes" to Question 1 identifies a cost as an asset, and leads to Question 2. Answering "no" to Question 1 identifies the cost as a non-asset cost – either a General cost or a Customer cost - and leads to Question 7 to further determine how such cost should be allocated.

Question 2 asks "are all the costs attributable to customer demand?" Question 2 is designed to determine whether some or all of an asset cost should be allocated to the Customer cost category by testing whether the asset costs are primarily driven by increases in the number of customers or increase in

[7] Questions 1, 2, 7, 8, and 9 are common to both the Interconnection Level Decision Tree and the Higher Than Interconnection Voltage Decision Tree. Questions 3, 4, 5, and 6 are only asked in the Interconnection Voltage Decision Tree.

customer demand. Answering “yes” to Question 2 identifies a cost as a demand-based asset cost, and leads to Question 3 to further examine how the cost should be allocated among the Shared and Local cost categories. Answering “no” to Question 2 identifies the cost as a customer-based asset cost, and allocates the cost to the Customer cost category.

Question 3 asks, “would a decrease in demand result in entirely unused assets?” Question 3 is designed to determine whether an asset should be considered entirely Local by testing whether the asset would become stranded if an individual customer or small group of Residential customers’ decrease in load would result in the asset being stranded. Answering “yes” to Question 3 identifies the cost as fully Local, and leads to Question 6 to determine if such costs should be recovered from Buyback Service customers. Answering “no” to Question 3 leads to Question 4 to further determine if a demand-related asset cost is either fully Local or at least partially Shared.

Question 4 asks, “does an increase in system coincident demand increase the costs?” The purpose of Question 4 is to determine if a cost should be considered entirely Local if it is linked to individual customer non-coincident demand. Answering “no” to Question 4 concludes that the cost is linked to individual customer non-coincident demand instead of the coincident demands of multiple customers, identifies the cost as fully Local, and leads to Question 6 to determine if such costs should be recovered from Buyback Service customers. Answering “yes” to Question 4 identifies the cost as at least partially Shared, and leads to Question 5 to determine if the cost should be considered fully Shared or allocated between the Shared and Local cost categories.

In the ACOS Methodology Order, the Commission addressed stakeholder concerns - particularly those of Advanced

Energy Economy Institute, et al. (AEEI) - regarding Question 4. Several stakeholders including AEEI recommended modifications to Question 4 noting that there are significant and cost-relevant coincident demands beyond just the overall system-coincident period, including the coincident demand of the customer class, and the demands coincident with the peak periods of the local area within the distribution system. AEEI reasoned that if the system-coincident demand were the only coincident demand considered by Question 4, the aggregate demands of hundreds or thousands of customers could be considered Local costs if such other demand peaks occurred outside the system-coincident demand peak periods. The JU countered, and the Commission ultimately agreed, that Question 4 was intended to consider the system-coincident demand periods, and that other types of coincident demands would be addressed in Question 5.[8]

Question 5 asks, "does an increase in non-coincident peak demand increase the costs?" The purpose of Question 5 is to determine if a cost is entirely Shared or only partially Shared. Answering "no" to Question 5 identifies a cost as entirely Shared, whereas answering "yes" to Question 5 results in an allocation of costs between the Shared category and the Local category. After considering a number of methods for allocating costs between Shared and Local as a result of answering "yes" to Question 5, the Commission required the utilities are to allocate costs to the Shared category in same proportion as the ratio of a service class's Coincident Peak (CP) demand to its Non-Coincident Peak (NCP) demand, with the remainder being allocated to the Local cost category and

[8] Several stakeholders suggest further consideration of Question 4 in their comments regarding the Utilities' June 14, 2022 Filings. Those comments are summarized and addressed in the Comments and Discussion sections below, respectively.

thereafter leads to Question 6 to determine if such costs should be recovered from Buyback Service customers.

Question 6 asks, "could a kW of reverse power flow increase the costs?" The purpose of Question 6 is to determine which Local costs should be recovered through Buyback Service rates, since the injections provided to the system through Buyback Service may not contribute to system costs in the same way as demands drawn from the grid under Standby Service. Answering "yes" to Question 6 identifies a Local cost as one that should be recovered through both Standby Service rates and Buyback Service rates. Answering "no" to Question 6 identifies a Local cost as one that should not be recovered from Buyback Service customers. In effect, Question 6 allows all costs allocated to the Local cost category to be subject to examination to determine if it is reasonable to recover such costs from Buyback Service customers, and is especially important since Buyback Service customers are almost universally also Standby Service customers and thus may potentially risk double-recovery of certain costs if not carefully examined.

Question 7 follows Question 1 for costs that are not considered a "type of asset" and asks, "does the cost apply to all cost categories?" Question 7 is designed to determine whether non-asset costs are General or Customer costs by testing whether the cost applies to all cost categories or only to the Customer category. Answering "yes" to Question 7 identifies a cost as General, which is further broken out between asset-based taxes and other general costs by answering Question 9. Answering "no" to Question 7 identifies the cost as a Customer cost, which leads to Question 8.[9]

[9] Question 8 is intentionally presented out of numerical order, and is described in greater detail below.

Question 9 follows Question 7 for costs that do not apply to all cost categories and asks, "is the cost a tax related to either a specific asset or cost which varies with demand?"[10] Question 9 is intended to test whether a General cost falls into the administration and general subcategory, or if it is instead a tax on specific demand-related assets that should instead be allocated similarly to the asset the tax is based on. General costs identified as asset-based by answering "yes" to Question 9 are to be added to the asset costs such taxes are associated with, whereas general costs identified as not asset-based by answering "no" to Question 9 are to be allocated to the Customer cost category.

The Higher Than Interconnection Voltage Level Decision Tree is somewhat simplified and includes a series of five questions. The questions posed by the Interconnection Voltage Decision Tree and the Higher than Interconnection Voltage Decision Tree overlap. Of the nine questions that must be answered as part of the Interconnection Voltage Decision Tree, the Higher than Interconnection Voltage Decision Tree requires answering Questions 1, 2, 7, 8, and 9. Using the Higher than Interconnection Voltage Decision Tree, Customer-related asset costs and non-asset general costs are allocated among the cost categories in the same way as in Questions 1, 7, 8, and 9 as under the Interconnection Voltage Decision Tree. However, non-Customer-related asset costs determined to be demand-related by

[10] Question 9 was added to the Decision Tree by the Commission in the ACOS Methodology Order, whereas Questions 1 through 8 were proposed as part of the preceding Staff Whitepaper. See Case 15-E-0751, supra, Whitepaper on Allocated Cost of Service Methods Used to Develop Standby and Buyback Service Rates (filed November 25, 2020) (Staff Whitepaper).

answering "yes" to Question 2 are allocated entirely to the Shared cost category.[11]

Once all costs have been initially allocated to either the Customer, Local, or Shared cost categories, revenues from the collection of reactive power charges are netted out from the total revenue requirement to be collected from Standby and Buyback Service customers. Reactive power revenues are deducted from each cost category in proportion of that cost category's contribution to total costs – for example, if the Customer cost category is 20 percent of total costs, then 20 percent of reactive power revenues would be deducted from the Customer cost category.

Question 8 is chronologically the last Decision Tree question to be asked, as it requires all Customer costs to have already been identified through application of both Decision Trees. Question 8 asks, "should the Customer Charge be set to a predetermined level and any difference in costs and revenues be re-allocated?" For the sake of simplicity and ensuring that a standardized methodology for setting Standby and Buyback Service rates and charges is used, the Commission specified that utilities should answer "yes" to Question 8, and that the Standby and Buyback Service Customer Charge is to be set at the same level as the Customer Charge for the OASC. The Commission recognized that there may be some instances where a utility is unable to recover the full amount of the revenue requirement allocated to the Customer cost category through the Customer Charge, and required that any "spillover Customer costs" are to be allocated first to the Local cost category (and thus

[11] Answering "no" to Question 2 under the Higher than Interconnection Voltage Decision Tree results in costs being allocated to the Customer cost category in the same way as under the Interconnection Voltage Decision Tree.

recovered through the Contract Demand Charge), or, only if necessary, to the Shared cost category (and thus recovered through the As-Used Daily Demand Charge). Following application of Question 8, all costs and associated revenue requirements have been allocated to the Customer, Local, and Shared cost categories.

Recognizing that the updated Standby and Buyback Service rates would likely be significantly different than the prior rates, and could result in significant bill impacts for some existing customers that reasonably relied on the prior rates and rate-setting methodology to justify business decisions regarding installing generation technologies, the Commission found that existing Standby and Buyback Service customers may be inappropriately harmed by an immediate transition to the updated rates. The Commission required the utilities to implement a five-year phase-in of the new rates, starting immediately with a 16.7 percent to 83.3 percent mix of the updated rates the previous rates ratio, and continuing to mix in an additional 16.7 percent from the updated rates and 16.7 percent out of the previous rates per year until the end of the five-year period. After the five-year period, applicable customers' rates would reflect only updated methodology. The Commission also directed the utilities to include provisions allowing existing customers to choose between immediately taking service under the updated rate structure or the five-year phase-in. With the development of the new rate-setting methodology, the Commission found that it is no longer reasonable to provide a Reliability Credit for customers taking service under the updated rate structure. However, the Commission required the utilities to allow customers participating in the five-year phase-in to also continue to be able to earn a Reliability Credit with a similar five-year phase-out structure (i.e., 16.7 percent phasing out per year).

Notwithstanding potential improvements to energy storage system’s bills under the updated Standby and Buyback Service rates, the Commission found that it was necessary to accelerate the stand-alone portion of the energy storage market, and to do so by offering customers that install stand-alone energy storage systems a temporary exemption from paying Buyback Service Contract Demand Charges based on energy storage discharge capacity incremental to the charging capability paid for through Standby Service Contract Demand Charges (Buyback Exemption). The Commission specified that the Buyback Exemption would be available for a 15-year period following the in-service date of the installation, covering the anticipated initial useful life of the battery cells. To provide the energy storage market certainty regarding the availability of the Buyback Exemption, the Commission required that projects would be eligible to participate in the Buyback Exemption if such installation has either made a 25 percent deposit toward its interconnection costs or has fully paid its interconnection costs, if applicable, by December 31, 2025. The Commission required that both new and existing stand-alone energy storage installations would be eligible to participate in the Buyback Exemption, however, specified that customers that are currently participating in an existing NWA project would not be eligible to participate.

Rate Design Order

The Rate Design Order considered draft tariff filings which were made by the Utilities between September 23, 2019, and September 24, 2019 (September 2019 Filings), which were themselves required by the 2019 Standby Rate Order.[12] The September 2019 Filings included: (1) proposed ACOS studies; (2) draft tariff revisions for Standby Service mass market customers; and (3) Buyback Service rate provisions. The Rate Design Order also considered requests submitted by stakeholders for modifications to provisions requiring that the utilities purchase up to five MW of UCAP from Buyback Service customers which had gone into effect following the 2019 Standby Rate Order on July 1, 2019.

The Rate Design Order found that the September 2019 Filings were generally consistent with the Commission's directives established in the 2019 Standby Rate Order, but provided additional guidance and requirements in three areas: (1) mass market customer standby service rates; (2) Buyback Service rates; and (3) requirements regarding utility purchases of UCAP from customers. To implement the Rate Design Order's findings and directives, the Commission directed each utility to file updated draft tariff leaves for Commission consideration, which are the subject of the present Order.

In the Rate Design Order, the Commission made four findings regarding mass market standby service rate design. First, the Rate Design Order noted that Con Edison, Central Hudson, and O&R had not proposed to include super-peak components within their respective As-Used Daily Demand Charges, whereas National Grid, NYSEG, and RG&E each proposed to include such super-peak periods, and determined that it is preferable to include a super-peak period within the As-Used Daily Demand Charge. The Rate Design Order directed Central Hudson, Con

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[12] Case 15-E-0751, Order on Standby and Buyback Service Rate Design and Establishing Optional Demand-based Rates (issued May 16, 2019) (2019 Standby Rate Order).

Edison, and O&R to include such super-peak period As-Used Daily Demand Charges within their revised draft tariff filings.

Second, the Commission considered the utilities' proposals for setting the amount of revenues which would be collected through the peak period and super-peak period components of the As-Used Daily Demand Charge.[13] In their September 2019 filings, each utility proposed that As-Used Daily Demand Charge super-peak periods would be applicable during the months of June through September, and NYSEG also proposed to implement a winter super-peak period in addition to its designated summer super-peak period. In their September 2019 Filings, the utilities each proposed different methodologies for how they would allocate revenues between the on-peak and super-peak As-Used Daily Demand Charge components. Central Hudson proposed to develop its super-peak period As-Used Daily Demand Charge by dividing 15 percent of the class-specific As-Used Daily Demand revenue requirement by the billing determinants for the super-peak period.[14] Con Edison proposed to develop the As-Used Daily Demand rates for the summer and non-summer months based on the relationship between summer and non-summer revenues. National Grid proposed to develop its As-Used Daily Demand Charge such that 60 percent of revenues are collected through year-round on-peak period charges, and 40 percent of

[13] This is distinct from consideration of the amount of revenues which would be collected through the Customer Charge, Contract Demand Charge, and Daily As-Used Demand Charge, which was the subject of Commission consideration in the ACOS Methodology Order.

[14] In its September 2019 Filing, Central Hudson explained that the 15 percent allocation was based on the ratio of its summer peak demand to the average of its peak demand experienced during the summer and winter months. That is, the peak demand was 15 percent higher in the summer period than the average of the summer and winter peak demands.

revenues are collected through summer super-peak period charges. NYSEG and RG&E proposed to design As-Used Daily Demand Charge components such that the ratio of the super-peak period charge to the on-peak charge is two to one, i.e., that the super-peak charge is double the on-peak charge.[15] O&R proposed to design its As-Used Daily Demand Charge components to recover a specified percentage of the transmission revenue requirement from the applicable service class, with 50 percent of transmission revenue requirements recovered through the super-peak period charge for secondary voltage service classes, and 25 percent of such revenue requirements recovered through the super-peak period charge for primary voltage service classes. The Commission found each of the utilities' As-Used Daily Demand Charge design proposals to be reasonable, and noted that none of the proposed methods were clearly preferable over others.

Third, the Commission considered the methodology for measuring and determining demand for mass market standby customers, including the duration over which demand is measured (integration interval) and how frequently such measurements occur (measurement frequency). The Commission noted that variations in both the integration interval and measurement frequency can impact how sensitive the measured demand is to short spikes in customer demand, with shorter integration durations and more frequent measurements resulting in greater sensitivity of the measured demand to short spikes. The Commission found it inappropriate to adopt a highly granular

[15] The resulting rates at NYSEG would collect approximately 50 percent of the Daily As-Used Demand Charge revenue through the super-peak period charges, and the remainder through on-peak period charges, whereas RG&E's rates would collect approximately 40 percent of the Daily As-Used Demand Charge revenues through super-peak period charges and the remainder through on-peak period charges.

approach to measuring demand for mass market customers, and directed each of the utilities to implement an integration interval of 60 minutes for mass market customers that would otherwise be billed under a non-demand service classification in their revised draft tariff filings. The Commission noted that while most utilities' typical demand measurement frequency is rolling 15-minute intervals, measurement frequency intervals were not specified in the utilities' September 2019 Filings, and directed each utility to specify the proposed measurement frequency in their draft tariff filings.

Fourth, the Commission considered the utilities' proposals for how they would establish the Contract Demand kW amount used for the Contract Demand Charge. The Commission noted that in their September 2019 Filings, Central Hudson, National Grid, NYSEG, and RG&E had proposed using a 15-minute integration interval to measure demand for the purpose of setting the Contract Demand kW amount, and noted an inconsistency with the 60-minute integration interval it had directed the utilities to implement for measuring demand for mass market customers. The Commission directed Central Hudson, National Grid, NYSEG, and RG&E to submit revised draft tariffs which set the Contract Demand kW consistent with the way demand would be billed.[16]

Regarding Buyback Service rates, the Commission found that Con Edison's method for determining the amount of incremental Contract Demand kW to be superior and more cost reflective than other utilities' proposals, including consideration of instances where a customer is exempt from paying Standby Service rates but is still required to pay

[16] That is, on the basis of a 60-minute demand integration interval, and the same measurement frequency for determination of demand specified in the revised draft tariffs.

Buyback Service rates. Specifically, Con Edison's methodology applies the Buyback Service Contract Demand rate to the customer's Buyback Service Contract Demand in excess of: (1) the Contract Demand if billed under Standby Service; or, (2) the monthly demand billed under another rate if not billed under Standby Service.[17] The Commission required Central Hudson, National Grid, NYSEG, O&R, and RG&E to each include revisions in their draft tariff filings to conform with Con Edison's methodology for setting incremental Buyback Service Contract Demand kW for dual-service customers.

The Rate Design Order made three findings or clarifications regarding requirements for utilities to purchase UCAP from Buyback Service customers as required by the 2019 Standby Rate Order. First, the Commission considered proposals by each utility to purchase up to 5 MW of UCAP as directed in the 2019 Standby Order. The Commission noted that National Grid, NYSEG, and RG&E proposed to limit the purchase quantity of UCAP from a customer at 5 MW, whereas Con Edison and O&R proposed to only purchase UCAP from facilities with a nameplate rating of 5 MW or less. The Commission clarified that the purchase of UCAP is intended to be based on the actual quantity of UCAP eligible to be purchased instead of any requirements regarding generator nameplate capacity, and required Con Edison and O&R to file revised draft tariffs to conform with National Grid, NYSEG, and RG&E's methodology.

Second, the Commission considered comments submitted by stakeholders recommending modifications to the rules and requirements already implemented by the utilities which required

[17] For example, a dual Standby and Buyback Service customer with 100 kW of Standby Service Contract Demand kW and 150 kW of Buyback Service Contract Demand would pay 100 kW-worth of Standby Service Contract Demand Charge and 50 kW-worth of Buyback Service Contract Demand Charge.

Buyback Service customers to register to become Market Participants with the New York Independent System Operator (NYISO) to be eligible to sell UCAP to the utilities through Buyback Service. Specifically, commenters suggested that registering as a Market Participant with the NYISO is a burdensome process which goes against the Commission's intent of requiring utilities to purchase UCAP directly from Buyback Service customers, and suggested that utilities could purchase UCAP from customers using existing Value of Distributed Energy Resources (VDER) Value Stack tariff provisions. The Commission agreed with commenters that requiring customers to register as Market Participants was inappropriate and that using the VDER Value Stack Alternative Capacity Values provide a simple capacity compensation for customers. The Commission directed the utilities to allow payments for UCAP purchases under Buyback Service through the Value Stack Alternative 3 Capacity Value (Alternative 3) for dispatchable distributed energy resources (DERs) or through any of the three Value Stack Alternative Capacity Values for non-dispatchable DERs.[18]

Finally, the Commission clarified the requirements for exceptions made for legacy UCAP purchase contracts existing prior to the 2019 Standby Rate Order. The Commission clarified that the exception for contracts made prior to the 2019 Standby Rate Order to purchase more than 5 MW of UCAP from a facility would apply to the facility itself, not the contract, which are renewed or re-negotiated periodically, nor to the customer in the event that the facility changes ownership during the term of a contract. The Commission further clarified that if such a legacy contract to purchase more than 5 MW of UCAP from a facility were renewed, the payment rate for such purchases must

[18] Non-dispatchable DERs include solar, wind, run of river hydro, and tidal generation.

follow the applicable VDER Value Stack Alternative Capacity Value.[19]

DRAFT TARIFF FILINGS

Central Hudson

In its filing Central Hudson states that it applied the Decision Tree Methodology on a Functionalized Revenue Requirement basis to its Rate Years 2 and 3 revenue requirements and billing determinants to develop Standby and Buyback Service rates under its present Rate Plan. Central Hudson explains that it: (1) applied the Interconnection Voltage Decision Tree to interconnection voltage costs, and the Higher than Interconnection Voltage Decision Tree to higher voltage costs; (2) answered Decision Tree questions based on definition of Local costs as those incurred to serve the maximum demand of up to 10 residential customers, or individual customers for larger customer types; (3) based Decision Tree answers on the typical usage of distribution equipment; (4) treated the functionalized costs associated with taxes other than income tax as adders to the relevant assets; (5) used the ratio of CP/NCP to allocate costs that cannot be determined to be either fully Shared or fully Local; and (6) set Standby and Buyback Service Customer Charges at the same level as the Customer Charge applicable to the OASC. Central Hudson explains that it developed the Standby rates for each customer type to be revenue neutral to the OASC, and it proposes to recover approximately 10 percent of the annual Shared cost revenue requirement through the super-peak period As-Used Daily Demand Charge based on the ratio of Central

[19] That is, a utility can continue to purchase more than 5 MW of UCAP from a facility if it had an existing contract to do so prior to the date of the 2019 Standby Rate Order, however, the terms of such purchase must follow one of the applicable VDER Value Stack Capacity Compensation Alternative methodologies.

Hudson's summer system peak demand to the average of the Central Hudson's summer and winter system demands used in its ECOS study.

Central Hudson provides numerous draft tariff modifications to implement its proposed updated Standby and Buyback Service rates. These tariff modifications include: (1) establishing a As-Used Daily Demand super-peak period of 2 p.m. to 7 p.m. during summer weekdays in addition to the existing on-peak period and Contract Demand Charge; (2) defining a 60-minute demand interval and 60-minute demand measurement frequency for mass market customers; (3) clarifying that Buyback Service Contract Demand would only apply the increment of Contract Demand above the amount of Contract Demand paid for through Standby Service or monthly billed demand under the OASC; (4) requiring all Standby customers choosing to purchase their supply from Central Hudson to be on hourly pricing; (5) modifications to the UCAP purchasing requirements to flow Company-purchases of UCAP through the VDER cost recovery mechanism and striking requirements that customers wishing to sell capacity to Central Hudson would have to register as a NYISO market participant; (6) clarifying that any customer in a metered service classification may opt-in to Standby Service;[20] (7) tariff language for existing customers to effectuate a 5-year phase-in of the new standby rates, with an option to take service under the new rates immediately; (8) tariff language for existing customers to effectuate a 5-year phase out of the Reliability Credit, eliminating the Reliability Credit for customers taking service under full new standby rates; (9) tariff language to effectuate the 15-year Buyback Exemption beginning with a customer's in-service date for stand-alone

[20] Unmetered service classes, for example, street and area lighting, would not be eligible for Standby Service.

energy storage systems; and (10) tariff language barring customers participating in Non-Wire Alternatives (NWA) projects from participating in the Buyback Exemption.

In addition to the tariff modifications described in its filing letter, Central Hudson included several other draft modifications to its tariff.[21] First, on draft leaf 272.5, Central Hudson proposes to exempt customers without on-site generation who set their own Contract Demand kW amount from the Contract Demand Exceedance Penalty provision. This penalty provision requires customers to pay for between 12 to 24 months of incremental Contract Demands for customers that exceed a self-set Contract Demand. Second, on draft leaves 272.13, 272.13.1, and 272.14, Central Hudson proposes to eliminate tariff obsolete language related to Solar photovoltaic (PV) and Wind generation units less than 15 kilovolt-amperes (kVa) in capacity. Third, the draft tariff leaf 272.17.2 includes language to implement the Multi-Party Campus Offset Tariff required by the Commission as part of the 2019 Standby Order whereby customers connected to a generating facility by a private thermal loop are allowed to take part in multi-party offset arrangements.[22] Finally, on draft tariff leaves 272.18-272.21, Central Hudson proposes modifications to the application for Standby Service to conform with the modifications described above.

In its filing, Central Hudson expresses concern regarding setting the Standby and Buyback Service Customer Charge at the same level as that used for the OASC. Central Hudson notes that its existing Standby and Buyback Service

[21] These modifications are provided in red-line draft tariffs attached to Central Hudson’s filing as Appendix D but are not described in the filing letter.

[22] 2019 Standby Order.

Customer Charge is developed to recover the full amount of identified Customer costs from the ECOS study, and that setting the Standby and Buyback Service Customer Charge at the same level as the OASC under the requirements of the March 2022 Order would result in lower Customer Charges for all but one of its Standby service classes. Central Hudson expresses specific concern regarding the Residential customer class, whose Standby Service Customer Charge would be reduced from its present level at $46.99 to an updated level of $19.50, noting that the difference would be recovered through the Contract Demand Charge and may impact utilization of standby rates by Residential heat pump and electric vehicle owners.[23]

Central Hudson also proposes to establish a definition of an existing Standby and Buyback Service customer as one who was already taking Standby or Buyback Service as of March 16, 2022, the effective date of the March 2022 Order. Since Central Hudson did not have any Standby or Buyback Service customers as of that date, it notes that the language regarding the 5-year phase-in of the updated standby rates for existing customers, 5-year phase-out of the Reliability credit would not be necessary to include in the tariff. Central Hudson also notes that since it had no existing customers, there would be no impacts to customer bills and a bill impact analysis would therefore not be necessary. Central Hudson proposes to establish a true-up mechanism for revenues received from customers under the present rates and the updated rates either through the Revenue Decoupling Mechanism (RDM) for Standby Service customers or by deferring such revenues for future disposition in its next base rate filing for Buyback Service customers.

[23] Central Hudson did not provide any additional information or analysis to support this claim.

Finally, Central Hudson identifies several issues related to billing customers under the updated Standby and Buyback Service rates in the near term. Central Hudson states that it is presently rolling out a new billing system which is presently being tested to ensure system stability. Central Hudson states that since it presently has no Standby Service customers, billing customers under a Standby Service rate of any kind would require either manual calculations or programming Standby Service billing into the new billing system. Central Hudson states that even if Standby Service customer bills are manually calculated, development work would be done on the billing system to properly display and report the manually-calculated bills. Central Hudson argues that requiring the company to bill customers under the new Standby Service rates, manually or otherwise, would create challenging conditions for implementing the new billing system and require superseding other critical billing system development work. Central Hudson proposes to delay offering the updated Standby Service rates to customers until after it has fully automated such rate offerings, which it forecasts would be available sometime during the second half of 2024.

On June 27, 2023, Central Hudson made a supplemental filing at the request of Department of Public Service Staff. In its supplemental filing, Central Hudson notes that its July 2022 Filing proposes removing language on draft leaves 272.13, 272.13.1, and 272.14. Central Hudson explains that its proposed deletions on the relevant draft leaves were intended as housekeeping changes to reflect cancellation of Special Provision 14.7, which was closed to new customers as of January 2007, and Central Hudson does not have any existing customers taking service under this provision. Central Hudson explains that it proposed to remove the relevant portions of draft leaves

272.13, 272.13.1, and 272.14 at the same time as other tariff amendments are being made to this service classification.

Con Edison

Con Edison states that its ACOS study was performed on a functionalized revenue requirement basis using the results of the company's 2017 ECOS study submitted in Case 19-E-0065. Con Edison states that it used the Decision Tree methodology to allocate costs to the Customer, Shared, and Local cost categories, and notes that it allocated Administrative and General costs to the Customer cost category. For non-Customer costs at the interconnection voltage level, Con Edison followed the Interconnection Voltage Decision Tree, allocating costs to the Shared and Local categories, and used the ratio of a Class's CP to NCP demands where necessary to allocate costs split among the Shared and Local categories. For non-Customer costs above the interconnection voltage level, Con Edison followed the Higher than Interconnection Voltage Level Decision Tree, and allocated costs entirely to the Shared category. Con Edison then used the proportion of costs allocated to the Shared category and costs allocated to the Local category for each Service Class to develop the revenue requirement amounts to be collected through the As-Used Daily Demand Charge and the Contract Demand Charge, respectively, for that Service Class.

Con Edison provides further insight into its answers to several individual Decision Tree questions, specifically, Questions 4, 5, 6, and 8. Regarding Question 4 ("does an increase in system coincident demand increase the costs?"), Con Edison states that while it asserts that the appropriate answer is "no" for secondary and primary voltage level customers, it proposes to answer Question 4 as "yes" for the purposes of its present filing. Con Edison explains that the cost drivers for secondary and primary voltage customers are non-coincident peak loads, and therefore an increase in system coincident demand could occur without affecting the non-coincident peak loads, which in turn would not affect interconnection voltage-level costs for customers connected to the secondary and primary voltage systems. Con Edison provides an example showing how an increase in coincident peak demand at approximately 5 p.m. would not result in new class demand peaks for the large commercial customer class (SC 9), which experiences its class NCP demand at approximately 2 p.m., or for the residential service class (SC 1) which experiences its class NCP demand at approximately 10 p.m. Con Edison states that answering "no" to Question 4, in combination with assignment of administrative and general costs to the Customer cost category and setting the Customer Charge for Standby Service at the same level of the customer charge as the OASC would produce Contract Demand Charges which are significantly higher than the current Standby Service Contract Demand Charges. Instead, to avoid a result which Con Edison asserts would be considered contrary to the Commission's policy objectives and which would be unacceptable to stakeholders, Con Edison proposes to answer Question 4 as "yes" for the purposes of its present filing only, and asserts the right to change its determination in the future.

Regarding Question 5 ("does an increase in non-coincident peak demand increase the costs?"), Con Edison explains that its answer is "yes" because NCP demands are an important driver of both primary and secondary distribution system costs at customers' interconnection voltage levels. As evidence of this claim, Con Edison provides that class NCP demands are incorporated into the allocator for primary and secondary demand related costs in its ECOS study.

Regarding Question 6 ("could a kW of reverse power flow increase the costs?"), Con Edison states that its answer is "yes." Con Edison asserts that, to the extent that reverse power flow requires the use of the grid, Buyback Service customers should contribute to the costs of the grid. Con Edison explains that large Buyback Service customers are assigned interconnection costs to cover incremental costs the company incurs to provide a safe and reliable connection that can accommodate such customers' injections into the grid, however, Con Edison asserts that these customers use otherwise-available headroom and can impose additional costs when that headroom would have otherwise been needed to serve other customers. Con Edison argues that use of the grid by Buyback Service customers can accelerate the need for upgrades to those pieces of local infrastructure which are not covered by individual customer interconnection studies. Con Edison states that while any one customer's reverse power flow many not trigger upgrades, the combined injections of multiple customers can cause both voltage and thermal violations which would require upgrades that impose system costs.

Con Edison notes that its answer to Question 8 ("should the customer charge be set to a predetermined level and any difference in costs be re-allocated?") is "yes" because the Commission directed the utilities to set the Customer Charge equal to the OASC's Customer Charge in the ACOS Methodology Order. Con Edison states that it allocates spillover Customer costs not able to be recovered through the Customer Charge to the Contract Demand Charge.

Regarding rate design, Con Edison confirms that the ACOS-based rates developed as part of this effort, including the new mass market optional demand rate, are designed to be revenue neutral to the OASC. Con Edison explains that it set the Customer Charge for the Standby and Buyback Service rates equivalent to the Customer Charge applicable to the OASC, however, the company notes that Rate I of SCs 5, 8, 9, and 12 do not currently include a specific Customer Charge. Con Edison proposes to set the Customer Charge for the Standby and Buyback Service rate applicable to SC 5, 8, 9, and 12 to the $50 per month level that it proposed as part of its most recent rate proceeding.[24] Con Edison explains that it then subtracted (1) the revenues associated with the Customer Charge, and (2) revenue requirements associated with spillover customer costs – determined for each SC by multiplying the number of bills by the difference between the Customer Charge of the OASC and the customer costs identified in the ACOS study - from the revenue requirement required from each service class to determine the adjusted revenue requirement for each SC. Con Edison explains that the adjusted revenue requirement was allocated among transmission costs, substation costs, primary costs, and secondary costs based on the percentage allocators resulting from the ACOS study.

To develop its proposed Standby Service Contract Demand Charges, Con Edison states that it determined the class revenue requirements to be recovered through the Contract Demand Charge by first applying the applicable Local cost percentage identified in the results of its ACOS study to the adjusted revenue requirement, then adding in the revenue requirement associated with spillover customer costs. Con Edison states that it then divided these Contract Demand revenue requirements by its estimated Contract Demand billing determinants to develop the Standby Service Contract Demand Charges applicable to each SC. Con Edison further explains that it estimated the Contract Demand billing determinants by dividing (1) twelve times the sum

[24] Case 22-E-0064, Con Edison – Electric Rates, Electric Rate Panel Testimony and Exhibits ERP-1 to ERP-2 (filed January 28, 2022).

of maximum billing demands for customers in the class by (2) the sum of the twelve monthly billing demands for customers in the class. Con Edison states that it developed its proposed Buyback Service Contract Demand Charges in the same manner as proposed for Standby Service, however, revenue requirements associated with spillover customer costs are not added to the adjusted revenue requirement for Buyback Service customers.

To develop its proposed As-Used Daily Demand Charges, Con Edison proposes to use the same On-Peak and Super-Peak periods as its current Standby Rate construct. Con Edison proposes to define Super-Peak periods as 8 a.m. to 6 p.m. Monday through Friday during the summer, excluding holidays. The Company proposes to define On-Peak periods as 8 a.m. to 10 p.m. Monday through Friday year-round excluding holidays, with different rates for the summer On-Peak period and winter On-Peak period. Any other times not included in either the Super-Peak or On-Peak periods would be considered as an Off-Peak period. Con Edison asserts that the Commission approved the use of its current As-Used Daily Demand Charge periods in the March 2022 Orders for commercial customers, and proposes to apply the same time periods to the optional demand-based rates for mass market customers.[25]

Con Edison explains that it determined the class revenue requirements to be recovered through the As-Used Daily Demand Charge by multiplying the class's adjusted revenue requirement by the applicable Shared cost percentage identified in the results of its ACOS study. The revenue requirement to be collected through the As-Used Daily Demand Charge was then

[25] The Commission disagrees with Con Edison's characterization that its proposed On-Peak and Super-Peak As-Used Daily Demand Charge periods were approved in the March 2022 Orders, as further discussed later in this Order.

divided by the applicable estimated billing determinants to develop the As-Used Daily Demand Charge for each service class. Con Edison states that it developed its estimated billing determinants for the On-Peak and Super-Peak periods using load research data demonstrating the relationships between NCP demand during each applicable period (i.e., the On-Peak period and Super-Peak period separately) and the average daily demand for each service class. Con Edison states that it then developed different summer and non-summer On-Peak period As-Used Daily Demand Charges based on either: (1) the relationship of summer and non-summer revenues for SCs 1 and 2; or (2) the relationship of summer and non-summer rates for all other SCs.

Con Edison proposes a number of tariff modifications, in addition to the changes in the rates themselves, to implement the updated Standby and Buyback Service rates, and other changes required to implement the directives of the March 2022 Orders including: (1) modifications to eligibility and applicability for Standby Rates for mass market customers, including participation in the RDM of their OASC; (2) methodology for setting Contract Demand for mass market customers on a 60-minute integrated demand basis measured in hourly increments; (3) requiring all Standby Rate customers taking supply service from Con Edison to participate in mandatory hourly metering; (4) restricting eligibility for mass market standby rate customers from opting out of advanced metering infrastructure (AMI) or automated meter reading (AMR); (5) restricting eligibility for mass market customers from participating in multi-party offset tariff arrangements; (6) defining existing Standby and Buyback Service customers as those already taking service as of March 16, 2022, and allowing such customers to participate in a six-year phase-in of the updated Standby Service rates and associated six-year phase-out of the Reliability Credit;[26] (7) eliminating requirements for Buyback Service customers to become NYISO Market Participants, clarifying that Con Edison will purchase up to 5 MW of UCAP from Buyback Service customers, and providing such customers a choice of Value Stack Alternative Capacity Values depending on whether the generating technology is dispatchable or non-dispatchable; (8) implementing the Energy Storage Buyback Exemption;[27] (9) modifying recovery of certain surcharge mechanisms for mass market standby rate customers to be recovered based a customer's Contract Demand kW instead of kWh energy use.

Con Edison notes in its bill impacts table that present Standby Service customers as a whole will experience bill decreases of approximately 21 percent, with individual bill impacts ranging from as much as an 89 percent decrease to a 9 percent increase. Regarding revenue impacts to the company resulting from the differences between the updated Standby Service rates, Con Edison states that following the release of the March 2022 Orders, the company proposed to expand the RDM to include Standby Service customers as part of its latest rate proceeding – if approved, there would be no need for a bespoke deferral mechanism, as revenue shortfalls would be recovered

[26] Con Edison proposes to include two sets of Standby Service rates in its tariff, one for customers taking service under the full updated rates, and one for existing customers making use of the phase-in. Con Edison refers to its phase-in duration as six years, however the Commission understands this to be the same phase-in duration as required in the March 2022 Orders, since the sixth year would be priced at the full updated rates.

[27] Con Edison's draft tariff leaves did not include information regarding eligibility for customers participating in existing NWA projects.

through the RDM.[28] For Buyback Service revenues, which are not included in an RDM, Con Edison proposes to track the Buyback Service revenues billed under the updated Buyback Service rates for existing customers against manually-calculated Buyback Service revenues which would have been billed under the present rates, and proposes to defer the difference, with interest, to be collected from, or refunded to, customers within the same OASC.

Con Edison notes that billing customers using the proposed updated Standby and Buyback Service rates, and accompanying tariff changes, will require additional time to implement since Con Edison is in the process of migrating to a new billing system. There are three dates that Con Edison identifies as viable to begin automated billing for various types of Standby and Buyback Service customers. First, Con Edison notes that it could begin automated billing for existing and new commercial (i.e., non-mass market) customers under the proposed updated rates, and existing customers making use of the phase-in period, as soon as 3 months following a Commission Order, but no sooner than September 1, 2023. Second, Con Edison states that it could begin automated billing for mass market customers under the proposed Standby delivery rates as soon as 8 months following a Commission Order, but no sooner than January 1, 2024, but would not be able to begin billing for supply service at hourly market rates concurrently. Finally, Con Edison identifies July 1, 2025, as the soonest it could begin automated billing of hourly supply pricing for mass market customers and non-mass market customers with demands less than 500 kW. Con Edison explains that its proposed timeline will

[28] Case 22-E-0064, supra, Electric Rate Panel Testimony and Exhibits_ERP-1 to ERP-2 (submitted January 28, 2022), pp. 46-48.

give it sufficient time to perform necessary bill programming and testing to ensure successful billing for customers under the updated Standby and Buyback Service rates.

National Grid

National Grid states that it performed an ACOS Study to allocate its embedded costs on a FERC account level to the Customer, Shared, and Local cost categories. National Grid states that it applied the Interconnection Voltage Decision Tree to costs relevant to the voltage at which a customer class interconnects to the distribution system, and applied the Higher Than Interconnection Voltage Decision Tree for costs at voltage levels above that which the customer class interconnects to the distribution system, resulting in mapping of shared and local costs at the FERC account level for customers at the secondary voltage level, primary voltage level, and transmission voltage level.[29] National Grid states that the mapping resulting from the ACOS study identifies costs as either fully Shared, fully Local, or Allocated between Shared and Local. National Grid states that it further mapped Allocated costs to the Shared category based on the ratio of CP to NCP allocators for each OASC using allocators identified in the ECOS study submitted as part of its most recent rate proceeding, with the remaining costs being assigned to the Local category.[30]

National Grid states that the results of its mapping for the secondary voltage level were used to develop the shared and local percentages for the standby customers in SC 1, SC 2 non-demand, SC 2 demand, and SC 3 secondary OASCs. Similarly,

[29] That is, National Grid developed three sets of allocations, one each for the Secondary, Primary, and Transmission voltage levels, and applied those same allocations to all SCs which interconnect at the relevant voltage levels.

[30] Case 20-E-0380, National Grid – Rates, Rate Design (Electric)-2020 NMPC Filing Package (submitted July 31, 2020), pp. 43-44.

National Grid states that the results of the primary voltage level mapping were used to develop the shared and local percentages for standby customers in SC 3 primary and SC3A secondary/primary OASCs. National Grid states that the results of the transmission voltage level mapping were used to develop the shared and local percentages for standby customers in SC 3 subtransmission/transmission, SC 3A subtransmission, and SC 3A transmission OASCs.

National Grid states that its initial implementation of the Decision Tree Methodology would have resulted in significant increases to Contract Demand Charges for customers in service classes that interconnect at the primary voltage level, largely due to the company's answer to Decision Tree Question 4. The Company states that its initial answer to Question 4 ("does an increase in system coincident demand increase the costs?") would have been "no," reasoning that the cost drivers for primary distribution system costs are non-coincident peak loads, and therefore an increase in system-coincident peak demand may not result in increased costs of the affected equipment. National Grid states that the combination of its answer to Question 4 and other changes directed in the March 2022 Order would have resulted in significantly higher Contract Demand Charges and large bill impacts in some cases.

Instead, to avoid a result which National Grid asserts would be considered contrary to the Commission's policy objectives and which would be unacceptable to stakeholders, National Grid proposes to answer Question 4 as "yes" for the purposes of its present filing only, and asserts the right to change its determination in the future. Therefore, National Grid's revised ACOS study and resulting Shared and Local percentages submitted in this filing reflects answering "yes" to Question 4.

National Grid states that it used the Shared percentages by OASC resulting from its revised ACOS study as inputs to the company's Rate Year 2 revenue requirements for the SC 7 Standby Service class to determine the revenue requirement to be collected through the As-Used Daily Demand Charge and Contract Demand Charge on a revenue neutral basis. Although not described in its filing letter, National Grid demonstrates in Attachment 4.2 of its filing that it set the Customer Charge for Standby Service customers equivalent to the Customer Charge of the OASC, and developed the Contract Demand Charge by dividing the revenue requirement to be collected through the Contract Demand Charge by the Contract Demand billing determinants. National Grid states that it developed the On-Peak and Super-Peak As-Used Daily Demand Charges by multiplying the As-Used Daily Demand Charge revenue requirement by 60 percent and 40 percent, respectively, and dividing by the applicable billing determinants.[31]

National Grid proposes to implement the Super-Peak period As-Used Daily Demand Charge during the summer months of June through September only, to be applicable from 1 p.m. to 6 p.m. during weekdays, excluding holidays. To accommodate the new summer Super-Peak period, National Grid proposes to modify its existing On-Peak period As-Used Daily Demand Charge to be applicable from 8 a.m. to 1 p.m. and from 6 p.m. to 10 p.m. on weekdays, excluding holidays, during June through September.

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[31] National Grid explained its proposals to recover a 60 percent share of the As-Used Daily Demand Charge revenue requirement in the On-Peak component with the remainder to be collected through the Super-Peak component as part of its September 2019 Filing – "[t]his distribution ensures that the As-Used Super-[P]eak Daily Demand rate is sufficiently higher than the As-Used On-[P]eak Daily Demand rate to encourage load reduction or shifting away from the Super-[P]eak period." National Grid September 2019 Filing, p. 3.

National Grid proposes to retain its existing On-Peak period As-Used Daily Demand Charge during non-summer months, from 8 a.m. to 10 p.m. weekdays, excluding holidays, from October through May. Any other periods not included in the summer Super-Peak period, summer On-Peak period, or non-summer On-Peak period would be considered Off-Peak and not incur an As-Used Daily Demand Charge.

National Grid provides information regarding how it calculates demand for its customers. National Grid notes that it uses two different methodologies to determine demand for its commercial customers, depending on which metering technology is used for the various OASCs. For smaller commercial customers that are billed on demand but do not require interval metering for hourly supply pricing, the company determines 15-minute demand in 5 minute rolling intervals, and then multiplies the 15-minute demand by four to determine hourly demand. For larger commercial customers with interval meters, the Company measures demand once each during each 15-minute interval and then multiplies by 4 to determine hourly demand. National Grid states that it is currently evaluating whether it could determine demand consistently for all demand customers once AMI is in place. For mass market customers, National Grid proposes to use a 60-minute demand interval, and to set mass market customers' Contract Demand kW using the maximum 60-minute demand measurement in such customer's first bill under standby rates, with adjustments going forward if the customer's maximum demand is higher.

Consistent with requirements of the March 2022 Orders, National Grid proposes to allow all customers to opt-in to standby rates. National Grid proposes to designate customers who are not required to take Standby Service but elect to opt in to standby rates as "optional rate customers." National Grid proposes that Optional Rate Customers that do not already have interval metering installed would pay an incremental metering charge for installation of an interval meter and associated telecommunications costs, based on the same monthly rate that is currently available to customers that opt into voluntary hourly pricing. National Grid proposes that once a customer opts into standby rates, such customer would not be able to opt out of AMI.

National Grid proposes several other Standby Service tariff modifications to effectuate the requirements of the March 2022 Orders including: (1) modification of certain surcharge mechanisms for mass market customers taking Standby Service to assess charges on a per kW of Contract Demand basis; (2) updates to deferral surcredit amounts for mass market Standby Service customers to reflect revised delivery rates; (3) updates to delivery rates in Standby Service special provision J, applicable to wholesale generators taking service from the NYISO, to reflect updated delivery rates; (4) requiring all Standby Service customers who take electric supply service from National Grid to be billed for supply on an hourly basis, including capacity charges based on a customer’s individually assigned capacity tag; (5) implementation of the 5-year phase in of the updated delivery rates available to existing customers, prorated as necessary to address the likely differences between the effective date of the compliance tariffs and the company’s rate years; and (6) phase-out or elimination of the Reliability Credit for existing customers that choose to participate in the updated rate phase-in, or new customers and existing customers not participating in the phase-in, respectively.

National Grid proposes to make several modifications to its Buyback Service tariff. First, National Grid proposes to include a Customer Charge and Contract Demand Charge for its

Buyback Service customers who do not take service under a different service classification. National Grid further proposes to specify the Contract Demand kW amounts that Buyback Service customers that also take service under a different service classification, consistent with Con Edison's methodology as directed in the March 2022 Orders. Second, National Grid proposes to implement the Buyback Exemption for standalone energy storage systems installed by December 31, 2025, which are not participating in an NWA project.[32] Third, National Grid proposes to recover the costs associated purchases of capacity from Buyback Service customers under the Value Stack through the Electric Supply Reconciliation Mechanism supply service surcharge. Fourth, National Grid proposes to modify its RDM to include Buyback Service delivery charges in the RDM reconciliation of the applicable OASC.

Finally, the company states that it has included tariffs to allow Buyback Service customers with non-dispatchable resources to select from one of the three VDER capacity payment alternatives, but notes that it does not agree with allowing Buyback Service customers to select capacity alternatives 1 or 2. Instead, National Grid recommends that the Commission restrict purchases of capacity through Buyback Service solely to Value Stack Alternative 3. National Grid states that it would not be able to enforce the five MW UCAP purchase limit if a customer selects Value Stack Alternative Capacity Value 1 (Alternative 1) or Value Stack Alternative Capacity 2 (Alternative 2). National Grid cautions that there is an opportunity for a significant windfall for higher capacity

[32] National Grid's proposed tariff language would restrict any standalone energy storage project from participating in both the Buyback Exemption and an NWA project, requiring the customer to choose one or the other.

factor hydroelectric generators receiving capacity payments under Alternatives 1 or 2, since those options were developed using typical solar PV generation patterns and capacity factors. National Grid states that windfall payments to hydroelectric generating facilities under Alternatives 1 and 2 would likely increase costs for supply service customers.

National Grid submitted bill impacts of its modified Standby rates for its existing customers. Of National Grid’s 33 existing Standby Service customers, ten customers would experience delivery bill decreases between 15 and 35 percent, thirteen customers would experience delivery bill decreases between zero and 10 percent, seven customers would experience delivery bill increases between 1 and 10 percent, and three customers would experience delivery bill increases between 10 and 29 percent.

National Grid identifies three phases necessary to implement automated billing for the updated Standby and Buyback Service rates. National Grid estimates that it could implement the Phase 1 by July 1, 2023, and Phases 2 and 3 by October 1, 2023. Phase 1 would implement billing system modifications necessary to bill existing Standby Service customers, including adding the new As-Used Daily Demand Super-Peak period and associated changes to the summer On-Peak period, the phase-in option for existing Standby Service customers, and transitioning all Standby Service customers to hourly supply price billing. Phase 2 would include programming new rate codes for mass market Standby Service customers, including implementing 60-minute demand billing and hourly supply pricing for such customers. Phase 3 would implement billing system modifications to update Buyback Service rates and automate billing for Buyback Service customers. National Grid notes that it would manually bill

Buyback Service changes prior to completing automation, as needed.

On June 26, 2023, National Grid made a supplemental filing in response to Department of Public Service Staff questions, providing three pieces of additional information and clarification. First, National Grid clarifies that it would calculate the 60-minute integrated demand for mass market customers by summing the four 15-minute intervals in the hour, which differs from its present method for calculating demand for commercial and industrial demand-billed customers.[33] Second, National Grid provides an update to its estimated billing implementation schedule. National Grid estimates that it can implement Phase 1 of its billing implementation by the first day of the calendar month following three months after the issuance of a Commission Order. National Grid estimates that it could implement both Phases 2 and 3 by the first day of the calendar month following six months after the issuance of a Commission Order. National Grid cautions that its updated billing implementation plan is based on the assumption that there would be no structural rate design changes from the March 2022 Orders which would require reprogramming.

Third, National Grid provides additional supporting information to its assertion that use of allowing Buyback Service customers to select capacity Alternatives 1 or 2 would present a significant windfall for higher capacity factor hydroelectric generators. National Grid demonstrates that each of the 15 hydroelectric generating facilities presently enrolled in Buyback Service would receive higher capacity payments under

[33] As explained above, National Grid uses one of two methods for calculating 60-minute integrated demands for its current demand-billed customers, both of which multiply the maximum 15-minute integrated demand in the hour by four.

Alternative 1, many by a significant margin. Overall, National Grid shows that use of Alternative 1 would result in increased capacity payments to its existing hydroelectric facilities of approximately $1.1 million, or about a 250 percent increase compared to present payment amounts. National Grid also provides information for what payments to these facilities would be under Alternative 3. National Grid demonstrates that most facilities would receive lower payments under Alternative 3, however, some facilities would receive higher payments. Overall, National Grid shows that use of Alternative 3 would result in decreased capacity payments to its existing hydroelectric facilities of approximately $128,000, a decrease of approximately 29 percent.

NYSEG and RG&E

In their filing, NYSEG and RG&E state that they developed their ACOS studies based on the ECOS studies submitted by the Companies in their most recent rate proceedings on a FERC Account level.[34] NYSEG and RG&E explain that revenue requirements for each service class were identified by each of the following functions: (1) Production Demand and Energy; (2) Transmission Demand; (3) Distribution Primary Demand; (4) Distribution Primary Customer; (5) Distribution Secondary Demand; (6) Distribution Secondary Customer; and (7) all other Customer costs. NYSEG and RG&E state that it applied the Interconnection Voltage Decision Tree or Higher Than Interconnection Voltage Decision Tree, as applicable, to each combination of function and classification for each FERC Account to determine the total shared, local, and customer revenue requirements for each class and function combination for each service classification. NYSEG and RG&E state that they then

[34] Cases 22-E-0317, et al., NYSEG and RG&E – Rates, Bickey Rimal (ECOS) Testimony (submitted May 26, 2022).

calculated percentages of shared, local, and customer revenue requirements for each service classification for use in rate design.

NYSEG and RG&E confirm that the updated Standby Service rates have been designed to be revenue neutral for all applicable service classifications. NYSEG and RG&E state that the Customer Charge for Standby and Buyback Service customers were set equivalent to the Customer Charge of the OASC. NYSEG and RG&E do not describe the process for designing Standby and Buyback Service rates in detail in their filing letter, however, Appendices 1 and 2 to the letter demonstrate that the Companies subtract Customer Charge revenues from the total revenue requirement, allocate spillover customer costs to the local cost category, then multiply the remaining revenue requirements by the percentage shared and local allocators to determine the amount of revenue requirement to be collected through the As-Used Daily Demand Charge and Contract Demand Charge, respectively. As shown in Appendices 1 and 2, NYSEG and RG&E propose to develop the Contract Demand Charge by dividing the amount of revenue requirement to be collected through such charge by the applicable Contract Demand billing determinants. As shown in Appendices 1 and 2, NYSEG and RG&E propose to set the As-Used Daily Demand Charge by dividing the revenue requirements to be collected though such charge by the applicable billing determinants, set such that the charge during the Super-Peak period is double the charge during the On-Peak period. NYSEG and RG&E propose to implement a five-year phase in for existing customers that elect not to transition to the updated Standby Service rates immediately, including a five-year phase-out for the Reliability Credit.

NYSEG and RG&E each propose to implement As-Used Daily Demand Super-Peak components, however, each Company proposes different Super-Peak hours. NYSEG proposes to impose a Super-Peak As-Used Daily Demand Charge component in both the summer and winter months, with no Super-Peak component during specified "shoulder" months between summer and winter. During summer months of June through September, NYSEG proposes to designate the hours of 7 a.m. to 2 p.m. and from 6 p.m. to 11 p.m. as On-Peak hours, with 2 p.m. to 6 p.m. designated as Super-Peak hours, and all other hours designated as Off-Peak. During winter months of December, January, and February, NYSEG proposes to designate the hours of 7 a.m. to 5 p.m. and from 9 p.m. to 11 p.m. as On-Peak hours, with 5 p.m. to 9 p.m. as Super-Peak hours, with all other hours designated as Off-Peak. RG&E proposes to impose a Super-Peak As-Used Daily Demand Charge component in the summer months only, which like NYSEG is June through September. RG&E proposes, NYSEG proposes to designate the hours of 7 a.m. to 2 p.m. and from 6 p.m. to 11 p.m. as On-Peak hours, with 2 p.m. to 6 p.m. designated as Super-Peak hours, and all other hours designated as Off-Peak. During all non-summer months RG&E proposes to designate the hours of 7 a.m. to 11 p.m. as On-Peak hours, with all other hours designated as Off-Peak.

NYSEG and RG&E state that they developed the Buyback Service Contract Demand Charge to include only the portion of the costs allocated to the Local cost category which could be increased due to reverse power flow, and do not include spillover customer costs. NYSEG and RG&E's draft tariffs demonstrate that Buyback Service customers will not be charged a Customer Charge if they are also a Standby Service customer, and specify that Buyback Service Contract Demand will only be assessed in the amount incremental to the Standby Service contract demand. NYSEG and RG&E propose to require Buyback Service customers with dispatchable resources to be paid the

Alternative 3, whereas non-dispatchable resources would be allowed to choose to take payment under either Capacity Alternatives 1, 2, or 3. NYSEG and RG&E propose to implement the Buyback Exemption.[35]

To effectuate allowing all customers to opt in to the updated Standby Service rates, NYSEG and RG&E propose to add a new Optional Demand Service Class, SC 15 for both utilities. For each utility, SC 15 would be available for customers without generation or customers that are not eligible for the traditional Standby Service classification, and the rates under SC 15 would be set equivalent to the Standby Service rates for each OASC. NYSEG and RG&E propose that SC 15 customers be required to have an AMI meter, and that mass market customers would have their demands measured on a 60-minute interval, whereas other customers would have their demands measured based on the interval used for measuring demand for the customer's OASC.[36] NYSEG and RG&E propose that SC 15 customers would be subject to all surcharges and the RDM based on the customer's OASC. NYSEG and RG&E propose that SC 15 customers would have the option to purchase their electric supply service from a third party, however, customers that take supply service from the Companies would be served under the Hourly Supply tariff, including hourly Location-Based Marginal Pricing charges and customer-specific Installed Capacity tags, as well as the Supply Adjustment Charge and Merchant Function Charge.

NYSEG and RG&E submitted bill impacts for its existing Standby Service customers. Of the 31 current NYSEG Standby

[35] NYSEG and RG&E's draft tariff leaves do not include information regarding eligibility for customers participating in existing NWA projects.

[36] NYSEG and RG&E note that AMI installations in their service territories are scheduled to begin during the fourth quarter of 2022, continuing through 2025.

Service customers, seven customers would see bill increases of seven percent on average, ranging from a two percent increase to an 11 percent increases, two customers would see neither a bill increase nor decrease, and 22 would experience a bill decrease of eight percent on average, ranging from as little as a one percent decrease to as much as a 46 percent decrease. Of the 18 current RG&E Standby Service customers, eight customers would see bill increases of 11 percent on average, ranging from a 2 percent increase to an 11 percent increases, two customers would see neither a bill increase nor decrease, and 22 would experience a bill decrease of eight percent on average, ranging from as little as a one percent decrease to as much as a 46 percent decrease.

NYSEG and RG&E propose a process for collecting lost revenues for existing Standby Service customers that decide to participate in the updated Standby Service rates. For each such customer, NYSEG and RG&E propose to calculate the customer's bill under both the current Standby Service rates and the redesigned Standby Service rates, and defer the difference. NYSEG and RG&E propose to address any accumulated deferral amounts in a future rate proceeding.

NYSEG and RG&E propose to automate implementation of the redesigned rates for current Standby Service customers, as well as customers that would choose such rates under SC 15. NYSEG and RG&E note that they are currently upgrading their billing systems stemming from the deployment of AMI meters, and that programming for automation of the updated Standby Service rates could only occur after completion of programming other automated billing matters, which the Companies forecast would be completed by end of the first quarter of 2023. NYSEG and RG&E estimate that automated standby rate billing would take approximately 10 months to complete, therefore, the Companies forecast that automated billing for both existing Standby Service customers and SC 15 customers would not become widely available until mid-2024 due to the combination of AMI rollout schedule, overall billing system automation requirements, and incremental time needed to automate the updated standby rates.

On June 27, 2023, NYSEG and RG&E made a supplemental filing in response to Department of Public Service Staff questions. In their supplemental filing, NYSEG and RG&E note that the on NYSEG draft tariff leaf number 289 of P.S.C. No. 120 and on RG&E draft tariff leaf number 243.1 of P.S.C. No. 19, the Companies propose specific Super-Peak, On-Peak, and Off-Peak periods for the As-Used Daily Demand Charge in the tables labeled "Redesigned Rates." NYSEG and RG&E explain that the Super-Peak and On-Peak periods listed under the Redesigned Rates would apply during Monday through Friday only, and that weekends and holidays would be considered as an Off-Peak period.

O&R

O&R states that its ACOS study was performed on a functionalized revenue requirement basis using the results of the company's 2019 ECOS study submitted in Case 21-E-0074. O&R states that it used the Decision Tree methodology to allocate costs to the Customer, Shared, and Local cost categories, and notes that it allocated Administrative and General costs to the Customer cost category. Using its answers to the Decision Tree questions, O&R explains that it calculated a percentage of non-Customer interconnection voltage-level costs allocated between the Shared and Local cost categories, with non-Customer higher than interconnection voltage-level costs allocated entirely to Shared, and notes that it used the ratio of a class's CP to NCP to allocate costs to the Shared category where necessary.

O&R provides further insight into its answers to several individual Decision Tree questions, specifically, Questions 4, 5, 6, and 8. Regarding Question 4 ("does an increase in system coincident demand increase the costs?"), O&R states that while it asserts that the appropriate answer is "no," it proposes to answer Question 4 as "yes" for the purposes of its present filing. O&R explains that the cost drivers for secondary and primary voltage customers are non-coincident peak loads, and therefore an increase in system coincident demand could occur without affecting the non-coincident peak loads, which in turn would not affect interconnection voltage-level costs for customers connected to the secondary and primary voltage systems.[37] O&R states that answering "no" to Question 4, in combination with assignment of administrative and general costs to the Customer cost category and setting the Customer Charge for Standby Service at the same level of the customer charge as the OASC would produce Contract Demand Charges which are significantly higher than the current Standby Service Contract Demand Charges. Instead, to avoid a result which O&R asserts would be considered contrary to the Commission's policy objectives and which would be unacceptable to stakeholders, O&R proposes to answer Question 4 as "yes" for the purposes of its present filing only, and asserts the right to change its determination in the future.

Regarding Question 5 ("does an increase in non-coincident peak demand increase the costs?"), O&R explains that its answer is "yes" because NCP demands are an important driver of both primary and secondary distribution system costs at customers' interconnection voltage levels. O&R asserts that the

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[37] Unlike Con Edison's filing, O&R did not provide additional data demonstrating specific service classifications' NCP demands occurring outside the CP window, nor did it provide an example demonstrating the impact of increasing demand during the CP hour.

way costs are allocated to service classes in its ECOS study is satisfactory evidence of its claim.

Regarding Question 6 ("could a kW of reverse power flow increase the costs?"), O&R states that its answer is "yes." O&R asserts that, to the extent that reverse power flow requires the use of the grid, Buyback Service customers should contribute to the costs of the grid. O&R explains that large Buyback Service customers are assigned interconnection costs to cover incremental costs the company incurs to provide a safe and reliable connection that can accommodate such customers' injections into the grid, however, O&R asserts that these customers use otherwise-available headroom and can impose additional costs when that headroom would have otherwise been needed to serve other customers. O&R argues that use of the grid by Buyback Service customers can accelerate the need for upgrades to those pieces of local infrastructure which are not covered by individual customer interconnection studies. O&R states that while any one customer's reverse power flow many not trigger upgrades, the combined injections of multiple customers can cause both voltage and thermal violations which would require upgrades that impose system costs.

O&R notes that its answer to Question 8 ("should the customer charge be set to a predetermined level and any difference in costs be re-allocated?") is "yes" because the Commission directed the utilities to set the Customer Charge equal to the OASC's Customer Charge in the ACOS Methodology Order. O&R states that it allocates spillover Customer costs not able to be recovered through the Customer Charge to the Contract Demand Charge.

Regarding rate design, O&R confirms that the ACOS-based rates developed as part of this effort, including the new mass market optional demand rate, are designed to be revenue neutral to the OASC. O&R explains that it set the Customer Charge for the Standby and Buyback Service rates equivalent to the Customer Charge applicable to the OASC. O&R states that it then subtracted (1) the revenues associated with the Customer Charge, and (2) revenue requirements associated with spillover customer costs – determined for each SC by multiplying the number of bills by the difference between the Customer Charge of the OASC and the customer costs identified in the ACOS study - from the revenue requirement required from each service class to determine the adjusted revenue requirement for each SC. O&R explains that the adjusted revenue requirement was allocated among transmission costs, substation costs, primary costs, and secondary costs based on the percentage allocators resulting from the ACOS study.

To develop its proposed Standby Service Contract Demand Charges, O&R states that it determined the class revenue requirements to be recovered through the Contract Demand Charge by first applying the applicable Local cost percentage identified in the results of its ACOS study to the adjusted revenue requirement, then adding in the revenue requirement associated with spillover customer costs. O&R states that it then divided these Contract Demand revenue requirements by its estimated Contract Demand billing determinants to develop the Standby Service Contract Demand Charges applicable to each SC. O&R further explains that it estimated the Contract Demand billing determinants by dividing (1) twelve times the maximum billing demands for customers in the class by (2) the sum of the twelve monthly billing demands for customers in the class. O&R states that it developed its proposed Buyback Service Contract Demand Charges in the same manner as proposed for Standby Service, however, revenue requirements associated with spillover customer costs are not added to the adjusted revenue requirement for Buyback Service customers.

O&R notes that its current As-Used Daily Demand Charge is assessed from 8 a.m. to 11 p.m., Monday through Friday, excluding holidays, with a different summer and winter charge rate.[38] To develop its proposed As-Used Daily Demand Charges, O&R proposes to use the same On-Peak and Super-Peak periods as it proposed in its September 2019 Filing, defining Super-Peak periods as 8 a.m. to 6 p.m. Monday through Friday during the summer, excluding holidays.[39] O&R proposes to define On-Peak periods as 6 p.m. to 11 p.m. Monday through Friday, excluding holidays, during the summer, and from 8 a.m. to 11 p.m. Monday through Friday, excluding holidays, during the non-summer months.[40] Any other times not included in either the Super-Peak or On-Peak periods would be considered as an Off-Peak period. O&R asserts that the Commission approved the use of its current As-Used Daily Demand Charge periods in the March 2022 Orders for commercial customers, and proposes to apply the same time

[38] Demand during all other times is considered off-peak and therefore not assessed a corresponding As-Used Daily Demand Charge.

[39] In its September 2019 Filing, O&R explains that it selected the 8 a.m. to 6 p.m. Super-Peak period based on times of the company's system peak for each day of each summer month for the prior three years. O&R explains that in each of those three years the majority of summer peaks occurred at 6 p.m. or earlier, therefore it selected 6 p.m. as the terminus for the Super-Peak period. O&R explains that it chose to retain the 8 a.m. starting point of the Super-Peak period to be consistent with the start time of its On-Peak period for its existing Standby Service rates.

[40] In its September 2019 Filing, O&R states that it chose to retain the existing time period for its non-summer On-Peak period.

periods to the optional demand-based rates for mass market customers.[41]

O&R explains that it determined the class revenue requirements to be recovered through the As-Used Daily Demand Charge by multiplying the class's adjusted revenue requirement by the applicable Shared cost percentage identified in the results of its ACOS study. O&R proposes to apply the following three rules to determine the amount of revenue requirement to be collected during the Super-Peak and On-Peak periods. First, the summer Super-Peak rate was set to recover a certain percentage of the class-specific transmission revenues – with 50 percent of the residential and non-residential secondary service classes' transmission revenues to be collected through the Super-Peak As-Used Daily Demand Charge, 25 percent of other classes' transmission revenues to be collected through the Super-Peak period charge. Second, the On-Peak period charges for summer and winter were set to be equivalent. Third, there is no charge during the Off-Peak period. O&R states that it then determined the specific As-Used Daily Demand charges by dividing the revenue requirements determined for each period by the applicable daily demand billing determinants for each period. O&R states that the billing determinants in each period were developed using relationships between NCP demand during each applicable period (i.e., the On-Peak period and Super-Peak period separately) and the average daily demand for each service class.

O&R proposes a number of tariff modifications, in addition to the changes in the rates themselves, to implement

[41] The Commission disagrees with O&R's characterization that its proposed On-Peak and Super-Peak As-Used Daily Demand Charge periods were approved in the March 2022 Orders, as further discussed later in this Order.

the updated Standby and Buyback Service rates, and other changes required to implement the directives of the March 2022 Orders including: (1) modifications to eligibility and applicability for Standby Rates for mass market customers, including participation in the RDM of their OASC; (2) methodology for setting Contract Demand for mass market customers on a 60-minute integrated demand basis measured in hourly increments; (3) requiring all Standby Rate customers taking supply service from O&R to participate in mandatory hourly metering; (4) restricting eligibility for mass market standby rate customers from opting out of advanced metering infrastructure (AMI) or automated meter reading (AMR); (5) establishing a multi-party offset tariff, with the restriction that mass market customers are not eligible to partake in such arrangements; (6) defining existing Standby and Buyback Service customers as those already taking service as of March 16, 2022, and allowing such customers to participate in a six-year phase-in of the updated Standby Service rates and associated six-year phase-out of the Reliability Credit;[42] (7) eliminating requirements for Buyback Service customers to become NYISO Market Participants, clarifying that Con Edison will purchase up to 5 MW of UCAP from Buyback Service customers, and providing such customers a choice of Value Stack Alternative Capacity Values depending on whether the generating technology is dispatchable or non-dispatchable; (8) adding language stating that Buyback Service Contract Demand Charge will only apply to

[42] O&R proposes effectuate the phase-in by calculating the customer's monthly bill under the existing Standby Service rates and under the full updated rates, then applying the phase-in percentage for the applicable year to the difference, and either crediting or charging the customer for such difference. O&R refers to its phase-in duration as six years, however the Commission understands this to be the same phase-in duration as required in the March 2022 Orders, since the sixth year would be priced at the full updated rates.

Buyback Service Contract Demand kW in excess of the customer's Standby Service Contract Demand kW, and established that Buyback Service customers will not be charged a Customer Charge if they take serve under both Buyback Service and another service classification through the same service point; (9) implementing the Energy Storage Buyback Exemption;[43] (10) modifying recovery of certain surcharge mechanisms for mass market standby rate customers to be recovered based a customer's Contract Demand kW instead of kWh energy use.

O&R notes that it has not submitted a bill impact analysis to prevent the disclosure of customer-specific information because it has only one Standby Service customer. Regarding revenue impacts to the company resulting from the differences between the updated Standby Service rates, O&R states that following the release of the March 2022 Orders, the company began including Standby Service customers in its RDM as approved in the Commission's April 14, 2022 Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans, with Additional Requirements in Case 21-E-0064. O&R states that since it has no customers currently paying the Contract Demand Charges under Buyback Service there will be no difference in revenues between the existing and revised rates, and therefore there will be no need to defer any revenues.

O&R notes that billing customers using the proposed updated Standby and Buyback Service rates, and accompanying tariff changes, will require additional time to implement since O&R is in the process of migrating to a new billing system. O&R states that it can accommodate manual billing of existing Standby Service customers under either the phased-in rate

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[43] O&R's draft tariff leaves did not include information regarding eligibility for customers participating in existing NWA projects.

schedule or the full updated rates as early as three months following release of a Commission Order, with automation of such processes to follow within 8 months of a Commission Order, but not sooner than January 1, 2024. O&R states that it could achieve automatic billing of all new Standby Service customers, mass market and commercial, within 8 months of a Commission Order, but not sooner than January 1, 2024, but notes that MHP billing would not be available for such customers immediately. O&R states that automated billing under MHP supply rates for mass market customers and non-mass market customers with less than 300 kW of demand could be achieved by July 1, 2025. O&R explains that its proposed timeline will give it sufficient time to perform necessary bill programming and testing prior to ensure successful billing for customers under the updated Standby and Buyback Service rates.

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 September 21, 2022 [SAPA Nos. 15-E-0751SP43, 15-E-0751SP44, 15-E-0751SP45, 15-E-0751SP46, 15-E-0751SP47, 15-E-0751SP48]. The time for submission of comments pursuant to these notices expired on November 21, 2022. The comments received are addressed below.

COMMENTS

A total of four sets of comments were submitted by the following stakeholders: Advanced Energy Economy Institute (AEEI); Cubit Power One, Inc. (Cubit); the E Cubed Company, LLC on behalf of Energy Spectrum, Inc. (Energy Spectrum); and the New York Battery and Energy Storage Technology Consortium (NY-

BEST). Cubit submitted a set of supplemental comments on April 13, 2022.

AEEI

In its comments, AEEI recognizes that both Con Edison and National Grid state in their respective filings that those utilities had purposefully answered Question 4 of the Decision Tree as "yes" instead of strictly adhering to Question 4 as adopted in the ACOS Methodology Order by answering "no." AEEI states that it appreciates and supports Con Edison's and National Grid's decisions to answer Question 4 as "yes," since answering "no" would have resulted in a cost allocation which would likely have been unacceptable to stakeholders and contrary to the Commission's policy objectives. AEEI requests that the Commission accept Con Edison and National Grid's responses to the Decision Tree, including their decisions to purposefully answer Question 4 as "yes." While AEEI supports Con Edison's and National Grid's current proposals, AEEI states that it remains concerned that Question 4 needs further development for future applications, and suggests that Question 4 as currently approved does not accurately distinguish between local and shared costs, and may not achieve the Commission's goals in approving the Decision Tree.

AEEI explains that it first raised its concerns with Question 4 in response to the Department of Public Service Staff Whitepaper preceding the ACOS Methodology Order, particularly that the focus of Question 4 on peak-coincident demand was too narrow because it did not consider local peaks and peaks driven by aggregate demand of large numbers of customers when the local peaks are not timed with the overall system peak.[44] AEEI states that, in effect, Question 4 acts as a gate which, if answered "no" results in the costs under consideration being allocated entirely to the Local cost category, or if answered "yes" results in the costs under consideration continuing through the Decision Tree resulting in some or all of such costs being allocated to the Shared cost category. AEEI explains that the logical conclusion envisioned in Question 4 – that assets that are not sensitive to an increase in system peak-coincident demand must be designed to serve individual customer demand – is undermined by the common occurrence on the distribution system where a local peak demand not coincident with the overall system peak drives the need to upgrade a portion of the distribution system serving a large number of customers.

AEEI states that under the presently-approved language of Question 4, whether a cost is determined to be shared or local is entirely dependent on when peak demand conditions occur during the day, and whether those peak conditions happen to be coincident with the overall system peak period – that is, if a cost-driving demand peak occurs during the overall system coincident peak demand period it will be at least partially allocated to the Shared cost category, but if that peak occurs during some other time it will be allocated entirely to the Local cost category regardless of other characteristics of that demand peak. AEEI notes that in its filing Con Edison states that none of its customer class peaks are coincident with the overall system peak, which, in effect, would result in all

[44] Case 15-E-0751, Comments of Advanced Energy Economy Institute, the Alliance for Clean Energy New York, and the Advanced Energy Management Alliance on the Staff Whitepaper on ACOS Study Methods (submitted March 8, 2021), pp. 8-9; Case 15-E-0751, supra, AEEI, ACE, and AEMA Reply Comments on Staff ACOS Methods Whitepaper (submitted April 12, 2021), pp. 5-6.

primary and secondary voltage distribution costs being allocated to the Local cost category as Question 4 is currently written.

AEEI states that the effect of Question 4 – allocating the entirety of a cost to the Local cost category based predominantly on whether a cost-driving demand peak is coincident with the overall system demand peak – is fundamentally flawed. AEEI asserts that a "no" answer to Question 4 cannot conclude that the costs of an asset are linked with serving a single customer's demand (i.e., the traditional definition of a Local cost relied on by the Commission) should be entirely allocated to the Local cost category because there is a possibility, or even likelihood, that the asset was built to serve a local peak consisting of the aggregate demands of hundreds or thousands of customers that are not coincident with the overall system peak. Further, AEEI asserts that an allocating large swathes of costs to Local due to answering "no" to Question 4 would be contrary to the Commission's long-held definition of local costs as those needed to serve an individual customer, and the ACOS Methodology Order's clear statement that the Decision Tree was not intended to allocate costs of assets sized to meet the aggregate demand of multiple customers to the Local cost category.

Cubit

Cubit states that it owns and operates an 11 MW CHP site on Staten Island, which is interconnected to the Con Edison distribution system, and sells its energy into the NYISO market through Con Edison's Wholesale Distribution Service (WDS) tariff. Cubit states that the WDS tariff consists of a specified rate that customers pay (WDS Rate), and an agreement which sets for the terms and conditions for provision of service by Con Edison. Cubit states that the WDS tariff is filed under the Federal Energy Regulatory Council's (FERC) jurisdiction, however, FERC has historically set the WDS Rate based on the standby and buyback service rates approved by the Commission, deferring to the Commission's regulatory process to set reasonable rates for service between utilities and WDS tariff customers.

Cubit notes that Con Edison's proposed rates would result in significantly lower buyback service rates, which are also used for setting the WDS Rate. Cubit states that the updated rates, as low as one seventeenth of the present rates, would reduce the WDS Rate that Cubit pays between 70 percent and 97 percent. However, Cubit expresses concern with Con Edison's proposal to wait to make the proposed rates available to customers until September 2023 due to technical limitations resulting from the need to migrate to a new billing system to automate billing. Cubit questions why Con Edison should not manually bill affected customers until automated billing is available, and states that it understands that Con Edison presently bills Cubit through a manual process. Cubit requests that the Commission approve the standby and buyback service rates proposed by Con Edison, and requests that the Commission direct Con Edison to implement those rates in advance of the forecast September 2023 timeline proposed by Con Edison in its filing. Further, Cubit requests that the Commission direct Con Edison to retroactively apply the proposed buyback service rates to the date Con Edison filed its proposed rates, July 14, 2022, by directing Con Edison to issue Cubit a refund against difference between present rates and the proposed rates.

Cubit requests that the Commission direct Con Edison to provide more clarity and transparency in how it uses the Commission-approved retail delivery rates to develop the WDS Rate that Con Edison files for approval with FERC. Cubit states that it is unclear which customer groups in Con Edison's buyback service class, SC-11, are used to calculate the WDS Rate, or how Con Edison weights buyback demand charges within those customer groups to develop the WDS Rate. Cubit argues that it should not have to undergo a lengthy discovery process through the FERC proceeding to seek on-the-record information about how Con Edison calculates the WDS Rate, and requests that the Commission direct Con Edison to disclose the inputs and methodology it uses to develop the WDS Rate.

In its April 13, 2023 supplemental comments, Cubit reasserts its requests expressed above, and also requests that the Commission either: (1) accept Con Edison's filed Standby and Buyback Service rates with any justified downward adjustment retroactive to July 14, 2022; or (2) file comments to express support or non-opposition to FERC's acceptance of Cubit's complaint for a reduction in the WDS Rate in the docket of Cubit's then-forthcoming request for rehearing at FERC by May 12, 2023. Cubit explains that the WDS Rate represents its single highest operational expense, and, if approved by FERC, an updated WDS Rate based on Con Edison's proposed Standby and Buyback Rates would result in a decrease of approximately 70 percent in Cubit's monthly service charges. Cubit asserts that the Commission's input is essential to maintain Cubit's only remaining procedural vehicle to challenge Con Edison's current WDS Rate as unjust and unreasonable, and states that it cannot wait until Con Edison's proposed implementation date of September 1, 2023, or beyond for the updated Standby and Buyback Service rates to go into effect, followed by additional delays for FERC to approve an updated WDS Rate.[45]

[45] As shown in FERC's March 16, 2023 Order Denying Complaint, which Cubit attached to its supplemental comments, Con Edison commits to filing an updated WDS Rate schedule for FERC consideration once the Commission's review of its proposed rates is complete.

Energy Spectrum

Energy Spectrum states that it represents an existing standby service customer that became eligible for the Reliability Credit adopted by the Commission in its January 21, 2017 Con Edison Rate Order, and has earned a credit under that program each year thereafter. Energy Spectrum notes that Con Edison proposes to phase out the Reliability Credit for existing customers alongside a six-year phase in of updated standby service rates, and that the Reliability Credit would be eliminated following that phase in period or if a customer elects to use the updated standby service rates. Energy Spectrum recommends that the Commission review the plan to eliminate the Reliability Credit and authorize continuation of such for its original purpose of incentivizing customers to favor demand-reducing measures during the critical summer period.

NY-BEST

NY-BEST recommends that the Commission approve the utilities' filed ACOS studies and associated rates and draft tariffs, with certain modifications and clarifications. NY-BEST identifies two areas of clarification needed for the present filings, and identifies two areas for future improvement.[46]

[46] NY-BEST also identifies a third area of clarification for the present filings, noting that O&R's filing did not include information regarding SC 25 Rate 3 which is applicable to standalone energy storage systems sized between one and five MW, among other types of customers as well. As part of O&R's latest rate plan, the standby service rates which had previously been separated into their own service class, SC 25, have been incorporated as a rate option into the parent service class. What had previously been SC 25 Rate 3 is now the "Standby Service Rates" option of SC 9. (continued...)

First, NY-BEST states that it is disheartened that some of the utilities' filed rates, as proposed, would not become available for customer participation until September of 2023. NY-BEST disagrees that this delay is necessary, and requests that the Commission direct the utilities to make the updated rates and tariffs effective and available to customers no later than 30 days following the effective date of this Order.

Second, NY-BEST requests that the Commission clarify rules regarding whether customers participating in NWA projects are eligible for the Buyback Exemption established in the ACOS Methodology Order. NY-BEST states that the ACOS Methodology Order was very clear that energy storage systems participating in existing NWA projects are not eligible for the Buyback Exemption, but request further clarity regarding whether energy storage projects would be eligible for the Buyback Exemption if they participate in future NWA projects. NY-BEST requests that the Commission explicitly state whether the energy storage systems participating in new NWA projects are eligible for the Buyback Exemption.

Third, as a future action NY-BEST recommends that the Commission re-examine Decision Tree Question 4. NY-BEST states that in their respective filings, Con Edison, National Grid, and O&R each intentionally answered Decision Tree Question 4 incorrectly, inputting "yes" instead of "no." NY-BEST states that it supports Con Edison, National Grid, and O&R's decision to answer "yes" to Question 4, as answering "no" would result in an allocation of network costs to the Local category in opposition to the spirit of the ACOS Methodology Order. NY-BEST

See Case 21-E-0074, et al., O&R – Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans, with Additional Requirements (issued April 14, 2022).

asserts that Con Edison, National Grid, and O&R's decision to purposefully answer Question 4 incorrectly recognizes that the phrasing of Question 4 fails to achieve the intended distinction between shared and local equipment in the Decision Tree. NY-BEST requests that the Commission further explore this issue with stakeholders and utilities to work together to clarify application of Question 4, either as part of future discussions in this Proceeding or through separate guidance.

Fourth, as a future action NY-BEST requests that the Commission examine the 1,500 kW demand threshold used for determining if a Con Edison customer takes service under SC 9 Rate IV or Rate V.[47] NY-BEST explains that there is a significant difference between the rates charged by Con Edison under SC 9 Rates IV and V for both Low Tension customers, which would pay a Contract Demand Charge under Rate V of approximately half the rate for Rate IV, and High Tension customers, which would pay a Contract Demand Charge under Rate V of approximately double the rate for Rate IV.[48] NY-BEST states that the significant differences in Contract Demand Charge rates between the Low Tension and High Tension rates near the 1,500 kW break-point would result in an inappropriate bias for energy storage systems to be sized less than 1,500 kW and interconnect to the High Tension system. NY-BEST states that, to the best of its knowledge, the 1,500 kW break-point between SC 9 Rates IV and V has been in place since at least 2004, and has not been

[47] SC 9 Rate IV is for customers with demand less than 1,500 kW, while SC 9 Rate V is for customers with demand greater than or equal to 1,500 kW.

[48] NY-BEST notes that a Low Tension customer would pay a Contract Demand Charge of $8.04 per kW under SC 9 Rate IV, versus $4.33 per kW under Rate V. High Tension customers would pay a Contract Demand Charge of $0.50 per kW under SC 9 Rate IV, versus $2.32 per kW under SC 9 Rate V.

discussed at length in rate proceedings since. Therefore, NY-BEST requests that the Commission direct Con Edison to examine the purpose and justification for the 1,500 kW break-point between SC 9 Rates IV and V, and either eliminate or fully justify its purpose and how it is aligned with cost causation.

LEGAL AUTHORITY

The Public Service Law (PSL) grants the Commission broad legal authority to prescribe regulatory requirements necessary to carry out the provisions contained therein. For instance, PSL Section 5(1) grants the Commission jurisdiction over the sale or distribution of electricity. Furthermore, PSL Section 5(2) permits the Commission to "encourage all ... corporations subject to its jurisdiction to formulate and carry out long-range programs, individually or cooperatively, for the performance of their public service responsibilities with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources."

Pursuant to PSL Section 65(1), every electric corporation must safely and adequately "furnish and provide [electric] service, instrumentalities, and facilities as shall be safe and adequate and in all respects just and reasonable." Section 66(1) extends general supervision to electric corporations having authority to maintain infrastructure "for the purpose of ... furnishing or transmitting electricity." Pursuant to Section 66(2), the Commission may "examine or investigate the methods employed by ... corporations ... in manufacturing, distributing, and supplying ... electricity," as well as "order such reasonable improvements as will best promote the public interest ... and protect those using ... electricity."

DISCUSSION

The Commission finds that the Utilities' July 2022 Filings are generally consistent with the requirements set forth in the March 2022 Orders, and therefore, with several specific exceptions noted below, accepts the results of the Utilities' ACOS studies, redesigned Standby and Buyback Service rates, and other tariff modifications needed to implement such redesigned rates. While there are several areas which require further development, the Commission agrees with AEEI, Cubit, and NY-BEST that the July 2022 Filings should be accepted, with certain modifications, to avoid further delay of the significantly improved Standby and Buyback Service rates.

ACOS Studies

The Commission finds that the Utilities generally followed the Decision Tree methodology to develop their respective ACOS studies, but directs that future ACOS studies include a rationale for each Decision Tree response. The purpose of the ACOS Studies and Decision Trees is to develop a rational and reasoned basis for the allocation of costs between Customer, Shared, and Local categories. As stated in the 2019 Standby Rate Order, the Commission expects the Utilities to provide supporting data to justify their proposed assignment of costs between Shared and Local cost categories.[49] In the ACOS Methodology Order, the Commission placed responsibility for filing ACOS studies and defending the reasonableness of the proposals within such study squarely with the Utilities.[50] Put simply, the rationale of *why* the answer to a Decision Tree question is "yes" or "no" is just as important to the process of

[49] 2019 Standby Rate Order, p. 28.

[50] ACOS Methodology Order, p. 38.

developing an ACOS study as the answer to the question itself, and such narrative must be provided in future ACOS studies.

While most of the Utilities accurately answered the Decision Tree questions for each combination of interconnection voltage and service classification, National Grid answered Decision Tree questions for each interconnection voltage level, then applied the Decision Tree answers applicable to each interconnection voltage to the service classifications interconnecting at that voltage level. National Grid's procedure produces the same answers to Decision Tree questions for each service class interconnecting at the relevant voltage level because it applied the same answers to all service classes at the voltage level, as opposed to through careful consideration of the Decision Tree questions for each combination of service class and voltage level. As discussed in the ACOS Methodology Order, the Decision Tree Methodology is intended to be granular enough to produce different answers to Decision Tree questions for different service classes interconnecting at the same voltage level if warranted, for example, as a result of their differing use of the system.[51] Future ACOS studies shall be performed to separately determine answers to Decision Tree questions for each combination of interconnection voltage level and service classification.

The Commission agrees with Con Edison, National Grid, and O&R's proposal to answer Question 4 as "yes" for the purposes of their respective filings, and agrees with AEEI and NY-BEST that re-examination of Question 4 and further modifications to the Decision Tree Methodology are required. The Commission accepted Question 4 in the ACOS Methodology Order based on the rationale that Question 4 would work as intended.

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[51] ACOS Methodology Order, p. 49.

Question 4 considered whether equipment would experience peak loads during the system-coincident peak hour, while other relevant peak hours were considered by Question 5. The Commission stated that "Question 4 considers only coincident peak demand by design, since Question 5 considers other non-coincident demands." While it is true that Questions 4 and 5 examined how the same piece of infrastructure under different demand conditions is as intended, the ACOS Methodology Order missed the critical importance of the order of the Decision Tree Questions 4 and 5, and also missed the flaw in the reasoning that any piece of equipment, where an increase in the coincident peak demand does not increase costs, must be entirely Local.

While the Commission agrees that revisions to the Decision Tree Methodology are necessary to fix the issues with Question 4, we find that there is not enough information presently on the record to implement an immediate fix with a high degree of certainty. NY-BEST offers a helpful suggestion that the Commission accept Con Edison, National Grid, and O&R's ACOS studies now, and provide further guidance for development of future ACOS studies in a future Commission order – we find this to be a reasonable step forward. Therefore, the Commission directs Department of Public Service Staff to expediently develop a recommendation for alleviating the issues with Question 4 of the Decision Tree Methodology for public comment and Commission consideration. The Utilities are expected to use the resulting updated Decision Tree Methodology as the basis of the next ACOS study following the Commission's determination on Department of Public Service Staff's recommendation directed herein.

While Con Edison and O&R did provide a rationale for their answers to Decision Tree Question 5 ("does an increase in non-coincident peak demand increase the costs?"), the Commission finds it useful to comment on those Companies' rationale.[52] In essence, both Con Edison and O&R assert that the answer to Question 5 is "yes" because their respective ECOS studies incorporate class NCP demands into the allocator for primary demand-related and secondary demand-related costs. A more complete rationale would provide information as to *why* the allocator includes NCP demands and how those NCP demands drive cost causation for the specific pieces of equipment being considered.

Similarly, the Commission finds it necessary to comment on Con Edison and O&R's rationale for their answers to Decision Tree Question 6 ("could a kW of reverse power flow increase the costs?"). Con Edison and O&R argue that, to the extent that a kW of reverse power flow requires the use of the their respective grids, Buyback Service customers should contribute to grid costs. The Commission agrees, but only to the extent that Buyback Service customers' use of the grid imposes costs – customers should not be charged solely for use of the grid if there are no identifiable or quantifiable costs caused by that usage. Therefore, for future ACOS studies, costs associated with reverse power flow, if any, shall be clearly identified and quantified.

Furthermore, Con Edison and O&R's argument that "[w]hile any one customer's reverse power flow may not trigger upgrades, the combined injections of multiple customers can cause both voltage and thermal violations which would require that upgrades that impose system costs" ignores both the long-

[52] Although the Commission accepts Con Edison and O&R's ACOS study for the purposes of this Order, discussion of the Commission's expectations for the rationale used as the basis for answers to Decision Tree questions should provide helpful context and guidance for future ACOS studies.

standing definition of Local costs.[53] Opinion 01-4 provided a general definition of Local facilities as "those [facilities] that are closer to a customer's site and were put in place mostly to serve the individual customer."[54] The ACOS Methodology Order directed that Local costs apply for most service classes to those costs required to serve a single customer, whereas for the residential service class local costs would apply to costs required to serve small groups of no more than 10 customers.[55] Con Edison and O&R's arguments relying on unidentified costs imposed by the "combined injections of multiple customers," therefore, conflicts with the Commission's guidance and therefore should be improved upon in future ACOS filings. If costs associated with reverse power flow can be satisfactorily identified and quantified, they should rightfully be included in Buyback Rate development.

As-Used Daily Demand Charge Rate Design

As noted above, the Commission disagrees with Con Edison and O&R's assertion that their 10-hour Super-Peak As-Used Daily Demand periods were approved as part of the Rate Design Order. While the Rate Design Order directed Con Edison and O&R to propose Super-Peak As-Used Daily Demand periods and associated charges for mass market customers, the Rate Design Order neither specifically approved nor specifically denied either Con Edison or O&R's proposed Super-Peak As-Used Daily Demand periods for commercial and industrial customers. The Commission's silence on design of the specific Super-Peak As-

[53] Case 99-E-1470, Proceeding on Motion of the Commission as to the Reasonableness of the Rates, Terms and Conditions for the Provision of Electric Standby Service, Opinion No. 01-4 (issued October 26, 2001) (Opinion 01-4), p. 3.

[54] Opinion 01-4, pp. 8, 15-16.

[55] ACOS Methodology Order, p. 52.

Used Daily Demand periods was intentional, since the Utilities were directed to make changes to their proposals for mass market customers, while the Commission would be later revisiting both the rate levels and rate design characteristics. This Order is the appropriate venue for the Commission's holistic review of the Utilities' Standby Service, Buyback Service, and mass market optional demand rate proposals. Therefore, despite Con Edison and O&R's incorrect assertion that the Commission had approved their respective Super-Peak As-Used Daily Demand periods and associated charges, those issues were not already settled and are open for consideration in this Order for all Utilities.

The 2019 Standby Rate Order directed Central Hudson, National Grid, NYSEG, O&R, and RG&E to develop "more granular" As-Used Demand Charges with Off-Peak, On-Peak, and Super-Peak periods, and, in lauding Con Edison's Rider Q four-hour granular and location-based As-Used Daily Demand Super-Peak period, established an expectation, but not a requirement, that Super-Peak As-Used Daily Demand periods should be meaningfully more granular than the existing On-Peak As-Used Daily Demand periods.[56] Further, the Rate Design Order explained that Con Edison's Rider Q represented a significant improvement in time-varying price signals by establishing Super-Peak periods that aligned with that utility's CSRP Call Windows by network.

As shown in Appendix B, Summary of Proposed As-Used Daily Demand Periods, which are applicable to all service classes, Central Hudson, National Grid, NYSEG, and RG&E each propose four- or five-hour Super-Peak periods, whereas both Con Edison and O&R propose ten-hour Super-Peak periods. The Super-

[56] 2019 Standby Rate Order, pp. 33-34. Con Edison's Rider Q pilot program allows customers to opt into granular four-hour Super-Peak As-Used Daily Demand periods corresponding to the four-hour Commercial System Relief Program (CSRP) Call Windows applicable to the customer's location.

Peak periods proposed by Central Hudson, National Grid, NYSEG, and RG&E are in nearly-perfect alignment with the four-hour Call Windows for each utility's CSRP peak-shaving demand response program, and Con Edison's ten-hour Super-Peak period is in rough alignment with its CSRP Call Windows.[57] The Commission finds that four- and five-hour Super-Peak As-Used Daily Demand periods proposed by Central Hudson, National Grid, NYSEG, and RG&E, each of which represents significant overlap with each utility's CSRP Call Window, to be reasonable for each of those utilities.

Deeper consideration is necessary in determining whether the ten-hour periods proposed by Con Edison and O&R are reasonable. Con Edison's system is characterized by concentrations of many customers with similar load characteristics located in different parts of its service territory, leading to that Company having four applicable four-hour CSRP Call Windows throughout its service territory.[58] For example, mid-town Manhattan's overall load characteristics are driven predominantly by large office buildings, resulting in local peak demands in the late morning to early afternoon, whereas highly residential portions of Brooklyn and Queens experience peak demands significantly later in the evening.[59]

While the Commission is unclear on which significant demand peaks need to be managed from the 8 a.m. to 11 a.m.

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[57] Central Hudson, National Grid, NYSEG, O&R, and RG&E each have a CSRP Call Window between 2 p.m. and 6 p.m. during summer non-holiday weekdays.

[58] Con Edison's CSRP Call Windows are from 11 a.m. to 3 p.m., 2 p.m. to 6 p.m., 4 p.m. to 8 p.m., and 7 p.m. to 11 p.m., depending on the local conditions of each area.

[59] Most highly Commercial areas experience peak load conditions during either the 11 a.m. to 3 p.m. or the 2 p.m. to 6 p.m. Call Windows, and most highly residential areas experience peak loads during either the 4 p.m. to 8 p.m. or the 7 p.m. to 11 p.m. Call Windows.

period, Con Edison's 8 a.m. to 6 p.m. Super-Peak period fully, or mostly, covers the CSRP Call Windows applicable to nearly the entirety of Con Edison's service territory.[60] Con Edison's existing Super-Peak period precedes the 2019 Standby Rate Order and that Order did not direct Con Edison to make any changes to that Super-Peak period. Requiring significant changes to the existing Super-Peak period would likely result in significant bill impacts, which have not yet been studied for Con Edison's 51 current Standby Service customers. In addition, Rider Q remains a viable option for customers to participate in for a more temporally and locationally granular As-Used Daily Demand Charge. Therefore, since Con Edison was not directed to establish a more granular Super-Peak period in the 2019 Standby Rate Order, the pre-existing Super-Peak period covers a significant majority of the range of CSRP Call Windows applicable in Con Edison's service territory, and Con Edison customers continue to have the option to participate in Rider Q, the Commission finds that Con Edison's pre-existing Super-Peak As-Used Daily Demand period remains reasonable and should be approved.

While Con Edison's proposed ten-hour Super-Peak period is reasonable, O&R's proposed ten-hour Super-Peak period is not reasonable based on the same rationale. Where Con Edison's CSRP Call Windows cover a 12-hour period from 11 a.m. to 11 p.m. in various areas of its service territory, O&R has only a single

[60] Prior to the COVID-19 pandemic, the 7 p.m. to 11 p.m. included a significant portion of the highly residential portions of Con Edison's service territory in Brooklyn and Queens. Due to changes in load characteristics from the pandemic, only one area in Con Edison's service territory, Randall's Island, presently has a 7 p.m. to 11 p.m. CSRP Call Window.

CSRP Call Window from 2 p.m. to 6 p.m.[61] Con Edison's ten-hour Super-Peak period has only three of the ten hours occurring outside of an applicable CSRP Call Window, whereas O&R's would have six of the ten hours occurring outside of a typical CSRP Call Window. O&R does not have a pre-existing Super-Peak As-Used Daily Demand period, and presently only has one Standby Service customer.[62] O&R customers do not have a Rider Q equivalent more-granular rate design option to choose from.

In its September 2019 Filing, O&R explained that it selected 6 p.m. as the terminus for the Super-Peak period because the majority of summer peaks occurred at 6 p.m. or earlier in the previous three years – the Commission finds O&R's rationale for ending the Super-Peak period at 6 p.m. to be logical and supported by actual load data. On the other hand, in its September 2019 Filing, O&R explains that it chose to retain the 8 a.m. starting point of the Super-Peak period to be consistent with the start time of its On-Peak period for its existing Standby Service rates – the Commission finds this determination to be arbitrary and was not supported by data demonstrating peak load conditions during the early hours of the day. Therefore, the Commission finds that O&R's proposed ten-hour Super-Peak As-Used Daily Demand Charge is unreasonable since there is no compelling evidence that a period two-and-a-half times as long as the typical CSRP Call Window is necessary.

[61] O&R's electric tariff does not define a specific CSRP Call Window. However, no CSRP Planned Events have been called outside of the 1 p.m. to 6 p.m. window typical for New York utilities, with the exception of Con Edison, since the inception of the CSRP at O&R in 2015.

[62] O&R's single Standby Service customer is just as deserving of protection from significant bill impacts as Con Edison's 51 customers, however, this statement illustrates that the impacts of changes to rate design on customers is potentially more severe in total at Con Edison than at O&R.

In this Order the Commission requires O&R to redesign its Super-Peak As-Used Daily Demand period and associated charge with a more specific set of requirements, and make other rate design changes as necessary, as part of the compliance tariff filing discussed in greater detail below.[63] While the Commission does not find sufficient evidence on the record, to date, to dictate a specific number of hours or which specific hours during the day the Super-Peak period must apply during, the Super-Peak period should closely match the applicable CSRP Call Window. Any deviation in the Super-Peak period from the CSRP Call Window must be accompanied by a compelling rationale and evidence demonstrating that a different or longer Super-Peak period is necessary.

Buyback Exemption and participation in NWAs

In the ACOS Methodology Order, the Commission directed the Utilities to implement the Buyback Exemption such that customers already participating in existing NWA projects would not be eligible to also participate in the Buyback Exemption.[64] The purpose of the restricted eligibility for the Buyback Exemption was to prevent customers who had already negotiated the terms and conditions of their participation in an NWA project from earning a windfall by first negotiating a high contract price to participate in the NWA project prior to implementation of the Buyback Exemption, then achieving significant unanticipated cost savings through the Buyback Exemption, both of which would be funded by other customers. Both counter-parties to future NWA project procurement contracting negotiations will be able to “price in” the value of

[63] O&R will need to modify its On-Peak As-Used Daily Demand period and associated charge, for example, to accommodate changes to the Super-Peak period directed in this Order.

[64] ACOS Methodology Order, pp. 131-132.

the Buyback Exemption, which is why it is reasonable for future NWA project participants to also participate in the Buyback Exemption. The Commission reaffirms that customers who participate in NWA projects will be eligible to also receive the Buyback Exemption, provided that the contract specifying terms for such participation was executed no earlier than March 16, 2022, the effective date of the ACOS Methodology Order.

Although the restriction for customers already participating in NWA projects was discussed specifically, the ACOS Methodology Order could have been more clear, and as a result, none of the Utilities accurately implemented the eligibility restriction for the Buyback Exemption.[65] Con Edison, NYSEG, O&R, and RG&E did not include any restriction against existing NWA project participants also participating in the Buyback Exemption, whereas Central Hudson and National Grid included language which would restrict any customer from simultaneously participating in any NWA project and the Buyback Exemption. Considering the inconsistent treatment of eligibility requirements for the Buyback Exemption in the Utilities' draft tariffs, the Commission finds NY-BEST's request for clarity and specificity on whether customers participating in future NWA projects would be eligible to also participate in the Buyback Exemption to be salient and necessary. Therefore, the Commission reaffirms that customers who participate in NWA projects shall be eligible to also receive the Buyback Exemption provided that the contract specifying terms for such participation was executed no earlier than March 16, 2022, the effective date of the ACOS Methodology Order. Central Hudson,

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[65] The proposal to exclude certain NWA project-participants from the Buyback Exemption is described on page 105 of the ACOS Methodology Order, whereas discussion of customer eligibility to participate in both NWA projects and the Buyback Exemption is on pages 131-132.

Con Edison, National Grid, NYSEG, O&R, and RG&E are directed to file tariff revisions updating and specifying the eligibility requirements of the Buyback Exemption as stated above.

Purchases of Capacity through Buyback Service

The Commission finds merit in National Grid's concern that applying Alternative 1 to that Company's existing fleet of capacity purchase agreements through Buyback Service would result in an improper windfall for hydroelectric generating stations. At its core, the issue revolves around the fact that Alternatives 1 and 2 were designed based on the typical generating characteristics of solar PV systems, whereas hydroelectric generating facilities are likely to have higher capacity factors.[66] As a result, every kW of nameplate hydroelectric generation capacity installed produces significantly more energy than an equivalently-sized solar PV system, while simple application of Alternative 1 or Alternative 2 would compensate such systems based on assumptions applicable to solar PV generation. The Commission is persuaded that further action is necessary to remedy the windfall that hydroelectric generators, and other non-dispatchable resources with typical capacity factors meaningfully higher than those of typical solar PV systems, would receive.

While the impacts provided by National Grid are convincing that hydroelectric generators should not receive capacity payments under an Alternative 1 or Alternative 2 structure, without modification, National's Grid's proposed remedy to apply Alternative 3 to non-dispatchable hydroelectric generation is not persuasive. First, National Grid's proposal

[66] Case 15-E-0751, Order on Net Energy Metering Transition, Phase one of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017), pp. 99-100, 102 (Value Stack Order); Case 15-E-0751, Order Regarding Value Stack Compensation (issued April 18, 2019), pp. 30-32.

constitutes an upending of the long-established policy that intermittent resources should be compensated under either Alternative 1 or Alternative 2, which take into account a resource's lack of control over the amount of electricity generated in any given hour, without sufficient rationale other than the fact that such resources would receive a windfall under Alternative 1.[67]

Of the 13 hydroelectric generators which would be affected by a change in capacity payment methodology, seven such units would experience decreased capacity payments under Alternative 3 compared to their present contracts.[68] Of the units negatively impacted, three units would experience payment reductions between 29 percent and 37 percent, two units would experience payment reductions of approximately 60 percent, and two generators would experience payment reductions of 80 to 100 percent. Of the units which would experience an increase in payments under Alternative 3 compared to their current contracts, two customers would be better off under Alternative 3 even than taking payment at Alternative 1, and four customers would receive higher capacity payments than their current contracts under either Alternatives 1 or 3. However, Alternative 1 would provide a higher payment than Alternative 3.

While the overall impact of use of Alternative 3, considering the impacts of both customers that would be harmed by and benefit from use of Alternative 3, is a reduction in capacity payments of approximately 30 percent, those customers harmed by use of Alternative 3 would experience reductions in capacity payments of approximately 60 percent on average. The

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[67] Value Stack Order, p. 102.

[68] While National Grid shows that there are 15 hydroelectric generators taking Buyback Service from it, units 9 and 10 are not impacted by changes in capacity compensation methodology.

Commission finds it inappropriate to direct such a significant change as part of this Order on procedural grounds. Fundamentally, the July 2022 Filings were required by the Commission to implement determinations which had been considered settled in the ACOS Methodology Order and the Rate Design Order. Customers were not provided sufficient notice that the Commission would potentially be re-opening issues settled in the previous orders, and, indeed, no stakeholders commented on National Grid's proposal to modify capacity payment methodologies for non-dispatchable resources despite clear impacts to an industry represented by frequently-vocal trade groups with a clear financial stake in the outcome of National Grid's proposal.

While the Commission is persuaded that simple application of Alternative 1 and Alternative 2 to non-dispatchable generating technologies with a higher capacity factor than solar PV is unreasonable, and finds insufficient basis to consider National Grid's proposal to apply only Alternative 3, the Commission has previously grappled with similar issues in the December 12, 2019 Order Regarding Value Stack Compensation for High-Capacity-Factor Resources in this proceeding (High Capacity Factors Order). In the High Capacity Factors Order, the Commission considered similar issues related to the application of the Market Transition Credit (MTC) and/or Community Credit by dispatchable fuel cell resources, and adopted a capacity factor-based adjustment factor intended to right-size the MTC and Community Credit payments available to high capacity factor generators.[69] In the High Capacity Factors Order, the Commission decided not to adjust the MTC or Community Credit available to hydropower and wind generation units,

[69] High Capacity Factors Order, pp. 14-15.

despite recognizing their higher typical capacity factors in comparison to solar PV, but instead directed Department of Public Service Staff to monitor interconnection queues and Value Stack participation levels and to recommend further changes to generator compensation as appropriate.[70]

The Commission directs Department of Public Service Staff to expeditiously develop a recommendation to remedy the windfalls that high capacity factor non-dispatchable resources would receive for public comment and Commission consideration. This further process for the Commission to consider the Department of Public Service Staff's recommendation will also ameliorate the procedural deficiencies noted above regarding consideration of National Grid's proposal. Until this issue is resolved, the Utilities are directed to maintain their present methodologies for determining capacity payment rates. In the interim, the Utilities shall, however, allow any customer that wishes to choose to receive payment based on Alternative 3 to do so, with the caveat that once a customer selects Alternative 3 that customer will be unable to move back to either Alternative 1 or 2.

Implementation Timeline

Each of the Utilities proposes to wait to begin billing customers under the updated Standby and Buyback Service rates, and implementing the mass market optional demand rate, until after billing can be automated, which few exceptions.[71]

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[70] High Capacity Factors Order, pp. 15-16.

[71] O&R states that it can bill commercial and industrial customers under the updated Standby and Buyback service rates through an automated process after eight months, but could bill manually after three months. Similarly, National Grid states that it could automate Buyback Service billing after a period of six months, but would manually bill Buyback Customers until then.

The Utilities' proposed timelines for implementing the updated Standby Service, Buyback Service, and mass market optional demand rates are shown in Appendix C.[72]

For commercial and industrial customers, Con Edison, National Grid, and O&R state that they need a period of three months to implement billing at the updated Standby and Buyback Service rates for their existing customers, as well as implement the phase-in for existing customers that choose such option. Central Hudson, NYSEG, and RG&E request longer periods to implement the updated rates – with NYSEG and RG&E requesting ten months to implement the updated rates, or approximately June of 2024, and Central Hudson stating that implementation of the updated rates would not occur until the second half of 2024.

For the new mass market optional demand rates, National Grid states that it could implement automated billing after six months, whereas Con Edison and O&R request eight months to implement the delivery portion of the mass market optional demand charge, NYSEG and RG&E request a period of ten months, and Central Hudson states that it could implement such rates during the second half of 2024. Con Edison and O&R estimate that they would be able to fully implement the hourly supply portion of the mass market optional demand rate by July 1, 2025.

There are three groups of customers that are meaningfully affected by the Utilities' plans to implement the updated Standby Service, Buyback Service, and optional demand rate: (1) existing and new customers that are required to take

[72] Where the utility has specified a number of months following a Commission Order, the estimated first month following that period is provided in parentheses – for example Con Edison estimates that it needs three months to implement billing its existing Standby Service customers, resulting in billing under updated rates in January 2024.

Standby and/or Buyback Service, (2) existing and new commercial and industrial customers that choose to opt into Standby Service as a rate option, and (3) mass market customers that choose to participate in the mass market optional demand rate.

The Commission finds that it is reasonable to require the Utilities to implement the updated Standby and Buyback Service rates as quickly as is feasible for existing commercial and industrial customers that are required to take Standby and/or Buyback Service, including requiring manual billing under the updated rates if necessary. While the Commission appreciates NY-BEST's enthusiasm to begin service under the updated Standby and Buyback Service rates, a 30-day requirement to begin billing under the updated rates is not feasible from either a quality assurance perspective – even manual billing under the updated rates will take time to implement and test for accuracy – and as a consequence of most of the Utilities needing to update their filed rates to account for the revenue requirements of a new rate year. In this regard, Con Edison, National Grid, and O&R's plan to implement the updated Standby and Buyback Service rates for their commercial and industrial customers is reasonable. Central Hudson, NYSEG, and RG&E's plans to delay billing under the updated rates well into 2024, however, are not reasonable. Central Hudson, Con Edison, National Grid, NYSEG, O&R, and RG&E are directed to begin billing existing and new customers required to take Standby and Buyback Service under the updated rates following a three-month implementation period, beginning no later than 90 days after the effective date of this Order.[73]

[73] The Utilities should plan to bill the affected customers manually if their planned implementation of automated billing for such customers extends beyond the 90-day implementation period.

A more measured approach is appropriate for groups of customers that would opt into the updated Standby Service rates as a rate option, since such customers are not required to take service under those rates. The Commission agrees with the Utilities that billing should be automated before customers are allowed to opt-in to the updated Standby Service rates. The Commission is concerned that setting aggressive implementation deadlines for these rate options would have a detrimental effect on implementation of other critical billing issues, such as implementing accurate billing and crediting for Community Distributed Generation projects. Therefore, the Commission will accept the Utilities' planned implementation schedules.

To ensure that the Utilities are paying appropriate attention to automating billing for these optional rates, Central Hudson, Con Edison, National Grid, NYSEG, O&R, and RG&E are directed to report their progress on a quarterly basis until automation of such functions is complete, with the first such report due on or about January 2, 2024.[74] These quarterly reports are not intended to be new onerous reporting requirements, but simple updates providing information on the Utilities' progress toward billing automation based on the timelines summarized in Appendix C, providing an updated forecast of when the utility anticipates completion of such automation, and may be ceased once automation is complete. The Commission may direct corrective action if a utility is not on track to automate distribution charges by the earlier of the forecast timelines summarized in Appendix C, or July 1, 2024.[75]

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[74] The first business day after the close of the fourth quarter.

[75] Automation of hourly supply charges is less critical to proper functioning of the optional demand-based rates. Therefore, the Commission will focus on ensuring that delivery charges are automated in a timely manner.

Tariff Issues and Clarifications

The Commission finds that the Utilities' draft tariffs reasonably implement the redesigned Standby Service, Buyback Service, and mass market optional demand rates, and reasonably implement the other requirements of the 2019 Standby Rate Order, the Rate Design Order, and the ACOS Methodology Order, with several exceptions. Therefore, the utilities draft tariff language is approved, except as discussed below. Given that a significant amount of time has passed since the Utilities made their July 2022 Filings and the effective date of this Order, it is likely that the specific rates and charges proposed in the July 2022 Filings need to be updated, for example to reflect the present year of existing Rate Plans. Therefore, Central Hudson, Con Edison, National Grid, NYSEG, O&R, and RG&E shall file updated tariff leaves reflecting the determinations made in this Order to become effective on a temporary basis on January 1, 2024, on not less than 15 days' notice (Compliance Tariff Filing). Because these tariff leaves are being filed in compliance with this Order, and because Stakeholders have had an opportunity to comment as part of this proceeding, the newspaper publication requirements of PSL §66(12)(b) and 16 NYCRR §720-8.1 shall be waived.

There are several minor tariff issues which bear discussion or require further amendments in Central Hudson, National Grid, and NYSEG and RG&E's draft tariffs. For Central Hudson, it included language on draft leaf 272.5, which would have exempted customers without onsite generation to Contract Demand Exceedance fees, which is unnecessary and shall not be included in Central Hudson's Compliance Tariff Filing. Absolving customers without generating equipment from paying Contract Demand Exceedance fees is problematic for two reasons. First, Contract Demand Exceedance fees are an appropriate counterbalance against the incentive to inappropriately reduce Contract Demand Charges for customers that set their own Contract Demand kW amounts, regardless of the presence or absence of a generator. Contract Demand Exceedance fees are applicable only to customers that set their own Contract Demand kW amount, and are assessed only when such customers exceed the amount of Contract Demand that they elected themselves.[76] Contract Demand Exceedance fees are based on repayment for Contract Demand kW amounts that the customer should have been paying all along, but which that customer had previously avoided due to setting an inappropriately low Contract Demand kW amount. The presence of the Contract Demand Exceedance fee, therefore, acts as a deterrent against customers electing a lower level of Contract Demand than they actually need, and should apply to all customers that set their own Contract Demand kW amounts.

Second, Central Hudson's draft leaf 272.4 establishes that only commercial and industrial customers that operate on-site generation would be eligible to establish their own Contract Demand kW amounts. Therefore, no customer without onsite generation would be able to set their own Contract Demand kW amounts. There is no need to exempt customers without onsite generation from Contract Demand Exceedance fees because Contract Demand Exceedance fees are not applicable to customers without onsite generation since Central Hudson would set the Contract Demand kW for such customer in all instances.

For National Grid, the draft tariffs it submitted as part of the July 2022 Filings did not include a specific description of how it would measure the 60-minute integrated demand for mass market customers. In National Grid's supplemental filing, it explains that it would sum the four 15-

[76] Contract Demand Exceedance fees are not imposed if a customer exceeds the Contract Demand kW amount assigned by the utility.

minute interval meter readings on the hour to determine a mass market customer's 60-minute interval demand. The Commission finds the company's proposed process to measure 60-minute interval demand for mass market customers to be reasonable, and directs National Grid to include such information in the tariff leaves it submits as part of the Compliance Tariff Filing.

For NYSEG and RG&E, those companies included tables defining the various Off-Peak, On-Peak, and Super-Peak As-Used Daily Demand periods on draft tariff leaf 289 for NYSEG and draft tariff leaf 243.1 for RG&E. While each leaf specifically defined weekends and holidays as being part of the Off-Peak As-Used Daily Demand period under the "prior rates" heading, weekends and holidays are not addressed in the "redesigned rates" tables. In their supplemental filing, NYSEG and RG&E clarified that the On-Peak and Super-Peak As-Used Daily Demand periods would only apply during non-holiday weekdays, meaning that weekends and holidays would be considered as Off-Peak. The Commission finds this clarification to be reasonable and necessary. Therefore, NYSEG and RG&E are directed to include such information in their updated tariff leaves submitted as part of the Compliance Tariff Filings.

Other Issues

The Commission declines to act on the requests made by NY-BEST regarding demarcation of Service Classes within Con Edison's tariff, Cubit's request for Commission intercession in FERC proceedings, and Energy Spectrum's request to reconsider phase-out and elimination of the Reliability Credit. Regarding NY-BEST's request that the Commission examine the 1,500 kW demand threshold used for determining if a Con Edison customer takes service under SC 9 Rate IV or Rate V, NY-BEST's request is not germane to implementation of the ACOS study methodology, design of the Contract Demand, As-Used Daily Demand, or Customer charges, or other Standby and Buyback Service or mass market optional demand rate issues the Commission is considering in this proceeding. The Commission declines to undertake the review that NY-BEST seeks as part of this proceeding, and finds that a Con Edison rate proceeding would be an appropriate venue for such an examination.

In its comments, Energy Spectrum states that it is concerned with Con Edison's proposal to phase-out and then eliminate the Reliability Credit, and requests that the Commission review such proposal. Con Edison's proposed phase-out of the Reliability Credit reflected in its July 2022 Filing was directed by the Commission as part of the ACOS Methodology Order, which itself was based on a DPS Staff Whitepaper and multiple rounds of substantive public comments. The Commission completed its review of the proposal to phase-out and eliminate the Reliability Credit as part of the ACOS Methodology Order, and Energy Spectrum provides no compelling rationale or basis for why that determination should be reversed. Therefore, the Commission declines to reconsider the decision to phase-out and eliminate the Reliability Credit as requested by Energy Spectrum.

The Commission declines to intercede on Cubit's behalf in its proceedings before FERC. The Commission also declines to direct Con Edison to retroactively apply the proposed buyback service rates to the date Con Edison filed its proposed rates, and declines to provide a refund to Cubit, as it as requests. Providing any of the relief that Cubit requests would require the Commission to find that the previous rates were unreasonable. The Commission makes no such finding in this Order. While the updated methodology for setting Standby and Buyback Service rates is a significant improvement, the prior methodology for setting Standby and Buyback Service rates were set on a rational basis in 2002 and 2003 based on the information available at the time, were improved incrementally in various proceedings since their inception, and had continued to be set using that basis since then, in the absence of a more compelling basis. Therefore, the Commission will not find that the prior rates were unreasonable, does not find that a refund is justified, and will not interfere with FERC's proceedings as Cubit requests.

CONCLUSION

While some additional work is required to fully cap off the near-decade of sustained effort in the Commission's re-examination of Standby and Buyback Service rates envisioned in the REV Track 2 Order, the updated Standby and Buyback Service and mass market optional demand rates authorized in this Order represent a significant step forward in developing advanced rate design options that most closely and efficiently reflect cost causation.[77] To fully bring the Commission's examination of Standby and Buyback Service rates to a close, in this Order the Commission has accepted the Utilities' ACOS Study results; directed the utilities to file effective tariff leaves to implement the updated rates for new and existing customers that are required to take Standby and Buyback Service as quickly as is feasible, with full implementation of these rates as advanced rate options on an opt-in basis following successful automation of billing processes; and directed Department of Public Service Staff to develop and propose solutions to the final remaining issues regarding correction of the Decision Tree Methodology's Question 4 and to purchases of capacity from high load factor

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[77] Case 14-M-0101, Reforming the Energy Vision, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016) (REV Track 2 Order), pp. 127-130.

non-dispatchable resources through Value Stack Alternative 1 or 2 Capacity Values.

The Commission expects several actions following this Order. First, the Commission is requiring the utilities to file compliance tariffs on a temporary basis. Therefore, the Commission expects to review those temporary tariffs and either accept such tariffs or direct further modifications in a future order.[78] Second, the Commission anticipates addressing the Department of Public Service Staff proposals on updates to the Decision Tree Methodology and purchases of capacity from high-load factor non-dispatchable resources, including opportunities for stakeholder comments, in one or more future Commission orders. Following these upcoming orders, the Commission expects that ACOS Studies using the Decision Tree Methodology will become a standard part of utility rate proceedings, except for proposed methodological changes to be considered on a statewide basis as discussed in the ACOS Methodology Order.[79]

<u>The Commission orders</u>:

1. Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; New York State Electric & Gas Corporation; Niagara Mohawk Power Corporation d/b/a National Grid; Orange and Rockland Utilities, Inc.; and Rochester Gas & Electric Corporation shall provide detailed rationale and explanation to support all answers to Interconnection Voltage and Higher Than Interconnection Voltage Decision Tree questions submitted as part of any Allocated Cost

[78] The Commission anticipates addressing tariff leaves in effect temporarily regarding exemptions to Standby Service rates as directed in the May 18, 2023 Order Continuing and Modifying Standby Rate Exemptions in Case 19-E-0079 as part of the same Order considering the temporary tariffs directed herein.

[79] ACOS Methodology Order, p. 23.

of Service Study performed subsequent to the effective date of this Order.

2. Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; New York State Electric & Gas Corporation; Niagara Mohawk Power Corporation d/b/a National Grid; Orange and Rockland Utilities, Inc.; and Rochester Gas & Electric Corporation shall examine Interconnection Voltage and Higher Than Interconnection Voltage Decision Tree questions separately for each combination of service classification and interconnection voltage level as part of any Allocated Cost of Service Study performed subsequent to the effective date of this Order.

3. Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; New York State Electric & Gas Corporation; Niagara Mohawk Power Corporation d/b/a National Grid; Orange and Rockland Utilities, Inc.; and Rochester Gas & Electric Corporation shall clearly identify any costs associated with reverse power flow as part of answers to Interconnection Voltage and Higher Than Interconnection Voltage Decision Tree questions as part of any Allocated Cost of Service Study performed subsequent to the effective date of this Order.

4. Department of Public Service Staff shall expeditiously develop and submit a recommendation to alleviate the issues associated with Question 4 of the Interconnection Voltage Decision Tree, as described in the body of this Order, for public comment and Commission consideration.

5. Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; New York State Electric & Gas Corporation; Niagara Mohawk Power Corporation d/b/a National Grid; Orange and Rockland Utilities, Inc.; and Rochester Gas & Electric Corporation shall file updated tariff leaves reflecting the determinations made in the body of this

Order to become effective on a temporary basis on January 1, 2024, on not less than 15 days’ notice.

6. Orange and Rockland Utilities, Inc. shall include a redesigned As-Used Daily Demand Super-Peak period, a redesigned Super-Peak period As-Used Daily Demand Charge, and other rate design changes as necessary, to more closely align with typical Commercial System Relief Program call window periods, as described in the body of this Order as part of the temporary tariff leaves filed in compliance with Ordering Clause No. 5.

7. Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; New York State Electric & Gas Corporation; Niagara Mohawk Power Corporation d/b/a National Grid; Orange and Rockland Utilities, Inc.; and Rochester Gas & Electric Corporation shall include tariff language allowing customers who participate in Non-Wire Alternative projects with contracts executed no earlier than March 16, 2022, to simultaneously participate in the Buyback Exemption, as described in the body of this Order, as part of the temporary tariff leaves filed in compliance with Ordering Clause No. 5.

8. Department of Public Service Staff shall expeditiously develop and submit a recommendation to remedy potential windfalls associated with high capacity factor non-dispatchable resources’ participation in either Value Stack Capacity Alternative 1 or 2, as described in the body of this Order, for public comment and Commission consideration.

9. Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; New York State Electric & Gas Corporation; Niagara Mohawk Power Corporation d/b/a National Grid; Orange and Rockland Utilities, Inc.; and Rochester Gas & Electric Corporation shall include tariff language retaining the present methodology for determining

capacity payment rates for high capacity factor non-dispatchable resources, and also allow such resources to voluntarily select to be compensated under Value Stack Capacity Alternative 3, as described in the body of this Order, as part of the temporary tariff leaves filed in compliance with Ordering Clause No. 5.

10. Central Hudson Gas & Electric Corporation shall not include tariff language exempting customers without onsite generation from Contract Demand Exceedance fees, as described in the body of this Order, as part of the temporary tariff leaves filed in compliance with Ordering Clause No. 5.

11. Niagara Mohawk Power Corporation d/b/a National Grid shall include tariff language establishing the 60-minute integrated demand methodology for mass market customers as the sum of four fifteen-minute interval meter reads on the hour, as described in the body of this Order, as part of the temporary tariff leaves filed in compliance with Ordering Clause No. 5.

12. New York State Electric & Gas Corporation and Rochester Gas & Electric Corporation shall include tariff language clarifying the on-peak, super-peak, and off-peak periods applicable to the As-Used Daily Demand Charge for each utility, as described in the body of this Order, as part of the temporary tariff leaves filed in compliance with Ordering Clause No. 5.

13. Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; New York State Electric & Gas Corporation; Niagara Mohawk Power Corporation d/b/a National Grid; Orange and Rockland Utilities, Inc.; and Rochester Gas & Electric Corporation shall begin billing customers required to take Standby or Buyback Service within 90 days of the effective date of this Order.

14. Newspaper publication requirements pursuant to PSL §66(12)(b) and 16 NYCRR §720-8.1 related to the tariff filings directed in Ordering Clause No. 5 are waived.

15. 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.

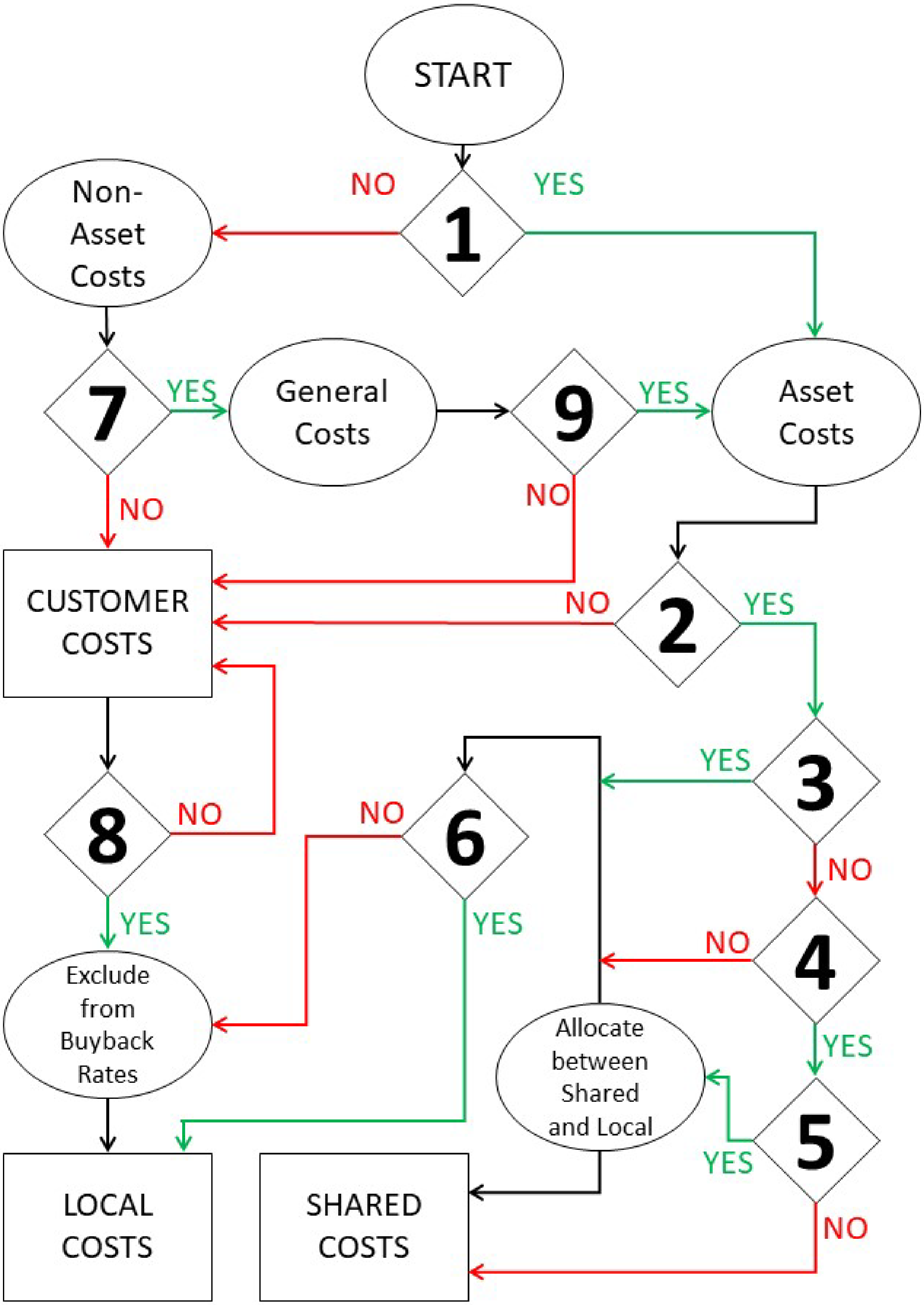
16. This proceeding is continued.

By the Commission,

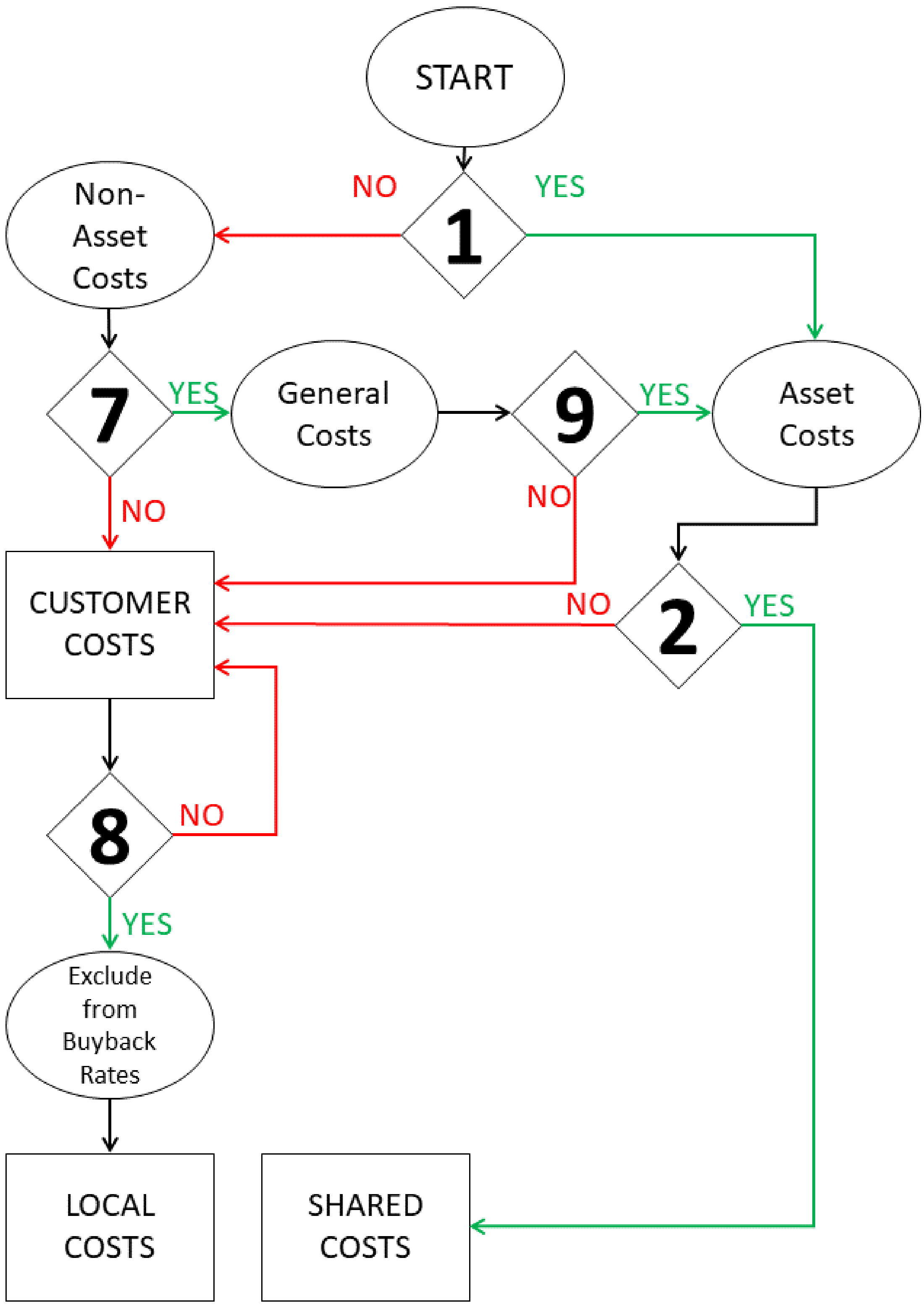
(SIGNED) MICHELLE L. PHILLIPS
Secretary

DECISION TREES

INTERCONNECTION VOLTAGE LEVEL



HIGHER THAN INTERCONNECTION VOLTAGE LEVEL



LEGEND

Question No.	Question Text
1	Is the cost linked to a type of asset?
2	Are all the costs attributable to customer demand?
3	Would a decrease in demand result in entirely unused assets?
4	Does an increase in system coincident demand increase the costs?
5	Does an increase in non-coincident peak demand increase the costs?
6	Could a kW of reverse power flow increase the costs?
7	Does the cost apply to all cost categories?
8	Should the Customer Charge be set to a predetermined level and any difference in costs and revenues be re-allocated?
9	Is the cost a tax related to either a specific asset or cost which varies with customer demand?

SUMMARY OF PROPOSED AS-USED DAILY DEMAND PERIODS

Utility	Summer		Winter		Shoulder
	On-Peak	**Super-Peak**	**On-Peak**	**Super-Peak**	**On-Peak**
Central Hudson[1]	7 a.m. – 11 p.m.	2 p.m. – 7 p.m.	7 a.m. – 11 p.m.	N/A	N/A
Con Edison[1]	8 a.m. – 10 p.m.	8 a.m. – 6 p.m.	8 a.m. – 10 p.m.	N/A	N/A
National Grid	8 a.m. – 1 p.m. and 6 p.m. – 10 p.m.	1 p.m. – 6 p.m.	8 a.m. – 10 p.m.	N/A	N/A
NYSEG	7 a.m. – 2 p.m. and 6 p.m. – 11 p.m.	2 p.m. – 6 p.m.	7 a.m. – 5 p.m. and 9 p.m. – 11 p.m.	5 p.m. – 9 p.m.	7 a.m. – 11 p.m.
O&R	8 a.m. – 6 p.m.	6 p.m. – 11 p.m.	8 a.m. – 11 p.m.	N/A	N/A
RG&E	7 a.m. – 2 p.m. and 6 p.m. – 11 p.m.	2 p.m. – 6 p.m.	7 a.m. – 11 p.m.	N/A	N/A

Notes:

All On-Peak and Super-Peak periods exclude weekends and holidays.

1. Central Hudson and Con Edison's Super-Peak As-Used Daily Demand Charges are additive to On-Peak period As-Used Daily Demand Charges

PROPOSED BILLING IMPLEMENTATION TIMELINES

Task	Central Hudson	Con Edison	National Grid	NYSEG/RG&E	O&R
New Standby Rates for existing and new C&I customers	Second half of 2024	3 months, but not before September 2023 (January 2024)	3 months (January 2024)	10 months (August 2024)	3 months for manual billing (January 2024) 8 months for automated billing but no earlier than January 2024 (June 2024)
Existing Customer Phase-In Rate Option	Second half of 2024	3 months, but not before September 2023 (January 2024)	3 months (January 2024)	10 months (August 2024)	3 months (January 2024)
New Buyback Delivery Charges	Second half of 2024	3 months, but not before September 2023 (January 2024)	6 months, would bill manually as needed (April 2024)	10 months (August 2024)	3 months for manual billing (January 2024) 8 months for automated billing but no earlier than January 2024 (June 2024)
Mass Market Customer Opt-In Delivery Rates	Second half of 2024	8 months, but not before January 2024 (June 2024)	6 months (April 2024)	10 months (August 2024)	8 months, but not before January 2024 (June 2024)
Mass Market customer hourly supply rates	Second half of 2024	July 2025	6 months (April 2024)	10 months (August 2024)	July 2025
Non-MHP C&I customer hourly supply rates	Second half of 2024	July 2025	3 months (January 2024)	10 months (August 2024)	July 2025